Purchase of Offshore Wind Renewable Energy Certificates

NY RFP No. ORECRFP18-1

Table of Contents

Table of Figures

Attachments

1. Resumes
2. Executed Lease OCS-A 0512
3. Landfall and Cable Routing Study
4. Wind Resource Assessment (Equinor)
5. Wind Resource Assessment (KVT)
6. Quantification of Losses and Uncertainty for Offshore Wind Farm Energy Assessments
7. Creditor Letters of Support
8. Tax Analysis
9. Equinor Annual Reports
10. Equinor US Financial Statements
11. Fisheries Survival Fund v. Sally Jewel Opinion
12. Interconnection Evaluation Study
13. Interconnection Information
14. Interconnection One-Line Diagram
15. System Reliability Impact Study
16. Permitting Matrix
17. Stakeholder Tracking Matrix
18. Site Assessment Plan
19. Site Assessment Plan Approval
20. Turbine Certification Plan
21. Confirmation of Certification Plan Feasibility
22. Sample Supplier Declaration
23. Project Master Schedule
24. Main Activity Logic Chart
25. Permitting Schedule
26. Construction Schedule
27. WTG Schedule
28. Foundations Schedule
29. Cables Schedule
30. Electrical System Schedule
31. Marine Operations Schedule
32. Supplier Letters of Support
33. Port Letters of Support
34. Fisheries Liaison & Outline Coexistence Plan
35. Fisheries Outreach Matrix
36. Example Survey Flyer
37. Example Fisheries Newsletter
38. Example Statement of Common Ground
39. Community Letters of Support
40. Empire Wind Press Coverage

41. Visual Simulations
42. GIS Shape Files
43. ICF Economic Benefits Study
44. Supplier Estimates of Job Creation
45. Mark-Up of Draft Agreement

1 EXECUTIVE SUMMARY

Proposers are required to provide an executive summary of the Proposal that documents the eligibility of the proposed Offshore Wind Generation Facility, the proposed Contract Tenor, the overall Project schedule including expected Commercial Operation Date, any contingencies specific to the Proposal or to other Proposals, and other factors Proposers deem to be important.

Equinor Wind US LLC ("Equinor Wind") welcomes the opportunity to submit this proposal to supply offshore wind renewable energy certificates ("ORECs") to the New York State Energy Research and Development Authority ("NYSERDA"). Equinor Wind believes that NYSERDA's procurement of ORECs through this solicitation process has the potential to set New York on the path towards achieving the objectives set out in Governor Cuomo's Green New Deal, including supporting the development of 9 gigawatts ("GW") of offshore wind resources by 2035, creating thousands of high-quality, green energy jobs for New York workers, and positioning New York to take a leading role in driving this dynamic new industry forward throughout the region.

As a leading developer of offshore wind resources, Equinor Wind is excited about the prospect of partnering with New York to bring affordable, low-carbon energy to New York consumers and to help establish New York as a national leader in the offshore wind industry. As discussed further below, Equinor Wind is currently pursuing the development of the Empire Wind offshore wind project in the New York Offshore Wind Area pursuant to a lease issued by the U.S. Department of the Interior, Bureau of Ocean Energy Management ("BOEM"). Located south of Long Island and near the entrance of New York harbor, the lease area is expected to be able to support the development of up to 2 GW of installed generation capacity.

Leveraging over four decades of experience developing complex offshore energy projects and the close proximity of its lease area to New York, Equinor Wind is pleased to submit four offers to supply ORECs to NYSERDA. Equinor Wind's offers in this proceeding are the culmination of almost two years of work by a dedicated and experienced team focused on developing offshore wind resources off the New York coast. As described further herein, Equinor Wind has conducted extensive analyses of the project site, potential layouts and project design, market conditions, and other factors, all with the goal of designing a facility that provides significant value to New York by ensuring that the state's environmental and economic development objectives are met as efficiently and cost-effectively as possible. Figure 1 provides an overview of key elements of Equinor Wind's offers.

Figure 1: Summary of Offers

[redacted]

[redacted]

Each of Equinor Wind's offers has been tailored to allow New York to take a substantial step towards achieving the State's offshore wind development objectives while fostering the growth and development of a supply chain and workforce that has the potential to make New York the hub of the offshore wind industry on the east coast. [redacted]

[1] Throughout this proposal Equinor Wind has highlighted in yellow text that contains confidential information or trade secrets that are exempt from public disclosure. A statement supporting these claims of confidentiality is provided under separate cover.

[redacted]

[redacted]

- [redacted]
- [redacted]

[redacted]

- [redacted]
- [redacted]
- [redacted]
- [redacted]
- [redacted]

In short, Equinor Wind believes that the development of the Empire Wind Project has the unique potential to support New York's renewable development goals while generating significant economic and environmental benefits and giving New York workers and businesses the skills and support necessary to position New York as a hub for the growing offshore wind industry on the east coast.

1.1 Equinor: An Experienced and Dependable Partner

Equinor Wind is a direct, wholly owned subsidiary of Equinor US Holdings Inc. ("Equinor US") and an indirect, wholly owned subsidiary of Equinor ASA (collectively, "Equinor"). Equinor is an international energy company, headquartered in Norway, with operations in 37 countries. Equinor has approximately 22,000 employees worldwide, is listed on the New York and Oslo stock exchanges (NYSE: EQNR, OSE: EQNR), and has a current market capital valuation in excess of $65 billion. With an extensive portfolio of offshore wind, oil, and gas facilities developed over its 40 year history, Equinor has a proven track record of successfully developing large-scale energy projects in some of the most challenging ocean environments around the world.

Recognizing the changing landscape for energy production, Equinor is committed to complementing its existing oil and gas portfolio with an expanding fleet of renewable energy and other low-carbon energy solutions.

With significant in-house capabilities and resources focused specifically on meeting the challenges of offshore energy development, backed by ample financial resources, Equinor is quickly becoming a leader in the development of offshore wind throughout the world:

- Equinor has developed, constructed, and operates two major bottom-fixed offshore wind farms in the United Kingdom ("UK"): (1) the 317 MW Sheringham Shoal offshore wind farm and (2) the 402 MW Dudgeon offshore wind farm.

- Equinor also is the developer, owner, and operator of the 30 MW Hywind Scotland wind farm, the world's first floating offshore wind farm.

- Equinor is a partner in the Arkona project, a 385 MW wind farm located in the Baltic Sea approximately 22 miles from the German coastline, which is in the final stages of development and has started delivering power to the grid.

- Equinor also owns an interest in the Dogger Bank offshore wind farms, a series of proposed projects currently under development in the UK with a projected nameplate capacity of 3.6 GW, as well as the Baltyk projects, a series of projects located in the Baltic Sea with an estimated combined capacity of approximately 3 GW.

Consistent with Equinor's commitment to renewable and low-carbon energy solutions, Equinor also is pursuing the development of offshore wind projects on the east and west coasts of the United States, and is quickly becoming a leader in the growing offshore wind industry in the United States. For example, Equinor recently invested $135 million in acquiring one of three offshore wind lease areas off the coast of Massachusetts.

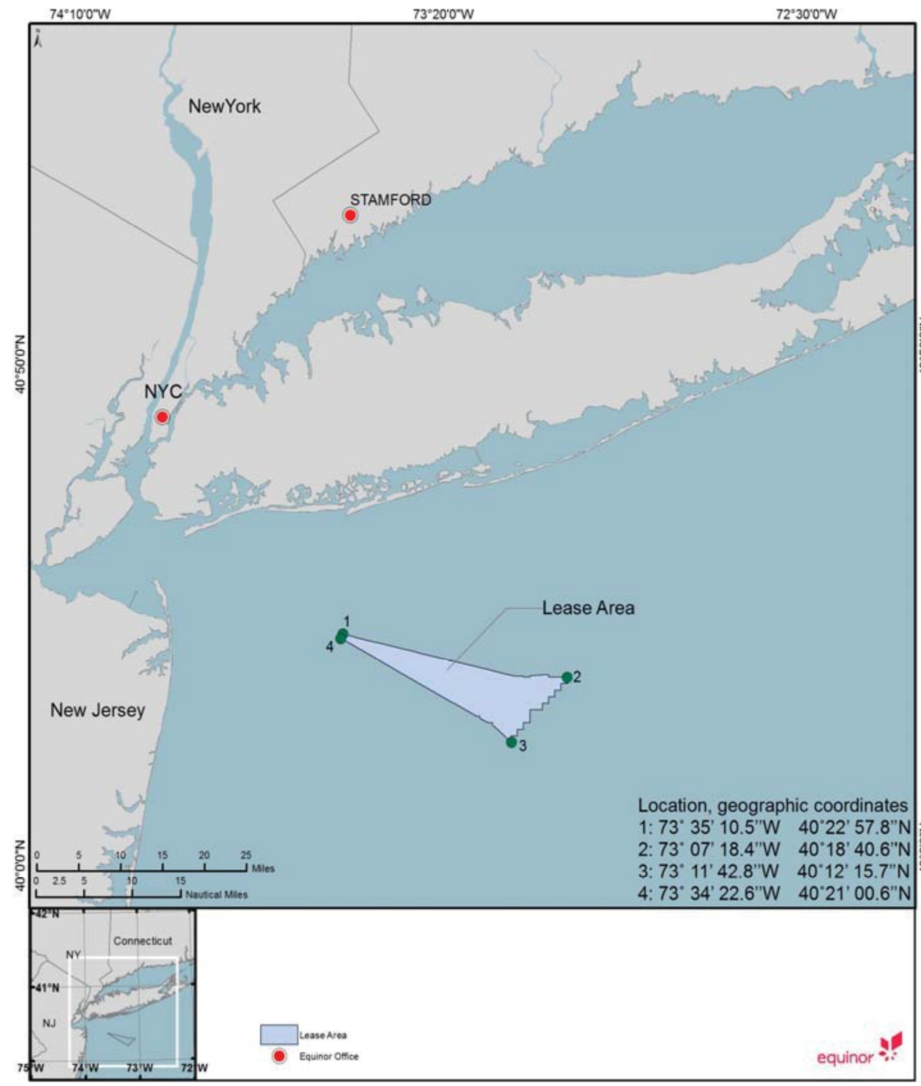
Equinor's history of successfully developing offshore wind projects and its ample financial resources give Equinor Wind several advantages that will allow it to supply offshore wind to New York at an attractive price that provides value to New York ratepayers. These advantages include:

- [redacted]
- [redacted]
- [redacted]

1.2 The Empire Wind Project: Made for New York

The Empire Wind Project is uniquely positioned to help New York efficiently and cost-effectively meet its environmental and economic objectives. As depicted in Figure 2 below, the Empire Wind Project is being developed in an offshore wind lease area located south of Long Island and near the entrance of New York harbor, pursuant to a lease signed and executed by the BOEM on March 15, 2017.

Figure 2: Project Lease Area



The lease area covers approximately 80,000 acres and is expected to support the development of up to 2 GW of installed generation capacity, enough to power more than one million homes.

Since executing its lease, Equinor Wind has been evaluating the potential of the lease area to support the development of offshore wind resources. Equinor Wind has conducted a range of analyses and studies concerning wind resources, metocean conditions, environmental and maritime conditions and constraints, potential submarine cable routes, landfall locations, and interconnection points. Equinor Wind also has had extensive discussions with numerous wind turbine, foundation, and other equipment suppliers in an effort to identify the optimal combination of equipment capable of most efficiently and cost-effectively generating renewable energy while operating reliably in the harsh ocean environment. The proposals set out in this application are the culmination of Equinor Wind's efforts to develop a project that supports New

York's ambitious offshore wind development and environmental objectives, promotes the development of a robust supply chain for offshore wind within New York, and maximizes the value of the Empire Wind Project to New York workers and ratepayers alike.

[redacted]

- [redacted]
- [redacted]
- [redacted]
- [redacted]

At the same time, the Empire Wind Project will use technologies and equipment that have been shown to operate reliably and safely even under the harshest operating conditions. [redacted]

[redacted]

[redacted]

[redacted]

In addition to the extensive efforts made by Equinor Wind to optimize the design of the Empire Wind Project, Equinor Wind is on track to achieve commercial operation on a commercially reasonable timeframe that aligns with New York's environmental objectives. [redacted], including securing approval of Equinor Wind's Site Assessment Plan ("SAP") by BOEM on November 21, 2018, and is actively engaging with relevant federal, state, and local agencies and governments to ensure the timely receipt of necessary permits and approvals.

Equinor Wind also has engaged in extensive dialogue with potentially affected stakeholder groups, including coastal communities, environmental organizations, commercial and recreational fisheries organizations, labor organizations, and local businesses, to promote public understanding and support for the development of the Empire Wind Project. Through these efforts, Equinor Wind has solicited the views of relevant stakeholder groups and the public to ensure that their views are reflected in the design and development of the Empire Wind Project and to allow Equinor Wind to proactively address issues of concern as they arise. As a result of these efforts, the Empire Wind Project has received substantial support from relevant communities and stakeholder groups, including representatives of local communities, trade groups, environmental groups, and local businesses and ports.

1.3 Summary

New York's decision to proceed with this initial solicitation process represents a critical first step towards achieving New York's ambitious environmental and economic objectives. As a company deeply committed to the growth of offshore wind resources in the United States and around the world, Equinor Wind welcomes the opportunity to partner with New York to foster the development of renewable resources off the New York coast and to accelerate New York's emergence as a leader in the offshore wind industry.

2 PROPOSER EXPERIENCE

Proposers are required to demonstrate project experience and management capability to successfully develop and operate the Project proposed. NYSERDA is interested in project teams that have demonstrated success in developing generating facilities of similar size and complexity and can demonstrate an ability to work together effectively to bring the Project to commercial operation in a timely fashion.

2.1 Organizational Chart

An organizational chart for the Project that lists the Project participants and identifies the corporate structure, including general and limited partners.

As shown in Figure 3, Equinor Wind is a direct wholly owned subsidiary of Equinor US, and an indirect wholly owned subsidiary of Equinor ASA. Equinor ASA is an international energy company, headquartered in Norway, that has operations in over 37 countries and approximately 22,000 employees worldwide. Equinor ASA is listed on the New York and Oslo stock exchanges and has a current market capital valuation in excess of $65 billion.

Figure 3: Equinor Wind US LLC Corporate Structure

[redacted]

2.2 Specific Experience

Statements that list the specific experience of Proposers and each of the Project participants (including, when applicable, Proposers, partners, and proposed contractors), in developing, financing, owning, and operating generating and transmission facilities, other projects of similar type, size and technology, and any evidence that the Project participants have worked jointly on other projects.

Equinor has over 40 years of experience developing, owning, and operating large scale, offshore energy projects. Equinor is the largest operator on the Norwegian continental shelf—operating over 40 fixed and floating offshore oil and gas assets—and is a license holder in numerous oil and gas fields worldwide. Through its experience developing, owning, and operating large-scale energy assets, Equinor ASA and its subsidiaries have built up extensive technical and commercial resources and expertise focused on every stage of offshore project development, including engineering, procurement, project and contract management, permitting, finance, health, and safety.

The resources, experience, and technical capabilities that Equinor has acquired from developing large scale, offshore oil and gas facilities are allowing Equinor to quickly become a global leader in the development and operation of offshore renewable resources. Notably, Equinor has a demonstrated record of successfully developing, financing, constructing, operating, and maintaining offshore wind facilities. Specifically, Equinor currently owns, operates, and markets the output of three operating offshore wind facilities in the UK, including the world's first floating offshore wind farm. Equinor also is a partner in the Arkona offshore wind facility, a 385 MW project located off the coast of Germany that recently commenced operation and is expected to be complete in 2019. Equinor also is actively pursuing the development of offshore wind projects throughout Europe and the United States. In particular, Equinor is part of a consortium developing the 3.6 GW Dogger Bank offshore wind generation facility located off the coast of the UK and has acquired a 50% interest in a series of offshore wind facilities currently under development off the coast of Poland in the Baltic Sea.

Equinor's seamless transition from a leading oil and gas developer into a leading developer of offshore renewable resources is a product of the company's commitment to renewable energy development and the product of a project execution model that has been refined over decades operating in harsh ocean environments and that can be readily applied to the development of offshore wind resources. Importantly, the development of offshore wind projects present challenges, and requires technical capabilities, similar to those associated with the development and operation of large-scale, offshore oil and gas projects. These include project management, environmental analysis, marine engineering, coordination of marine/vessel operations, lifting operations, coordination of personnel, equipment transport, and the selection and management of contractors. As a result, the extensive technical and commercial capabilities that Equinor has acquired over its 40-year history allow it to effectively develop and manage offshore wind facilities through every stage of project development, from initial site assessment through commercial operation and management of the asset. Equinor's relevant experience and capabilities include:

- **Project Design**: Equinor has extensive experience designing complex offshore structures and facilities that can operate reliably in the ocean environment. This includes designing and selecting each component of an offshore wind facility's electrical system and interconnection facilities, including turbine design and layout, sub-sea support structures, and submarine cables. The insights gained from operating offshore energy assets for decades allow Equinor to design offshore wind projects that are optimized to maximize production and facility availability and minimize downtime.

- **Sub-Sea Installation**: Equinor has a long track record of successfully installing, maintaining, and retrieving bottom fixed sub-sea installations. In connection with its oil and gas business and growing offshore wind portfolio, Equinor has successfully installed and constructed facilities employing the full range of substructure concepts, including monopiles, gravity-based structures, and jackets. Equinor's experience gives it a deep understanding of the risks, challenges, costs, and benefits associated with different technologies.

- **Marine Vessel Coordination and Deployment**: Equinor has demonstrated experience successfully coordinating maritime and vessel operations around the world. Equinor employs industry best practices to seamlessly coordinate maritime vessels transporting equipment, personnel, and other cargo in order to ensure the efficient and timely construction of its offshore projects while minimizing disruption to maritime and fisheries resources.

- **Environmental Assessment**: Environmental impact assessments are an integral part of successfully developing all offshore projects and Equinor has vast experience working with marine life, environmental baseline data collection and monitoring, and protecting the environment through responsible development and mitigation. Equinor is participating in joint industry projects investigating the impacts from offshore wind projects on wildlife, including on seabirds and marine mammals, and sits on numerous stakeholder groups including, the Fishing Liaison for Offshore Wind and Wet Renewables, the Sound and Marine Life Program, the Fisheries Technical Working Group, and the Environmental Technical Working Group. These groups are focused on promoting best practices to minimize the impact of the development of offshore renewable generation on commercial fisheries and marine ecology.

- **Operations and Maintenance**: Equinor operates 24-hour, 7-day a week operations and maintenance centers to monitor each of its operating offshore wind facilities and to ensure that any issues that may arise are timely identified and remedied. Composed of a multi-disciplinary team of experts, including engineers, marine coordinators, planners, and wind farm technicians, Equinor's operations and maintenance team works in close coordination to minimize outages and ensure that each of Equinor's projects operates reliably and safely.

- **Interconnection**: Equinor has experience with every phase of interconnecting offshore wind projects to the grid, including evaluating potential interconnection points and installing and constructing onshore and offshore interconnection facilities and substations. Equinor has experience working closely with transmission providers and local utilities to facilitate the timely and cost-effective interconnection of its projects to the grid.

- **Energy Marketing**: Equinor's marketing and trading group has a long history of maximizing the value of Equinor's portfolio of oil, gas, and electric generation assets, including evaluating and hedging market risk and negotiating offtake agreements with customers.

- **Financing**: Equinor has extensive experience financing complex offshore energy projects, including numerous offshore wind projects of similar size and scope to the Empire Wind Project. [redacted]

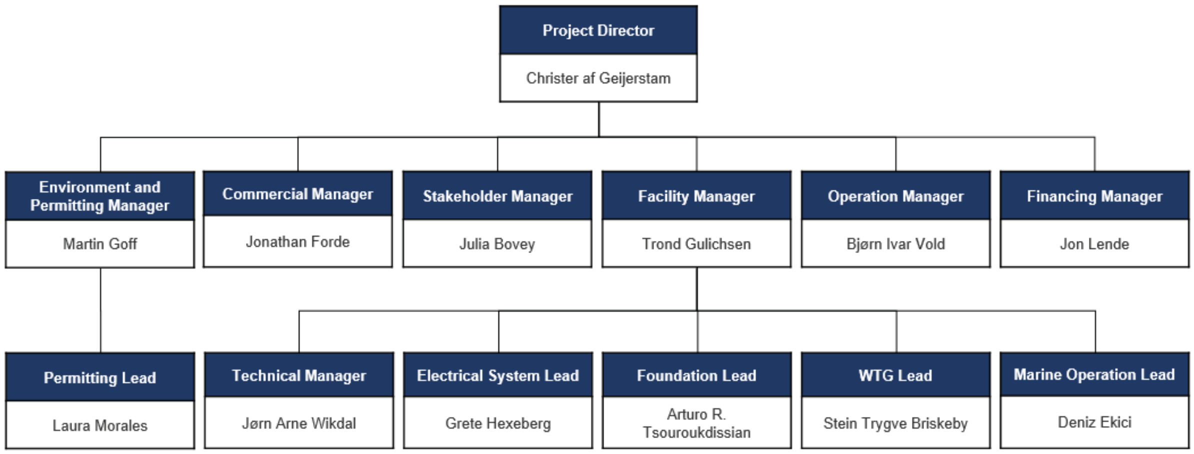
Equinor's expertise, technical capabilities, and financial strength make Equinor Wind uniquely well-suited to help New York meet its offshore wind development goals. Equinor Wind plans to continue to draw upon the extensive capabilities of its parent and affiliates to operate and maintain the Empire Wind Project, employing the same methodologies and approaches that have been used by Equinor to successfully and reliably operate utility-scale offshore wind projects in Europe.

2.3 Key Personnel

A management chart that lists the key personnel dedicated to this Project and resumes of the key personnel. Key personnel of Proposer's development team having substantial Project management responsibilities must have:
a. Successfully developed and/or operated one or more projects of similar size or complexity or requiring similar skill sets; and
b. Experience in financing power generation projects (or have the financial means to finance the Project on Proposer's balance sheet).

Leveraging the extensive experience and technical capabilities of Equinor and its affiliates, Equinor Wind has assembled a highly qualified and experienced team focused on the design, development, construction, and operation of the Empire Wind Project. Figure 4 below provides a management chart depicting key team members and their respective titles.

Figure 4: Empire Wind Management Chart



A brief description of the experience of each of these key employees is provided below and copies of these employees' resumes are provided as Attachment 1. In addition to the individuals listed below, as a subsidiary of Equinor, Equinor Wind can seamlessly leverage the expertise of over 4,500 additional employees with expertise covering a wide range of subjects and technical skills relevant to the development of offshore wind resources.

Christer af Geijerstam – *Project Director*

Mr. af Geijerstam is the Empire Wind Project Director and President of Equinor Wind. Since joining Equinor in 2008, Mr. af Geijerstam has held positions in strategy, business development, project development, and asset management for Equinor's oil, gas and offshore wind assets. Prior to joining Equinor, Mr. af Geijerstam worked in Norway's Ministry of Petroleum and Energy in the agency's Exploration Unit, where he was responsible for administering license rounds for the Norwegian Continental Shelf. Mr. af Geijerstam holds a master's degree in economics from the University of Oslo.

Martin Goff – *Environment and Permitting Manager*

Mr. Goff has worked in Environmental Impacts and permitting of offshore wind projects for Equinor Wind since 2012. As a Chartered Marine Scientist, Mr. Goff has a B.Sc. in Ocean Science from the University of Plymouth, England, and an M.Sc. in Applied Physical Oceanography from the University of Wales, Bangor, with over 10 years of experience in the metocean field prior to joining Equinor. Mr. Goff was responsible for the environmental assessments and permitting of the Dogger Bank Teesside A&B offshore wind farms, U.K., which included managing relationships with the maritime community and landowners. He also held the role of Landowner Manager during the construction of the now fully operational 402 MW Dudgeon Offshore Wind Farm, as well as advising on environmental impacts and permitting in support of business development opportunities for new projects. Mr. Goff has worked in the U.S. offshore wind sector for the past two years as the Head of Environment and Permitting Manager for the Empire Wind offshore wind energy area, New York.

Jonathan Forde – *Commercial Manager*

Since joining Equinor in 2010, Mr. Forde has been active in developing Equinor's growing presence in the United States and has held a variety of roles supporting commercial evaluation, strategy, and business development of Equinor's oil, gas, and offshore wind resources. Mr. Forde currently serves as the Commercial Manager for Equinor Wind US, where he is responsible for securing the commercial agreements necessary for development and growth of Equinor's offshore wind portfolio in the United States.

Prior to joining Equinor, Jonathan completed his M.Sc. in Energy Economics at the Colorado School of Mines, an M.Sc. in Petroleum Economics and Management at the Institut Francais du Petrole, and a Bachelor of Arts in Chemistry and International Relations at Claremont McKenna College.

Julia Bovey – *Stakeholder Manager*

Ms. Bovey directs external affairs for Empire Wind. She first worked on offshore wind in 2004, when she left a 15-year career in journalism to join the Conservation Law Foundation ("CLF") in Boston, Massachusetts. At CLF, she helped advance public support and regulatory policy for New England's first proposed wind projects. Her work expanded to federal energy and climate policy when she moved to Washington, D.C., to join the Natural Resources Defense Council. She then joined the Obama Administration as the Federal Energy Regulatory Commission's ("FERC") Director of External Affairs. Following her time at FERC, she joined First Wind, then a leading independent developer of wind energy projects across the U.S., as Vice President, Federal Policy. She was subsequently appointed the first-ever Long Island Director of the New York State Department of Public Service. Ms. Bovey holds a B.A. from Columbia University, Barnard College, and an M.S. from Columbia University, School of Journalism.

Trond Gulichsen – *Facility Manager*

Mr. Gulichsen has worked with Project Development for Equinor since 2012. Mr. Gulichsen has an M.Sc. in Civil Engineering from the Norwegian University of Science and Technology in Trondheim, and a Master of Management from the BI Norwegian School of Management with 15 years of experience from both onshore and offshore projects prior to joining Equinor.

Mr. Gulichsen has held a wide range of positions in both the early phases and execution phases of projects, such as Project Director for the Peregrino Clean Energy project, Drilling Facility Manager in the Peregrino Phase II project, Construction and Site Manager for the Peregrino Main

FPSO project, Civil Construction Manager at the Ormen Lange Onshore Plant and Civil Engineering and Construction Manager at the Sunndal 4 Expansion Project.

Bjørn Ivar Vold – *Operation Manager*

Mr. Vold has worked with renewables and wind energy since 2010 and has extensive offshore wind experience from Statkraft, DNV GL, and Equinor. He currently works as operations manager for Empire Wind. Mr. Vold's relevant experience includes acting as Project Manager for the Lender Technical Due Diligence report produced for the world's largest offshore wind farm, Hornsea One (DNV GL) and acting as operation manager for one of the projects at the Dogger Bank development while with Statkraft. With comprehensive experience managing multi-disciplined international projects, offshore maintenance work in the North Sea, financial modeling and operational offshore wind concept selection, Mr. Vold brings a wide range of expertise to the Equinor team. Mr. Vold holds an M.Sc. in Industrial Economics from the Norwegian University of Life Science in Aas, Norway.

Jon Lende – *Financing Manager*

Mr. Lende is the Finance Manager for the Empire Wind Project and is responsible for all aspects related to financing and credit. Mr. Lende has been a senior member of Equinor's central Structured Finance team since 2008 and has been responsible for determining the ownership structure and financing solutions for a large number of projects. More specifically, Mr. Lende was responsible for approving and implementing the initial construction and long term financing of Equinor's investment in Sheringham Shoal together with the initial partner on the project, Statkraft. He had a similar role for the initial balance sheet financing of the Dudgeon Offshore Wind Project, including leading the subsequent project financing process in cooperation with partners, financial advisors, and other advisors. Furthermore, he led the refinancing of Dudgeon (£ 1.4 billion) which successfully closed in December 2018. Mr. Lende holds a degree in economics from Norwegian Business School.

Laura Morales - *Permitting Lead*

Ms. Morales has over 15 years of professional experience with expertise in both development and operational permitting, including, but not limited to the following programs: federal, state (NJ, NY, CT) and local land use (wetlands, riverine and coastal areas), National Marine Fisheries Service Incidental Take Permits, stormwater management, soil erosion and sediment control, National Pollutant Discharge Elimination System permitting and compliance, and spill prevention and response. She holds a Master's in Environmental Management and a BS in Zoology. She currently serves as Permitting Lead for State permitting on the Empire Wind offshore wind energy development area.

Jørn Arne Wikdal – *Technical Manager*

Mr. Wikdal's professional history comprises over 35 years in the offshore oil, gas, and wind industries focusing on structural engineering, marine operations, new-build and modification projects, engineering management, and project completion activities, covering both concrete and steel structures. Mr. Wikdal has an M.Sc. in Structural Engineering from the Norwegian University of Science and Technology in Trondheim, Norway. He currently works as Technical Manager for Equinor's Empire Wind Project in NY. Prior to that, he worked for Equinor as Technical Manager for the Dudgeon offshore wind farm, which was successfully completed and commissioned in October 2017.

Grete Hexeberg – *Electrical System Lead*

Ms. Hexeberg's professional history comprises over 25 years in the offshore wind, oil and gas industries and within the electrical power transmission area. For the last 10 years, Ms. Hexeberg has been part of the leadership team responsible for several offshore wind projects, including the Sheringham Shoal, Dudgeon, and Doggerbank offshore wind farms. During this period, she has held different management positions, including Technical Manager, Area Manager for Wind Turbine Generator Foundations, Area Manager for Electrical System Infrastructure and Consent and Stakeholder Manager. She has an M.Sc. degree in electrical engineering from the Norwegian University of Science and Technology with a focus on electrical power system analysis and design. She currently works as Electrical System Lead for Equinor Wind's Empire Wind Project.

Dr. Arturo Rodríguez Tsouroukdissian – *Foundation Lead*

Dr. Tsouroukdissian's professional history comprises over 15 years in the wind industry (onshore and offshore), focusing on civil structural dynamics, earthquake engineering, structural damping control, and research and development. He holds a B.S. and M.Sc. from SUNY Buffalo Civil Engineering Department and has a joint Ph.D. between Polytechnic Catalonia University and Kobe/Osaka University. He currently works as Wind Turbine Generator and Offshore Substation Topside Foundations Package Manager and Ports & Infrastructure Leader for Foundation and Wind Turbine Staging for Equinor's Empire Wind Project. Prior to that, he worked for GE as a foundation package manager of two 6 MW turbine prototype jacket substructures, Technical Interface Manager for Project Execution in Europe and the U.S., and as GE 12 MW Offshore Wind Technologies Program Manager. He is an author and co-author of over 30 conference and journal publications and holds 9 patents related to onshore and offshore wind technology.

Dr. Stein Trygve Briskeby – *Wind Turbine Generator Lead*

Dr. Briskeby has worked with renewables and wind energy since 2008 and has extensive offshore wind experience from numerous projects and roles with Equinor. He currently works as Wind Turbine Generator package manager for the Empire Wind Project and has responsibility for the wind turbine delivery. Other relevant experience includes acting as Engineering Manager and Wind Turbine Generator lead for Hollandse Kust Zuid I and II offshore wind bid project in the Netherlands; Wind Resource Assessment lead and Wind Turbine Generator package for Kriegers

Flak offshore wind bid project in Denmark; Engineering manager for Borssele I & II offshore wind bid project in the Netherlands; and Wind Resource Assessment lead for the Dudgeon offshore wind project in the U.K. With comprehensive multi-disciplinary experience, Dr. Briskeby brings a wide range of experience to the Renewable Energy Technology team in Equinor. Dr. Briskeby holds an M.Sc. in Materials Science and Engineering and a Ph.D. in Electrochemistry, both from the Norwegian University of Science and Technology in Trondheim, Norway.

Deniz Ekici – *Marine Operation Lead*

Mr. Ekici is a California and Rhode Island licensed Professional Engineer as well as a Project Management Institute certified Project Manager. He has over fifteen years of structural engineering and management experience in large capital projects. He has participated in offshore wind development projects in Northern Europe and Asia-PAC during the planning, execution and operation stages. He has overseen marine operations for major offshore wind component load-out, marine transport and installation phases such as foundations, jacket, transformer topside and WTG components (tower, nacelle, blades). Mr. Ekici has also presented multiple oil and gas and offshore wind related technical papers at various conferences around the world, including AWEA Offshore Wind, OTC Houston, OTC Asia, SNAME, SIEW Singapore Energy Week and Thailand Renewable Energy and Expo Conference.

In addition to the key team of individuals set out above and the in-house capabilities of the broader Equinor group, Equinor Wind has retained numerous consultants with significant experience to support the development of the Empire Wind Project. Key consultants include:

- **Tetra Tech**: Equinor Wind has retained Tetra Tech to serve as lead environmental consultant for the project team. Tetra Tech is responsible for the permitting scope, inclusive of environmental assessments, stakeholder engagement, and preparation of federal and state permit applications. Tetra Tech is one of the largest full-service environmental consulting firms in the United States, with a core competency of over 17,000 environmental engineers, scientists, and planners in over 400 offices worldwide, working in more than 100 countries around the globe. As an industry leader, Tetra Tech has served as the lead consultant on the development of more than 50 offshore facilities, including deepwater ports, oil and gas platforms, subsea pipelines and transmission cables, and renewable energy projects, including wind, wave, and hydrokinetic projects across the United States. In support of these projects, Tetra Tech has conducted detailed impact assessments for various resources, including aquatic and terrestrial wildlife, wetlands/water bodies, threatened and endangered species, archaeological/historic resources, scenic resources, and land use. Tetra Tech has also led the design and execution of complex offshore marine studies (*e.g.*, geophysical, geotechnical, marine cultural, offshore avian and bat, and marine species and habitat evaluations) and completed hundreds of National Environmental Policy Act-compliant environmental impact assessment reports.

- **Sea Risk Solutions**: Sea Risk Solutions is supporting the development of the Empire Wind Project by providing information and strategies to mitigate risks to maritime interests and resources. Sea Risk is acting as Fisheries Liaison Officer for the Empire Wind Project, including coordinating a substantial fisheries outreach effort. The founding partner of Sea Risk, Stephen Drew, spent 15 years developing and managing the Marine Liaison group for a major subsea cable supplier. He managed marine relations and risk mitigation at cable landings in 25 countries and served five years on the International Cable Protection Committee Board of Directors. He has negotiated and served as liaison officer in cable/fishing agreements on the US West Coast. His partner, Wolfgang Rain, joined Sea Risk Solutions as a Partner after nine years managing the Marine Liaison program for a major cable supplier and ship operator and brings similar professional experience to the team. Mr. Drew previously supported NYSERDA as Fisheries Liaison Officer for the New York Offshore Wind Master Plan, where Stephen gained further experience with the northeast fisheries, especially the interaction between fisheries and offshore wind development in the New York Bight. More details regarding Sea Risk's efforts as Fisheries Liaison Officer are provided in Section 12.

- **Anatec Limited**: Anatec Limited is supporting the development of the Empire Wind Project by evaluating potential impacts and identifying mitigation measures associated with maritime navigation, including preparation of the Navigational Safety Risk Assessment. Anatec has extensive experience in carrying out navigation risk assessments for offshore renewable projects and for other marine users, including oil and gas developers, ports, marinas, and cable and dredging companies. Anatec's senior leadership team has over 20 years of experience working in marine and offshore environments safely and has received international recognition for its research studies concerning risk-based decision-making.

- **Mott MacDonald**: Equinor Wind has retained Mott MacDonald to provide technical and engineering services related to the proposed interconnection of the Empire Wind Project to New York, including evaluating potential interconnection points. Mott MacDonald has provided a multi-disciplinary team including engineers, environmental scientists, project managers, and land acquisition experts with decades of experience developing large-scale energy and infrastructure projects in New York and throughout the world. The team supporting the development of the Empire Wind Project has deep knowledge of New York and have been involved in large infrastructure projects throughout the state, including large independent power production facilities, interconnection facilities, substations, ports, tunnels, bridges, highways, and other civil construction projects.

- **SEARCH, Inc.**: Equinor Wind has retained SEARCH, Inc., the largest archaeology and cultural resources management company in the world, to assist with evaluating potential impacts to marine archaeological resources, including serving as the Qualified Marine Archaeologist for the project. SEARCH has completed more than 3,500 projects across 40 U.S. states and 36 countries, spanning five continents and three oceans. SEARCH specializes in the full spectrum of cultural services related to Archaeology, Maritime Archaeology, Architectural History, History, Archives, Collections Management, Museum Services, Documentary Media, and Public Affairs.

- **ICF International, Inc.**: Equinor Wind has retained ICF, a global consulting services company, to assist in developing price forecasts and evaluating the economic and social impacts of the Empire Wind Project. ICF has over 40 years of experience consulting in the energy industry providing engineering consultation, economic analysis, and policy guidance to utilities, renewable energy projects, and governments around the world. ICF's team includes over 5,000 employees across more than 65 offices worldwide.

- **Kjeller Vindteknikk:** Equinor Wind has retained Kjeller Vindteknikk, a leader in wind measurement and analysis, to confirm the wind resource and projected output of the Empire Wind Project. Kjeller Vindteknikk has 20 years of experience performing wind assessments for wind projects in Sweden, Norway, Iceland, Bulgaria, Macedonia, and the United States. Its team of meteorologists, physicists, engineers, and technicians have installed more than 200 measurement stations and performed a full suite of analyses on those data sets to support wind development.

[redacted]

- **Sargent & Lundy**: Equinor Wind has engaged Sargent & Lundy to evaluate the impact of interconnecting the Empire Wind Project to the NYISO grid. Sargent & Lundy is a power engineering consulting company that provides a comprehensive suite of consulting, engineering, design, analysis, and project services for power projects worldwide.

2.4 Successful Projects

A listing of projects the Project sponsor has successfully developed or that are currently under construction. Provide the following information for each project as part of the response:
a. Name of the project
b. Location of the project
c. Project type, size, and technology
d. Commercial Operation Date
e. Estimated and actual capacity factor of the project for the past three years
f. Availability factor of the project for the past three years
g. References, including the names and current addresses and telephone numbers of individuals to contact for each reference.

Equinor has a proven track record of successfully developing, constructing, and operating offshore wind projects. As described further, Equinor currently operates numerous projects in Europe and has a number of significant projects currently under development in Europe and the United States. The following sections provide an overview of Equinor's existing projects as well as projects in development.

2.4.1 Sheringham Shoal

The Sheringham Shoal Offshore Wind Farm, located north of Sheringham, UK, was completed in 2012. Equinor is the operator of the joint venture company Scira, which owns Sheringham Shoal. The wind farm is located 11 miles from shore and consists of 88 turbines on monopile foundations with a total nameplate capacity of 317 MW. The project is connected to the grid through two offshore substations, two offshore cables, and an onshore cable.

Figure 5: Sheringham Shoal

2.4.2 Dudgeon

The Dudgeon Offshore Wind Farm, located north of Cromer, UK, was completed in 2017. Equinor is the operator of the joint venture company that owns Dudgeon. The wind farm is located 20 miles from shore and consists of 67 turbines on monopile foundations with a total nameplate capacity of 402 MW. The project is connected to the grid through an offshore substation and two export cables consisting of both onshore and offshore facilities. On December 14, 2018, Equinor, along with the joint owners of Dudgeon, completed a hybrid refinancing of the project totaling more than $1.7 Billion (£1.4 Billion).

Figure 6: Dudgeon

2.4.3 Arkona

The Arkona Offshore Wind Farm, located northeast of Sassnitz, Germany, has started delivering power to the grid, and will be completed in early 2019. Equinor holds a 50% stake in the project. E.ON owns 50% and is operating the project on behalf of the consortium. The wind farm is located 22 miles from shore and consists of 60 turbines with a nameplate capacity of 385 MW. The turbines are secured to the seabed using a monopile design and are connected to the grid through an offshore substation and cables running to shore.

Figure 7: Arkona

2.4.4 Hywind Demo

The Hywind Demo project, located west of Karmøy, Norway was completed in 2009 and is the world's first floating wind turbine. Equinor designed and developed the project which consists of a single turbine on a floating spar foundation anchored to the seafloor. The project has produced electricity for more than eleven years without any major component failures and continues to generate electricity. Over that time period, it has withstood wind speeds reaching 89 mph and waves in excess of 60 feet. Equinor operated the project until February 1, 2019, when ownership of the facility was transferred to Unitech Offshore. Unitech plans to use the project as a platform for teaching and training as well as research and development of new offshore wind technologies.

Figure 8: Hywind Demo

2.4.5 Hywind Scotland

The Hywind Scotland wind farm, located east of Peterhead, Scotland was completed in 2017. Equinor designed, developed and operates the project, which incorporates experience gained from the Hywind Demo Project. With a total installed capacity of 30 MW, the project consists of five 6 MW turbines on floating spar foundations anchored 328 feet down to the sea floor. The project consists of a mixture of available technology and new patents developed and owned by Equinor. Through this experience, Equinor continues to expand its expertise in this new model of offshore wind development. The project is owned by Equinor and Masdar.

Figure 9: Hywind Scotland

2.4.6 Projects Under Development

Dogger Bank

The Dogger Bank Offshore Wind Farm is a series of three proposed projects currently under development east of Yorkshire, UK. Alongside the other members of the Forewind consortium, Equinor secured all the necessary consents and owns a 50% interest in all 3 proposed projects in a consortium with SSE plc. The 400,000 acre development is located 80–120 miles offshore, with a projected nameplate capacity of 3.6 GW. The current plan contemplates connecting the projects to the grid in Creycke Beck and Teesside.

Massachusetts Wind Lease

Consistent with its strong commitment to offshore wind development in the United States, on December 14, 2018, Equinor submitted a winning bid of $135 million for one of three lease areas off the coast of Massachusetts auctioned off by BOEM. Upon execution of the lease, Equinor will have the opportunity to explore the potential development of offshore wind resources in the lease area, which covers 128,811 acres.

Baltyk

Equinor is in a 50/50 joint venture with the polish utility Polenergia in the Baltyk II and Baltyk III Offshore Wind Farms, located off the coast of Poland in the Baltic Sea. The farms have a planned capacity of 1,440 MW with the potential to power more than two million Polish households. First power for Baltyk II and Baltyk III is planned for mid-2020. Also, Equinor has signed an agreement to acquire a 50% interest in the Baltyk I license, which allows for the development of a wind farm with a capacity up to 1,560 MW. This project is in the early stage of development and will be further matured in a joint venture with Equinor and Polenergia.

2.4.7 Operating Project Details

Figure 10 below provides detailed information for each of Equinor’s operating projects including the location, technology used, and key performance metrics.

Figure 10: Summary of Operating Projects

[redacted]

2.5 Partners

With regard to Proposer's Project team, identify and describe the entity responsible for the following, as applicable:
a. Construction Period Lender, if any
b. Operating Period Lender and/or Tax Equity Provider, as applicable
c. Financial Advisor
d. Environmental Consultant
e. Facility Operator and Manager
f. Owner's Engineer
g. EPC Contractor (if selected)
h. Transmission Consultant
i. Legal Counsel

As a result of its long history of offshore development, Equinor has extensive in-house capabilities and resources devoted to offshore wind development and has strong relationships with outside consultants and companies focused on supporting the development of offshore wind resources. Leveraging these relationships, Equinor Wind has retained numerous consultants with significant experience relevant to the development of the Empire Wind Project. Key consultants include:

a. **Construction Period Lender**: [redacted]
b. **Operating Period Lender and/or Tax Equity Provider:** [redacted].
c. **Financial Advisor**: [redacted]
d. **Environmental Consultant:** Equinor Wind has engaged Tetra Tech, SeaRisk Solutions, and SEARCH Inc. to provide environmental consulting services.
e. **Facility Operator and Manager:** Equinor Wind will be responsible for managing and operating the Empire Wind Project, leveraging the expertise of its parent and affiliates in operating offshore projects around the world.
f. **Owner's Engineer/EPC Contractor:** The Empire Wind Project does not plan to engage any single Owner's Engineer or EPC Contractor. Instead, the procurement and development strategy for the Empire Wind Project will consist of multiple contracts with qualified contractors chosen through a rigorous vetting and selection process, as described further in Section 9.1.2. Equinor has successfully used this approach when constructing other offshore wind projects in Europe.

g. **Transmission Consultant:** Equinor Wind has engaged Sargent & Lundy, Mott MacDonald, and Tetra Tech to advise Equinor on matters concerning the interconnection of the Empire Wind Project to the grid and its impact on the New York transmission system.

h. **Legal Counsel:** Legal advice to the Empire Wind Project has been provided by Bracewell LLP.

i. **Tax Advisor:** Empire Wind has engaged Deloitte Touche Tohmatsu Limited, which has provided advice concerning federal tax laws related to the Empire Wind Project.

2.6 Experience with NYISO Market

Details of Proposer's experience in NYISO markets. With regard to Proposer's experience with NYISO markets, please indicate the entity that will assume the duties of Market Participant for your proposed Offshore Wind Generating Facility. Please provide a summary of Proposer's or Market Participant's experience with the wholesale market administered by NYISO as well as transmission services performed by Con Edison, NYPA, and PSEG-LI/LIPA.

Equinor Wind currently anticipates leveraging the expertise of Equinor's Marketing & Trading division to optimize the value of the Empire Wind Project. More specifically, Equinor Wind plans to enter into a power purchase agreement ("PPA") with Equinor Marketing & Trading, who will act as market participant for the asset and be responsible for marketing the output and capacity of the Empire Wind Project. As discussed further below, Equinor's Marketing & Trading Division already has extensive experience with wholesale markets for electricity and is currently responsible for marketing the output of Equinor's operating offshore wind facilities. This expertise promises to be further enhanced by Equinor's acquisition of Danske Commodities ("Danske"), one of the largest short-term traders of electricity in Europe.

2.6.1 Experience with Electricity Markets

Equinor Marketing & Trading

Developed over the 40-year life of the company, Equinor's Marketing & Trading division has a long history of analyzing market conditions and identifying opportunities to maximize the value of Equinor's portfolio of assets. [redacted]

[redacted]

[redacted]

[redacted]

Equinor's Marketing & Trading division has accumulated a wealth of experience marketing and optimizing the value of energy, capacity, and ancillary services from offshore wind resources in wholesale markets. Currently, Equinor's Marketing & Trading division is responsible for marketing electricity and associated products from Equinor's existing offshore wind projects, all of which are located in the UK: Sheringham Shoal, Dudgeon, and the Hywind Scotland floating offshore wind park. [redacted] As a result of this experience, Equinor's Marketing & Trading division has built up substantial capabilities focused exclusively on marketing the output of offshore wind resources, including trading, market analysis, and technical support. Equinor's Marketing & Trading division also has significant experience and resources focused on wind production forecasting, [redacted]

Equinor Marketing & Trading has spent significant resources evaluating the NYISO market, including evaluating potential risks and opportunities associated with the development of the Empire Wind Project. In addition to leveraging the insights gained from its management of Equinor's existing offshore wind facilities, Equinor engaged ICF to provide detailed price forecasting and modeling information and to provide guidance regarding market participation. Combining ICF's modeling with Equinor's proprietary modeling and short-term and long-term assumptions, Equinor's Marketing & Trading division has conducted market simulations to project expected electricity and capacity income over the life of the Empire Wind Project considering a range of potential scenarios and uncertainties, including price formation in adjacent markets, import/export balances within the region, new builds and retirements and long-term fuel and emissions costs.

Based on these analyses, Equinor has concluded that the Empire Wind Project is well-suited to generate significant energy and capacity revenues over the life of the asset. [redacted]

- [redacted]
- [redacted]
- [redacted]

[redacted]

Acquisition of Danske Commodities

On July 6, 2018, Equinor announced that it had reached an agreement to buy 100% of the shares of Danske. After approval by relevant regulatory authorities, the transaction was consummated on February 1, 2019. Equinor's acquisition of Danske only promises to further enhance the capabilities of Equinor's Marketing & Trading division. Founded in 2004, Danske is one of Europe's largest short-term electricity traders and has extensive experience trading electricity and associated products in markets around the world. For instance, in 2017, Danske traded 318 terawatt hours of electricity across 37 countries. The acquisition of Danske will further strengthen Equinor's ability to optimize the value of its portfolio of assets, including the Empire Wind Project.

An overview of Danske's experience managing electricity market positions in several sectors is provided below.

Renewables

With over 10 years of experience and a portfolio of more than 6,000 MW under management, Danske is among the leading players in renewable generation offtake contracts in Europe. Danske specializes in maximizing the value of renewable energy. Danske pioneered the market for direct marketing contracts in Germany and has significant experience with the optimization of renewable energy generation, including standard and non-standard PPAs. Over the course of a decade, Danske has developed and refined how renewable energy is traded in Europe. To balance and optimize the variable production output from these sources, they rely on in-house meteorologists, market analysts, and advanced forecasting models. Superior market access and around-the-clock availability enables customers to extract the full value of renewable assets. Products offered include:

- PPAs on both standard and individually structured terms
- Production management and balancing
- Production hedging from the day-ahead timeframe up to 10 years
- Trading of all relevant renewable energy certificates
- Participation in relevant reserve markets to support the balancing of the grid
- 24/7/365 market monitoring, trading, and operations

Risk Management

Danske provides utilities, energy supply companies and large industrial consumers with trading and risk management solutions. They deliver consumption forecasting, procurement of fixed or variable volumes as well as individual hedging strategies that protect customers from adverse price developments in the volatile electricity markets.

Danske enables wholesale and industrial customers to structure their energy procurement in a cost-effective way and manage their volume and balancing risk. With extensive experience and an advanced forecasting model, they optimize customer portfolios. Danske builds long-term relationships and provides utilities and wholesale energy suppliers with flexible, bespoke solutions. This enables them to offer competitive products and prices to their customers. Products offered include:

- Market access, enabling customers to trade standard products in power markets
- Consumption management and balancing, based on individual portfolio analysis
- Consumption optimization, capturing opportunities in the volatile short-term markets
- Hedging solutions tailored to the specific consumption profile and end-user needs
- Trading of all relevant certificates, either in the market or directly from the renewable assets

[redacted]

2.6.2 Experience with Transmission and Interconnection

Equinor Wind is actively working with NYISO and the relevant transmission owners to ensure timely interconnection of the Empire Wind Project. [redacted] Since submitting this request, Equinor Wind has engaged in regular meetings with NYISO to discuss the interconnection request and monitor the interconnection process.

[redacted]

Equinor also has extensive experience with successfully interconnecting its projects to the wholesale transmission grid. Notably, in the UK, Equinor has successfully developed and operates three offshore wind farm, including the associated interconnection facilities. Equinor has secured grid connection agreements for these wind farms and has also conducted tests and studies to verify the performance of the wind farm to ensure compliance with the technical and operational requirements established by the grid operator/owners.

3 PROJECT DESCRIPTION AND SITE CONTROL

Identify the BOEM wind energy area where the proposed Offshore Wind Generation Facility will be located. Provide documentation that Proposer has a valid lease or irrevocable lease option to develop the leased area within this wind energy area over the entire Contract Tenor.

Provide a site plan (or plans) including a map (or maps) that clearly identifies the location of the proposed Offshore Wind Generation Facility, collection facilities, offshore and onshore route of the generator lead line to the interconnection point, converter station(s), and the assumed right-of-way width. Identify the anticipated interconnection point, support facilities, and the relationship of the interconnection point to other local infrastructure, including transmission facilities, roadways, and waterways.

Identify any rights that Proposer or its development partner has at the interconnection point and for the generator lead line right of way. Provide a detailed plan and timeline for the acquisition of any additional rights necessary for interconnection and for the generator lead line right-of-way. Include these plans and the timeline in the overall Project schedule in Section 6.4.10.

In addition to providing the required map(s), provide a site layout plan that illustrates the location of all on-shore and offshore equipment and facilities and clearly delineates the perimeter of the area in which offshore wind turbines will be placed. Identify the distance in statute miles between the nearest shoreline point and the nearest Offshore Wind Generation Facility turbines.

3.1 Project Location and Description

3.1.1 Lease Area and Project Overview

Equinor Wind is pursuing the development of the Empire Wind Project in the New York Wind Energy Area, a federal offshore wind lease area located south of Long Island. Equinor Wind has been granted the right to pursue development of offshore wind resources within the New York Wind Energy Area pursuant to renewable energy lease number OCS-A 0512, a copy of which is provided as Attachment 2. The lease area spans approximately 123 square miles ("mi^2") and is located approximately 14 miles south of Long Island at its nearest point. Figure 11 provides a map depicting the location of the lease area and its distance from shore.

Figure 11: Lease Area Distance from New York Shore

[redacted]

The New York Wind Energy Area represents the closest offshore wind lease area to New York and has been designated as suitable for the potential development of offshore wind resources through a multi-step process that included solicitations of commercial interest in the area, environmental assessments and analyses, and extensive dialogue with potential lessees, stakeholders, states, and local governments. Based on preliminary navigational safety and risk assessments, Equinor Wind currently estimates that the lease area is capable of supporting the development of up to 2 GW of installed generation capacity, enough to power more than 1 million homes.

[redacted]

[redacted]

Figure 12: Schematic of the Project Showing Arrangement of All Major Elements

[redacted]

[redacted]

Figure 13: Empire Wind Site Layout

[redacted]

Each element of the Empire Wind Project has been calibrated to optimize production from the facility and ensure that New York's environmental objectives are met as efficiently and cost-effectively as possible. [redacted]

[redacted] At the same time, the Empire Wind Project will use technologies and equipment that have been shown to operate reliably and safely under even the harshest ocean conditions. [redacted]

A more detailed overview of the location of major Empire Wind Project components is included in the following sections.

Wind Turbine Generators and Offshore Collection Facilities

The proposed layout of the Empire Wind Project has been optimized to maximize production from the facility while respecting existing uses of fisheries, maritime navigation, and ocean resources. Since executing the offshore lease, Equinor Wind has been evaluating a wealth of information concerning wind conditions and other metocean data to determine the optimal turbine array that maximizes production, minimizes wake effects, and leaves sufficient space and layout considerations to accommodate existing uses of the outer continental shelf, including commercial fishing. [redacted]

Figure 14: Anticipated WTG Layout and Offshore Substation

[redacted]

Offshore Cable Route

Equinor Wind has evaluated a variety of potential submarine cable routes to determine the best cable route to various landfall locations. These efforts have included extensive consultation with New York state and federal agencies as well as a detailed study of potential cable routes performed by Tetra Tech. [redacted] These paths were developed to respect existing uses by avoiding known conflict areas and mitigating any potential impacts that could not be avoided, and takes into account information received through stakeholder discussions and 2018 surveys. The final path will be determined based on the additional data received from surveys being performed in 2019 and 2020. [redacted]

Interconnection Point and Landfall Location

Equinor Wind engaged Mott MacDonald to evaluate potential landfall locations and interconnection points in New York. [redacted]

[redacted]

[redacted]

Land Acquisition

Equinor Wind already has taken substantial steps towards acquiring the property rights necessary for the construction of the Empire Wind Project.

- **Federal Waters**: As a condition of the executed lease agreement for Lease Area OCS-A-512, Equinor Wind will receive easements necessary for the full enjoyment of the lease, including easements necessary for the purpose of installing transmission and distribution cables associated with the Empire Wind Project.[4] These easements will be granted upon approval of Equinor Wind's Construction and Operations Plan ("COP"). A detailed timeline for the submission of Equinor Wind's COP is provided in Section 8.
- **State Waters**: For the portion of the export cables within state waters, Equinor Wind will need to obtain an easement from the New York State Office of General Services, Bureau of Land Management. A complete description of state permitting requirements is provided in Section 8.
- **Onshore Export Cables and Substation**: Upon landfall, easements and access agreements will be required for several project facilities, including onshore export cables and interconnection facilities, the new onshore substation, and any required substation upgrades. In support of permit applications, Equinor will initially need to secure rights of access with landowners to perform field surveys (*e.g.*, wetland delineation, cultural resources, geotechnical, and land surveys). Equinor has begun discussions with property owners that may be impacted by the Empire Wind Project. [redacted]

[4] 30 C.F.R. § 585.200(b)

4 ENERGY RESOURCE ASSESSMENT AND PLAN

Provide a summary of all collected wind data for the proposed Offshore Wind Generation Facility site. Identify when and how (e.g., meteorological mast or LiDAR – for "Light Detection and Ranging") the data was collected and by whom.
Indicate where the data was collected and its proximity to the proposed Offshore Wind Generation Facility site. Include an identification of the location and height for the anemometers and/or "range gate" heights for sensing by LiDAR that were used to arrive at an assessment of the site generation capability. Describe any additional wind data collection efforts that are planned or ongoing. Provide at least one year of hourly wind resource data. Data collected from the site is preferred, though projected data is permissible. The method of data collection must also be included.
Provide a wind resource assessment report for the Proposed Offshore Wind Generation Facility site. Include an analysis of the available wind data which addresses the relationship between wind conditions and electrical output. Provide a site-adjusted power curve. Each curve should list the elevation, temperature and air density used.

4.1 Introduction

Equinor has acquired extensive technical expertise in collecting, analyzing, and modeling wind data through its experience developing and operating offshore energy projects in Europe. In particular, Equinor's Metocean Department is responsible for analyzing an array of metocean data in order to determine the optimal design and layout for Equinor's oil, gas, and offshore wind projects, including wind speed and direction, wave height and direction, temperature, salinity, extreme weather events, and other factors that can have a significant impact on the design, operation, maintenance, and life of offshore energy projects. Through this experience, Equinor's Metocean Department has developed a set of best practices and models that it employs to evaluate and analyze every aspect of developing, operating, and maintaining offshore energy projects. In fact, Equinor's Metocean Department took the lead in developing the publicly available Metocean Reference Extreme Software, which is widely used within the Metocean community for analysis of extreme conditions and as a benchmark for verifying the accuracy of Metocean software.

Equinor's Metocean Department has analyzed a range of wind resource and metocean data in order to provide a foundation for the design of the Empire Wind Project and estimating the likely output from the facility over the contract term. Among other things, Equinor has prepared a wind assessment report detailing the net yearly energy output for the Empire Wind Project. As detailed in the wind resource assessment performed by Equinor provided as Attachment 4, Equinor's analysis of metocean data concerning the project site demonstrate that the Empire Wind Project has the potential to reliably deliver significant quantities of renewable energy, both on an annual basis and over the life of the project. Additionally, Equinor retained Kjeller Vindteknikk to provide a third-party analysis wind resource assessment, which is provided as Attachment 5. Their assessment closely corresponds to Equinor's own assessment. Equinor believes that these estimates of production provide a sound basis for moving forward with the development of the Empire Wind Project.

4.2 Data Sources

4.2.1 Existing Data Sources

[redacted]

Figure 16: Lease Area Data Collection Point

[redacted]

[redacted]

[redacted]

[redacted]

Figure 17: Stations and Buoys Used for the Hindcast Validation Relative to the Lease Area

[redacted]

[redacted]

[redacted]

4.2.2 Ongoing Data Collection Efforts

[redacted] Equinor Wind is in the process of implementing a comprehensive program to collect and analyze meteorological data for the New York Wind Area, including wind speed and direction at multiple heights and information on other meteorological and metocean conditions. Specifically, on December 2, 2018, Equinor Wind installed one floating light detection and ranging buoy (“FLiDAR 1”), one metocean buoy, and one subsurface current meter mooring within the lease area. An additional FLiDAR will be installed in “Buoy Deployment Area 2” (“FLiDAR 2”) during the first scheduled service visit in spring 2019. The location of these buoys are depicted in Figure 18, below. The proposed facilities and devices represent state-of-the-art equipment that incorporates the best available technologies, mooring components, and mooring design to ensure reliability and quality data collection.

Figure 18: Buoy Layout for Metocean Data

[redacted]

[redacted]

[redacted]

4.3 Wind Resource Assessment

[redacted]

4.3.1 Annual Energy Production Estimate

[redacted]

[redacted]

4.3.2 Losses

[redacted]

Figure 19: Loss Table for 816 MW Project

[redacted]

[redacted]

Figure 20: Predicted Energy Production

[redacted]

4.3.3 Power Curve and Wind Data

A detailed overview of the power curves for the Empire Wind Project is provided in the Wind Resource Assessment report. In addition, one year of wind data is provided as an exhibit to the Wind Resource Assessment Report.

5 OPERATIONAL PARAMETERS

Provide partial and complete planned outage requirements in weeks or days for the Offshore Wind Generation Facility. Also, list the number of months required for the cycle to repeat (e.g., list time interval of minor and major overhauls, and the duration of overhauls).
Provide all the expected operating constraints and operational restrictions for the Project, the reason for the limitation, and characterize any applicable range of uncertainty.

Equinor Wind is designing, and plans to operate, the Empire Wind Project to safely and reliably deliver offshore wind to New York over the contract term and the operational life of the project. Equinor Wind plans to achieve this objective both by designing the Empire Wind Project using best in class technologies that have been shown to operate reliably in the unforgiving ocean environment and by employing operational and maintenance practices that have been refined over decades operating large and complex offshore energy projects, including Equinor's existing offshore wind facilities. As described in the following sections, these operational and maintenance activities are motivated by an unwavering commitment to ensuring that Equinor's projects are operated safely and in a manner that maximizes project availability, reduces costs, is environmentally responsible, and is backed by the financial and logistical resources of the broader Equinor group.

5.1 Equinor's Operations and Maintenance Experience and Approach

Equinor has been operating offshore wind farms since 2009 and has built up a demonstrated track record of successfully operating and maintaining offshore wind farms. Currently, Equinor is responsible for operation and maintenance activities at its Sheringham Shoal, Dudgeon, and Hywind Scotland projects. Employing insights and expertise that have been developed over the course of four decades operating and maintaining large and complex offshore energy projects, Equinor has been able to achieve a high level of availability and reliability at its existing wind farms. [redacted]

Equinor's approach to Operations and Maintenance ("O&M") is driven by a commitment to ensuring the safe and reliable operation of its projects under a full range of operational conditions and is informed by decades of experience operating and maintaining large-scale offshore energy projects. The objective of ensuring safe and reliable operations is reflected in every stage of the project lifecycle, from initial design and construction through the operational life of the facility. Equinor is focused on designing a project that minimizes operational and maintenance risk and integrates remote control and monitoring of each project, allowing Equinor to proactively identify and resolve potential issues before they occur. Equinor employs industry best practices to safely operate and optimize the value of its facilities, reduce life cycle costs, and extend the operational life of its assets.

[redacted]

[redacted]

- [redacted]
- [redacted]
- [redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

5.2 Operations and Maintenance Protocols

5.2.1 Monitoring and Staffing

Continuous monitoring of Empire Wind's performance is a foundational principle of Equinor's approach to O&M and has been successfully employed at Equinor's existing offshore wind projects. For instance, Equinor currently operates a 24/7 control room responsible for monitoring the performance and operations of its existing offshore wind generation facilities. Equinor also has extensive experience operating 24/7 control rooms in connection with its offshore oil and gas facilities. Typically, an offshore wind farm control room includes sophisticated supervisory control and data acquisition ("SCADA") systems, high voltage switching, marine communication and monitoring systems, and other systems that ensure that Equinor is able to continuously monitor projects and support personnel and vessels.

[redacted]

- [redacted]

- [redacted]
- [redacted]
- [redacted]
- [redacted]
- [redacted]
- [redacted]
- [redacted]
- [redacted]

[redacted]

[redacted]

[redacted]

- [redacted]
- [redacted]
- [redacted]
- [redacted]

[redacted]

5.2.2 Emergency Preparedness

Equinor is committed to providing a safe and secure environment for everyone working at Empire Wind. Equinor's approach to O&M is founded upon the goal of ensuring "zero harm" and Equinor continuously works to foster a culture of safety and security in everything the company does. The Empire Wind Project and supporting personnel will be well-equipped to deal with any emergency situations that may arise during project operation and will employ emergency response procedures based on industry best practices and Equinor's experience with onshore and offshore energy projects around the world.

[redacted]

[redacted]

[redacted]

[redacted]

In addition, the Empire Wind Project will be fully integrated within, and be able to draw upon, Equinor's broader emergency and crisis response organization. Equinor has a robust emergency and crisis management team that is well-versed in carrying out emergency operations. This includes a Global Management Assist Team ("GIMAT") consisting of personnel that are trained in effectively responding to emergency situations and that can be deployed across the globe to assist Equinor project sites. The GIMAT's approach to emergency response builds upon the Incident Command System, a U.S.-developed approach to command, control, and coordination of emergency response. The GIMAT can be called upon by the Empire Wind Project to provide additional resources when necessary to support emergency operations.

5.3 Maintenance Schedule and Duration

5.3.1 Planned Outages

Planned maintenance outages will be scheduled in a manner designed to both maximize the safety of maintenance operations and minimize the disruption to the output of the facility. In order to maximize the output of the facility, planned outages will be scheduled during periods in which potential production is at its lowest (typically summer season/low wind seasons) and will be coordinated with NYISO in accordance with its tariff to minimize the potential reliability impacts of outages.

[redacted]

[redacted]

[redacted]

[redacted]

To ensure maximum availability and reliable production for all project components, a number of maintenance tasks are scheduled and completed over several years. These tasks have been summarized below. Notably, when planning maintenance operations, Equinor conducts simultaneous work when feasible, in order to reduce downtime. Therefore, the total downtime for each component is not the sum of the individual maintenance tasks. [redacted]

Figure 22: Typical Maintenance Downtimes

[redacted]

[redacted]

[redacted]

5.3.2 Forced Outages

As a general matter, forced outages can occur at any time of the year in response to unexpected equipment failures, physical damage to the facility, and other factors creating a need for unplanned maintenance or repairs. [redacted]

6 BUSINESS ENTITY AND FINANCING PLAN

6.1 Financial Outlook

Submit information and documentation that demonstrates that a long-term contract resulting from this RFP process would either permit Proposers to finance Proposals that would otherwise not be financeable or assist Proposers in obtaining financing of its Proposal.

As described further below, Equinor plans to [redacted] and Equinor has already demonstrated a major commitment to offshore wind by financing its existing projects. However, the willingness of Equinor to fund and develop the Empire Wind Project depends upon its ability to obtain long-term contracts to de-risk the project and provide revenue certainty over the life of the project. As a result, obtaining a long-term contract to supply ORECs through this RFP process is critical to the future development of the Empire Wind Project.

6.2 Organizational Structure

Describe the business entity structure of Proposers' organization from a financial and legal perspective, including all general and limited partners, officers, directors, managers, members and shareholders, and involvement of any subsidiaries supporting the Project. Provide an organization chart showing the relationship among the different Project participants. For joint ventures, identify all owners and their respective interests, and document Proposers' right to submit a binding Proposal.

As noted above, this bid is being submitted by Equinor Wind, which is a Delaware limited liability company. Equinor Wind is a wholly owned subsidiary of Equinor US, which, in turn, is an indirect wholly owned subsidiary of Equinor ASA. Figure 23 depicts the organizational structure of Equinor Wind.

Figure 23: Equinor Organization

[redacted]

As described further below in Section 6.3, Equinor Wind currently anticipates funding the development and operation of the Empire Wind Project [redacted]

The leadership of Equinor Wind consists of individuals with significant experience with the development of complex offshore energy resources. An overview of the officers and directors of Equinor Wind is provided below.

6.2.1 Equinor Wind US LLC

Officers

Christer af Geijerstam - *President*

Christer af Geijerstam has held his current position since August 31, 2018 after serving as Manager of Business Development. Mr. af Geijerstam brings a wealth of experience from a range of business areas including strategy, business development, project development, and asset management for oil, gas and offshore wind assets. Prior to joining Equinor in 2008, he worked in Norway's Ministry of Petroleum and Energy in the agency's Exploration Unit.

Michael Olsen – *Leader (Business Development)*

Michael Olsen has held his current position since August 31, 2018. In this role, Mr. Olsen is responsible for business development, public policy, and regulatory issues that impact the company's offshore wind activities in the United States. He was previously Senior Counsel in the Washington, D.C. office of Bracewell LLP. Prior to that, Mr. Olsen served for almost six years in the Bush Administration at the U.S. Department of the Interior, most recently as Deputy Assistant Secretary for Land and Minerals Management. During his time with the U.S. Department of the

Interior, he oversaw a wide range of energy and environmental issues, including the development of offshore renewable energy.

Martin Goff – *Leader (Permitting)*

Martin Goff has held his current position since December 14, 2017. Mr. Goff brings over 10 years of experience in the metocean field prior to Equinor in 2012. As noted above, Mr. Goff was responsible for the environmental assessments and permitting of the Dogger Bank Teesside A&B offshore wind farms in the U.K. and served as Landowner Manager for the 402 MW Dudgeon Offshore Wind Farm.

Tim Thompson – *Project Lead (Business Development)*

Mr. Thompson joined Equinor in 2007 and has served as an officer of Equinor Wind since December 2017. Mr. Thompson is currently serving as Commercial Manager for Equinor's US offshore wind projects. Prior to his work on US offshore wind, he worked primarily as a commercial negotiator and Manager for offshore oil and gas projects in the Gulf of Mexico, negotiating both with other companies and BOEM. Prior to joining Equinor in 2007, Mr. Thompson served various commercial roles across numerous oil and gas regions in the US for Conoco and ConocoPhillips over a 23-year career. Mr. Thompson holds a bachelor's degree in Petroleum Land Management from University of Texas School of Business.

Tom Geczik – *Manager (Tax)*

Mr. Geczik joined Equinor in 2016 as US Tax Manager and has served as an officer of Equinor Wind since 2017. In his current role, Mr. Geczik provides tax related services to Equinor Wind and ensures that US federal income tax compliance as well as state income tax compliance are completed for this entity. Mr. Geczik has worked in tax since 1992, previously in the tax departments of national accounting firms and for the past 18 years in the tax departments of large corporations. Mr. Geczik has a Bachelor of Science in Accounting from Boston College, a Juris Doctor from Case Western Reserve University and a LL.M in Taxation from New York University.

Kathleen Parchinski – *Leader (Tax)*

Ms. Parchinski has worked in Equinor's Tax Department since 2009 and has served as Leader of Tax for Equinor Wind since August 2017. Her current responsibilities include providing tax support to Equinor's US operations, including the New Energy Solutions business, as well as Equinor's International affiliates' activities in the US. Prior to joining Equinor, Ms. Parchinski was a Tax Manager at Ernst & Young. Ms. Parchinski has a Bachelor of Business Administration in Accounting from Pace University and is a Certified Public Accountant.

Miguel Estrada – *Leader (Tax)*

Mr. Estrada has been a tax professional with Equinor since 2017 and has served as the Leader-Tax of Equinor Wind since August 2017. His current responsibilities include supporting the US Equinor group with federal and state income tax compliance and reporting. Prior to joining Equinor, Mr. Estrada was an International Tax Director with a multinational oil and gas service provider in Houston, TX. Mr. Estrada has a Bachelor of Business Administration (Accounting) from the University of Houston and is a Certified Public Accountant licensed by the state of Texas.

Josh Kaplan – *Assistant Secretary*

Mr. Kaplan has been legal counsel with Equinor since July 2017 and has served as assistant secretary of Equinor Wind since August 2017. His current responsibilities include providing counsel on all energy transactional and regulatory matters with a focus on crude oil and associated products in North, Central and South America. Prior to joining Equinor, Mr. Kaplan was assistant general counsel at Noble Americas Corp. where his practice included in addition to the aforementioned energy products, significant work on ethanol, biodiesel, RINs, RECs and related renewable energy credit related matters. Mr. Kaplan has a bachelor of science in Business Administration from the University at Albany, State University of New York and a Juris Doctor from New York Law School.

Christiano Salgado – *Manager (Safety, Security, and Sustainability)*

Mr. Salgado joined Equinor in 2007 and has served as Manager – Safety Security and Sustainability ("SSU") since 2017. Since joining Equinor, Mr. Salgado has held a number of positions within the Company's SSU division. Currently, Mr. Salgado is the SSU Manager for North America in Equinor's Marketing, Midstream and Processing business unit. In this role, he has responsibility for a broad range of SSU functions, including the identification and implementation of SSU best practices, engagement with suppliers to perform supplier verifications and training on Equinor's safety standards, and general emergency response readiness for Equinor's MMP activities in North America. Mr. Salgado has a bachelor of science in Biology and Ecology from the Federal University of Rio de Janeiro – Brazil and a master of science in Biology (Ecology and Evolution) from the University of Houston.

Todd Walls – *Chief Financial Officer*

Todd Walls has been working in Equinor's Finance & Control division since 2013 and has served as Equinor Wind CFO since February 2015. His current responsibilities include accounting and financial service support to Equinor US Mid, Downstream, and Alternative Energy companies. Prior to joining Equinor, Mr. Walls held Controllership positions at LouisDreyfus, Noble, and FCStone. Mr. Walls holds Bachelor of Science degrees in Accounting and Finance from Bryant University.

Meagan Keiser – *Secretary*

Ms. Keiser has been legal counsel with Equinor since 2010 and has served as the Secretary of Equinor Wind since 2013. Her current responsibilities include providing legal support to Equinor's

New Energy Solutions business unit, with a focus on the company's North and South American offshore wind and solar energy activities. Ms. Keiser is lead counsel for the Empire Wind and Boardwalk Wind projects. Prior to joining Equinor, Ms. Keiser was an associate in the energy group at a Washington DC law firm. Ms. Keiser has a Bachelor of Science in Biology and Environmental Sciences from Duke University and a Juris Doctor from the Washington University School of Law.

Knut Aanstad – *President (Former)*

Knut Aanstad served as President from February 7, 2017 through August 31, 2018.

Heidi Aakre – *President (Former)*

Heidi Aakre served as President from June 20, 2016 through February 7, 2017.

Bent Pendersen – *President (Former)*

Brent Pendersen served as President from March 19, 2013 through June 20, 2016.

Gary Aucoin – *Manager (Safety, Security, and Sustainability) (Former)*

Gary Aucoin served as Manager of Safety, Security, and Sustainability from February 24, 2015 through June 30, 2017.

Martin Pastore – *Assistant Secretary and Vice President (Tax) (Former)*

Martin Pastore served as Assistant Secretary and Vice President of Tax from March 19, 2013 through June 30, 2017.

Directors

Trine Ingebjørg Ulla - *Chairman*

Trine Ingebjørg Ulla has served as Director of Equinor Wind since March 19, 2013. Ms. Ulla has held leading positions with Equinor since 2007, and in Equinor's wind business since 2009. She currently holds the position of Senior Advisor to the Senior Vice President for Equinor's Wind and Low Carbon development activities, and has previously headed up Business Development for floating wind and Asset Management for Equinor's wind business. Ms. Ulla is Bid Manager for the Empire Wind and Boardwalk Wind projects. She also serves as Director of Dudgeon Offshore Wind Limited, Wind Power AS, and Equinor New Energy AS. Prior to joining Equinor, Ms. Ulla held leading positions with Norsk Hydro and Saga Petroleum. Ms. Ulla has a Master's degree in Chemical Engineering from the Norwegian University of Science and Technology.

Heidi Aakre – *Director*

Ms. Aakre joined Equinor in 1991 and has held several management roles during this time. Ms. Aakre was the President of Equinor Wind from 2016-2017 and has served as a Director since February 2017. Currently, Ms. Aakre is the Vice President of Midstream Asset Management – North America, supporting Equinor's Marketing, Midstream and Processing business unit. Ms. Aakre is also the President of Equinor Pipelines LLC, Equinor's US midstream company, and is the location manager for the company's Stamford office. Prior to joining Equinor, Ms. Aakre worked as a chemical engineer for the Rogaland Research Institute. Ms. Aakre received a Bachelor's degree in Chemical Engineering from the Bergen School of Engineering and a Master's degree in Business Administration from the Norwegian School of Economics and Business Administration.

Olav Leivestad – *Director*

Mr. Leivestad joined Equinor in 1992 and has held several positions within the company's Finance & Control network. Since 2012, Mr. Leivestad has been employed in the Equinor New Energy Solutions business unit as a financial / business controller and he has been a Director of Equinor Wind since 2013. Mr. Leivestad's current responsibilities including advising senior management and decision makers on business proposals within New Energy Solutions unit related to offshore/onshore wind, low carbon solutions and solar activities. Mr. Leivestad has a master's degree in Finance and Internationalization from the University of Kristiansand, Norway.

Charles O'Brien - *Director*

Mr. O'Brien has been Managing Counsel with Equinor since 1999 and has served as a Director of Equinor Wind since 2013. His current responsibilities include providing legal support to Equinor's Marketing, Midstream & Processing business unit, with a focus on the company's North and South American natural gas, crude oil and refined products liquids activities. Prior to joining Equinor, Mr. O'Brien was an attorney in the Trading & Markets Division of the U.S. Commodity Futures Trading Commission in Washington DC and worked as a trading assistant for several commodity brokerage firms in Chicago. Mr. O'Brien has a Bachelor of Arts in Economics from the University of Illinois at Urbana-Champaign and a Juris Doctor from the Catholic University of America, Columbus School of Law in Washington, DC.

6.3 Financing Plan

Provide a description of the financing plan for the Project, including construction and term financing. The financing plan should address the following:
a. Who will finance the Project (or are being considered to finance the Project) and the related financing mechanism or mechanisms that will be used (i.e., convertible debenture, equity or other) including repayment schedules and conversion features
b. The Project's existing initial financial structure and projected financial structure
c. Expected sources of debt and equity financing
d. Describe how any such agreements would differ, contingency on NYERDA's selecting either the Fixed OREC or Index OREC form of pricing
e. Estimated construction costs

f. The projected capital structure
g. Describe any agreements, both pre and post Commercial Operation Date, entered into with respect to equity ownership in the proposed Project and any other financing arrangement.

6.3.1 Financing Approach

Equinor's strong financial position and access to global capital markets gives Equinor the flexibility and freedom to fund development of the Empire Wind Project in a manner that reduces total costs and optimizes the value of the project for New York. [redacted]

[redacted]

[redacted]

- [redacted]
- [redacted]
- [redacted]
- [redacted]

[redacted]

[redacted]

[redacted]

6.4 Similar Financing

Provide documentation illustrating the experience of Proposer in securing financing for projects of similar size and technology. For each project previously financed provide the following information:
a. Project name and location
b. Project type and size
c. Date of construction and permanent financing
d. Form of debt and equity financing
e. Current status of the project

Equinor has extensive experience financing complex offshore energy projects and has demonstrated the ability to successfully finance offshore wind energy projects of size and scope similar to the proposed Empire Wind Project. As detailed further below in Figure 24, Equinor has funded these projects using a combination of balance sheet and external financing. In total, Equinor has invested over $1.4 billion in the development of its existing offshore wind fleet.

Figure 24: Similar Financings

[redacted]

6.5 Financial Resources and Strength

Provide evidence that Proposer has the financial resources and financial strength to complete and operate the Project as planned.

Equinor Wind, through its U.S. parent, Equinor US, and ultimate parent, Equinor ASA brings with it an unparalleled capability to finance development of the Empire Wind Project. Equinor ASA is an international energy company, headquartered in Norway, that has operations in over 37 countries and approximately 22,000 employees worldwide. Equinor ASA is listed on the New York and Oslo stock exchanges and has a current market capital valuation in excess of $65 billion. Equinor ASA is the largest operator on the Norwegian continental shelf, and a license holder in numerous oil and gas fields worldwide.

Recognizing the changing landscape for energy production, the development of the Empire Wind Project reflects Equinor ASA's strong commitment to complementing its existing oil and gas portfolio with profitable renewable energy and other low-carbon energy solutions. Equinor ASA currently expects that approximately 15% to 20% of its investments will be directed towards renewable and low-carbon energy solutions by 2030. Equinor ASA already has demonstrated a major financial commitment to the development, construction, and operation of offshore wind resources with the development of its existing offshore wind fleet.

Equinor ASA's and Equinor US's ample financial resources and strong credit ratings ensure that these companies have access to the capital markets. In addition, Equinor has access to the global debt markets through the following programs and mechanisms:

- **US Shelf Registration Statement**: Equinor ASA has filed a shelf registration with the U.S. Securities and Exchange Commission. This filing permits Equinor ASA to engage in multiple public offerings without developing a separate prospectus for each offering.

- **Euro Medium Term Note Programme**: Established in 1997 and listed on the London Stock Exchange, the program ensures Equinor ASA access to non-US markets.

Equinor ASA also has access to a $5 billion revolving credit facility supported by twenty-one leading global banks, including Bank of America, Merril Lynch, Citi, Goldman Sachs, JP Morgan, and Morgan Stanley. [redacted] Letters of support from creditors attesting to the strong financial position of Equinor can be found in Attachment 7.

[redacted]

[redacted]

6.6 Role of PTC or ITC

Describe the role of the Federal Production Tax Credit or Investment Tax Credit (or other incentives) on the financing of the Project, including presumed qualification year and percentage. The Proposal may not be contingent on receipt of the Production Tax Credit or Investment Tax Credit.

[redacted]

[redacted]

- [redacted]
- [redacted]

[redacted]

[redacted]

[redacted]

6.7 Financial Statements and Annual Report

Provide complete copies of the most recent audited financial statement and annual report for each Proposer for each of the past three years; including affiliates of Proposer (if audited statements are not available, reviewed or compiled statements are to be provided). Also, provide the credit ratings from Standard & Poor's and Moody's (the senior unsecured long-term debt rating or if not available, the corporate rating) of Proposer and any affiliates and partners.

Because Equinor Wind is a private company, Equinor Wind does not have any credit ratings or financial statements. However, copies of the financial statements of Equinor ASA for the past three years are provided as Attachment 9. In addition, the unconsolidated financial statements of Equinor US for the past three years are provided as Attachment 10.

The current credit ratings of Equinor ASA and Equinor US with Moody's and Standard and Poor's are set forth below in Figure 25[6]:

Figure 25: Credit Ratings

	Equinor ASA		Equinor US
	Moody's	Standard & Poor's	Standard & Poor's
Long-term rating	Aa3	AA-	A
Short-term rating	P-1	A-1+	A-1
Outlook	Stable	Stable	Stable

[6] Currently, Equinor US is only rated by Standard & Poor's.

6.8 Board of Directors

List the board of directors, officers and trustees for the past three years and any persons who Proposer knows will become officers, board members or trustees.

An overview of the officers and directors of Equinor Wind is provided in Section 6.2.

Additionally, as a wholly owned subsidiary of Equinor ASA, Equinor Wind has the ability to draw upon significant resources from its parent company. An overview of the officers and directors of Equinor ASA is provided below.

6.8.1 Equinor ASA Officers and Directors

Officers

Eldar Stære – *President and Chief Executive Officer*

Eldar Sætre has held his current position since October 15, 2014. Mr. Sætre joined Equinor in 1980. He served as Executive Vice President and CFO from October 2003 until December 2010 and as Executive Vice President for Marketing, Processing & Renewable Energy from 2011 until 2014. Mr. Sætre holds a MA in Business Economics from the Norwegian School of Economics and Business Administration in Bergen.

Jannicke Nilsson – *Chief Operating Officer*

Jannicke Nilsson has held her current position since December 1, 2016. Ms. Nilsson joined Equinor in 1999 and has held a number of central management positions within Upstream Operations Norway, including Senior Vice President for Technical Excellence in Technology, Projects & Drilling, Senior Vice President for Operations North Sea, Vice President for Modifications and Project Portfolio Bergen, and Platform Manager at Oseberg South. In August 2013 she was appointed Programme Leader for the Equinor Technical Efficiency Programme, responsible for a project portfolio delivering yearly efficiency gains of 3.2 billion USD from 2016. She holds a M.Sc. in Cybernetics and Process Automation and a B.Sc. in Automation from the Rogaland Regional College/University of Stavanger.

Lars Christian Bacher – *Chief Financial Officer*

Lars Christian Bacher has held his current position since August 1, 2018. Mr. Bacher joined Equinor in 1991 and has held a number of leading positions in Equinor, including that of Platform Manager on the Norne and Statfjord fields on the Norwegian continental shelf. He was in charge of the merger process involving the offshore installations of Norsk Hydro and Equinor. He has also been Senior Vice President for Gullfaks operations and subsequently for the Tampen area, and Equinor's Canadian operations within Development & Production International. He most recently served as Executive Vice President of Development & Production International before moving to his current position. Mr. Bacher holds M.Sc. in Chemical Engineering from the

Norwegian Institute of Technology and a business degree in Finance from the Norwegian School of Economics and Business Administration.

Hans Henrik Klouman – *General Counsel and Senior Vice President (Legal)*

Hans Henrik Klouman has held his current position since August 1, 2011. Mr. Klouman combines a broad legal background and business knowledge with international experience. He has held various executive and board positions in different industries since he began practicing law in 1987. He joined Equinor in 2011, after serving as CEO of SEB Enskilda in Norway for four years. Prior to joining SEB Enskilda in 2007, he was Executive Vice President and General Counsel with the leading Norwegian insurance, pension and banking group Storebrand from 1994 to 2007. From 1987 and until joining Storebrand in 1994 Mr. Klouman worked in the Financial Supervisory Authority, as a Deputy Judge in Sandefjord District Court, in the Norwegian law firm Thommessen, for the Ministry of Finance and at the Oslo Stock Exchange. He holds a Cand. Jur. from the University of Oslo, LLM (Master of Law) from the University of Southampton, UK and a degree from Harvard Business School's Advanced Management Program.

Reidar Gjærum – *Senior Vice President (Corporate Communication)*

Reidar Gjærum has held his current position since May 1, 2005. Mr. Gjærum combines broad communication experience from Norwegian business, journalism, and politics. He joined Equinor as Senior Vice President in 2005 after serving as Executive Vice President for Communications at EDB Business Partners. Prior to EDB Business Partners, Mr. Gjærum held executive positions at JKL Oslo, Telenor, and the Confederation of Norwegian Enterprise. He holds a degree from Harvard Business School's Program for Management Development.

Jon Arnt Jacobsen – Senior Vice President (Audit)

Jon Arnt Jacobsen has held his current position since April 1, 2017. Mr. Jacobsen joined Equinor in 1998 as Senior Vice President for Group Finance. From 2004, he served six years on Equinor's Corporate Executive Committee as Executive Vice President for Manufacturing & Marketing. From 2011 to 2017 he was Equinor's Chief Procurement Officer. Prior to joining Equinor, he worked for Den norske Bank in several capacities within corporate banking, including General Manager at the Singapore branch from 1995 to 1998. Mr. Jacobsen also worked as an analyst at Esso Norge. He holds various degrees from Agder Regional College and the Norwegian Business School, as well as an MBA from the University of Wisconsin.

Magne André Hovden – *Senior Vice President (Corporate People and Leadership)*

Magne André Hovden has held his current position since September 1, 2011. Mr. Hovden joined Equinor in 2009 as VP HR for Projects & Procurement. He has also held executive positions within the oil service and shipbuilding industry. Prior to joining Equinor he was Chief of Staff in STX Europe, previously known as Aker Yards. He also has more than 10 years leadership experience from various roles in the Aker group. He was Senior Vice President of Corporate Human Resources & Health, Safety and the Environment at Aker Solutions, and Senior Vice President of

Human Resources in Engineering & Construction at Aker Kværner. He holds a Cand. Psychol. from the University of Oslo.

Irene Rummelhoff – *Executive Vice President (Marketing, Midstream, and Processing)*

Irene Rummelhoff has held her current position since August 17, 2018. Ms. Rummelhoff joined Equinor in 1991. She has held a number of management positions within international business development, exploration, and the downstream business in Equinor. Her most recent position, which she held from June 2015, was an Executive Vice President New Energy Solutions. She holds a Master’s degree in Petroleum geosciences from the Norwegian Institute of Technology.

Arne Sigve Nylund – *Executive Vice President (Development and Production Norway)*

Arne Sigve Nylund has held his current position since January 1, 2014. Mr. Nylund was employed by Mobil Exploration Inc. from 1983 to 1987. Since 1987, he has held several central management positions in Equinor. He holds a degree in mechanical engineering from Stavanger College of Engineering with further qualifications in Operational Technology from Rogaland Regional College/University of Stavanger. He is also a business graduate of the Norwegian School of Business and Management.

Torgrim Reitan – *Executive Vice President (Development and Production International*

Torgrim Reitan has held his current position since August, 17 2018. Prior to his current role, Mr. Reitan served as Executive Vice President of Development and Production USA as well as Executive Vice President and Chief Financial officer of Equinor. He has held several managerial positions in Equinor, including Senior Vice President of trading and operations for Natural Gas, Senior Vice President in Performance Management and Analysis, and Senior Vice President of Performance Management, Tax, and M&A. From 1995 to 2004, he held various positions in the Natural Gas business area and corporate functions in Equinor. He holds a M.Sc. from the Norwegian School of Economics and Business Administration.

Margareth Øvrum – *Executive Vice President (Development and Production Brazil)*

Margareth Øvrum has held her current position since October 15, 2018. Ms. Øvrum has worked for Equinor since 1982 and has held central management positions in the company, including the position of Executive Vice President for Health, Safety and the Environment and Executive Vice President for Technology & Projects. She was the company's first female platform manager, on the Gullfaks field. She was Senior Vice President for operations for Veslefrikk and Vice President of Operations Support for the Norwegian continental shelf. She joined the Corporate Executive Committee in 2004. Her most recent position was Executive Vice President for Technology, Projects, and Drilling, which she held from September 2011. She holds a Master's degree in Engineering from the Norwegian Institute of Technology in Trondheim, specializing in technical physics.

Anders Opedal – *Executive Vice President (Technology, Projects, and Drilling)*

Anders Opedal has held his current position since October 15, 2018. Mr. Opedal joined Equinor in 1997 as a petroleum engineer in the Statfjord operations. Previously, he worked for Schlumberger and Baker Hughes. He has held a range of positions in Equinor in Drilling and well, Procurement and projects. He served as Chief Procurement Officer in Equinor from 2007-2010. In 2011, he took on the role as Senior Vice President for Projects in Technology, Projects and Drilling responsible for Equinor's approximately NOK 300 billion project portfolio. He served as Equinor's Executive Vice President and Chief Operating Officer before taking the role as Senior Vice President for Development & Production International, Brazil. His most recent position, which he held from August 2018, was Executive Vice President for Development & Production Brazil. He holds an MBA from Heriot-Watt University and Master's degree in Engineering from the Norwegian Institute of Technology in Trondheim.

Tim Dodson – *Executive Vice President (Exploration)*

Tim Dodson has held his current position since January 1, 2011. Mr. Dodson has worked in Equinor since 1985 and held central management positions in the company, including the positions of Senior Vice President for Global Exploration, Exploration Norway and the Technology Arena. He holds a Bachelor's degree of Science in Geology and Geography from the University of Keele.

Al Cook – *Executive Vice President (Global Strategy and Business Development)*

Al Cook has held his current position since May 1, 2018. Mr. Cook joined Equinor in 2016 as the Senior Vice President in Development & Production International overseeing operations in Angola, Argentina, Azerbaijan, Libya, Nigeria, Russia and Venezuela. He joined from BP, where he was Chief of Staff to the CEO. Cook joined BP in 1996, taking on a series of project development and commercial roles in the North Sea and Gulf of Mexico. He then worked in field operations in the North Sea from 2002 to 2005, becoming Offshore Installation Manager. From 2005, he led the IGB2 Project in Vietnam and acted as President for BP Vietnam. Cook worked from 2009 to 2014 as BP's Vice President leading the development of the Shah Deniz field in Azerbaijan and construction of the Southern Gas Corridor. He holds a Masters in Natural Sciences from St. John's College, Cambridge University and International Executive Programme at INSEAD.

Pål Eitrheim – *Executive Vice President (New Energy Solutions)*

Pål Eitrheim has held his current position since August 17, 2018. Mr. Eitrheim joined Equinor in 1998. He has held a range of positions in Equinor in Azerbaijan, Washington DC, the CEO office, and Brazil. In 2013, he led the Secretariat for the investigation into the terrorist attack on the In Amenas gas processing facility in Algeria. His most recent position, which he held from February 2017, was Senior Vice President and Chief Procurement Officer. He holds a Master's Degree in Comparative Politics from the University of Bergen, Norway and University College Dublin, Ireland.

Directors

Jon Erik Reinhardsen – *Chair*

Jon Erik Reinhardsen has served as a member of the board since September 1, 2017 and also serves a chair of the Compensation and Executive Development Committee. Mr. Reinhardsen was the Chief Executive Officer of Petroleum Geo-Services from 2008 to August 2017. PGS delivers global geophysical and reservoir services. The company has its headquarters in Oslo, Norway and offices in 17 countries with approximately 1,800 employees. In the period 2005 to 2008 Reinhardsen was President of Growth for Primary Products in the international aluminum company Alcoa Inc.. From 1983 to 2005, Reinhardsen held various positions in the Aker Kværner group, including Group Executive Vice President of Aker Kværner ASA, Deputy Chief Executive Officer and Executive Vice President of Aker Kværner Oil & Gas AS in Houston, and Executive Vice President in Aker Maritime ASA. He holds a Master's Degree in Applied Mathematics and Geophysics from the University of Bergen. He has also attended the International Executive Program at the Institute for Management Development in Lausanne, Switzerland.

Roy Franklin – *Deputy Chair*

Roy Franklin has served as a member of the board since July 1, 2015. Mr. Franklin previously served as a member of the board from October 2007 to June 2013. He serves as the Chair of the Board's Safety, Sustainability, and Ethics Committee and is a member of the Board's Audit Committee. He has broad oil and gas experience from management positions in several countries, including positions with BP, Paladin Resources plc and Clyde Petroleum plc and holds a Bachelor of Science in Geology from the University of Southampton, UK.

Bjørn Tore Godal

Bjørn Tore Godal has served as a member of the board since September 1, 2010 and is a member of the Board's Compensation and Executive Development Committee and the Board's safety, Sustainability and Ethics Committee. Mr. Godal was a member of the Norwegian parliament for 15 years from 1986 to 2001. At various times he served as Minister for Trade and Shipping, Minister for Defense and Minister of Foreign Affairs for a total of eight years between 1991 and 2001. From 2007 to 2010, he was Special Adviser for international energy and climate issues at the Ministry of Foreign Affairs. From 2003 to 2007, he was Norway's ambassador to Germany and from 2002 to 2003 he was senior adviser at the Department of Political Science at the University of Oslo. From 2014 to 2016, Mr. Godal led a government-appointed committee responsible for the evaluation of the civil and military contribution from Norway in Afghanistan in the period 2001 to 2014. He holds a Bachelor of Arts degree in Political science, History and Sociology from the University of Oslo.

Ingrid Elisabeth di Valerio

Ingrid Elisabeth di Valerio has served as a member of the board since July 1, 2013. Ms. Di Valerio is also the employee-elected member of the board and serves on the Board's Audit Committee.

She has been employed by Equinor since 2005 and works in materials discipline for Technology, Projects & Drilling. Di Valerio was Tekna's main representative in Equinor from 2008 to 2013. She also sat on Tekna's central committee from 2005 to 2013. Ms. Di Valerio is a Chartered engineer (mathematics and physics) who studied at the Norwegian University of Science and Technology in Trondheim.

Per Martin Labråten

Per Martin Labråten has served as a member of the board since June 8, 2017 and is a member of the Safety, Sustainability and Ethics Committee. Mr. Labråthen has worked as a process technician at the petrochemical plant on Oseberg field in the North Sea. Labråthen is now a full-time employee representative as the leader of IE Equinor branch. He holds a craft certificate as a process/chemistry worker.

Wenche Agerup

Wenche Agerup has served as a member of the board since August 21, 2015 and is a member of the Board's Compensation and Executive Development Committee. Ms. Agerup is Senior Vice President Group Holdings in Telenor ASA. She was previously Executive Vice President (Corporate Affairs) and General Counsel in Telenor from 2014 to 2018 and Executive Vice President for Corporate Staffs and General Counsel of Norsk Hydro ASA from 2010 to 2014. She has held various executive roles in Hydro since 1997, including within the company's M&A-activities, the business area Alumina, Bauxite, and Energy, as a plant manager at Hydro's metal plant in Årdal and as a project director for a Joint Venture in Australia where Hydro cooperated with the Australian listed company UMC. She holds a MA in Law from the University of Oslo, Norway and a Master of Business Administration from Babson College.

Rebekka Glasser Herlofsen

Rebekka Glasser Herlofsen has served as a member of the board since March 19, 2015 and is a member of the Board's Audit Committee. In April 2017, Ms. Herlofsen took on a new position as Chief Financial Officer in Wallenius Wilhelmsen Logistics ASA, an international shipping company. Before joining WWL ASA, she was the Chief Financial Officer in the shipping company Thorvald Klaveness. She has broad financial and strategic experience from several corporations and board directorships. Ms. Herlofsen's professional career began in the Nordic Investment Bank, Enskilda Securities, where she worked in corporate finance from 1995 to 1999 in Oslo and London. During the next ten years she worked in the Norwegian shipping company Bergesen d.y. ASA (later BW Group). During her period with Bergesen d.y. ASA/BW Group she held leading positions within M&A, strategy and corporate planning and was part of the group management team. She holds a M.Sc. in Economics and Business Administration and Certified Financial Analyst Program from the Norwegian School of Economics.

Jeroen van der Veer

Jeroen van der Veer has served as a member of the board since March 18, 2016 and is the chair of the Board's Audit Committee. Mr. Van der Veer was the Chief Executive Officer in the international oil and gas company Royal Dutch Shell Plc (Shell) from 2004 to 2009, when he retired. Van der Veer thereafter continued as a non-executive director on the Board of Shell until 2013. He started with Shell in 1971 and has experience within all sectors of the business and has significant competence within corporate governance. He holds an M.Sc. Mechanical Engineering from Delft University of Technology, Netherlands and an M.Sc. in Economics from Erasmus University, Rotterdam, Netherlands. He also holds an honorary doctorate from the University of Port Harcourt, Nigeria.

Stig Lægreid

Stig Lægreid has served as a member of the board since July 1, 2013. Mr Lægreid has been employed in ÅSV and Norsk Hydro since 1985 as project engineer and constructor for production of primary metals and as a weight estimator for platform design. He is now a full-time employee representative as the leader of NITO, Equinor. He holds a Bachelor degree in Mechanical Construction from OIH.

Anne Drinkwater

Anne Drinkwater has served as a member of the board since July 1, 2018 and is a member of the Board's Audit Committee and the Board's Safety, Sustainability, and Ethics Committee. Ms. Drinkwater was employed with BP in the period 1978 to 2012, holding a number of different leadership positions in the company. In the period 2009 to 2012 she was chief executive officer of BP Canada. A British citizen, she has extensive international experience, including being responsible for operations in the US, Norway, Indonesia, the Middle East and Africa. Through her career Ms. Drinkwater has acquired a deep understanding of the oil and gas sector, holding both operational roles, and more distinct business responsibilities. She holds a Bachelor of Science in Applied Mathematics and Statistics from Brunel University London.

Jonathan Lewis

Jonathan Lewis has served as a member of the board since July 1, 2018 and is a member of the Board's Compensation and Executive Development Committee and the Board's Safety, Sustainability, and Ethics Committee. Mr. Lewis joined as Chief Executive Officer to Capita in December 2017; having previously spent 30 years working for large multi-national companies in technology-enabled industries. Lewis came to Capita from Amec Foster Wheeler plc, a global consulting, engineering and construction company, where he was CEO from 2016 to 2017. Prior to this, he held a number of senior leadership positions at Halliburton from 1996 to 2016. He has previously held several directorships within technology and the oil and gas industry. He has an education from the Stanford Executive Program at the Stanford University Graduate School of Business, a PhD in Reservoir Characterization, Geology/Sedimentology from University of Reading and a Bachelor of Science Degree in Geology from Kingston University.

6.9 Security Capability/Plan

Demonstrate Proposer's ability (and/or the ability of its credit support provider) to provide the required security, including its plan for doing so.

Equinor strong financial rating and assets will ensure that Equinor Wind has ready access to letters of credit, parental guarantees, and other forms of security necessary to meet its contractual obligations. In particular, Equinor has ready access to letters of credit or bank guarantees through bilateral agreements with a number of reputable, international banks. A bank issuing a letter of credit or bank guarantee on behalf of Equinor ASA or an affiliated company will normally also be a participant in the Equinor group multicurrency revolving credit facility described above. [redacted]

6.10 Credit Events

Provide a description of any current or recent credit issues/ credit rating downgrade events regarding Proposer or affiliate entities raised by rating agencies, banks, or accounting firms.

None.

6.11 Litigation Events (Project)

Disclose any pending (currently or in the past three years) litigation or disputes related to projects planned, developed, owned or managed by Proposer or any of its affiliates in the United States, or related to any energy product sale agreement.

On September 30, 2018, the United States District Court for the District of Columbia issued an opinion granting motions for summary judgment against a coalition of parties that sought to challenge BOEM's sale of a lease area for the development of offshore wind projects off of the coast of New York. A copy of the opinion is provided as Attachment 11. Shortly thereafter, Fisheries Survival Fund ("Fisheries") filed a motion asking the district court to alter or amend the judgment based on new evidence, namely the issuance of several power purchases agreements for offshore wind facilities proposed for areas other than off New York. Both BOEM and Equinor Wind have opposed Fisheries' motion. The court has yet to act on Fisheries' motion and is under no deadline to do so. Fisheries still retains the opportunity to appeal the September 30, 2018 decision.

Other than this action, there have not been any litigation or disputes related to projects, planned, developed, owned or managed by Equinor Wind or any of its affiliates in the United States or related to any energy product sale agreement.

6.12 Project Lifetime Expectations

Provide the expected operating life of the proposed Project and the depreciation period for all substantial physical aspects of the offer, including generation facilities, generator lead lines to move power to the grid, and transmission system upgrades.

Equinor Wind currently anticipates that the Empire Wind Project and its components will have a [redacted]

Each of the facilities described above will be depreciated in accordance with applicable IRS requirements.

6.13 Affiliated Entities and Joint Ventures

List all of Proposers' affiliated entities and joint ventures transacting business in the energy sector.

As noted above, Equinor Wind is a wholly owned subsidiary of Equinor ASA, an international energy company headquartered in Norway. Through its subsidiaries, Equinor ASA engages in the development of offshore wind facilities as well as the exploration, development, and production of oil and gas around the world. Equinor ASA is the leading operator on the Norwegian continental shelf and has substantial international operations. A full overview of the Equinor ASA and its subsidiaries' business activities are provided in the annual report provided as Attachment 9.

6.14 Litigation Events (General)

Describe any litigation, disputes, claims or complaints, or events of default or other failure to satisfy contract obligations, or failure to deliver products, involving Proposer or an affiliate, and relating to the purchase or sale of energy, capacity or RECs or other electricity products.

Equinor Wind, its parents, and affiliates have not been the subject of any significant, relevant, and adverse litigation, disputes, claims, or complaints, events of default or failure to satisfy contract obligations, or failure to deliver products relating to the purchase or sale of energy, capacity, or RECs or other electricity products.

6.15 Investigation Disclosure

Confirm that Proposer, and the directors, employees and agents of Proposer and any affiliate of Proposer are not currently under investigation by any governmental agency and have not in the last four years been convicted or found liable for any act prohibited by State or Federal law in any jurisdiction involving conspiracy, collusion or other impropriety with respect to offering on any contract, or have been the subject of any debarment action (detail any exceptions).

Equinor Wind, its parents, affiliates, directors, the key employees described above, and agents listed above are not the subject of any significant, relevant, and adverse investigation by any governmental agency and have not in the last four years been convicted or found liable for any act prohibited by state or federal law in any jurisdiction involving conspiracy, collusion, or other impropriety with respect to offering on any contract and have not been the subject of any disbarment action.

7 INTERCONNECTION AND DELIVERABILITY

7.1 Interconnection Request Documentation

Provide documentation to show evidence of the interconnection request to NYISO or any neighboring control areas for Capacity Resource Interconnection Service ("CRIS") or for Energy Resource Interconnection Service, or similar interconnection standards in neighboring control areas. For Proposals where capacity is to be delivered to NYCA, Proposers should describe any required transmission system upgrades and provide an estimate of the required transmission system upgrade costs under NYISO CRIS to meet deliverability requirements in NYISO. Evidence that Proposer has a pending, valid interconnection request is sufficient. Describe the status of any planned interconnection to the grid. Any interconnection studies undertaken by the applicable control area or third parties on behalf of Proposer must be provided.

As noted above, Equinor Wind is proposing to interconnect the Empire Wind Project at the [redacted] As described in detail in the Interconnection Evaluation Study provided as Attachment 12, as starting point for its analysis, Mott MacDonald [redacted]

- [redacted]
- [redacted]
- [redacted]
- [redacted]

Based on the results of these analyses, and extensive dialogue with Equinor Wind, [redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

7.2 Interconnection Facilities Diagram

Provide a copy of an electrical one-line diagram showing the interconnection facilities and the relevant facilities of the transmission provider.

A copy of the electrical one-line diagram showing the interconnection facilities and the relevant transmission facilities of the transmission provider are provided as Attachment 14.

7.3 Proposed and Anticipated Interconnection Upgrades

Identify and provide an estimate of cost, supported by an independent third party, for all proposed or anticipated interconnection and transmission upgrades, including any transmission upgrades beyond the point of interconnection that are needed to ensure delivery of energy from the Offshore Wind Generation Facility into NYCA. Describe measures to identify and control the regulatory and operational risks related to the delivery of energy from the Offshore Wind Generation Facility.

7.3.1 Estimate of System Upgrade Costs

In order to provide a basis for estimating the costs associated with interconnecting the Empire Wind Project to the NYISO system, Equinor Wind engaged Sargent & Lundy Consulting to perform an interconnection study of the Empire Wind Project. As detailed in the System Reliability Impact Study for the Empire Wind Project provided as Attachment 15, Sargent & Lundy performed an [redacted] Sargent & Lundy currently estimates that the interconnection of the Empire Wind Project will [redacted]

7.3.2 Estimate of Interconnection Facilities Cost

Equinor Wind plans to construct interconnection facilities that will deliver energy produced by the Empire Wind Project directly into the New York Control Area. These facilities will include an offshore substation, export cables, a new onshore substation, and related interconnection facilities. The design of this system is based on the design of the electrical system of the Dudgeon offshore wind project, which has allowed Dudgeon to achieve an unparalleled level of reliability and availability since commencing commercial operations. Based on Equinor Wind's experience

[redacted]

7.4 Energy Delivery into NYCA

Demonstrate that energy and associated ORECs generated by the facility can be delivered into the NYCA. For an Offshore Wind Generation Facility interconnecting in an adjacent Control Area, describe how Proposer intends to fulfill the External Project Delivery Requirement.

As noted above, the Empire Wind Project will interconnect directly to the New York Control Area.

7.5 Available Capacity

Provide detail regarding the available capacity, at the time of submission, of the proposed Injection Point.

[redacted]

8 ENVIRONMENTAL ASSESSMENT AND PERMIT ACQUISITION PLAN

8.1 Permits, Licenses, and Environmental Documentation List

Provide a comprehensive list of all the permits, licenses, and environmental assessments and/or environmental impact statements required to construct and operate the Project. Along with this list, identify the governmental agencies that are responsible for issuing approval of all the permits, licenses, and environmental assessments and/or environmental impact statements. If a Proposer has secured any permit or has applied for a permit, please indicate this in the response. Provide the anticipated timeline for seeking and receiving the required permits, licenses, and environmental assessments and/or environmental impact statements. Include a Project approval assessment which describes, in narrative form, each segment of the process, the required permit or approval, the status of the request or application and the basis for projection of success by the milestone date. All requirements should be included on the Project schedule.

Equinor Wind has reviewed federal and state permitting requirements in detail in order to identify the regulatory frameworks governing the construction and operation of the Empire Wind Project. As noted in Section 3 of this application, the Empire Wind Project will be located in federal waters off the coast of New York and interconnected to the New York Control Area.

This Environmental Assessment and Permit Acquisition Plan (for the purpose of this section, the “Plan”) provides a summary of the information required for each applicable regulatory approval, as well as a strategy for obtaining these approvals, including efficient coordination among agencies to facilitate a more streamlined permitting timeline. The Plan is supported by comprehensive environmental and technical assessments that are either in process or planned. Additional details are provided in the permitting matrix provided as Attachment 16. Details on the timeline and associated milestones for this Plan have also been incorporated into Section 10 of this application.

The following sections provide a narrative overview of the federal, state, and local approvals that will be required for the Project to initiate construction. As discussed further below, Equinor Wind already has taken significant steps towards obtaining the permits and approvals necessary for the development of the Empire Wind Project. Notably, Equinor Wind has obtained approval of its SAP from BOEM and is actively preparing its COP.

Equinor Wind also has been actively engaged with relevant stakeholders, including state and federal agencies about the Empire Wind Project and required permits and approvals. These include: the New York State Department of State (“NYSDOS”), New York State Department of Environmental Conservation (“NYSDEC”), New York State Office of Parks, Recreation and Historic Preservation (“NYSOPRHP”) , New York State Department of Public Services (“NYDPS”), New York State Office of General Services (“NYSOGS”) and NYSERDA, including ongoing participation in New York State’s Environmental Technical Working Group (“E-TWG”) and Fisheries Technical Working Group (“F-TWG”). Additional details describing when and how state agencies are and will be involved are provided below, summarized in the permitting matrix provided as Attachment 16 and tracked in the Stakeholder Tracking Matrix, see Attachment 17.

8.1.1 Federal Permits

U.S. Dept. of Interior, Bureau of Ocean Energy Mgmt.

The federal permitting process will be largely coordinated by BOEM and will include a review of environmental impacts under the National Environmental Policy Act of 1969 ("NEPA").[8] Under NEPA, federal agencies evaluate the potential impacts of any proposed major federal action with the potential to significantly affect the quality of the human environment. Through this process, federal agencies will also consider alternatives to the proposed action. BOEM serves as the lead federal agency for NEPA review and compliance with respect to the Empire Wind Project.

BOEM's jurisdictional obligations are defined under the Outer Continental Shelf Lands Act ("OCSLA") as implemented through regulations governing Renewable Energy and Alternate Uses of Existing Facilities on the Outer Continental Shelf. Under OCSLA, as amended by the Energy Policy Act of 2005, the Secretary of the Interior is authorized to issue leases for wind and other alternative energy development on the outer continental shelf ("OCS"). The OCS is defined as all submerged lands and seabeds within U.S. navigable waters, seaward and outside of the state jurisdiction or 3 nm.[9] Under delegated authority from the Department of the Interior, BOEM issued Lease OCS-A-0512 to Equinor Wind. This lease is the primary mechanism by which BOEM regulates the use of the submerged lands for the Empire Wind Project.

Detailed information about proposed activities and schedule requirements for the BOEM process are defined in both the Lease and in applicable regulatory guidelines. A summary of these requirements and timelines is provided in Figure 26.

[8] 42 U.S.C. § 4321 *et seq*.
[9] *See* 43 U.S.C. § 1301.

Figure 26: BOEM Requirements and Lease OCS-A-0512 Stipulations

Filing/Milestone	Description	Required by	Date
SAP Survey Plan	A description of methods and timing of surveys necessary to meet the information requirements of 30 C.F.R. § 585.610-611, including shallow hazards, geological, biological, geotechnical, and archaeological surveys. Plan submitted to BOEM for review and comment.	Lease Addendum C, Section 2.1.1 Survey Plan(s)	At least 30 calendar days prior to the date of the pre-survey meeting At least 90 days prior to start of marine surveys
Pre-Survey Meeting for the SAP surveys	Hold a pre-survey meeting with BOEM at which a qualified marine archaeologist must be present to discuss the SAP Survey Plan.	Lease Add. C, Stipulation 2.1.2 Pre-Survey Meeting(s) with the Lessor	At least 60 days prior to start of SAP surveys
SAP	Plan due at the end of the Preliminary Term (*i.e.*, 12 months after the Effective Date) describing the activities to collect wind resource and metocean measurements using buoys or fixed-platform meteorological towers.	30 C.F.R. §§ 585.235(a)(1) and 585.601(a)	Prior to the end of the Preliminary Term
Semi-Annual Progress Report	A semi-annual progress report throughout the duration of the site assessment term providing a brief narrative of the overall progress since the last progress report.	Lease Add. C, Stipulation 2.2.1 Semi-Annual Progress Report	Every 6 months after SAP approval
Construction and Operation Survey Plan	A plan describing the methods and timing of surveys necessary to meet the information requirements of a COP (§ 585.626 and 627). These surveys include shallow hazards, geological,	Lease Add. C, Stipulation 2.1.1 Survey Plan(s)	At least 30 calendar days prior to pre-survey meeting

Filing/Milestone	Description	Required by	Date
	biological, geotechnical, and archaeological.		At least 90 days prior to start of marine surveys
Pre-Survey Meeting for the COP surveys	Hold a Pre-Survey Meeting with BOEM at which a Qualified Marine Archaeologist must be present, to discuss the COP Survey Plan.	Lease Add. C, Stipulation 2.1.2	At least 60 days prior to start of COP surveys
Construction and Operation Plan	A plan describing the activities for constructing and operating an offshore wind project that includes the requirements of § 585.601, 626, and 627.	30 C.F.R. § 585.601(b)	6 months prior to the end of the 5-year Site Assessment Term
Facility Design Report	A report that provides specific details of the design of any facilities, including cables and pipelines that are outlined in the approved SAP and/or COP, which demonstrates that the design conforms to the responsibilities listed in §585.105(a).	30 C.F.R. § 585.701	May be submitted with COP or following COP approval.
Fabrication and Installation Report	A report that describes how the facilities will be fabricated and installed in accordance with the design criteria identified in the FDR; the approved SAP and/or COP, and generally accepted industry standards and practices.	30 C.F.R. § 585.702	May be submitted with COP or following COP approval.

Equinor Wind already has taken significant steps towards obtaining the approvals necessary to develop the lease area. In accordance with BOEM's requirements, on June 18, 2018, Equinor Wind submitted a SAP to BOEM setting out its plan for the installation of metocean facilities at the Empire Wind Project site. On August 22, 2018, BOEM notified Equinor Wind that its SAP was complete. Equinor Wind amended the SAP in July 2018, August 2018, and October 2018. A copy of the SAP is provided as Attachment 18.

On November 21, 2018, after appropriate consultations with relevant federal, state and tribal entities, local governments, and potentially affected stakeholders, BOEM approved the SAP, clearing the way for the subsequent installation of the metocean facilities in the lease area. A copy of BOEM's approval of the SAP is provided as Attachment 19. On December 2, 2018, Equinor Wind installed the metocean facilities in the lease area.[10]

The next step in the process is for Equinor Wind to continue with site assessment and proceed with development of its COP. [redacted]

In addition to the environmental assessments that will be presented in the COP, Equinor Wind is required to prepare a preliminary Oil Spill Response Plans ("OSRP") and a Safety Management System ("SMS") associated with *operations* of the wind farm. The OSRP will be prepared in accordance with 30 CFR 254 "*Oil Spill Response Requirements for Facilities Located Seaward of the Coastline*," and will document the types and quantities of oil-filled equipment associated with the WTGs and offshore substation(s), as well as spill response capabilities and procedures. The SMS will be prepared in accordance with the BOEM and Bureau of Safety and Environmental Enforcement ("BSEE") Technology Assessment Program #633- "*Wind Farm/Turbine Accidents and the Applicability to Risks to Personnel and Property on the OCS, and Design Standards to Ensure Structural Safety, Reliability, Survivability of Offshore Wind Farms on the OCS*," and the applicable guidelines, while also considering relevant standards set forth in USCG regulations for unmanned facilities or other safety regulations under 33 CFR 142 through 33 CFR 146. Additionally, Equinor Wind will draw upon its experience in offshore wind operations in Europe to support the development of these documents. Both the OSRP and SMS documents will be subject to the review and approval of BSEE.

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[10] Prior to deployment of the metocean facilities, Equinor Wind submitted and received approval for a private aid to navigation ("PATON") from the U.S. Coast Guard ("USCG"). In addition, the metocean facilities are covered under Nationwide Permit #5, "Scientific Measurement Devices," which does not require pre-construction notification to the U.S. Army Corps of Engineers ("USACE"). *See* Section 8.1.1 for additional details on USACE permitting anticipated for the Project.

[11] Per Secretarial Order 3355, BOEM is obligated to undertake a page-limited Environmental Impact Statement ("EIS") and target completion of its NEPA review (*i.e.*, publication of a final EIS) within 12 months of the publication of a Notice of Intent to prepare an EIS. Additionally, per Executive Order 13807, a Memorandum of Understanding was signed by federal regulatory agencies to agree to a single timeline of environmental reviews and authorization decisions for proposed major infrastructure projects, prepare a single EIS, sign one ROD, and issue all necessary authorization decisions within 90 days of issuance of the ROD.

Following COP approval, Equinor Wind will submit a Facility Design Report ("FDR") and Fabrication and Installation Report ("FIR") for BOEM approval prior to construction. In accordance with 30 C.F.R. § 585.705, Equinor Wind will be required to enlist a Certified Verification Agent ("CVA") to review and certify the FDR and FIR to ensure that the facilities are designed, fabricated and installed in conformance with accepted engineering practices and the FDR and FIR. [redacted]

U.S. Army Corps of Engineers

Equinor Wind has been in the process of conducting site investigations in federal waters (*e.g.*, geotechnical, geophysical borings) to support the design of the export cable and the wind farm. These activities meet the requirements of a Nationwide Permit #6 for Survey Activities.[12] As discussed in previous sections, activities associated with facilities associated with the SAP qualify for a Nationwide Permit #5.

Equinor Wind anticipates that an Individual Permit from the U.S. Army Corps of Engineers ("USACE"), New York District will be required for dredging and installation activities in Waters of the U.S. For dredging and excavation, Section 404 of the Clean Water Act ("CWA") (33 U.S.C. § 1344) prohibits the discharge of dredged or fill material into navigable waters of the United States without a permit from the USACE. Navigable waters are "subject to the ebb and flow of the tide and/or presently used, or have been used in the past, or may be susceptible for use to transport interstate or foreign commerce" (33 C.F.R. § 329.4). Section 401 of the CWA requires applicants to obtain a certification or waiver from the NYSDEC for any activity that may result in a discharge of a pollutant into waters of the United States, including any dredged or fill materials. Section 10 of the Rivers and Harbors Act of 1899 (33 U.S.C. § 401 *et seq.*) requires a permit from the USACE for construction of any structure, such as wind turbine generators and/or a submarine transmission cable, in or over any navigable waters of the United States. USACE also regulates dredging activities pursuant to Section 10 of the Rivers and Harbors Act. USACE is expected to be a cooperating agency under NEPA to satisfy the NEPA requirements for the Individual Permit. The CWA application package will include: ENG Form 4345, project drawings, and other supporting information. In the event that activities propose impacts to wetlands subject to USACE jurisdiction (*e.g.*, tidal wetlands), Equinor Wind will be required to complete field delineations to define the wetland boundary and corresponding buffer. The delineation is subject to review and approval by USACE through the permitting process. Depending on the nature and extent of dredging activities, USACE may require sampling and analysis of proposed dredge material to characterize this material within the permit application. Any characterization of proposed dredge material will also be coordinated with NYSDEC within state jurisdictional

[12] Any activities located in state waters will require the state water quality certificate and coastal zone consistency determination. This is predicated on proposed activities meeting NY-regional specific conditions. Equinor Wind is consulting with both NYSDEC and NYSOGS for work proposed within the 3 nm jurisdictional boundary and preparing the required documentation in support of this work.

waters see Section 8.2 below. Depending on the nature of these impacts, mitigation may be required.

USACE also regulates occupancy for any project that would be located within a federally sponsored project (*e.g.*, navigational channels, anchorages, beach replenishment), regardless of whether the sponsorship is partial or whole under Section 408 of the CWA. Equinor Wind will review the project details with USACE to determine the applicability of these requirements to the Project.

U.S. Coast Guard

The USCG, Sector New York will issue a PATON approval for navigational lighting on structures above the waterline (*e.g.*, FLiDAR buoys, WTGs, and offshore substation platforms) once the USACE permit is obtained. Approximately two weeks prior to the initiation of construction activities, the USCG will publish a Local Notice to Mariners ("Notice"), which will remain in effect throughout the construction period. USCG will also be a cooperating agency under NEPA and will review the Navigation Safety Risk Assessment associated with the proposed facilities. A separate PATON application and corresponding Notice will be required for the wind farm operations.

U.S. Environmental Protection Agency

The United States Environmental Protection Agency ("EPA"), Region 2 will review the Empire Wind Project for potential air emissions associated with construction and operation and maintenance vessels with respect to state non-attainment areas for criteria pollutants. The EPA will require an air quality permit for project-related activities on the OCS under the Clean Air Act ("CAA"), including emergency generators, should they be installed in the turbine towers, and marine vessels used for construction and/or operation while such vessels are physically attached to the seafloor.

As part of the OCS air permit process, a Corresponding Onshore Area ("COA") will be identified by the EPA in order to determine what federal and state air quality regulations may apply to the project. In most cases, the COA will be the nearest point of land to a proposed project. In this case, New York is geographically closest to the lease area and it will likely be designated the COA by default.

To protect human health, the EPA establishes National Ambient Air Quality Standards ("NAAQS") pursuant to the CAA that apply to outdoor air throughout the country. For each NAAQS pollutant and averaging period, the EPA may designate a specified geographic area as being in attainment of the standard, as being in nonattainment of the standard, or as being a maintenance area (*i.e.*, an area that was previously in nonattainment but has since been redesignated as attaining the standard due to ongoing improvements in local air quality). Because the COA for the lease area will be a nonattainment or maintenance area for several pollutants, a General Conformity analysis pursuant to 40 C.F.R. pt. 93 will be required for air emissions occurring within 3 nm from shore (and potentially as far as 25 nm from the state seaward boundary), both for construction of the project and for any operational air emissions that will not be included in the OCS air permit. If calendar year emissions of any pollutant exceed the applicable General Conformity threshold, then a formal determination of General Conformity will be required.

The OCS air permit and General Conformity determination will cover offshore construction and operation, as well as onshore and offshore construction, but will not cover onshore operation (*i.e.*, stationary sources). If an onshore substation is built with an emergency generator engine for operations, that engine could require state-only minor source air permitting in New York. As Equinor Wind refines the design of the Empire Wind Project, Equinor Wind will engage with NYSDEC to determine applicable requirements.

Under Section 402 of the CWA, the EPA will issue a National Pollutant Discharge Elimination System ("NPDES") Vessel General Permit for the discharge of any pollutant into navigable waters outside of the New York State jurisdictional boundary. EPA has delegated authority to NYSDEC for any State Pollutant Discharge Elimination System ("SPDES") permits that may be required within state jurisdiction, see Section 8.2 below.

Other Federal Agencies

Because the Empire Wind Project is outside of the federal territorial seas (defined as 3 nm to 12 nm), the Federal Aviation Administration ("FAA") review of structures over 200 feet will not apply to the project. However, BOEM has incorporated FAA guidance on marking and lighting in its own guidance. See Section 9.2 of this proposal for a discussion on lighting.

The Department of Defense ("DoD") will be consulted to ensure that the location of the wind turbines, offshore substation platforms, and submarine transmission cable will not interfere with military practice areas, firing ranges, submarine routes, military radar and/or other features of concern.

Environmental resource protection agencies, including the National Oceanic and Atmospheric Administration, National Marine Fisheries Service ("NOAA NMFS") and the U.S. Fish and Wildlife Service ("USFWS"), Northeast Region (Region 5), will be responsible for reviewing project impacts to protected resources and evaluating the need for mitigation through prescribed best management practices. These agencies will have the opportunity to review environmental documents and comment through inter-agency consultations required pursuant to NEPA. NOAA NMFS and USFWS will review impacts to marine, coastal, and terrestrial threatened and endangered species protected by the federal Endangered Species Act ("ESA"). Impacts to non-listed species and habitats will also be evaluated under several other wildlife protection laws, including the Migratory Bird Treaty Act of 1918 ("MBTA"), the Bald and Golden Eagle Protection Act ("BGEPA"), the Marine Mammal Protection Act of 1972 ("MMPA"), and the Magnuson-Stevens Fishery Conservation and Management Act ("MSFCMA"). Additionally, in accordance with 50 C.F.R § 600.920(e)(1), BOEM and NOAA NMFS will assess impacts to Essential Fish Habitat.

Under the MMPA and ESA, NOAA NMFS and USFWS are required to review any activity that may result in the unintentional "taking" of marine mammals and of sea turtles and fish incidental to activities including construction projects. Incidental take is authorized if it is determined that the taking would: (a) be a small number; (b) have no more than a negligible impact; and (c) not have an unmitigable adverse impact. Incidental Take Authorizations can be provided in the form of an Incidental Harassment Authorization or a Letter of Authorization, depending on the nature and duration of the activity.

Implementation of the following federal statutes has been delegated to the State of New York:

- The Coastal Zone Management Act ("CZMA") requires that the NYSDEC, the agency responsible for administering the New York Coastal Management Program, provide a determination that construction and operation of the proposed Empire Wind Project is consistent with New York coastal protection policies.
- The CWA Section 401 permit ("State Water Quality Certificate") must be issued as a pre-requisite to the USACE permit.
- NYSDEC has delegated authority for CWA Section 404. In some locations, USACE Section 404 and NYSDEC permits will be required, see Section 8.2 below.
- NYSDEC has the delegated authority to implement Section 402 of the CWA and thus enforces the NYSDEC under its NYSDEC program and will issue permits required for the installation of the transmission cable to shore and substation upgrades see Section 8.2.

Additionally, the National Historic Preservation Act of 1966 ("NHPA") requires consultation with the State Historic Preservation Office and with the Tribal Historic Preservation Office of any Native American Tribes which may be affected by the Empire Wind Project. Section 106 of the NHPA requires federal agencies to take into account the effects of a proposed action on properties eligible for inclusion in the National Register of Historic Places ("NRHP") and, if applicable, develop plans to avoid, minimize, or mitigate adverse effects to the historic properties. "Properties" are defined as "cultural resources," which include prehistoric and historic sites, buildings, and structures that are listed on or eligible for listing in the NRHP.

8.1.2 State Permits

NY Public Service Commission and Department of Public Service Commission

The primary state environmental review and approval for the Empire Wind Project is defined by Article VII of the Public Service Law. At the conclusion of the Article VII process, Equinor Wind will be issued a Certificate of Environmental Compatibility and Public Need ("ECPN"), which is required for the siting of major utility infrastructure[13] in the state of New York. The Article VII application will address the proposed transmission system connecting the offshore wind farm to the interconnecting substation including any associated infrastructure upgrades (*e.g*. switching station) that may be required for deliverability at the interconnection point. Applications for major electric transmission lines, like the one to be proposed by Equinor Wind, are governed by 16 NYCRR Part 86 and 88. The Article VII process supersedes other State and local permits except for federally authorized permits, such as the NYSDOT Accommodation Permit subject to review by the Federal Highway Authority ("FHWA").

The Public Service Commission ("PSC") regulates investor-owned electric, natural gas, steam, telecommunications, and water utilities in New York State and issues the ECPN. The PSC decides any application filed under Article VII, the certification review process for major electric and gas transmission facilities. The Department of Public Service ("DPS"), who serve as staff to the PSC, is the State agency that carries out the PSC's legal mandates. Namely, one of DPS's responsibilities is to participate in all Article VII proceedings to represent the public interest.

The Article VII Application will be prepared based on the results of various technical studies. The application will include a description of the preferred alternative, presentation of the technical studies and potential impacts, a discussion of project need and an evaluation of alternatives. The application will also identify pertinent local regulations in the towns and counties traversed by the transmission line and will indicate those regulations that are considered unduly restrictive. The application will also include supporting direct testimony from the technical experts who will serve as potential witnesses during evidentiary hearings. Consultation with the PSC staff prior to completion of the Application will be used to provide guidance regarding the scope of the technical studies to be included in the Application.

Statutory parties to the Article VII process must be provided copies of the Article VII Application. These parties include: each municipality in which any portion of the facility is to be located, various state agencies, and each member of the state legislature through whose district the facility is to be located. Once the Article VII application is filed with the PSC, staff will conduct a completeness determination review of the application and initiate the review process.

New York State Department of Environmental Conservation

NYSDEC is primarily a cooperating agency in the Article VII review process. Subject matter experts in wetlands, wildlife, contaminated soils, fisheries etc. will participate in the discovery process during the Article VII review, however the ultimate approval of the Empire Wind Project rests with the PSC for wetlands permitting and other environmental approvals.

[13] Major electric transmission facilities are lines with a design capacity of 100 kV or more extending for at least 10 miles, or 125 kV and over, extending a distance of one mile or more.

NYSDEC has the delegated authority to implement Section 402 of the Clean Water Act and thus enforces the SPDES and will issue permit(s) for the installation of the transmission cable to shore (e.g., construction stormwater permit and/or discharge permit for construction dewatering).

New York State Department of State

NYSDOS, is responsible for administering the New York State Coastal Management Program ("NYS CMP"). Consistency review is the tool which enables the NYSDOS to manage coastal uses and resources while facilitating cooperation and coordination with involved state, federal and local agencies. The "consistency" of a proposed activity with the NYS CMP is determined through a set of coastal policies and procedures designed to enable appropriate economic development while advancing the protection and preservation of ecological, cultural, historic, recreational, and esthetic values.

New York State Office of General Services

NYSOGS holds title to the seabed within 3 nm of the coastline "in trust" for the people of the State of New York. Structures located in, on, or above submerged state-owned lands are regulated under the Public Lands Law and may require authorization from the state. A submerged lands lease will be required by the NYSOGS for the export cable to shore.

New York State Energy Research and Development Authority

NYSERDA is the lead agency coordinating offshore wind opportunities in New York State. In support of the Governor's proposal to meet 100 percent of New York's electricity needs with carbon-free sources by 2040, NYSERDA continues to work closely with coastal communities and the fishing and maritime industries to identify offshore wind sites to be included in New York State's Offshore Wind Master Plan ("Master Plan"). Although it has no permitting authority, it may impose certain conditions via issuance of the bid award in order to support meeting objectives described in the Master Plan. In addition, the assessments and surveys conducted by NYSERDA to inform the Offshore Wind Master Plan will be of significant value towards informing Equinor's development plans, permitting, and stakeholder outreach.

New York State Department of Transportation

As the onshore route may be located in state highways, parkways, and expressway rights-of-way, authorization may be required from the New York State Department of Transportation ("NYSDOT"), including a Highway Access Permit and a Permit for Use and Occupancy within State Rights-of-Way.

NYSDOT has an agreement with the FHWA regarding how utilities are accommodated on controlled access highways (Accommodation Plan for Longitudinal Use of Freeway Right-of-Way By Utilities); however, only communication utilities are permitted. Therefore, any request for a non-highway use of a controlled access highway (*i.e.*, for construction and operation of the

Empire Wind Project) is considered an exception to the Accommodation Plan and would require approval by the Federal Highway Administration. Unlike the other approvals described in this plan, the FHWA approval is issued to NYSDOT and not Equinor Wind.

State Coordination

The environmental assessment activity for the Empire Wind Project through the Article VII process, as described above, and will rely on input from NYSDEC, OPRHP, and NYSDOS to inform the review. These agencies will similarly play a significant role in the NEPA process and will be asked to coordinate with BOEM.

8.1.3 Local Permits

Since the Article VII process supersedes local permitting, the PSC has the authority to grant waivers from local ordinance requirements that are determined to be unreasonable or prohibitive to construction and operation of a transmission project determined to be in the public interest of New York residents. The threshold to obtain a waiver for local ordinances is high. Accordingly, this pathway will only be taken if there are no other commercial or technically viable alternatives. In the event that zoning variances may be required from local planning boards, the PSC will expect a good faith effort to have been made by Equinor Wind to reach an agreement between the municipalities, prior to seeking a waiver. Compliance with applicable ordinances and any requests for waivers (if needed) will be prepared as part of the initial Article VII application.

8.1.4 Federal and State Agency Coordination

As discussed above, as the lead federal agency under NEPA, BOEM is responsible for reviewing and approving the SAP Survey Plan, SAP, COP Survey Plan, and COP, as well as the FDR/FIR. BOEM will prepare an EIS upon the completeness determination of the COP. After public comment and formal review of the EIS, BOEM will issue an ROD for the Empire Wind Project. The ROD will explain BOEM’s decision, describe the alternatives BOEM considered, and discuss mitigation and monitoring to be undertaken by the project proponent, if necessary.

During its technical review of the abovementioned documents, BOEM will engage in formal consultation with the cooperating federal agencies (*e.g.*, USACE, USFWS, NOAA NMFS, EPA, etc.) under the CZMA, ESA, MBTA, BGEPA, MMPA, MSFCMA, CWA, and CAA. Additionally, state agencies, particularly those delegated authority as discussed in Section 8.2 above, will be engaged in review of the COP and other permit applications, in coordination with the federal NEPA review.

Similar to the federal review process, several consultations will be required prior to approval of permits, including the Division of Parks and Forestry, Natural Heritage Program for impacts to threatened and endangered species; and the Historic Preservation Office for consultation under the New York Register of Historic Places Act and Section 106 of the NHPA.

Equinor Wind has been actively engaged with these agencies and other stakeholders to share results and discuss potential impacts from the Empire Wind Project.

8.2 Pending Permits, Licenses, and Environmental Documentation Timing

Provide the anticipated timeline for seeking and receiving the required permits, licenses, and environmental assessments and/or environmental impact statements. Include a Project approval assessment which describes, in narrative form, each segment of the process, the required permit or approval, the status of the request or application and the basis for projection of success by the milestone date. All requirements should be included on the Project schedule in as described in Section 6.4.10.

This section describes the sequence for seeking and receiving the required permits, licenses, and environmental assessments and/or environmental impact statements. At the time that this proposal was prepared, Equinor Wind has completed activities associated with the SAP and certain COP surveys; therefore, the information presented is on a going forward basis. As the Empire Wind Project proceeds, a variety of tasks will be moving in parallel path. From study planning to survey execution and stakeholder outreach, the number of ongoing activities that must be tracked diligently in order to maintain consistency and quality will demand careful attention and thorough record keeping. Given the complexity of a proposed offshore wind farm and the number of technical details that must be managed, it is critical for the project team to have a well-developed process for keeping track of commitments and environmental requirements either offered by Equinor Wind or required through permitting. A Commitments Register has been developed that includes information about the origin of the commitments and/or environmental requirements (when they were made and who they were made to), what aspect of the facility the requirements apply to (*e.g.*, installation of the submarine cable, pre-construction notification, etc.), and estimated start/end of that commitment to ensure a successful project.

Equinor Wind believes in early and frequent engagement with relevant regulatory agencies. Public involvement in both the federal and state regulatory process is important and has and will continue to be managed proactively. Stakeholders include, but are not limited to: Congressional delegations; federal, state, and local regulatory agencies; citizen groups; environmental/nongovernmental groups; coastal states; Native American tribes; fishermen's organizations; recreation and tourism interests; marine trades; commercial interests; and the general public or other groups with broad interest in the Empire Wind Project. Details on outreach to these entities and others are further described in other sections of this RFP (*see e.g.*, Community Outreach Plan; Environmental Mitigation Plan, and Fisheries Mitigation Plan).

8.2.1 Phase I: COP, Article VII, Coastal Consistency and NYSDOT Submittals

Status: Under preparation

Anticipated Submittal: [redacted]

Anticipated Completion: [redacted]

In general, the COP and Article VII application are the two primary environmental and siting approvals that have the longest durations and require the most detailed impact assessments. Public involvement is a critical aspect of both review processes and therefore it is preferable to file both applications close together. Several environmental assessments are needed to support the characterization of baseline conditions and potential impacts, which are further detailed in [redacted]. These assessments are either in progress or will be initiated so that information can be incorporated into the COP and the Article VII applications, including but not limited to:

- Offshore site characterization surveys, including benthic, geophysical, metocean, geotechnical, and marine archeological assessments
- Offshore avian surveys
- Marine mammals and sea turtles monitoring
- Bat Monitoring
- Essential Fish Habitat Assessment
- Wetlands delineation
- Terrestrial cultural surveys
- Visual surveys
- Historic properties surveys
- Navigational risk safety assessment
- In-air noise
- Cable burial risk assessment
- Aviation risk assessment
- Underwater noise acoustic modeling
- Air quality modeling
- Sediment transport analysis
- Electromagnetic Field (“EMF”) modeling

Consultations with various agencies will be completed to support the assessments. As information becomes available, Equinor has been, and will be, proactive with sharing results with the appropriate authorities.

An additional requirement for the Article VII application is the SRIS, prepared by NYISO as a result of the interconnection requests filed by Equinor. It is anticipated that this will be received in advance of the submission of Equinor Wind’s application submittal to NYSDPS.

At the time Equinor Wind submits the COP to BOEM, a copy will be provided to NYSDOS, NYSDEC, NYSOPRHP, NYDPS, NYSOGS and NYSERDA, so that each agency may provide input on the COP concurrently with BOEM’s review. Equinor Wind has and will continue to consult with each of these agencies up to COP submissions in order to seek, and where required, apply any feedback. Upon receipt of comments from any of these agencies, Equinor will request a meeting to review and resolve any concerns that are expressed. A copy of all federal application materials will also be submitted to NYSDOS at the same time they are sent to the federal permitting agency to support the Coastal Consistency Determination. Equinor will certify to the federal agency and the NYSDOS that the Empire Wind Project complies and is consistent with the New York State Coastal Management Program. No federal agency can issue a permit for a project affecting New York's coastal area until the NYSDOS concurs with the consistency certification. By federal regulation, NYSDOS has six months to complete its review of a consistency certification and make a decision. Typically, most consistency reviews can be completed within one or two months. To date, Equinor has consulted with, and will continue to consult with the abovementioned agencies on development of the COP, and therefore those agencies have had and will have opportunities to input into and comment on the process prior to final COP submission.

Approval of the Article VII application will be contingent on NYSDOT and FHWA approving the proposal for certain portions of the export cable within NYSDOT rights of ways ("ROWs"). As such, Equinor intends to submit its application to NYSDOT at the same time as the Article VII application.

Under Secretarial Order 3355 and Executive Order 13807[14], [redacted]

8.2.2 Phase II: USACE, EPA, NYSOGS, NOAA NMFS Application Submittals

- *Status: Planning*
- *Anticipated Submittal:* [redacted]
- *Anticipated Completion:* [redacted]

The Atlantic seaboard has certain areas that are identified as hazard areas, as reflected on the NOAA Navigational Charts. These hazard areas can be associated with Unexploded Ordinance ("UXO"). To support micro-siting of offshore facilities, Equinor Wind will be completing a UXO survey to characterize and identify mitigation procedures of these hazards. The UXO survey would be designed based on the findings of a UXO desktop study and consultation with the DOD. The desktop study will include the following:

- UXO Hazard identification
- Empire Wind Project Operations Risk Analysis

[14] Per Secretarial Order 3355, BOEM is obligated to undertake a page-limited EIS and target completion of its NEPA review (i.e., publication of a final EIS) within 12 months of the publication of a Notice of Intent to prepare an EIS. Additionally, per Executive Order 13807, a Memorandum of Understanding was signed by federal regulatory agencies to agree to a single timeline of environmental reviews and authorization decisions for proposed major infrastructure projects, prepare a single EIS, sign one record of decision ("ROD"), and issue all necessary authorization decisions within 90 days of issuance of the ROD ("One Federal Decision").

- Risk Mitigation Recommendations

The UXO desktop study will serve as the basis for UXO field surveys, where survey methods will likely require Equinor Wind to apply for an IHA through the NOAA NMFS. Survey activities will also likely meet the conditions of the USACE NWP #6 (Survey Activities), but this will be confirmed as the scope is developed.

The lead agencies responsible for the COP and Article VII review will rely on other federal and state agencies to comment and coordinate the environmental reviews of the Empire Wind Project. Therefore, it will be necessary to prepare and submit the USACE, EPA OCS Air Permit and NYSOGS Underwater Utility Easement application packages soon after the COP and Article VII applications are submitted. Information gathered during the studies outlined and completed for Phase I permitting will support these applications. Additional site-specific data will be collected as well, including, but not limited more thorough geotechnical information and land survey. Detailed design drawings will also be prepared as part of the application packages.

8.2.3 Phase III: Supplemental Requirements for BOEM and PSC

- *Status: Planning*
- *Anticipated Submittal:* [redacted]
- *Anticipated Completion:* [redacted]

Upon COP approval, Equinor Wind will submit the FDR and the FIR for BOEM approval prior to construction (submittal is not contingent on the COP approval). Per §585.705, Equinor Wind will be required to enlist a CVA who will review and certify the FDR and FIR to ensure that the facilities are designed, fabricated and installed in conformance with accepted engineering practices. (Equinor Wind will nominate their CVA for BOEM approval as part of the COP submittal.)

Following issuance of the Article VII ECPN, Equinor Wind will prepare the various additional documents to verify its compliance with the certification order, including the Environmental Management & Construction Plan ("EM&CP"). This document must be formally filed with and approved by the PSC before construction can proceed. The EM&CP will detail the precise location of the proposed facilities and the special precautions that will be taken during construction to ensure environmental compatibility. It is important to note that the Article VII authorization does not include property rights. As such, the EM&CP cannot be issued until all property right are obtained, including the NYSDOT Accommodation Permit.

Both of these documents will rely on the additional design details that will have been developed as the project matures.

8.2.4 Phase IV: Remaining Permit Applications

- *Status: Planning*
- *Anticipated Submittal:* [redacted]

- *Anticipated Completion:* [redacted]

During this time frame, Equinor will submit the remaining permit applications required for project construction:

- The PATON to USCG for wind farm development;
- The IHA or LOA request to NOAA Fisheries for wind farm development;
- The Vessel Discharge Permit to EPA for wind farm development and operations; and
- The Notice of Intent and Stormwater Pollution Prevention Plan and SPDES permit applications to NYSDEC for export cable landing and routing and substation construction.

8.3 Construction Permit Close-out and Operations Turnover

As the construction phase of the Empire Project comes to a close, it may be necessary to complete certain obligations or commitments associated with permits obtained for construction. For example, Equinor Wind may be required to restore vegetation temporarily removed/disturbed as part of onshore export cable installation, with documented successful vegetation establishment after a certain timeframe of planting. Equinor Wind will continue to maintain the Commitments Register referenced in Section 8.2, such that these requirements are closed out appropriately.

Similarly, in preparation for operations, Equinor Wind will be turning the project over to the dedicated Operations Team. Leading up to the turnover, Equinor Wind will prepare an "Operations Compliance Matrix," which will identify all operations permits, required monitoring/recordkeeping, regulatory submittals (if applicable), and timeframes. This information is necessary such that the dedicated Environmental Compliance Manager for operations becomes familiar with and is able to establish a compliance program for implementation throughout the operations phase. Examples of items that would be part of this matrix, include but are not limited to:

- EPA Vessel Discharge Permit monitoring and annual reports;
- OSRP spill response training; and
- OSRP biennial review and submittal.

As part of the development of Standard Operating Procedures for the wind farm, Equinor Wind will consider relevant regulatory requirements associated with environmental compliance that need to be incorporated. For example, under the OSRP, spill response equipment will need to be inspected and maintained monthly and records of such inspections must be maintained for two years. Operations Team members will be trained on these at an established, applicable interval (*e.g.*, annual or other) to ensure continued environmental compliance.

8.4 Decommissioning

In a manner similar to the operations turnover, certain things will be required to maintain compliance during decommissioning activities. These are expected to be initially identified during the current permitting phase of the Empire Project and logged in the Commitments Register. Throughout operations, the Commitments Register will be reviewed periodically to ensure any nuances associated with decommissioning requirements are captured, such that upon initiation of decommissioning activities, the appropriate oversight resources can be dedicated to see this activity to completion.

9 ENGINEERING AND TECHNOLOGY

9.1 Preliminary Engineering Plan

Provide information about the specific technology or equipment including the track record of the technology and equipment and other information as necessary to demonstrate that the technology is viable. Provide a preliminary engineering plan which includes at least the following enumerated information. If specific information is not known, identify manufacturers, vendors, and *equipment that will be considered.*

a. Type of foundation, Offer Capacity, and generator lead line transmission technology

b. Major equipment components to be used, including nacelle, hub, blade, tower, foundation, transmission structures and platforms, electrical equipment and cable)

c. Manufacturer of each of the equipment components as well as the location of where each component will be manufactured

d. Status of acquisition of the equipment components

e. Status of any contracts for the equipment Proposer has or Proposer's plan for securing equipment and the status of any pertinent commercial arrangements

f. Equipment vendors selected/considered

g. Track record of equipment operations

h. Design considerations (technology selection, layout) for climate adaptation and resiliency such as sea level rise, potential impacts from increased frequency and severity of storms (i.e. superstorms, hurricanes), seismic activity, etc.

i. In the event the equipment manufacturer has not yet been selected, identify in the equipment procurement strategy the factors under consideration for selecting the preferred equipment as well as the anticipated timing associated with the selection of the equipment manufacturer, including the timing for binding commercial agreement(s).

9.1.1 Overview of Major Project Components and Technologies

Wind Turbine Generators

The wind turbines used in an offshore wind project can have a critical impact on project cost, performance, and reliability, including the project's ability to generate energy during low wind periods, the capacity factor of the project, and the frequency and cost of preventative and unplanned maintenance required. [redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

- [redacted]

- [redacted]

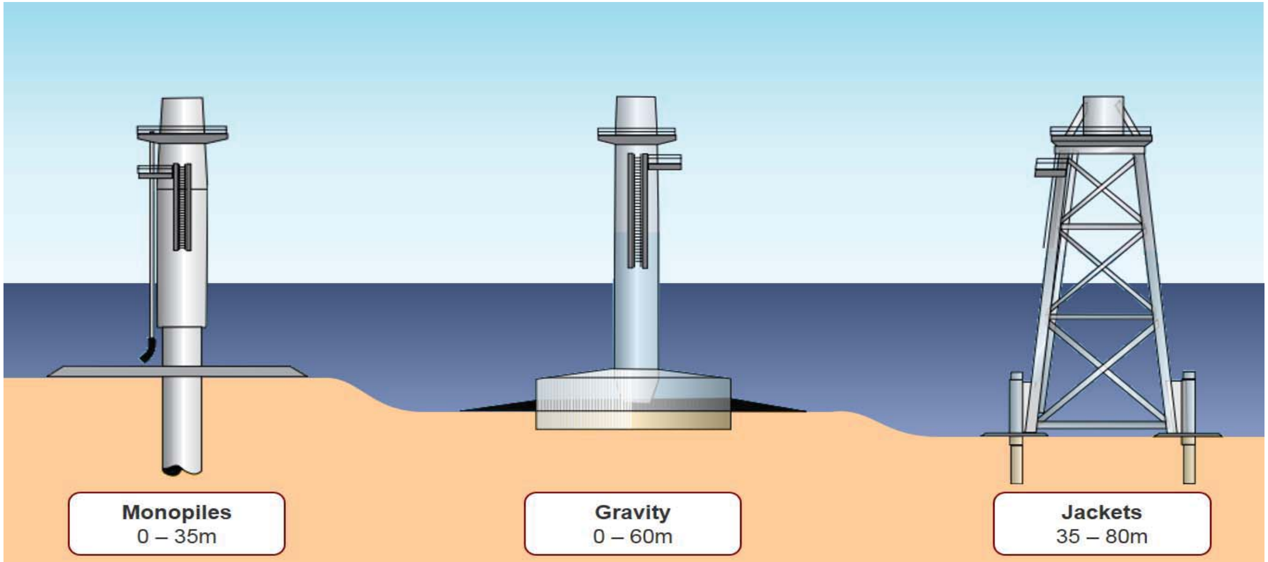
- [redacted]

[redacted]

Foundations

For the WTG foundations, Equinor Wind has conducted extensive studies and analysis of the costs, benefits, and feasibility of three potential foundations: gravity-based structures, monopiles, and jackets. Figure 29 shows each of these structures and the range of suitable water depths for each technology. [redacted]

Figure 29: Suitable Water Depths for Each Type of Foundation Technology



As part of these efforts, over the course of 2017 and 2018, Equinor Wind conducted a desktop study of soil conditions, gathered information regarding the Empire Wind Project site during a geophysical/geotechnical campaign, and has had discussions with numerous suppliers regarding potential foundations. [redacted] Details of both types of foundations can be found below.

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

Inter-Array Cables

[redacted]

[redacted]

[redacted]

[redacted]

Figure 34: Current Cable Install Locations

[redacted]

Offshore Substation

Equinor Wind has worked with Mott MacDonald, Wood Group House, and the ABB Group to identify a conceptual design for the offshore substation, [redacted]

[redacted]

[redacted] [redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

Export Cables

As noted above, in order to optimize the interconnection of the Empire Wind Project, Equinor Wind commissioned a series of studies to evaluate potential interconnection points and cable routes. Specifically, Equinor Wind commissioned a transmission study, performed by Mott MacDonald, [redacted]

[redacted]
A typical example of a landfall cable site, [redacted], is provided in Figure 36 below. However, design and configuration is directly related to site conditions (geology, available space, etc.).

[redacted]

[redacted]

[redacted]

Figure 37: Conceptual Design of Cable

[redacted]

[redacted]

Onshore Substation

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

9.1.2 Procurement Strategy

Since being granted rights to develop the lease area, Equinor Wind has been diligently evaluating potential design and supply options. Equinor Wind has issued requests for information to potential suppliers and has had extensive discussions regarding potential wind turbine technologies, foundations, and other major project components in order to obtain information regarding the costs, viability, and delivery timing of different technologies. Equinor Wind is committed to ensuring that the development of the Empire Wind Project fosters the growth and development of a robust offshore wind supply chain within New York that makes New York a hub of the offshore wind industry and allows the state to efficiently and cost-effectively meet its renewable energy goals. As described further in the Economic Benefits Plan provided in Section 16, Equinor Wind's proposed construction of the Empire Wind Project has been tailored to maximize the economic benefits to New York to the extent practicable while promoting the efficient and cost-effective development of the Empire Wind Project.

Equinor Wind is continuing discussions with suppliers and no equipment components have been acquired yet. Nevertheless, Equinor Wind has a well-defined procurement strategy that will both ensure that Equinor Wind is able to procure necessary components and equipment on a timeline that allows it to meet its target commercial operation date while ensuring that all project components meet Equinor Wind's rigorous quality standards and cost objectives. An overview of Equinor Wind's approach to equipment solicitation and supply chain management is provided below.

At this phase, the project is defining sourcing strategies based on scope of work and technical specifications for the different work packages and information provided by main potential suppliers through requests for information and studies. The project is in the process of pre-qualifying potential suppliers.

Equipment Solicitation and Supply Chain Management

Equipment solicitation and supply chain management are integrated into the planning, execution and operation of the Empire Wind Project. Procurement activities and the development of an overall procurement strategy start at an early stage of the project. This strategy incorporates lessons from previous offshore wind projects and is based on the Empire Wind Project's specific conditions and requirements, as well as market analysis and screening.

Equinor Wind's procurement process consists of the following main steps:

- Development of procurement strategy
- Development of a bidders list
- Contract Drafting
- Sourcing
- Contract award
- Contract management

Development of Procurement Strategy

The first step in the procurement process is to establish a defined procurement strategy in cooperation with the technical group within Equinor that will be installing and managing the procured product or equipment. This process also includes a risk assessment for the specific contract package to ensure that any potential issues are known and addressed early on.

[redacted]

[redacted]

Development of a Bidders List

Once a strategy is established, Equinor develops a bidder list. This process begins with identifying qualified suppliers. Each supplier must meet minimum requirements with regards to safety, quality, and integrity, which is confirmed through a due diligence process. Additionally, potential suppliers must sign a supplier declaration, agreeing to minimum standards for ethics, anti-corruption, security, health and safety, and respect for human rights. Furthermore, suppliers agree to promote these standards among sub-suppliers. A copy of a supplier declaration is provided as Attachment 22.

In addition, to these business requirements, suppliers must meet the project's technical requirements. Equinor uses a supplier qualification system, such as ISNetworld or Avetta, to vet and compare potential suppliers. In many cases, more potential suppliers will pass the minimum requirements than those that are selected to be added to a bidders list. Therefore, Equinor uses a prequalification process to shortlist suppliers and ensure that only qualified and capable suppliers are invited to tender a contract. This prequalification process is specifically tailored for each procurement and typically involves follow-up questions to potential suppliers, site visits, and/or audits, depending on the needs of the project.

Contract Drafting

The sourcing process starts with defining the scope of work and delivery in detail. Once settled, the contract documents are drafted, including terms and conditions, compensation format, proposed delivery milestones, payment schedules, technical requirements, and administrative requirements. This is completed by Equinor's procurement group in cooperation with other departments responsible for the project at issue. Equinor's procurement group will tailor each contract to reflect the size, scope, and complexity of a project.

[redacted]

Sourcing

Based on the results of the qualification process described above and in accordance with general requirements, Equinor will invite qualified suppliers to bid to supply the equipment or perform the work at issue. In order to guide the bid process, Equinor will develop detailed instructions that will define the information to be included in the bid, provide guidance regarding how to submit the bid, detail Equinor's evaluation criteria, and include the draft contract developed by Equinor. After a predefined period, Equinor receives the bids and starts the contract evaluation and negotiation phase.

Objective and non-discriminatory evaluation criteria are defined for the specific procurement and agreed to prior to the bid opening to ensure a fair and fact-based selection process. The evaluation is performed by a cross functional team and will cover the Health, Safety, and Environmental ("HSE"), technical, commercial, and schedule aspects of the bids. The evaluation process will continue until Equinor has identified which supplier best suits its business needs and the Empire Wind Project's specific requirements.

[redacted]

Contract Award

The Chief Procurement Officer ("CPO") holds the authority to legally commit Equinor to suppliers. All legal commitments are handled through the CPO in order to safeguard the principle of segregation of duties and ensure the appropriate involvement of both the requisitioning line and the procurement function.

As soon as the contract has been signed by both parties, unsuccessful bidders are informed in writing. Debrief meetings are proposed to assist them in improving future bids.

Figure 40 below depicts the expected contract structure for the Empire Wind Project and the expected contract award schedule. Equinor Wind reserves the right to combine or split contracts to improve project execution, mitigate risks, or reduce costs.

Figure 40: Expected Contract Structure

[redacted]

Contract Management

After the contract has been signed, a kick-off meeting with the supplier is held to ensure that the contract requirements and Equinor's expectations are well understood, and to agree on communication lines and routines during the contract period.

[redacted]

9.1.3 Manufacturer Location

Figure 41 provides an overview of the potential Tier 1 Suppliers for the main procurement packages and potential location for the manufacture of the main components and equipment. Tier 1 Suppliers are those parties that Equinor will directly contract with. Tier 2 supplier are those that may be subcontracted by Tier 1 Suppliers. Because Equinor Wind is still in the process of identifying potential Tier 1 Suppliers, the final location of the manufacturer will be finalized based on the outcome of Equinor's procurement process. As a result, the list below should not be considered final and is subject to change as Equinor Wind moves forward with development of the project.[19]

[redacted]

Figure 41: Potential Manufacturers and Locations

[redacted]

9.1.4 Design Considerations

As with any offshore installation, offshore wind projects are subject to numerous risks that have the potential to cause physical damage to the facility or otherwise disrupt operations, including extreme weather events and maritime collisions. For that reason, Equinor incorporates these risks into every aspect of project development, including project design, construction, and O&M. Figure 42 provides an overview of physical risks and mitigation measures relevant to the Empire Wind Project.

Figure 42: Overview of Physical Risks and Mitigation Measures

Risk	Potential Impact	Mitigation
Hurricanes	[redacted]	[redacted]
Lightning	[redacted]	[redacted]

		[redacted]	[redacted]
Fog	[redacted]	[redacted]	[redacted]
Rogue Waves	[redacted]	[redacted]	[redacted]

	[redacted]	[redacted]
Exposed Cabling	[redacted]	[redacted]
Climate Change	[redacted]	[redacted]

9.2 Lighting Controls Plan

Describe the lighting controls that will be utilized on the Offshore Wind Generation Facility and explain how these controls comply with the minimum contract standards and the Offshore Wind Order.

Equinor Wind is committed to minimizing the impact of the Empire Wind Project on the view from the New York coastline. As described further in Section 15 below, Equinor Wind has conducted a detailed study and simulation of the viewshed impact of the Empire Wind Project under a full range of conditions and at various times of day. This analysis demonstrates that the construction of the Empire Wind Project will not have an adverse effect on viewshed resources.

To further minimize the potential impact of the Empire Wind Project, Equinor Wind expects to install an Aircraft Detection Lighting System ("ADLS") at the Empire Wind Project. This system uses radar technology to monitor the airspace over and around the wind farm and ensures that lights will only be activated when an aircraft is in the vicinity of the wind farm. The system's detection coverage satisfies the FAA Obstruction Marking and Lighting Advisory Circular, which sets forth the requirements for lighting obstructions that may be a safety risk to air navigation. In accordance with this requirement, lighting shall be activated and illuminated prior to an aircraft penetrating the perimeter of a group of structures (*e.g.*, WTGs), which is a minimum of 3 nm horizontally and 1000 ft vertically. The system has previously been assessed by FAA Air Traffic Requirements personnel at an onshore wind resource area in US. The system was found to perform in accordance with the manufacturer's specifications and met the performance requirements identified in Advisory Circular 70/7460L.

Based on discussions with the wind turbine supplier, it is anticipated that this type of lighting system can be employed for the Empire Wind Project. If, during later stages of design, it is deemed infeasible, or a better technology becomes available, Equinor Wind will evaluate such technology for use in consultation with NYSERDA.

The installation of ADLS will minimize the potential impact of the Empire Wind Project on bird and bat species, as well as limit the impact on viewshed resources. Importantly, detailed assessments of the impact of lighting on birds, bats, and viewshed resources will be carried out as part of BOEM's NEPA process in the COP. Collectively, the measures set out herein and regulatory review process will ensure that the Empire Wind Project complies with minimum contract standards and applicable state and federal requirements.

10 PROJECT SCHEDULE

A Proposer must demonstrate that its Project can be developed, financed, and constructed within a commercially reasonable timeframe. Proposer is required to provide sufficient information and documentation showing that Proposer's resources, process, and schedule are adequate for the acquisition of all rights, permits, and approvals for the financing of the Project consistent with the proposed milestone dates that support the proposed Commercial Operation Date.

Proposers are required to provide a complete critical path schedule for the Project from the notice of award to the start of commercial operations. For each Project element listed below, provide the start and end dates:

1. Identify the elements on the critical path. The schedule should include, at a minimum, preliminary engineering, financing, acquisition of real property rights, Federal, state and/or local permits, licenses, environmental assessments and/or environmental impact statements (including anticipated permit submittal and approval dates), completion of interconnection studies and approvals culminating in the execution of the Interconnection Service Agreement, financial close, engineer/procure/construct contracts, start of construction, construction schedule, and any other requirements that could influence the Project schedule.

10.1 Critical Path Schedule

Equinor Wind has developed a detailed and standardized approach to planning and executing offshore wind projects, which has been used to successfully complete large and complex offshore projects in Europe. This approach is tailored to provide a basis for well-informed decision-making, ensure effective use of time and resources, and provide certainty for our stakeholders and partners.

The Empire Wind Project Master Schedule ("PMS") integrates the major tasks associated with the development of the project. This schedule was developed with input from manufacturers and the supply chain, as well as Equinor's past experience, to ensure that it is realistic and achievable given current conditions and main assumptions. [redacted]. As more data is gathered and concepts are further developed, the schedule will continue to be refined to accommodate this additional information. A copy of the PMS is provided as Attachment 23.

The PMS is based on a Main Activity Logic Chart, which depicts the sequence of activities from the design of the project through commissioning. A copy of the Main Activity Logic Chart is provided as Attachment 24.

The project plan is broken down into several defined work packages, some of which will be executed concurrently. A detailed timeline and discussion of each work package can be found below.

A description of Equinor Wind's plan respecting the financing of the Empire Wind Project is provided in Section 6.3. [redacted]

10.1.1 Permitting and Site Survey

As further detailed in Section 8, Equinor Wind will be required to obtain a range of local, state, and federal permits in order to construct the Empire Wind Project. Permitting is an integrated part of the project schedule and includes studies, assessments, and surveys for the COP and local permitting. Section 8 provides a detailed overview of the permits that will be required for the development of the Empire Wind Project and Equinor Wind's progress to date in obtaining the requisite approvals.

Prior to the development of the Empire Wind Project, Equinor Wind is conducting a range of surveys and assessments to further refine its understanding of the lease area and ensure that the Empire Wind Project is developed in a manner that minimizes disruption to the natural environment. [redacted] The information from these surveys will be used to further refine the design of the onshore and offshore components of the Empire Wind Project.

Attachment 25 provides a detailed permit schedule.

Information concerning Equinor Wind's plan for interconnection of the Empire Wind Project and associated land acquisition requirements is provided in Section 7 of this application.

10.1.2 Construction Schedule

Equinor Wind has developed a detailed schedule for the engineering, procurement, fabrication, and installation of major components of the Empire Wind Project. This schedule has been developed through extensive dialogue with prospective suppliers as well as Equinor's experience developing offshore wind facilities of similar size and scope. A high-level overview of the construction schedule is provided as Attachment 26. The following sections provide a more granular breakdown of the timing of the engineering, procurement, fabrication, and installation of individual components of the Empire Wind Project.

Wind Turbine Generators

[redacted]

Attachment 27 provides a detailed wind turbine generator schedule.

Foundations

[redacted]

[redacted]

Attachment 28 provides a detailed foundations schedule.

Cables

[redacted]

Attachment 29 provides a detailed cables schedule.

Electrical System

Equinor Wind has commissioned several studies covering the necessary equipment and layout of the offshore and onshore substations. [redacted] The equipment chosen for the onshore and offshore substations will provide the basis for the layouts, procurement, fabrication, and pre-commissioning of the onshore and offshore substations.

[redacted]

Based on discussions with NYISO, Equinor Wind currently anticipates that any network upgrades necessary to accommodate the interconnection of the Empire Wind Project will be completed [redacted] Civil and construction work at the onshore substation will continue after energization.

[redacted]

Attachment 30 provides a detailed electrical system schedule.

Marine Operations

Separate from the surveys discussed above, Equinor Wind will be conducting extensive marine operations to prepare the site and install equipment. [redacted]

The marine construction schedule will be further optimized to allow for simultaneous work on different aspects of the project.

Attachment 31 provides a detailed marine operations schedule.

Decommissioning

Equinor Wind is committed to responsibly developing Empire Wind, including the eventual decommissioning of the project in compliance with applicable regulations and the stipulations in

Equinor Wind's lease. Given the current stage of development, a decommissioning timeline has not been established. Prior to the end of the project lifetime, Equinor Wind will conduct an assessment of the project site employing best practices and analytical methods to determine the feasibility and potential risks associated with decommissioning of the Empire Wind Project. The results of this analysis will then be reflected in a decommissioning application, which will be submitted to BOEM for review and approval prior to the commencement of decommissioning activities. [redacted]

10.2 Offshore Construction Windows

Describe the anticipated permissible offshore construction windows, and how the construction milestones will be accommodated within these windows.

Installation windows have been established based on the metocean characteristics of the lease area in order to maximize efficiency in the project marine operations. These windows take into account the expected weather conditions and were calculated by installation contractors using their own software and verified by Equinor using its internally developed marine operations simulation software, MARSIM.

Equinor has vast experience conducting complex marine installation activities as a result of its oil, gas, and offshore wind projects. This experience has been reflected in designing a realistic installation schedule for the Empire Wind Project that takes into account the full range of factors that have the potential to impact marine operations, including environmental restrictions and regulations and expected weather conditions.

Marine Installation activities can occur year round, but the preferred windows for each task are provided below. [redacted]

Given its vast experience conducting complex marine operations, Equinor has developed a variety of procedures to ensure that project components are ready during a given installation window. These procedures include ensuring timely delivery of components, inspection for compliance with specifications, and coordinating vessel activities to allow for efficient use of resources.

[redacted]

- [redacted]

- [redacted]
- [redacted]
- [redacted]
- [redacted]
- [redacted]
- [redacted]
- [redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

11 CONSTRUCTION AND LOGISTICS

This section of the Proposal addresses necessary arrangements and processes for outfitting, assembly, storage, and deployment of major Project components such as turbine nacelles, blades, towers, foundations, and transmission support structures.

11.1 Major Tasks and Necessary Equipment

List the major tasks or steps associated with deployment of the proposed Project and the necessary specialized equipment (e.g., vessels, cranes).

The construction and deployment plan for the Empire Wind Project is based on insights gained over the course of Equinor's decades of experience constructing and deploying large scale offshore energy projects, including its existing offshore wind fleet. This construction and deployment plan has been calibrated to ensure timely completion of the Empire Wind Project given the characteristics of the lease area, permitting and regulatory requirements, the availability of necessary equipment and vessels, and offshore installation windows.

Figure 43 below provides an overview of the major tasks associated with deployment of the Empire Wind Project and the equipment necessary for each task.

Figure 43: Major Tasks and Equipment

[redacted]

[redacted]

11.2 Staging and Deployment

Describe the proposed approach for staging and deployment of major Project components to the Project site. Include a description and discussion of the laydown facility/facilities to be used for construction, assembly, staging, storage, and deployment.

Equinor has extensive experience coordinating port and maritime activities and employs industry best practices to seamlessly coordinate port and maritime operations to ensure the timely and cost-effective construction of offshore projects while minimizing disruption to maritime and fisheries resources.

The construction plan for the Empire Wind Project incorporates Equinor's insights and best practices gained over forty years of developing offshore projects. Equinor utilizes industry leading best practices in planning and executing offshore energy projects in accordance with the most rigorous health and safety standards. These best practices include stringent contractor evaluation and quality control measures, detailed planning aligned with industry and regulatory rules, and proprietary software built specifically for Equinor's needs and processes. Furthermore, Equinor utilizes KPIs to evaluate a project's development and provide insights for future improvements of these systems. Based on this experience, construction activities will be primarily divided into onshore and offshore components.

[redacted] The process of manufacturing, shipping, assembly, and in-field installation of major project components is discussed below and prospective supplier letters of support are provided in Attachment 32. Detailed information regarding the project schedule is provided in Section 10.

11.2.1 WTGs

The staging and deployment of the WTGs will consist of the following distinct tasks:

- Fabrication
- Transportation to staging port
- Transportation to site from the staging port and installation at the project site
- Commissioning

Fabrication

[redacted]

[redacted]

Transportation to Staging Port

[redacted] Additionally, the port facility will need to comply with International Ship and Port Security standards.

Since obtaining rights to the lease area, Equinor Wind has been collaborating with local ports and [redacted] Equinor Wind is working with local authorities and organizations to identify potential port facilities that can successfully service the project. A number of feasible candidate ports have been identified and discussions are ongoing with the port authorities and state agencies in the hopes of broadening the development options. Further details regarding potential ports are provided in Section 11.3 below.

Regardless of the port that is selected, [redacted] Each vessel will be equipped with specialized cranes and other equipment to facilitate the loading and unloading of equipment. An example of the types of vessels that typically are used for component transportation can be found in Figure 44 below.

[redacted]

[redacted]

[redacted], the WTG components will be unloaded from the transportation vessels. After off-loading, preservation measures will be in place at the staging port to maintain the WTG components until they are ready for load-out. Prior to load-out onto the transportation vessel for installation, Equinor Wind will conduct a "walk down" procedure to ensure the integrity of the components and compliance with specifications. Additionally, some initial component assembly and commissioning activities will occur at the quayside, in accordance with turbine manufacturer standard procedures, to reduce the commissioning time offshore.

Transportation to Site and Installation

Once pre-installation preparation and testing are complete, the wind turbines will be loaded on a transport vessel spread for transportation to the project site. [redacted] The transportation and installation process will continue year-round until construction of the project is complete. As a general matter, Equinor expects there to be some delays in the winter months due to adverse weather, but the current project schedule has been tailored to account for these delays. Equinor Wind will engage a qualified transportation and installation contractor for transportation and installation of the wind turbines components. The main contractor will be responsible for selecting the methodology that will be used to safely transport the components from the staging port to the lease area in compliance with the Jones Act. The foreign flagged MIV with appropriate crane capacity will be located offshore. [redacted]

[redacted]

[redacted]

Commissioning

Following installation, the WTGs will be prepared for operation and energization. [redacted]

[redacted]

11.2.2 Foundations

[redacted]

[redacted]

[redacted]

- [redacted]
- [redacted]
- [redacted]
- [redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted] [redacted]

[redacted]

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[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

- [redacted]
- [redacted]
- [redacted]
- [redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

11.2.3 Export Cables

Staging and deployment of the offshore export cables will consist of the following steps:

- Fabrication and transportation
- Surveys and pre-grapnel run
- Laying and burial
- Connection to offshore substation

Because the project Electrical System Design utilizes two export cables laid in parallel orientation between the Offshore Substation and the chosen landfall Interconnection Point ("ICP") for operational redundancy, the process described below will be performed twice with minor modifications to the survey and pre-grapnel run actions as noted below.

Fabrication and Transportation

Based on discussions with prospective suppliers and initial procurement efforts to date, Equinor Wind currently anticipates that the export cables will be [redacted]. Once fabricated, the cables will be loaded directly onto the CLV by the manufacturer and transported from the manufacturing facilities to the project site onboard the vessel. Figure 54 depicts a CLV in operation.

[redacted]

[redacted]

Surveys and Grapnel Run

Prior to any installation, a survey will be conducted to evaluate the seabed geology, assess the water depth, and identify any objects or conditions that would impact cable installation. Once the survey is complete, a grapnel run will be performed which involves pulling a grapnel train over the planned cable route to clear debris and ensure the seabed is ready for cable installation. Figure 13 above depicts the current export cable study area and alternative routes.

Laying and Burial

Once transported to the project site, the CLV will install the cable starting at the onshore landfall point and moving along the pre-determined cable route to the offshore substation. A simultaneous lay and burial or open trench method will be used in nearshore and offshore based on the results of the geotechnical survey campaign which commenced in 2018 and is expected to be completed in 2020. Burial depth will be determined by these studies, in consultation with regulatory authorities and existing cable operators (when crossing) [redacted]

[redacted]

Connection to Offshore Substation

Export and inter-array cable connection to the offshore substation will be executed in accordance with industry best practices. [redacted]

11.2.4 Offshore Substation

The staging and deployment of the offshore substation will consist of the following steps:

- Fabrication
- Transportation to project site
- Installation

Fabrication

[redacted] Topside fabrication will require a contractor experienced in complex interface management environments, fabrication facilities, and continuous material flow operations. Major equipment is expected to be delivered to the fabrication site from their respective manufacturing locations. Therefore, communication between the equipment manufacturer and site fabricator will need to be established in advance to ensure proper handling and installation of the equipment.

Transportation

Offshore substation transportation and installation tasks will be executed in accordance with industry best practices and compliance with the Jones Act regulations. [redacted] In the tug and barge arrangement, cargo will be loaded and secured on a barge and the barge will be towed offshore using tow tugs. Figure 55 depicts a typical tug and barge arrangement.

[redacted]

Installation

The transport marine spread with the offshore substation topside on deck will meet the Heavy Lift Vessel ("HLV") at the installation site. Prior to topside installation, the foundation of the topside interface will be prepared for installation. Once complete, the HLV will lift the topside and install onto the preinstalled foundation. Upon landing the topside onto the foundation, the steel interface between topside and foundation will be welded together. Figure 56 below depicts the Dudgeon jacket foundation on a barge and HLV installation of the offshore substation.

[redacted]

Upon completion of topside installation, offshore substation commissioning will commence. [redacted]

11.2.5 Inter-Array Cable

WTGs will be interconnected to the offshore substation through an inter-array network. The selected EPCI contractor will begin cable installation shortly after the first foundation is completed. [redacted]

[redacted]

11.2.6 Onshore Landfall and Cable Routing

Onshore landfall and cable routing will consist of the following steps

- Surveys and ground investigations
- Cable landfall
- Onshore export cable installation

Surveys and Ground Investigations

Environmental surveys and ground investigations will be performed prior to starting any construction activities at the landfall location and along the cable corridor from the landfall to the substation site. This information will inform the design and permitting of the project as appropriate.

Cable Landfall

Equinor Wind plans to use the HDD technique in order to minimize surface disturbance and environmental impacts. The HDD operation will involve vessels and divers to assist in the process. [redacted]

Equinor Wind plans to drill one borehole per cable circuit from shore to a water depth on the seabed suitable for the cable installation activities. [redacted] Figure 57 below depicts potential landfall location and cable routes.

Figure 57: Potential Cable Landfall Locations and Onshore Cable Study Area

[redacted]

Onshore Export Cable Installation

The onshore cable route will involve construction activities predominantly in the road lane and shoulder. Any necessary road closures will be done in collaboration with local authorities. [redacted] Once trenching on a section is complete, duct banks and cable surround will be installed, followed by the construction of joint bays between each section. The cable section will be installed in the ducts using a winch and connected at each joint bay. As each section is completed, it will be backfilled using sand, cement, and existing material along with protective cable covers laid above the duct bank. Once installed, the cables will be tested prior to being connected with the onshore substation and submarine export cables.

11.2.7 Onshore Substation

Construction of the new onshore substation will consist of the following main steps:

- Surveys and ground investigations
- Construction activities
- Electrical equipment installation
- Commissioning and energization

Surveys and ground investigations

Environmental surveys and ground investigations will be performed prior to any construction activities at the onshore substation site. These investigations will include activities such as boreholes, cone penetration test, groundwater control, and environmental surveys (*e.g.*, wetland delineations, tree surveys, as applicable). This process will produce full geotechnical and environmental reports for the site.

Construction Activities

The new substation that Equinor Wind plans to construct will likely require site preparation, including vegetation removal, a new access road, and site leveling. The onshore substation is expected to include the following:

- Substation building (electrical equipment HVAC room, battery room, control room, office)
- Outdoor equipment areas
- Permanent lighting, designed to minimize glare, and light spillage off-site
- Area for car parking and internal roads
- Security fencing and gates

Based on the ground investigation described above, piles will be driven to support the foundations to be installed on the site. Then, contractors will begin with the underground installations including drainage, sewer, and cable corridors followed by the foundations for the equipment and buildings. Once complete, construction will begin on the substation building for personnel and equipment. Finally, the site fencing, internal roads, and landscaping will be completed.

Electrical Equipment Installation

Once the substation site is ready, the main electrical high voltage ("HV") equipment will be installed on site.

The electrical HV equipment typically includes:
- Transformers
- Reactors
- Harmonic filters
- Switchgears

Due to the size and complexity of some of the equipment, specialized transport and installation personnel will be utilized. Utility systems, instruments, and automation systems will also be installed at this time followed by their associated instrument panels, batteries, and control equipment. The cables connecting the equipment will be installed through the preinstalled ducts and cable pull-through. The onshore export cable will be connected to the switchgear/high voltage breaker after high voltage testing is complete.

Commissioning and Energization

Prior to energizing the onshore substation all utility systems, instruments, and automation systems must be fully tested and commissioned. [redacted]

The offshore substation will be energized via the export cables, one at a time, from the onshore substation. [redacted]

11.2.8 Grid Interconnection and network upgrades

As explained in detail in Section 7, [redacted] Equinor Wind anticipates that any network upgrades necessary to accommodate the interconnection of the Empire Wind Project will be completed [redacted]

11.3 Marine Terminals and Waterfront Facilities

Identify the marine terminals and other waterfront facilities that will be used to stage, assemble, and deploy the Project for each stage of construction.
a. If available, evidence that Proposer or the equipment/service provider have right(s) to use a marine terminal and/or waterfront facility for construction of the Project (e.g., by virtue of ownership or land development rights obtained from the owner).
b. If not available, describe the status of acquisition of real property rights for necessary marine terminal and/or waterfront facilities, any options in place for the exercise of these rights and describe the plan for securing the necessary real property rights, including the proposed timeline. Include these plans and the timeline in the overall Project schedule in Section 6.4.10.
c. Identify any joint use of existing or proposed real property rights for marine terminal or waterfront facilities.

Equinor Wind has been investigating collaboration with local ports since executing its lease with BOEM. Since that time, Equinor Wind has commissioned several studies to investigate the feasibility of various ports located in New York, New Jersey, and other states along the eastern seaboard for wind turbine staging and [redacted]

[redacted]

[redacted]

[redacted] [redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

11.4 Number Type and Size of Vessels

Indicate the number, type and size of vessels that will be used, their respective uses, and how vessels will be secured for the required construction period. Explain how Proposer's deployment strategy will conform to requirements of the Merchant Marine Act of 1920 (the Jones Act).

Due to the nascent development of offshore wind farm projects in the U.S., there are a limited number of Jones Act-compliant vessels that are also feasible for offshore wind construction. Therefore, in order to develop the project safely and in a cost efficient manner, some foreign vessels will need to be used.

Equinor Wind and vessel operators will execute contractual agreements to address project marine construction activities. The marine coordination center established by Equinor Wind will track all vessels engaged in marine operations and maintain proper communications throughout the campaign in accordance with local and federal regulations.

[redacted]

Figure 60: Vessel Information

[redacted]

11.5 Responsibility Assignment

List the party or parties responsible for each deployment activity and describe the role of each party. Describe the status of Proposer's contractual agreements with third-party equipment/service providers.

An overview of the division of roles and responsibilities respecting staging and deployment activities is provided in Section 11.2. As noted in Section 9.1.2, Equinor Wind remains in discussion with potential contractors that would support staging and deployment activities and has not yet finalized contractual arrangements respecting these activities.

12 FISHERIES MITIGATION PLAN

Proposers must include in their Proposal a Fisheries Mitigation Plan in as much detail as possible that describes how Proposer will mitigate adverse impacts on the commercial fishing industry that may be caused by the Project. Elements of the Fisheries Mitigation Plan are described in detail in Appendix D. Proposers are advised to review the Fish and Fisheries Study prepared for the New York State Offshore Wind Master Plan with respect to the potential impacts of offshore wind energy development on the fishing industry, and also are advised to include in their mitigation plan the appropriate Best Management Practices described in the Master Plan and supporting studies.

Equinor Wind's Fisheries Mitigation Plan is provided under separate cover.

13 ENVIRONMENTAL MITIGATION PLAN

Proposers must include in their Proposals a detailed Environmental Mitigation Plan that describes how Proposer will mitigate adverse environmental impacts that may be caused by the Project. Elements of the Environmental Mitigation Plan are described in detail in Appendix E. Proposers are advised to review the environmental studies prepared for the New York State Offshore Wind Master Plan with respect to the potential impacts of offshore wind energy development on the environment, and also are advised to include in their mitigation plan the appropriate Best Management Practices described in the Master Plan and supporting studies.

Equinor Wind's Environmental Mitigation Plan is provided under separate cover.

14 COMMUNITY OUTREACH PLAN

Provide a community outreach plan that identifies proposed stakeholder engagement activities during construction and operation of the Project. Provide copies of any agreements with communities and other constituencies impacted by the Project, not already covered in the Fisheries Mitigation Plan or the Environmental Mitigation Plan. Discuss the status of implementing the community outreach plan. Provide documentation identifying the level of public support for the Project including letters from public officials, newspaper articles, etc. Include information on specific localized support and/or opposition to the Project of which Proposer is aware.

Equinor Wind believes that engagement with stakeholders is a critical component of successful project development. For that reason, Equinor Wind has been actively engaged with coastal communities, elected officials, relevant state agencies and the public since acquiring the rights to pursue development of an offshore wind project off the coast of New York. These efforts have been designed to ensure that these key groups are kept informed about the development of the project and to solicit feedback regarding their views and concerns. Equinor Wind has actively worked to take into account stakeholder views in the design of the Empire Wind Project, including tailoring the layout of the facility to respect certain uses of the existing lease area.

If the Empire Wind Project is selected through this RFP, Equinor Wind will continue to engage in efforts to ensure that stakeholders are informed of project developments and address issues of concern that may arise in the future. Equinor Wind believes that the Empire Wind Project currently enjoys significant stakeholder support, yet recognizes that project development is dynamic and that it will be critical to continue to work to strengthen Equinor Wind's relationship with potentially affected communities and other stakeholder groups as the project moves forward.

The company's stakeholder engagement is driven by four foundational principles that guide all of the work of Equinor Wind, Equinor ASA, and their affiliates both in New York and around the globe:

- **Openness:** We promote transparency and embrace diversity and new perspectives.
- **Courageousness:** We use foresight, identify opportunities, and manage risk.
- **Collaboration:** We engage with, respect, and earn the trust of our business partners and of society.
- **Caring:** We seek zero harm to people, acting in a sustainable, ethical, and socially responsible manner.

In accordance with these principles, Equinor Wind is firmly committed to developing the Empire Wind Project in a manner that takes into account the interests of New York stakeholders and supports New York's economic and environmental goals. Consistent with this commitment, Equinor Wind has been soliciting the views of a broad array of stakeholders, working to incorporate these ideas into the design, planning, construction and eventual operations of the project wherever possible.

14.1 Methodology

The Empire Wind team employs a systematic approach to stakeholder engagement that allows us to identify and track the full range of potentially affected stakeholders and their views. This approach allows Equinor to ensure that all stakeholder views are considered and addressed appropriately.

Equinor engages stakeholders in a manner that respects the level of impact the project could have on their lives and their specific areas of interest. In order to guide these efforts, Equinor organizes stakeholder engagement using three primary factors:

1. Areas of Influence
2. Stakeholder Interest Areas
3. Organization Type

14.1.1 Areas of Influence

In order to obtain a geospatial understanding of areas impacted by the project, Equinor Wind has created four zones that help us calibrate the level of engagement by location. These zones reflect the relative proximity of potentially affected stakeholder groups to the lease area. Figure 61 provides map of these zones.

Figure 61: Areas of Influence

[redacted]

Zone 1

- Current users of the offshore wind lease area and their representatives
- Communities adjacent to ports used for support of the Empire Wind Project

Zone 2

- People living within the viewshed of the project, including business owners, and their representatives.
- Conservationists focused on species in the lease area

Zone 3

- Beachgoers or seasonal visitors to the viewshed area
- Communities hosting construction of onshore cable, from landfall to substation, during the construction period
- Conservationists focused generally on ocean health

Zone 4

- All NY ratepayers

14.1.2 Stakeholder Interest Areas

In addition to the areas of influence explained above, each individual stakeholder with whom we engage or plan to engage is linked to its respective area(s) of interest. Some stakeholders have multiple interests in the project; others may have only one central interest. Ten primary interest areas have been delineated, under which multiple sub-interests may apply:

1. Commercial fishing
2. Recreational fishing
3. Viewshed
4. Navigation
5. Supply chain
6. Jobs
7. Environment
8. Cost
9. Climate Change
10. Local on-land construction (from cable landfall to substation)

14.1.3 Organization Type

Equinor Wind also tracks which types of organizations it is interacting with as a means to ensure equitability and responsiveness to a broad range of concerns (recognizing that not all stakeholders belong to an organization). To formulate an effective strategy and process, organizations are sorted into six central categories:

1. Affected Communities
2. Non-Government Organizations
3. Government
4. Commercial Organizations
5. Educational Institutions
6. Labor Unions

14.2 Engagement Activities to Date

Engagement with stakeholders and public officials surrounding development of offshore wind resources off the coast of New York has been ongoing since BOEM began formally considering the potential development of offshore wind resources within lease area OCS-A 0512. As detailed in Section 8 of this application, as part of this process, BOEM conducted extensive outreach to potentially affected state governments, public officials, and other stakeholders to solicit their views regarding the potential development of offshore wind resources in the lease area, including holding a series of technical workshops in both New Jersey and New York. During this same period, the State of New York was creating the Offshore Wind Master Plan, including more than a dozen studies of important elements of building responsibly-sited offshore wind arrays, and conducting extensive stakeholder engagement.

14.2.1 Comprehensive Approach to Outreach

Since signing the offshore wind lease in March 2017, Equinor Wind has worked to identify and engage stakeholders at multiple levels. The company's engagement consists of a variety of different approaches, tailored to reach the broadest possible segment of the stakeholder audience in the most effective and appropriate manner. These outreach efforts include:

- Frequent in-person meetings with highly engaged groups, such as environmental non-governmental organizations, labor unions, educators, biologists, government agencies, and representatives of affected communities.
- Direct outreach in the form of emails, phone calls, and meetings based on individual stakeholder levels of interest and satisfaction, as discussed in the methodology section above.
- Social media activity, including providing updates about the project on Facebook and Twitter.
- A website presence – www.empirewind.com – that provides constantly updated information about Empire Wind, including project characteristics, fisheries and environmental information, Frequently Asked Questions, and more.

- Ongoing discussions with public officials at the state and local levels to help ensure that constituent needs are recognized and addressed as the project evolves.
- Issuances of notices about Equinor Wind's survey activities to local police, fire, and others in potentially affected communities to encourage stakeholder engagement and keep these communities informed of developments and activities in the lease area.

14.2.2 Targeted Stakeholder Engagement

Equinor Wind has engaged in a wide variety of targeted stakeholder activities focused on different aspects of project development. Equinor Wind has met with NY labor unions, NY-based environmental advocacy groups, NY universities and community colleges, local elected leaders, commercial and recreational fisheries representatives, among a host of other groups. These efforts have included:

- Engagement with members of the commercial and recreational fishing communities through meetings held by BOEM, as well as our own outreach initiatives.
    - To date, the Equinor Wind team has had over 200 engagements with fishermen from New York and neighboring fishing communities such as New Jersey and Rhode Island, through our dedicated fisheries liaison.
    - Equinor Wind also has participated at numerous events and trade shows throughout the state for commercial and recreational fishermen, including the NY Sportfishing Federation Forum, in an effort to build relationships and keep these groups informed about the progress of the Empire Wind Project.
    - Equinor Wind also has developed a simulator that allows members of fishing communities to interact with a model of the Empire Wind Project, including navigating around and within the wind farm.
- Meetings with key labor leaders and groups, including the directors of the Building Trades Council for New York and Long Island and leaders of Climate Jobs NY, to solicit their input on developing supply chain, job training, and other important aspects of the project and to keep them informed of the types of employment opportunities that will be created by the Empire Wind Project.
- Close engagement with NYSERDA and other relevant New York State agencies, including the NYSDEC and NYSOPRHP.
- Frequent dialogue and collaboration with leading environmental advocacy groups, including the Natural Resources Defense Council, the National Wildlife Federation, and the Sierra Club, regarding the development of the project.
    - In 2017 and 2018, Equinor Wind held two in-depth environmental roundtables for representatives from local and national environmental organizations. The roundtables were held on Long Island and at the New York Aquarium in Coney Island, New York.

  - Equinor Wind also has solicited the input of these and other environmental organizations on its survey plans and has incorporated their feedback as appropriate.
- Dialogue with marine mammal experts to discuss monitoring efforts with regard to marine mammals in the lease area.
  - Notably, Equinor Wind has entered into a Grant Agreement with the Wildlife Conservation Society ("WCS") to facilitate buoy based real-time monitoring of the spatial and temporal distribution of the four key large whale species, including North Atlantic right whales, within the Lease Area. An additional sponsorship with WCS's New York Aquarium facilitates an educational display of the presence of whales as detected by the real-time buoys.
- Dialogue with southern New York utilities, including Consolidated Edison, PSEG Long Island, National Grid, the New York Power Authority, and the Long Island Power Authority to discuss potential partnerships and ways of collaborating with these utilities to contribute to meeting New York's environmental and reliability objectives.
- Frequent discussions with elected officials and their staff representing interested communities, including representatives of Nassau County and members of the New York Senate and Assembly representing Staten Island, the City of Long Beach, Brooklyn, and other potentially affected communities.
- Equinor Wind is actively collaborating on environmental research and monitoring with the State University of New York ("SUNY") Stony Brook's School of Marine and Atmospheric Sciences ("SoMAS") on Long Island, in an effort to enhance understanding of marine life in the lease area. SoMAS is in the process of completing a BOEM funded study to increase understanding of the Atlantic sturgeon in the New York Bight. Contributing to this, Equinor Wind installed three of SoMAS' Atlantic sturgeon sensors on the metocean moorings installed within the lease area in December 2018 as part of Equinor Wind's site assessment activities.
- Equinor Wind has been providing support and guidance to the SUNY Maritime College as it moves forward to establish the NY Offshore Wind Energy Center in cooperation with SUNY Farmingdale.
- Meetings with representatives of low- and moderate-income communities in proximity to potential port redevelopment sites.
- Engaging with Native American representatives, including leadership from the Shinnecock Indian Nation and the Unkechaugi Indian Nation on Long Island, to inform them of developments within the lease area and survey activities.
- Active participation with leading offshore wind industry associations, forums and events, including the New York Offshore Wind Alliance, the American Wind Energy Association, and the Business Network for Offshore Wind.

Equinor Wind believes that its stakeholder engagement to date has provided an effective means to identify and address potential stakeholder concerns and take these concerns into account in the design and planning of the project to the extent feasible, as well as to build public support for the project.

To demonstrate the level of public support for the Empire Wind Project, Equinor Wind is providing copies of letters of support received from relevant stakeholders as Attachment 39. In addition, copies of news articles about the Empire Wind Project are provided as Attachment 40.

14.3 Future Engagement

Equinor Wind recognizes that the community outreach efforts that have been made thus far are only the beginning, and that it will be critical to continue to engage in dialogue with interested stakeholders throughout project development and operation, to incorporate their feedback into project planning as appropriate. Equinor Wind expects that these efforts will include:

- Organization of open houses and an increasing number of events in potentially affected communities.
    - Close engagement, open houses, and meetings in communities hosting the project's cable landfall, underground cable route, and substation.
    - Public meetings and continued discussions with communities adjacent to ports that support the development, operation, and maintenance of the Empire Wind Project.
    - Continued engagement with representatives of potentially affected communities, from the leadership of Nassau and Suffolk Counties to representatives of coastal villages.
- Continued dialogue with Nassau County officials to examine which jobs and facilities created as a result of the Empire Wind Project could be located within the county.
- Continued discussions with businesses in Suffolk County who are eager to become suppliers to the offshore wind industry, including drone-manufacturer ULC Robotics, whose Suffolk County-built drones were used on the Block Island offshore project.
- Regular newsletter updates—by email, social media and in print—informing communities of the status of the project.
- Continued meetings with labor organizations to identify opportunities to work collaboratively to ensure that the development of the Empire Wind Project and broader offshore wind industry benefits New York workers.
- Continued briefings and collaboration with environmentalists and marine scientists, including daily contact with scientists who monitor whales and other marine life in and around the lease area.
- Close, frequent contact with those potentially affected by construction, including mariners, fishermen, and communities near ports or interconnection cable.

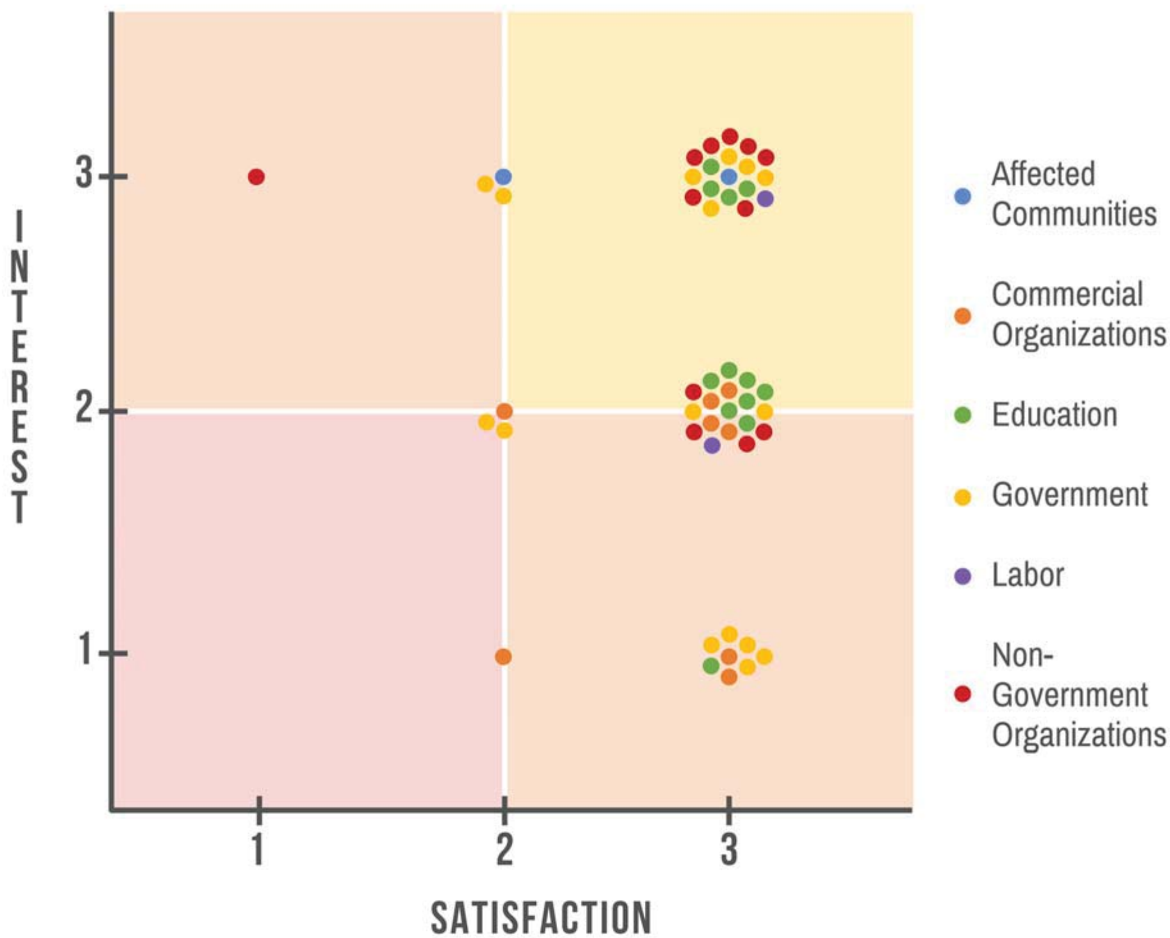
- Continued engagement and collaboration with local universities and colleges to promote awareness of offshore wind and help ensure that New York workers have the necessary foundational skills to capture the benefits of this growing industry.
- Continuing membership and support for civic, business, education, and other groups that enhance our host communities.

14.3.1 Stakeholder Mapping

Using the classification system and zone designations described in the Methodology section above, Equinor Wind maintains a database of current and potential stakeholders, both individuals and groups, for Empire Wind. The purpose of this database is to map Equinor Wind's engagement with stakeholders and ensure that all views are taken into account.

Figure 62 below provides an example of a scatter chart that Equinor Wind uses to track the interest of stakeholders and their level of satisfaction with the project. Stakeholders in the upper right portion are considered high interest and high satisfaction—stakeholders who are highly engaged and supportive, helping Equinor Wind to spread the word about the value of the project. Stakeholders in the upper left portion are highly interested, yet dissatisfied at present with what they know of the project.

Figure 62: Stakeholder Scatter Chart



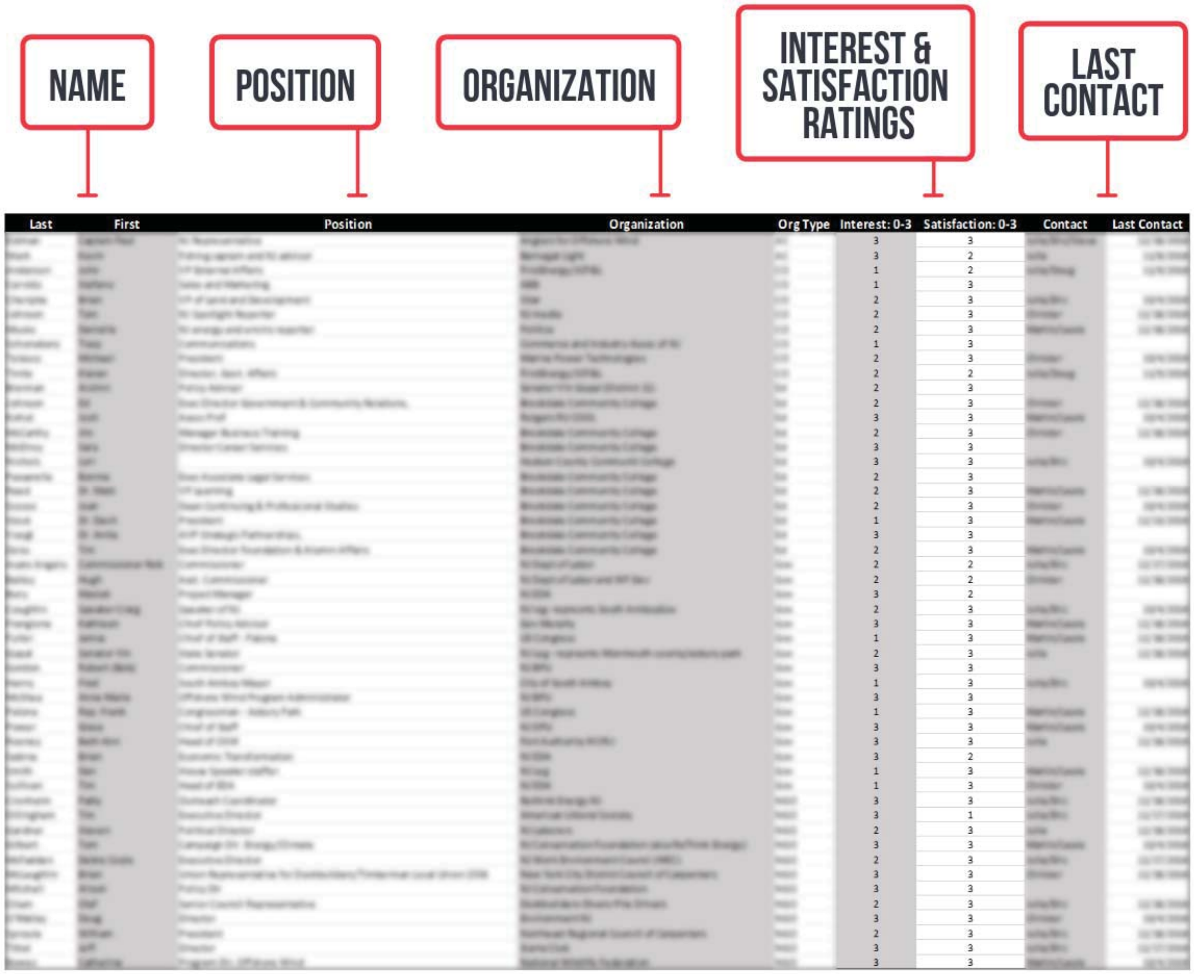
Mapping stakeholder views based on level of interest and satisfaction allows Equinor Wind to identify groups that may require further engagement to ensure that their interests and concerns are taken into account and addressed appropriately.

This approach has a proven track record of effectiveness and has already resulted in design changes to the Empire Wind Project. For example, following dialogue with commercial fishermen, Equinor Wind modified its plan for the turbine layout to ensure that it takes into account the direction that commercial fishermen typically drag their nets.

14.4 Stakeholder Engagement Matrix

Matching stakeholder categorization with rankings and project phases provides another useful tool to implement and manage stakeholder engagement. Figure 63 depicts a sample of the matrix—representing a sample of the outreach activity we have undertaken to date—shows the tracking method we use to help ensure all stakeholders receive the time and attention they require on the subjects they care about most.

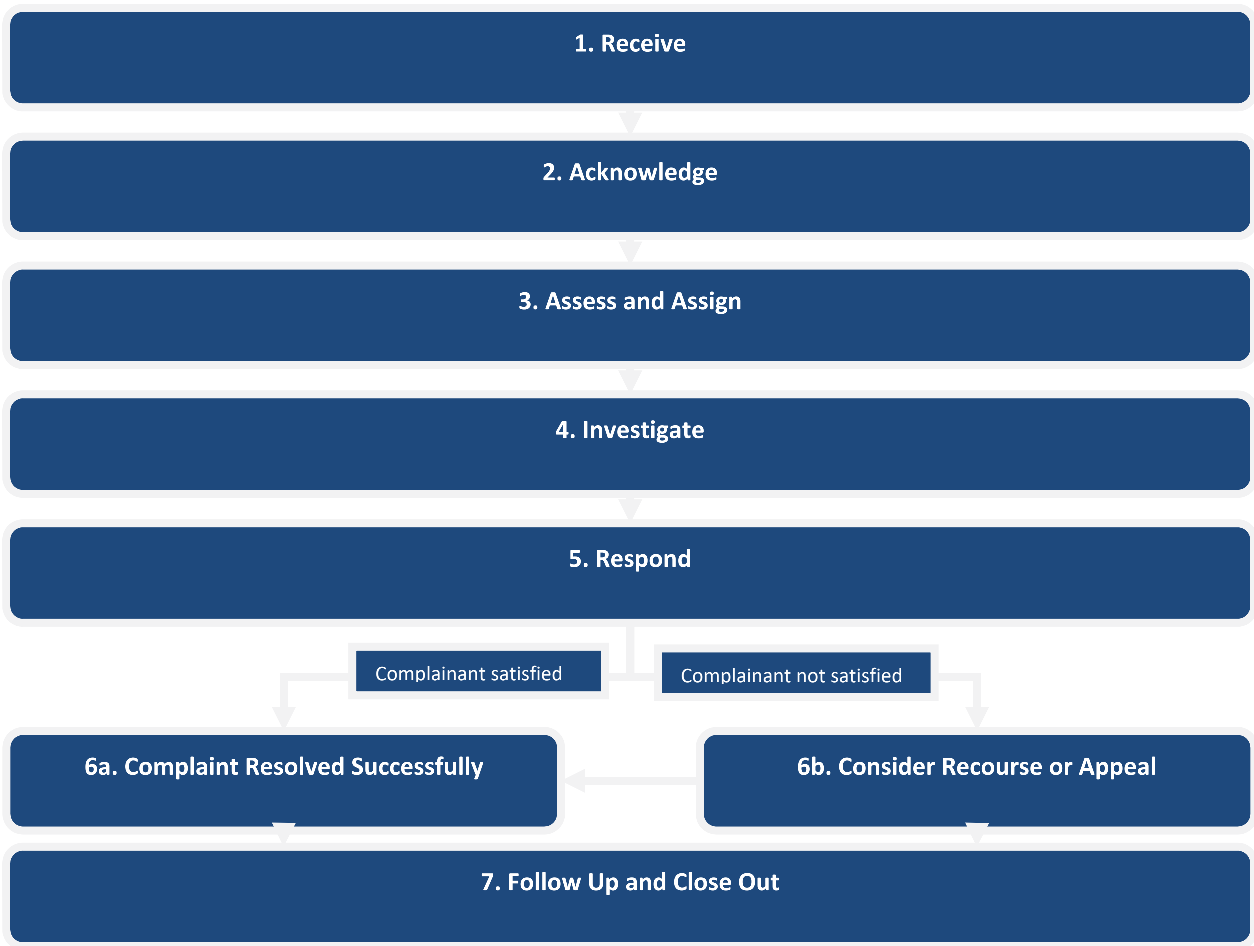
Figure 63: Stakeholder Engagement Matrix



14.5 Grievance Management

As described in our guiding principles, Equinor Wind strives to engage and cooperate with any and all stakeholders to resolve concerns. Nevertheless, we recognize that additional action is sometimes required to bridge different points of view. Accordingly, Equinor Wind has implemented an open and transparent stakeholder grievance process that ensures that grievances are received and responded to in a timely manner, and then tracked so that results can be analyzed. Figure 64 below provides an overview of the stakeholder grievance process.

Figure 64: Community Grievance Management Process



While our goal is always to resolve concerns before they reach the level of a formal grievance, Equinor Wind recognizes the value of establishing a formal process to allow stakeholders to raise concerns.

14.6 Monitoring and Reporting

Equinor Wind generates monthly reports detailing its engagement with stakeholders in order to ensure that the Equinor Wind team is consistently working towards the goal of taking into account stakeholder needs. Our team seeks continuous improvement over the course of every project.

14.7 Resources and Responsibilities

The Empire Wind team is comprised of individuals with the knowledge and experience necessary to carry out a highly complex project with the involvement and support of New York's dynamic stakeholder community.

Julia Bovey is the director of external affairs for Empire Wind. She has worked on stakeholder management, energy policy, and communications in the renewable energy space for 15 years, including for New York State at the Department of Public Service as the first Director of the Long Island Office. In that position, she gained invaluable experience working with Long Islanders to address their concerns about energy and the environment.

In addition, project team members are on the ground engaging stakeholders throughout the state, in keeping with our overall stakeholder strategy and the Engagement Matrix. For instance, Permitting Manager Martin Goff conducts roundtables with environmental scientists and meets with the regulatory agencies on a regular basis to provide project updates and discuss design concepts. As head of ports and foundations, Arturo Rodriguez is on hand for stakeholder meetings with communities near ports, answering questions and presenting information about potential effects on neighborhoods. Laura Morales, head of on-shore permitting, is engaged with leaders of communities that could potentially host the project's interconnection cable from landfall to substation and is also engaged with the regulatory authorities.

Empire Wind also counts on the knowledge and expertise of a team of local consultants on communications and stakeholder engagement.

14.8 Conclusion

Equinor Wind believes that ongoing community engagement is key to the success of the Empire Wind Project. Driven by the values of being Open, Courageous, Collaborative, and Caring, Equinor Wind looks forward to continuing to engage with stakeholders to ensure that the development of the Empire Wind Project listens and responds to stakeholders and aligns with New York's environmental and economic objectives.

15 VISIBILITY AND VIEWSHED IMPACTS

Proposers must address a Project's visibility from shore. If a Project is proposed to include turbines less than 20 statute miles from the nearest shoreline point of any state, Proposers must explain (i) how the Project will minimize adverse impacts related to visibility of turbines, including potential impacts on the local and state economy and historic and visual resources, such as publicly-accessible viewsheds, and (ii) how consideration of economic and environmental concerns contributed to the proposed distance from shore.

Additionally, all Proposals, regardless of distance from the nearest shoreline, must include a visibility study that presents visual simulations of the proposed Offshore Wind Generation Facility. Visibility studies must include a map or maps along with supporting GIS shape files that depict the nearest coastline, the boundary of the proposed site to be developed and any other reasonable reference points (e.g. coastal cities, historic sites, other wind energy areas). Simulations must be single frame, photographic images with superimposed simulations of the proposed wind turbine technology configured to represent a commercially-scaled and technically feasible scenario that is consistent with the proposed Project including operating capacity, wind turbine size, and generic spacing and configuration. Viewing instructions must be included on each simulation.

Visual simulations must represent, at a minimum, clear, partly cloudy, and overcast conditions during early morning, mid-afternoon, and late day, as well as one simulation at night with the turbines lit under clear conditions. Visual simulations must be provided from a minimum of two representative vantage points which represent the closest points to shore from any turbine within the Offshore Wind Generation Facility and, if applicable, any sensitive or historic viewpoints within 20 statute miles of the nearest turbine. The visibility study must also include analysis of the percentage of time during which different visibility conditions are expected to occur based on past meteorological data.

The simulations must be provided in a format suitable to be printed or electronically viewed by the public and/or the Scoring Committee.

Equinor Wind believes that the proposed location of the Empire Wind Project makes the project uniquely positioned to efficiently supply ORECs to support New York's renewable energy goals. As a practical matter, the distance of a project from shore is a critical driver of project costs. With the Empire Wind Project being developed in a portion of the lease area ranging from 14 to 25 miles offshore of Long Island, Equinor Wind believes that the Empire Wind Project will be capable of meeting New York's offshore wind needs more cost effectively than projects that are located farther from shore.

At the same time, Equinor Wind recognizes the importance of ensuring that the development of offshore wind projects does not adversely affect viewshed resources. The majority of New York's coastlines are highly developed and/or are popular tourist destinations. Seasonal tourism associated with beaches and offshore recreational activities (*e.g.*, water sports, sport fishing, whale watching) are important to the local economies. A number of historical resources (*e.g.*, lighthouses, old military bases) and preserved natural areas (*e.g.*, Gateway National Recreation Area, Fire Island National Seashore) are also located along the shoreline.

For that reason, Equinor Wind is tailoring the development of the Empire Wind Project in a manner that minimizes visibility and the potential impact on viewshed resources, including employing the following mitigation measures:

- Sympathetic maritime navigation night lighting systems for offshore and onshore structures where feasible; and
- Smart aviation lighting systems, such as an ADLS, further discussed in Section 9.2.

In addition, Equinor Wind has conducted a visibility study that simulates the visibility of the Empire Wind Project from Key Observation Points ("KOP") along the New York coastline consistent with NYSERDA's requirements in the RFP in order to evaluate the likely visual impact of the Empire Wind Project. As discussed further below, this visibility study demonstrates that the construction of the Empire Wind Project will not have a material impact on viewshed resources along the New York coastline. Even in clear conditions – which account for only 17% of daylight hours – the visibility of the Empire Wind Project will be limited to a small percentage of the viewshed. The Empire Wind Project will be less visible or not visible at all during partly cloudy or overcast conditions – which together account for approximately 66% of daylight hours. During the nighttime, the Empire Wind project will not be visible at all from the New York coastline except when its ADLS is engaged to ensure that the project is visible to approaching aircraft. As a result, the development of the Empire Wind Project is not expected to adversely affect the economies of coastal communities or historic and visual resources.

Equinor Wind notes that the visual impact of the Empire Wind Project will be thoroughly vetted through BOEM's evaluation of the COP. This provides further assurance that the Empire Wind Project will be developed in a manner that does not adversely affect viewshed resources.

15.1 Visual Simulation

15.1.1 Approach

In order to provide a foundation for Equinor Wind's visual assessment of the project, Equinor Wind reviewed and consulted existing visibility studies and resources concerning the lease area, including:

- NYSERDA's Visibility Threshold Study ("NYSERDA VTS") prepared as part of the New York Offshore Wind Master Plan;
- BOEM's Evaluation of Visual Impact on Cultural Resources/Historic Properties: North Atlantic, Mid-Atlantic, South Atlantic, and Florida Straights (2012); and
- BOEM's Renewable Energy Viewshed Analysis and Visualization Simulation for the New York Outer Continental Shelf Call Area: Compendium Report (2015) ("Compendium Report").

In accordance with industry practices, the Equinor Wind Empire Project visual simulation is based on an assessment of potentially impacted or sensitive viewing locations. A preliminary list of 34 sensitive viewpoints within 20 statute miles of the nearest turbine was initially developed based on viewpoints identified in BOEM's Compendium Report and on locations identified as having potential visibility. The list was subsequently refined to three *representative* KOPs for the visual simulations. Figure 65 illustrates the location of all viewpoints identified in the 20-mile buffer, including those selected for the visual simulations for this proposal.

Figure 65: Locations of Sensitive Viewpoints and those Selected for the Purposes of this Proposal

[redacted]

Equinor Wind selected the KOPs for the visibility simulation based on the proximity to the proposed location of the Empire Wind Project and taking into account viewing location types (*e.g.*, shoreline; inland/elevated views; and sensitive historic properties). The KOPs studied include:

- **Jones Beach State Park (Short Beach):** This is a shoreline viewpoint that is located on Short Beach, within Jones Beach State Park on Long Island, which represents the closest point to shore from any turbine in the lease area
- **Merrick Road Town Park:** This elevated viewpoint is from the historic Merrick Road Town Park and Golf Course

- **Jacob Riis Park Promenade:** Although this viewpoint is located just outside the 20-mile buffer, it is a location viewed from the narrowest point (*i.e.,* the apex of the triangle of the lease area)

Figure 66 below identifies each viewpoint and the distance of the nearest turbine location

Figure 66: Location of Simulations and Distance to Nearest Turbine for Empire Wind Project

Name	Location	Distance to Nearest Turbine[2]
Jones Beach State Park (Short Beach)[1]	Wantagh, NY	14.4 miles
Merrick Road Town Park and Golf Course	Merrick, NY	18.7 miles
Jacob Riis Park Promenade[1]	Queens, NY	20.2 miles
[1] Indicates a viewpoint included in BOEM's Compendium Report (2015), which was selected by BOEM in coordination with the National Park Service ("NPS"). [2] The distance is based on the proposed layout of the Empire Wind Project, assuming a 1-nm buffer from the outside boundary of the lease area.		

Once the KOPs were selected, Equinor Wind received approvals from the appropriate agencies and authorities to take representative photographs from each KOP location during an initial site visit. The photographs provided a baseline inventory of existing conditions of the viewshed from each KOP, including any existing visual obtrusions, such as marine vessels, or in the case of nighttime photos, any ambient lighting from the surrounding area. At each KOP, a panorama, or an overlapping series of photographs was captured using a NIKON D90 digital single lens reflex camera ("DSLR") equipped with a 35-millimeter ("mm") lens.[29] Photo documentation also included recording global positioning system ("GPS") coordinates and field notes (*e.g.*, date/time photographs were taken, weather, direction of photograph).

Using photographs taken during the site visit, the simulations were created by combining site photography with accurate, rendered computer models of the proposed facilities to predict what would be seen if the Empire Wind Project were represented in the photographed setting. This methodology also allows the simulations to capture the existing conditions, which includes vessel traffic from shipping lanes located in the area.

More specifically, to create the photo simulations, the location data captured by the GPS device attached to the camera during the site visit was transferred to design software that combines the geographic information system ("GIS") data and a 3D model of the Empire Wind Project. The views from the photographs were matched in the 3D modeling software using virtual cameras with the same focal length and field-of-view as the DSLR camera settings used to capture the photographs. Date- and time-specific lighting was added to the 3D model to depict early morning, mid-afternoon, late day, and nighttime. In order to simulate the various weather conditions, the Daylight Systems parameters in the 3D model were changed so that the amount of particulate

[29] When used with a 1.5x cropped-sensor camera such as the NIKON D90, a 35-mm lens is considered a "52-mm equivalent lens." A 52-mm equivalent lens is considered a "normal lens" that most closely approximates the field of vision of the human eye. In photos taken using the combination of the D90 and a 35-mm lens, the size and scale objects in the background and foreground are depicted realistically and are not distorted.

matter in the air could be adjusted so that the scene is completely clear or overcast. A haze-driven sky model was then used to adjust the visual falloff, or how far you can see in the given weather condition, based on the weather condition being simulated. Once the day, time and weather conditions were added to the 3D model, renderings from the virtual cameras were created. The renderings were then overlaid on the site photography and any necessary modifications to the existing landscape were made to the images.

As shown in Attachment 41, for each of the KOPs, visual simulations have been developed to represent clear, partly cloudy, and overcast conditions during early morning, mid-afternoon, and late day, as well as two simulations at night. One simulation at night is with the ADLS activated, which would only be when aircraft are within a certain distance of the wind farm The second nighttime scenario is when the turbines are not lit, as the ADLS is not activated. In this last scenario, turbines are not visible at all, as any navigational lighting at the base of the turbines would be below the horizon. In accordance with the RFP guidelines, the simulations have been provided in a format suitable to be printed or electronically viewed by the public and/or the Scoring Committee. For proper viewing, all simulations should be printed 11”x17” in full size with no scaling and viewed from an arm’s length away (approximately 24 inches).

As summarized in Figure 67, from areas along the coastline of New York, the perceived scale of the turbines will be relatively small, amounting to fractions of an inch for viewers onshore. The table below provides information regarding distance to the nearest turbine, amount of that turbine visible, and the size of the visible portion of the turbine represented in the simulation for each representative vantage point from which the simulations were created.

Figure 67: Summary of Visibility of Wind Turbines from KOPs

Name	Amount of Nearest Turbine Visible	Percent of Turbine Visible	Size of Visible Portion of Nearest Turbine in Simulation
Jones Beach State Park (Short Beach)	687.5 ft	14.4 miles	0.21 inches
Merrick Road Town Park and Golf Course	592.6 ft	18.7 miles	0.14 inches
Jacob Riis Park Promenade[1]	553.7 ft	20.2 miles/ 32.5 km	0.12 inches

15.1.2 Frequency of Scenario Conditions

As shown in the attached visual simulations,[30] Equinor Wind has evaluated the anticipated frequency of each simulation scenario. Because the Empire Wind Project is located within the Area of Analysis ("AoA") included in NYSERDA's VTS, the NYSERDA VTS was reviewed to identify the typical or average weather conditions and visibility conditions expected to occur within the Empire Wind Project area and the percentage of time during which different visibility conditions were expected to occur. The NYSERDA VTS assessed the visibility of a hypothetical wind farm at various distances (13.2 and 30 miles) from shore under different meteorological conditions within the AoA. The AoA identified in the NYSERDA VTS consisted of the Atlantic shoreline of Long Island and off-shore views roughly perpendicular to that shoreline. Weather data was examined in the study to determine how frequently each combination of visibility (*i.e*., less than 10 miles or greater than 10 miles), background sky conditions (*i.e*., clear, partly cloudy, or overcast), and time of day (morning, midday, afternoon) is likely to occur during a typical year. The analysis was based on hourly meteorological surface data collected from the DS3505 data set available from the National Climatic Data Center ("NDCD") for the weather stations at the John F. Kennedy International Airport and the Long Island-MacArthur Airport for a period of six years.

Based on data collected from the weather stations and the results of the analysis, during daytime hours,[31] overcast conditions were most common over the course of a year occurring approximately 60% of the daylight hours. Clear conditions occur in approximately 17% of the daylight hours, followed by partly cloudy conditions which occurred approximately 6% of daylight hours. Under these three types of conditions, it is assumed that visibility would be 10 miles or greater. For the remaining 16% of the daylight hours, for which NYSERDA did not classify, visibility was less than 10 miles.

The most frequent condition is overcast skies during the morning, which occurs 21.8% of daylight hours, followed by overcast skies during midday and afternoon hours, which occurs 21.5% and

[30] The related GIS shape files are provided as Attachment 42 to the bid.

[31] The NYSERDA VTS did not assess nighttime conditions with the exception of the use of nighttime aviation warning lights.

17% of daylight hours, respectively. The least frequent weather condition is partly cloudy skies during the midday hours (1.8% of total daylight hours). Figure 68 provides a summary of frequency of occurrence of the various time of day/weather scenarios.

Figure 68: Frequency of Occurrence of Various Time of Day/Weather Scenarios

Time of Day	Percentage of Daylight Hours		
	Clear	Partly Cloudy	Overcast
Morning	7.6	2.2	21.8
Midday	4.2	1.8	17.0
Afternoon	5.3	1.9	21.5
Total	17.1	5.9	60.3

15.1.3 Results

As shown in the visual simulations, the Empire Wind Project is not likely to be highly visible for the majority of the time under most conditions and, as a result, is not expected to have significant impacts on local or state economies dependent on tourism of publicly-accessible viewsheds. As provided in the visual simulations for this proposal, only portions of the proposed Project are expected to be visible from KOPs identified, and only under certain climatic conditions. In many cases, the visibility is limited to a very small percentage of the viewshed or not visible at all. For example, at the closest KOP, Jones Beach (Short Beach), turbines would account for only 0.21 inches of the total view space. Visibility slightly increases during late day timeframes, but is strongly influenced by clear or cloudy conditions, with turbines less visible during partly cloudy or overcast scenarios. As demonstrated by climate trend data compiled by NYSERDA, clear conditions only occurred in approximately 17% of daylight hours, which is another key point to consider when evaluating impacts to the viewshed. Further, the offshore areas within and adjacent to the lease area support commercial, military and recreational vessel traffic; thus, the scenic viewshed from an onshore vantage point is not currently unobstructed.

There will likely be some occasions when there will be visibility of some of the structures in the Empire Wind Project. Visibility varies widely based on conditions and impacts vary on subjective opinion and will be addressed based on feedback from stakeholders as the project continues to develop. It is important to note that in some cases, the presence and visibility of wind turbines has resulted in economic benefits, for example where people visit the coastline to see these features offshore, including offshore sightseeing trips. In any case, based on the mitigation measures discussed above (*e.g.*, sympathetic lighting and ADLS) and Equinor Wind's commitment to following state and federal regulations and best practices, impacts are not expected to be significantly adverse.

15.2 COP Visual Impact Assessment

While Equinor Wind believes that the visual study prepared in support of this RFP is sufficient to demonstrate that the development of the Empire Wind Project will not have a material impact on viewshed resources, the visual impact of the Empire Wind Project will be further evaluated and expanded as part of the COP. In particular, detailed landscape and visual impact assessments ("VIA") will be required to support BOEM's NEPA process[32] and associated consultations under Section 106 of NHPA. Section 106 of the NHPA requires that federal agencies take into account the effect of their undertakings on significant cultural resources, which includes historic properties that could be impacted by modified viewsheds during construction and operation. Historic properties that have been listed on, or are eligible for listing on, the National Register of Historic Places are considered significant cultural resources and may include properties of traditional, religious, and cultural importance to Native American tribes.

In order to provide a basis for BOEM's assessment, Equinor Wind will be preparing a separate VIA in support of the development of the Empire Wind Project. BOEM does not have specific guidelines on conducting a VIA or associated visual simulations. However, BOEM's *Guidelines for Information Requirements for a Renewable Energy Construction and Operations Plan (2016)* (BOEM's COP Guidelines) indicate that the visual resource assessment should apply appropriate viewshed mapping, photographic and virtual simulations, computer simulation, and field inventory techniques to determine, with reasonable accuracy, the visibility of the proposed project to sensitive and scenic viewpoints. Equinor Wind's approach to the VIA has been consistent with these guidelines, as described within this section. In addition to BOEM's COP Guidelines, NYSERDA is currently developing guidelines for offshore energy VIAs, which may be adopted by BOEM. The NYDPS also has requirements for conducting VIAs with photographic simulations for upland components of the Project. Depending on the timeframe that NYSERDA's guidance is available in relation to the timing of study completion and COP submission, Equinor Wind can review and incorporate the NYSERDA guidelines, as applicable.

On November 6, 2018, Equinor Wind submitted a VIA study plan to BOEM, the National Park Service ("NPS"), the NY ORPHP, and the NYSDEC. The VIA study plan for the Empire Wind Project was developed based on BOEM and federal agency guidelines. The VIA study plan provides information on determining project visibility, viewshed mapping, simulations (photographic, virtual, computer), identification of sensitive viewers/important viewpoints, and determining visual contrast. Currently, Equinor Wind anticipates that the VIA will evaluate the KOPs identified above as well as other points along the New York and New Jersey coasts. The VIA will also include visual simulations of additional locations, which will be produced in panoramic and formatted for larger viewing, as is the industry standard.

Since submitting the VIA study plan, Equinor Wind has received feedback from BOEM on the scope of the study, which will be reflected in the final VIA that is conducted. The NY ORPHP has

[32] 30 C.F.R. § 585.627(a)(7).

indicated that the plan was acceptable to its office and Equinor Wind has not yet received responses from NPS or NYSDEC.

Currently, Equinor Wind expects that the VIA will evaluate the impact on scenic areas that could be affected by the development of the project within a 35 mile radius of the study area surrounding the lease area, including the KOPs set out in this proposal. The selection of the Study Area was based on maximum visibility under optimal viewing conditions (*i.e.*, a clear, sunny day), the proposed turbine height/curvature of the earth, and the topography within the lease area. BOEM's study titled *Renewable Energy Viewshed Analysis and Visualization Simulation for the New York Call Area (2015)* (BOEM's NY Call Area Study) and the NYSERDA VTS were also consulted.

The VIA will provide a robust assessment of the full visibility of the Empire Wind Project, including both onshore and offshore components. The VIA will provide an assessment of all currently proposed and future phases of development and will include accurate and realistic photographic and virtual simulations, in addition to field inventory techniques and a delineation of the onshore viewshed to determine the visibility of the project. Among other things, the VIA will include:

- Detailed printouts, along with detailed viewing instructions, that will provide a realistic assessment of the likely visual impact of the construction and operation of the project; and

- A video simulation, including two condensed 24-hour time lapse videos that will depict the visibility of the project under a wide range of conditions and times of day/night.

Based on the preliminary results of the VIA, it is anticipated that viewers along the coasts of New York would have limited visibility of the project's offshore structures (wind turbines and offshore substations), with the impact varying based on location, elevation, and prevailing atmospheric conditions. A final version of the VIA will be submitted with the COP in 2019 and will be subject to review by BOEM, relevant state and federal agencies, and interested stakeholders through the NEPA process.

16 NEW YORK ECONOMIC BENEFITS

Proposers must submit their claimed Incremental Economic Benefits and Contingent Economic Benefits by category using the Offer Data Form and support these claims by submitting an Economic Benefits Plan. All claimed expenditures and investments should be in real dollars (U.S.) at the time of Proposal submission.
The Economic Benefits Plan must include descriptions and supporting documentation for their Incremental Economic Benefits and Contingent Economic Benefits claims, as described below.
The prorated portion of investments in oversized transmission and interconnection facilities not needed to support the Offshore Wind Generation Facility shall not be included as an Economic Benefit.

Equinor Wind is enthusiastic about the opportunity to support New York in achieving its objective of becoming a strategic hub for the offshore wind industry on the east coast. Equinor Wind believes that New York's demonstrated commitment to promoting the development of significant offshore wind resources as reflected in New York's Green New Deal, its central geographic location, well-developed port infrastructure, and highly skilled workers make the state well-suited to become the center of the growing offshore wind industry.

As the holder of an offshore wind lease within the New York Offshore Wind Energy Area, Equinor Wind and its parent companies are committed to the growth and development of the offshore wind industry in New York. Equinor Wind has already made significant investments in developing the offshore wind industry in New York in connection with its efforts to evaluate and develop its lease area. [redacted]

[redacted]

As discussed further below, if selected to supply ORECs to New York through this RFP, Equinor Wind will significantly expand its investments and commitments to New York by creating thousands of new jobs for New York workers, investing millions of dollars in New York bussinesses, and fostering the growth of a robust offshore wind supply chain and workforce that has the potential to make New York a regional hub for sourcing, logistics, and construction of offshore wind facilities.

[redacted]

Specifically, the selection of the Empire Wind Project through this RFP process will:

- **Create good paying jobs for New York workers**: [redacted]
- **Promote New York supply chain development**: [redacted]
- **Support the engagement of New York businesses and workers:** [redacted]
- **Benefit Ratepayers:** [redacted]
- **Create Additional Cost Savings Through Reducing Emissions**: [redacted]

[redacted]

16.1 Incremental Economic Benefits

The following subsections provide an overview of the incremental economic benefits that will be generated by the development, construction, and operation of the Empire Wind Project. As a general matter, this discussion focuses on the employment opportunities that will be created and the expenditures that will be made by Equinor Wind (or its affiliates) and its direct suppliers and contractors. As described further below, even when only the jobs and expenditures of Equinor Wind and its direct suppliers and contractors are taken into account, [redacted]

Figure 69: Overview of Category 1 and Category 2 Incremental Economic Benefits

	FTEs	Expenditures
Categories 1 and 2 Benefits	[redacted]	[redacted][34]

Equinor Wind believes that the Category 1 and Category 2 benefits set out above will foster the development of an offshore wind workforce and supply chain that will help ensure that New York workers and businesses benefit from the development of offshore wind resources to meet New York's environmental goals and those of other states throughout the region.

In addition to the economic benefits set out above, Equinor Wind plans to make significant investments in New York businesses and workers as well as research and development to promote New York's efforts to develop a robust offshore wind supply chain and workforce within the state. For example, Equinor Wind plans to establish a dedicated fund to promote workforce and community development and collaborate with local universities to support the creation of additional opportunities for New York workers.

Importantly, the incremental economic benefits set out above represent only a portion of the economic development opportunities that will be unlocked as a result of the development of the Empire Wind Project. In order to quantify the full range of economic opportunities that will be created in connection with the Empire Wind Project, Equinor Wind asked ICF to conduct an economic benefit study of the Empire Wind Project. [redacted]

[34] All expenditures are provided in 2019 dollars.

[redacted]

Figure 70: Total Incremental Economic Impact

[redacted]

16.1.1 Category 1: Project-Specific Spending and Job Creation in New York State Employment Opportunities

Job Creation

Based on Equinor Wind's internal estimates and information received from suppliers,[35] Equinor Wind currently anticipates that the development of the Empire Wind Project will create a range of short-term and long-term positions for New York workers in connection with the development of the Empire Wind Project, both during the initial period of project development and construction and during the operational life of the project. Specifically, [redacted]

[redacted]

[redacted]

[36] For the purpose of the Economic Development Plan, an FTE is defined as equal to 2,080 hours per year.

[redacted]

Figure 71: Employment Opportunities and Compensation

[redacted]

The following subsections provide an overview of source of the FTEs that will be generated by Equinor Wind and its direct suppliers and contractors as well as the types of jobs that will be created.

Project Development and Construction

[redacted]

[redacted]

[redacted]

[redacted]

Figure 72: Type of Construction Jobs

[redacted]

[redacted]

[redacted]

Based on internal estimates and discussions with potential suppliers, Equinor Wind currently estimates that the [redacted]

Figure 73: Type of O&M Jobs

[redacted]

Expenditures on In-State Goods, Services, and Compensation

[redacted] through the first three years of commercial operation, including payments for wages and compensation and in-state goods and services.[38] This investment includes, but is not limited to, the following:

[redacted]

- [redacted]
- [redacted]
- [redacted]
- [redacted]
- [redacted]
- [redacted]

Importantly, the expenditures that are described above do not include the significant expenditures that Equinor Wind anticipates making in New York associated with operation and maintenance of the project after the initial three years of commercial operation. [redacted]

Payments, Rents, and Taxes

[redacted]

[redacted]

Transmission and Interconnection Fees and Expenditures

[redacted]

[redacted]

16.1.2 Category 2: Offshore Wind Industry- Related Supply Chain and Infrastructure Investment

Supply Chain and Transportation Facilities

In addition to the employment opportunities and expenditures described above, Equinor Wind plans to make significant investments in New York ports and facilities. These investments will not only support the development of the Empire Wind Project but will ensure that New York has the infrastructure necessary to support the development of offshore wind facilities designed to serve New York's renewable energy goals and those of other states located along the eastern seaboard.

[redacted]

[redacted]

[redacted]

Figure 74: Type of Civil Construction Jobs

[redacted]

16.1.3 Category 3: Input Activities

Equinor Wind has developed a plan to increase the economic benefits associated with the Empire Wind Project through additional investments in, and engagements with, New York workers and businesses. These engagements and investments are an extension of Equinor's company-wide commitment to ensuring that its activities create lasting value for local communities through its business activities, including direct and indirect local employment, local procurement, and social investments.

Business Engagement Plan

Equinor Wind believes that a well-developed local supply chain is critical to the successful development of an offshore wind industry in New York and to reducing the costs associated with the development of such projects. For that reason, Equinor Wind is committed to ensuring that New York businesses are fully apprised of potential opportunities to support the development of the Empire Wind Project.

Equinor Wind already has engaged in substantial efforts to identify opportunities for New York businesses to support the development of the Empire Wind Project. Notably, in February 2018, Equinor Wind retained the Renewables Consulting Group, a company based in Brooklyn, New York, to create a New York and regional supplier database of companies capable of supporting the development of the Empire Wind Project. These efforts resulted in a supplier directory containing local and regional businesses capable of supporting the project ("Equinor Wind Supply Directory"). Equinor Wind has utilized the Equinor Wind Supply Directory as the foundation for its efforts to tailor the development of the Empire Wind Project in a manner that maximizes the economic opportunities and benefits created for New York.

The following subsections describe additional efforts that Equinor Wind plans to make to create opportunities for New York businesses and workers in the event that the Empire Wind Project is selected through this RFP process.

[redacted]

[redacted]

Communication of Opportunities to New York Businesses

Equinor Wind will use a dedicated online web portal to communicate opportunities to supply goods or services to the Empire Wind Project and provide updates on procurement activities in order to ensure that New York businesses are informed of opportunities to support the development of the project. In accordance with Section 2.2.9 of the RFP, in the event that the

Empire Wind Project is selected through this RFP, Equinor Wind will communicate all opportunities to support the Empire Wind Project with an anticipated contract value of $5 million or greater not already committed to the New York State vendor list maintained by NYSERDA at the time of execution of a contract awarded as a result of this RFP process. Equinor Wind is committed to making certain that these suppliers receive timely notification of opportunities to support the project and would welcome the opportunity to work with NYSERDA to establish a mechanism that ensures that suppliers that register and appear on the New York State vendor list are timely informed of opportunities as they arise. New York businesses that pursue opportunities to supply goods or services to the Empire Wind Project would then be evaluated in light of Equinor's existing procurement and supplier standards and requirements. [redacted]

Before sending out any request for information, request for proposals, or invitations to tender to potential suppliers, Equinor Wind will review the NYSERDA vendor list and the Equinor Wind Supply Directory to identify, and reach out to, potential New York suppliers qualified and capable of providing the goods or services at issue. These efforts would be in addition to establishing a mechanism to ensure timely communication to New York businesses of opportunities to support the project consistent with Section 2.2.9 of the RFP.

In addition to the outreach efforts described above, Equinor Wind will hold supply chain events following the selection of the Empire Wind Project through this RFP to help create additional opportunities for New York businesses. These supplier events will be timed to give New York businesses the opportunity to interact with Tier 1 Suppliers selected to support the development of the project and to identify potential subcontract and supplier opportunities.

Equinor Wind will also consider carefully how to target these events. A strategy successfully employed on previous projects includes working together with local business support organizations that will allow the project to engage with potential lower-tier suppliers. Our experience also suggests that focused supply chain engagement results in significant opportunities to local companies. The purpose of these events will be to encourage new entrants to the offshore wind sector, remove barriers to entry, and improve awareness and access to project opportunities.

Efforts to Shortlist Pre-Qualified New York State Companies

Equinor Wind is committed to ensuring that New York companies are given a fair opportunity to support the development of the Empire Wind Project, either directly to Equinor Wind or its Tier 1 Suppliers. For that reason, Equinor Wind will include New York businesses on Equinor Wind's bidders list so long as they have been pre-qualified as a potential supplier to Equinor Wind.

To be pre-qualified as a direct supplier to Equinor Wind and be admitted on the bidders' list, suppliers must have the capability and experience to deliver the proposed scope of work, meet pre-defined technical qualification requirements and satisfy minimum safety, quality, and integrity due diligence requirements. Qualification of new products/technology can take time, depending on the maturity of the product/technology. The prequalification process is specifically designed for each procurement and may include simple follow-up questions or thorough investigations (*e.g.*, site visits and audits).

If the Empire Wind Project is selected through this RFP process, Equinor Wind will support efforts by New York businesses to become pre-qualified to supply goods and services to the Empire Wind Project. As an initial matter, as part of the supplier events and other activities described above, Equinor Wind will provide New York businesses with information regarding the criteria that they must meet in order to be engaged to support the Empire Wind Project.

These efforts will compliment Equinor Wind's efforts to support pre-qualification efforts through its existing online portal, "How to become an Equinor Supplier," which provides guidance to potential bidders regarding how to qualify to do business with Equinor, gives potential bidders the opportunity to register their interest in supporting the project, and ask questions regarding qualification requirements. [redacted]

Subdividing Work Packages To Increase New York Firms' Prospects for Success

Equinor Wind currently is employing a multi-contract procurement strategy for the Empire Wind project based [redacted] Each of the parties that executes a contract (*i.e.,* Tier 1 Suppliers) will deliver different elements of the design, supply, fabrication, installation, commissioning, and operation of the project.

In addition to allowing Equinor Wind to identify the most cost-effective allocation of risk and responsibilities, Equinor Wind believes that a multi-contracting strategy will maximize the opportunities for New York businesses by increasing the opportunities to compete to obtain a contract supporting the project.

Requirements for Tier 1 Suppliers

[redacted]

[redacted]

- [redacted]
- [redacted]
- [redacted]
- [redacted]
- [redacted]

Workforce Development Plan

Equinor Wind appreciates the importance of ensuring that the Empire Wind Project contributes to the development of a workforce with the skills necessary to attract offshore wind manufacturers and developers to the State. While Equinor Wind believes that New York's world-class workforce already makes New York uniquely situated to benefit from the development of a robust offshore wind industry on the east coast, in the event that the Empire Wind Project is selected through this RFP, Equinor Wind plans to take a number of steps to foster the further growth and development of the workforce capabilities that will make New York a national leader in the offshore wind industry.

Creation of Community Benefits Fund

In the event that the Empire Wind Project is selected through this RFP, Equinor Wind will commit to provide a total of [redacted] to a new community benefits fund that will focus on supporting workforce transition and development and providing support for communities in the vicinity of sites associated with activities related to the development of the Empire Wind Project. The community benefits fund's primary focus will be on providing financial support for initiatives focused on fostering the development of a "green workforce" within New York. [redacted]

Support for the SUNY Offshore Wind Energy Center

In recent months, Equinor Wind has been providing support and guidance to the SUNY Maritime College as it moves forward to establish the NY Offshore Wind Energy Center in cooperation with SUNY Farmingdale. In the event that the Empire Wind Project is selected, Equinor Wind plans to continue its support of the Offshore Wind Energy Center by offering in-kind support to help develop offshore wind programs and training at the center. Equinor Wind also appreciates the importance of ensuring that graduates of the center are able to find employment upon graduation. For that reason, Equinor Wind has committed to interview successful graduates of the certificate program that submit an application for open positions with Equinor Wind.

Support for Local Apprenticeship and Internship Programs

Equinor has a long history of supporting job training in the communities in which it operates and manages a range of apprenticeship and internship programs that are designed to provide "on the job" training and support for members of the communities in which it operates. For instance, Equinor currently operates an apprenticeship and internship program in the UK that provides new entrants to the offshore wind labor force with hands-on training on Equinor's existing offshore wind assets. In order to identify local candidates for these programs, Equinor holds a "skills day" with local universities to raise awareness about the program and encourage local members of the community to apply.

If the Empire Wind Project is selected through this RFP, Equinor Wind will work to establish a local apprenticeship program similar to those operated in connection with its UK assets in order to provide opportunities to members of the local communities and ensure a pool of technicians within New York State with the skills necessary to support the growing offshore wind project. As part of these efforts, Equinor Wind will explore collaborating with local labor organizations and universities to identify suitable candidates and increase public awareness of these programs.

Supporting Workforce Transition

Equinor Wind strongly supports New York's effort to ensure that an increasing portion of the state's electricity needs are met using renewable energy. Equinor Wind recognizes, however, that the transition to new technologies and resources has the potential to create new challenges for New York workers as older generation resources retire or otherwise seek to exit the market.

Equinor Wind is committed to minimizing workforce disruption associated with the changing generation mix by creating new opportunities for workers seeking to transition from other parts of the electric sector to supporting the development and operation of renewable resources. Consistent with this objective, Equinor Wind plans to establish a bespoke, internal training program designed to draw upon workers that have experience operating thermal generation resources and provide them with the training necessary to support offshore wind resources. Equinor Wind currently expects that these efforts will include:

- Early recruitment of operations and maintenance staff to allow sufficient time for training with the goal of ensuring that the core operations and maintenance team would be in place one year prior to the start of operations.
- Involving operations and maintenance staff in construction and commissioning activities to ensure that these employees receive the training necessary to effectively assume responsibility for the project.
- Placing operations and maintenance personnel in training secondments to carry out "on the job" training at Equinor's existing offshore wind assets in Europe.
- Ensuring that there is an experienced team assembled in New York with a history in existing offshore wind farm operations at the time of the commencement of operations in order to ensure that newly hired employees receive the benefits of the experience gained from Equinor's more than 10-years of operation of offshore wind resources.
- Giving operations and maintenance employees access to Equinor's Internal Global Development Program, which highlights new talent within the company and places them on an accelerated intensive program to aid their development and to understand Equinor's strategy and culture.
- Fostering the development of skills by allowing operations and maintenance employees to attend Equinor University, which provides Equinor employees with training through courses that cover a wide range of subjects relevant to renewable resources. Access to this program will accelerate the competence of the Equinor New York workers and bolster the competence of the renewables workforce in New York state.

Engagement With Labor Organizations

Equinor Wind has already undertaken substantial efforts to create opportunities for New York workers through dialogue with New York labor unions and organizations. The New York Trades Council and Green Jobs NY have been especially helpful. For Instance, Equinor Wind has supplied the unions with detailed assessments of the types of jobs and skills needed at each stage of the project, from permitting and construction through to operations. In the event that the Empire Wind Project is selected through the RFP process, Equinor Wind will reach out to these labor organizations to solicit their input on how to enhance the employment opportunities for New York workers, including pursuing negotiation of a Project Labor Agreement with appropriate labor organizations.

Investments in Research & Development

Throughout its history, Equinor has supported research and development activities in connection with its offshore projects. The Empire Wind Project is no exception and Equinor Wind already is engaged in a number of efforts to promote the development of offshore wind research and development activities in New York State:

- Christer af Geijerstam, President of Equinor Wind, serves on the Board of Directors of the National Offshore Wind Research and Development Consortium ("R&D Consortium") administered by NYSERDA and Equinor Wind has committed to provide $50,000 to support the consortium's work

- [redacted]

- Equinor Wind is currently discussing a potential research and development partnership with the Long Island-based ULC Robotics, a developer and manufacturer of unmanned aerial vehicles, to explore the creation of advanced, purpose-built vertical take-off and landing aircraft to support offshore wind project operations. A copy of a letter of support from ULC is provided as Attachment 39.

- Equinor Wind is actively collaborating on environmental research and monitoring with SUNY Stony Brook's SoMAS on Long Island, in an effort to enhance understanding of marine life in the lease area. SoMAS is in the process of completing a BOEM-funded study to increase understanding of the Atlantic sturgeon in the New York Bight. Contributing to this effort, Equinor Wind installed three of SoMAS' Atlantic sturgeon sensors on the metocean moorings installed within the lease area in December 2018 as part of Equinor Wind's site assessment activities.

Equinor is working together with SUNY Stony Brook to apply for a grant from the R&D Consortium to develop high fidelity wind resource modeling, which has the potential to increase performance of offshore wind projects that are constructed to supply energy, capacity, and ORECs to New York. The models will be validated by operational data from Equinor wind farms, and local NY metocean conditions will be used as basis for the simulations of improved wind park control.

16.2 Contingent Economic Benefits

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

16.3 Verification Of Economic Benefits

Equinor Wind recognizes the importance of establishing a clear and transparent plan to ensure objective verification of the economic benefits actually generated by the development of a project selected to supply ORECs through this RFP. For that reason, Equinor Wind has developed a plan for verifying the Incremental and/or Contingent Economic Benefits generated by the Empire Wind Project. This verification plan is based on Equinor Wind's experience with demonstrating compliance with local content requirements in other jurisdictions and is founded upon ongoing evaluation and assessment of economic benefits throughout the contract term.

16.3.1 Verification Plan

In accordance with the requirements of the RFP, Equinor Wind will prepare an Economic Benefits Report documenting the total dollar amounts of actual economic benefits accrued to New York in Categories 1 and 2, as well as Equinor Wind's efforts to achieve the commitments described in Category 3. This Economic Benefits Report and supporting documentation will be subject to audit and verification by an independent Certified Public Account ("CPA") as described in the RFP.

[redacted]

[redacted]

[redacted]

16.3.2 Documentation

This section provides a preliminary overview of the types of documentation that Equinor Wind anticipates using as the foundation for verifying the economic benefits associated with the development of the Empire Wind Project. Equinor Wind notes that this list should be considered preliminary and is subject to change.

Value of Project-Specific Spending and Supply Chain Investments

[redacted]

[redacted]

Transmission Upgrades

In order to verify the amounts spent on upgrading transmission facilities, Equinor Wind expects that it will provide copies of the invoices received from the relevant transmission owner. However, the final documentation that will be used for verification will be confirmed following the execution of an interconnection agreement with NYISO.

Fees and Expenditures by Equinor Wind

Equinor Wind anticipates that it will use typical supporting documentation to verify the fees and expenses paid by Equinor Wind, including expense claims, invoices, contracts, and time sheets for Equinor project team members working within New York.

Category 3 Benefits

The documentation that could be used to substantiate Category 3 economic benefits could include agreements or other evidence of partnerships with relevant community groups and organizations, letters of support, memoranda of understanding, and documentation of internship and apprenticeship positions created.

16.4 Ratepayer and Emissions Impact

While the foregoing discussion focuses on the significant employment opportunities and investments in New York businesses and supply chain development that will be made in connection with the Empire Wind Project, developing the Empire Wind Project will generate a range of economic benefits that go beyond the benefits set out above. Notably, the development of the Empire Wind Project will confer additional economic benefits on New York by reducing production costs and emissions.

In order to quantify the full range of the rate and emissions-reduction benefits associated with the development of the Empire Wind Project, ICF simulated the operation of the wholesale electricity markets in the eastern interconnection using the ABB PROMOD IV production cost modeling software. As explained in detail in the attached ICF report, ICF's analysis demonstrates that the development of the Empire Wind Project will:

- **Significantly Reduce Production Cost:** [redacted]
- **Benefit Ratepayers:** [redacted]

[redacted]

- **Create Additional Cost Savings Through Reducing Emissions**: [redacted]

17 PROPOSER CERTIFICATION

Proposer must complete and submit the Proposer Certification in Appendix B. The Proposer Certification must be signed by an authorized officer or other duly authorized representative of Proposer.

Equinor Wind's Proposer Certification is provided under separate cover.

18 EXCEPTIONS TO AGREEMENT

If Proposer is proposing any exceptions to the Agreement, included as Appendix F, Proposer must provide a redlined markup of the Agreement and provide an explanation and justification for each requested change.

Note that ORECRFP18-1 is a competitive procurement. Competitive procurement rules and the Offshore Wind Order limit NYSERDA's ability to alter the terms of the Agreement. Should the Project receive an award, NYSERDA will contact Proposers to schedule a discussion regarding the terms identified in the redlined markup of the Agreement. Requested changes that recognize the limitations imposed by the competitive procurement rules and the Offshore Wind Order will have no impact on the scoring or evaluation of the Proposal.

A marked-up version of the draft agreement is provided as Attachment 45.

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Equinor Wind US LLC

Section 12

Fisheries Mitigation Plan

Table of Contents

Table of Figures

12 FISHERIES MITIGATION PLAN

Proposers must include in their Proposal a Fisheries Mitigation Plan in as much detail as possible that describes how Proposer will mitigate adverse impacts on the commercial fishing industry that may be caused by the Project. Elements of the Fisheries Mitigation Plan are described in detail in Appendix D. Proposers are advised to review the Fish and Fisheries Study prepared for the New York State Offshore Wind Master Plan with respect to the potential impacts of offshore wind energy development on the fishing industry, and also are advised to include in their mitigation plan the appropriate Best Management Practices described in the Master Plan and supporting studies.

12.1 Summary

Equinor Wind welcomes the opportunity to submit a Fisheries Mitigation Plan ("FMP") as part of its application to supply offshore renewable energy certificates to New York. Equinor Wind recognizes the importance of balancing the interests of responsible offshore wind energy development with fisheries resources and uses that may be present in the project area. From experience with the development of offshore wind energy facilities, Equinor Wind believes that the responsible development of offshore wind energy resources can be compatible with fisheries resources and commercial and recreational fishing.

Equinor Wind is submitting this FMP to provide an overview of the efforts that have been made to date to minimize the impacts to, and coexist with, the fishing industry and the measures proposed for the future to avoid or minimize impacts to the fishing industry as the project matures. This FMP has been prepared to set out Empire Wind's guiding principles towards fisheries coexistence and will be used for consultation with the fishing industry, including with the New York State Fisheries Technical Working Group ("F-TWG") to provide a roadmap for future work as the project matures.

As discussed further below, Equinor Wind's approach to fisheries mitigation is founded upon the fisheries mitigation hierarchy. More specifically, this approach means that we anticipate and avoid impacts on fisheries resource and fishers; minimize impacts where avoidance is not possible; and take steps to offset any significant residual adverse impacts that are predicted to remain. Equinor Wind believes that it is critical that the Empire Wind Project be developed in a manner that minimizes disruption to the natural environment, natural resources, and existing uses of the lease area.

Equinor Wind believes that mitigation measures to reduce impacts on fisheries should be identified and developed in close consultation with relevant fisheries stakeholders early in the project development process. This should be through an iterative process of project design, including site selection, cable routing, timing of works, and consideration of construction and operations methods. The Empire Wind Project Team has been following these principles rigorously since Equinor Wind secured the Lease Area in 2017. Equinor Wind endeavors to minimize disruption to fisheries at all stages of project life, including during survey activity, construction, operations, maintenance, and decommissioning. These consultations have already yielded valuable insights that have been incorporated in Equinor Wind's survey and planning processes. Among other things, Equinor Wind has taken the following steps to minimize the potential impact on fisheries resources:

- [redacted]
- [redacted]
- [redacted]

The following sections summarize Equinor Wind's approach to coexistence and communication with the commercial and recreational fishing communities throughout all stages of the project life. A summary is also provided that explains how impacts will be assessed and how mitigation measures will be considered and applied. Furthermore, the following sections set out principles for how Equinor Wind will work with the fishing industry to avoid or minimize impacts and collaborate on conducting research and monitoring. Naturally, the FMP will continue to evolve through consultation with the F-TWG and the fishing industry as the project develops through the continued use of adaptive management.

12.2 Coexistence Philosophy

Equinor Wind's approach and philosophy to project development is premised on the belief that the fishing industry and offshore wind energy developments can be compatible and can co-exist. Equinor Wind believes that co-existence can be achieved by carefully evaluating existing uses of the lease area, avoiding impacts where feasible, or reducing impacts through mitigation. This philosophy has proven effective within Equinor's European wind project portfolio and the best practices that have been developed in support of prior projects will now be leveraged here in the U.S.

Equinor Wind believes that a successful coexistence strategy requires open and regular communication between Equinor Wind and the fishing industry, starting with the development and survey phase, and continuing through permitting, construction, operation, and decommissioning of the wind farm. For that reason, in February 2018, Equinor Wind released a draft Fisheries Liaison & Outline Coexistence Plan ("FLP") to provide an overview of Equinor Wind's approach to development and consideration of fisheries resources. The FLP is available on the Empire Wind website and is provide as Attachment 34.

As set forth in the FLP, Equinor Wind does not intend to restrict or apply for broad-based restrictions on fishing activities within the operational wind farm area(s), or electrical export cable area(s). To the extent that any restrictions are necessary, these may be limited to standard safety zones during the construction phase, and operational safety zones around manned or sensitive offshore platforms. The approach to how safety zones will be employed will be determined through completion of a Navigational Safety Risk Assessment ("NSRA") and in consultation with the F-TWG, fishing community and relevant agencies (*e.g.*, U.S. Coast Guard; "USCG").

The FLP was developed to present Equinor Wind's proposed approach to liaising, consulting, and coexisting with the fishing industry. The FLP will continue to be updated and evolve in consultation with the fishing industry as the project moves through the various stages of development, including feedback on the FMP from fisheries working groups such as F-TWG and the Responsible Offshore Development Alliance ("RODA").

In addition to using in-house experience gained from past liaisons and coexisting with the fishing industry in Equinor Wind's offshore wind energy developments in Europe (*e.g.*, Sheringham Shoal, Dudgeon Offshore Wind Farm, Dogger Bank and Hywind Scotland), as well as decades of company-wide experience working with fisheries as part of our offshore Oil and Gas operations, Equinor Wind has been following industry best practices in the interest of achieving its objective of co-existence to evolve this FMP. Consistent with the NYSERDA's New York State Offshore Wind Master Plan (2017), this includes, but is not limited to:

- Development of Mitigation Measures to Address Potential Use Conflicts between Commercial Wind Energy Lessees/Grantees and Commercial Fishermen on the Atlantic Outer Continental Shelf, BOEM 2014-654;
- Best Practice Guidance for Offshore Renewables Developments: Recommendations for Fisheries Liaison - Fishing Liaison with Offshore Wind and Wet Renewables Group (FLOWW), UK;
- Fishing and Submarine Cables Working Together – published by the International Cable Protection Committee;
- Bureau of Ocean Energy Management (BOEM) 2015 – Guidelines for Providing Information on Fisheries Social and Economic Conditions for Renewable Energy Development on the Atlantic Outer Continental Shelf Pursuant to 30 Code of Federal Regulations (CFR) Part 585;
- BOEM 2013 – Guidelines for Providing Information on Fisheries for Renewable Energy Development on the Atlantic Outer Continental Shelf Pursuant to 30 CFR Part 585;
- BOEM n.d.(a) – Previously Identified Offshore Wind Development Concerns;
- BOEM n.d.(b) – Possible Best Management Practices and Mitigation Measures to Reduce Conflicts between Fishing and Wind Industries;
- Hooker 2014 – Bureau of Ocean Energy Management Fishing and Offshore Energy - Best Management Practices;
- McCann 2012 – Developing Environmental Protocols and Modelling Tools to Support Ocean Renewable Energy and Stewardship;

- Ecology and Environment 2014 – Development of Mitigation Measures to Address Potential Use Conflicts between Commercial Wind Energy Lessees/Grantees and Commercial Fishermen on the Atlantic Outer Continental Shelf: Report on Best Management Practices and Mitigation Measures;
- Virginia Coastal Zone Management Program (VCZMP) 2015 – Collaborative Fisheries Planning for Virginia's Offshore Wind Energy Area;
- Lipsky et al. 2016 – Addressing Interactions between Fisheries and Offshore Wind Development: The Block Island Wind Farm;
- Moura et al. 2015 – Options for Cooperation between Commercial Fishing and Offshore Wind Energy Industries: A Review of Relevant Tools and Best Practices;
- Gray et al. 2016 – Changes to fishing practices around the UK as a result of the development of offshore windfarms – Phase 1;
- Petruny-Parker et al. 2015 – Identifying Information Needs and Approaches for Assessing Potential Impacts of Offshore Wind Farm Development on Fisheries Resources in the Northeast Region;
- Mid-Atlantic Fishery Management Council (MAFMC) 2014 – Offshore Wind Best Management Practices Workshop;
- New York States Offshore Wind Master Plan: Fish & Fisheries Study, Section 6 and Appendix D (2017); and
- Anticipated best practice guidance tools that may be developed through initiatives such as F-TWG, E-TWG, RODA, and other groups.

Equinor Wind will continue to reference these resources, as well as others that may develop at appropriate stages of project maturity.

12.3 Communications and Collaboration

Openness is a core value and cornerstone of Equinor Wind's approach to fisheries liaison and communications. Regular, open consultation will be key to ensuring that all parties are well informed in order to provide meaningful input in design and mitigation options. This will facilitate working towards the joint objective of avoiding or minimizing impacts, while enabling the responsible and sustainable development of offshore wind energy in the Lease Area. All efforts for the Empire Wind Project will also contribute to any successful future lease areas within the New York Bight by sharing experiences and lessons learned throughout this process.

Active communication and dialogue with the fisheries stakeholders begins during the early planning stages of project development. Equinor Wind has used early feedback received from relevant stakeholders to minimize disruption from survey activity and as part of early phase spatial planning and project design. Further details regarding mitigation during surveys is provided in Section 12.7.2 and for spatial planning and project design in Section 12.7.4.

In order to ensure that Equinor Wind continues to engage with relevant stakeholders regarding the development of the Empire Wind Project, Equinor Wind will continue to consult with the fishing industry through its participation in working groups such as F-TWG, RODA and via our dedicated Fisheries Liaison Officer ("FLO"). Equinor Wind also is participating on international fisheries groups, including the UK's Fishing Liaison with Offshore Wind and Wet Renewables Group ("FLOWW"), where lessons learned and best practices developed in collaboration between developers and the fishing industry from a more mature offshore wind energy market can be applied to where relevant in the U.S.

Additionally, Equinor Wind has engaged and will continue to engage, in fisheries conferences and committees, maximizing the opportunities to discuss the Empire Wind Project and solicit feedback. For example, Equinor Wind has presented project updates at the New England Fisheries Habitats Committee in New Bedford, MA; the American Fisheries Society Annual Meeting in Atlantic City, NJ; and BOEM's New York Bight Task Force Meetings held in New York and New Jersey, as well as manning an Empire Wind information stand at the New York Sports Fishing Forum for recreational fishers in Long Island, NY. Equinor Wind expects to continue these efforts throughout the development of the project.

In addition, an Offshore Fisheries Liaison Representative ("OFLR") has been and will be present on board Equinor Wind's research and survey vessels during all project related survey activities in order to give the active fishers in the field an opportunity to communicate with the OFLR and/or document any active fishers in the field. This provides Equinor Wind and the FLO a "live" perspective of fisheries use in and around the project area. Additional details on the FLO and OFLR activities are provided in Sections 12.3.1 and 12.3.3, respectively.

Equinor Wind also participates in and has representatives on New York State's Environmental Technical Working Group ("E-TWG") ensuring there is overlap on fisheries resource issues with the F-TWG, and New York State's Maritime Technical Working Group ("M-TWG") covering overlapping maritime navigation and safety issues.

Equinor Wind is fully committed to continuing participation in the TWGs as the Empire Wind offshore wind energy development matures and is committed to consulting and working with representatives of the F-TWG on the FMP. Currently, Equinor Wind is represented on the F-TWG by Martin Goff, who has many years of experience cooperating with the fishing industry in relation to offshore wind, and Stephen Drew, FLO for Empire Wind, who has over 25 years of experience in collaboration between offshore industries and commercial fisheries. See Attachment 1 for Martin Goff's resume and see Section 12.3.1 for more detail on Mr. Drew's experience. Equinor Wind has attended all F-TWG meetings to date and currently is working with RODA and other fisheries organizations for the purpose of consulting on wind farm layouts and transit lanes. Equinor Wind has also attended and contributed to all E-TWG meetings scheduled to date, including attending New York State's "State of the Science Workshop" held in Long Island, New York (13-14 November 2018).

Effective, clear and inclusive communication is required to ensure Equinor Wind can reach as many affected stakeholders as possible in order to share project-related information and solicit feedback. Equinor Wind intends that its fisheries outreach will be as inclusive as possible. Equinor Wind expects that its primary engagement with fisheries stakeholders will be through Fisheries Industry Representatives ("FIR") or groups such as F-TWG and RODA, as well as engaging with individual fishers.

In the following sections, Equinor Wind has provided a summary of key communications and resources implemented to date and to be implemented for the continued life of the project(s).

12.3.1 Fisheries Liaison Officers

Equinor Wind has contracted an FLO with extensive knowledge and first-hand experience in the regional fishing industry to aid in facilitating communication between Equinor Wind and the fishing industry. The FLO also supports Equinor Wind in the identification of potential impacts and mitigation measures and assists with data gathering to inform the environmental and social impact assessments related to commercial and recreational fishing. The FLO will act on Equinor Wind's behalf throughout all development stages, including surveys and design; construction; operation; and decommissioning phases. The primary roles and responsibilities of Equinor Wind's FLO are:

- To serve as the primary point of contact between the project and the fishing fleets;
- To log all interactions between the project team and fisheries representatives accurately and in a way that can be shared by the project team;
- To maintain a fisheries stakeholder database and contact list for all identified fishers operating within or areas adjacent to the offshore wind lease area and export cable corridors throughout all stages of the project, with the database including details to aid further targeted engagement and mitigation
- To arrange meetings with the fishing industry throughout all stages of project development, with frequency, timings, and method of communication appropriate to the level of activity at the time;
- To consult the relevant FIRs (see Section 12.3.2 below);
- To maintain regular liaison with relevant fishermen's associations, individual skippers, and vessel owners, the Mid-Atlantic Fishery Management Council, and any relevant fisheries regulatory bodies as appropriate;
- To disseminate project-related activities which could potentially interact with fisheries. This can include:
    - A description of the survey activity or other works to be undertaken;
    - The location and timing of survey activities;
    - The coordinates of partially and/or fully installed infrastructure;
    - Updates on planned activities at the project;
    - Details of the vessels performing work at the project;

    - Survey and installation vessel transit routes to and from site;
    - The locations and timings of safety exclusion zones that may be required during installation or maintenance activities;
    - Health and safety standards and obligations pursuant to the International Regulations for Preventing Collisions at Sea;
    - Empire Wind contractor obligations towards fisheries, in line with the principles of the FLP/FMP; and
    - Conflict avoidance response procedures and reporting procedures;

- To be available to receive and relay back to Equinor Wind all relevant concerns from the fishing community in respect of the various activities associated with the project;
- To keep the fishing community updated of any changes in project design, or scheduling;
- To assess and advise Equinor Wind on the need for, and subsequently support Equinor Wind in organizing, guard vessels;
- To support Equinor Wind in developing procedures and managing the process for handling snagged gear or lost gear resulting from interaction with the wind farm structures;
- To monitor fishing activity within the wind farm site and export cable corridors during all phases of the project, including during survey activities for the purpose of data gathering and for the use in deconflicting fishing and surveys;
- To support Equinor Wind in making wind farm survey, installation and operations and maintenance contractors aware of relevant fishing activities, including any relevant fishermen's sensitivities, and procedures for communicating with fishing vessels at sea;
- To advise and support Equinor Wind on the procurement of OFLRs to be present offshore during survey activities; and
- To attend and contribute to working groups, including F-TWG.

Empire Wind Fisheries Liaison Officer, Stephen Drew, Sea Risk Solutions

Stephen Drew of Sea Risk Solutions ("Sea Risk") is representing Equinor Wind as FLO. Stephen previously supported NYSERDA as FLO for the New York Offshore Wind Master Plan, where Stephen gained further experience with the northeast fisheries, including crucial experience related to the interaction between fisheries and offshore wind development in the New York Bight. Equinor Wind believes that this consistency is beneficial to existing fisheries relations; comes with an existing network of contacts; and adds additional expert knowledge to Equinor Wind when it comes to expressions of concern or requests for mitigation to date.

Based in New Jersey, Stephen Drew is the Founding Partner of Sea Risk. Prior to founding the firm, Stephen spent 15 years developing and managing the marine liaison group for a major subsea cable supplier. He pioneered methods of proactive Automatic Identification System ("AIS") use for subsea cable protection in Singapore and The Gulf, achieving significant fault rate reduction. He managed marine liaison and risk mitigation at cable landings in 25 countries and served five years on the International Cable Protection Committee Board of Directors. He has negotiated and served as liaison officer in cable/fishing agreements on the US West Coast. Prior experience includes Fishery Industry Officer for the United Nations Food and Agriculture Organization; Fishery Observer Program Manager; and five years' commercial fishing in New England. He is fluent in Spanish, with working ability in Portuguese and French. He holds B.S. and M.M.A. (Master of Marine Affairs) degrees from the University of Rhode Island.

Empire Wind Fisheries Liaison Officer, Wolfgang Rain, Sea Risk Solutions

In addition to Stephen, Wolfgang Rain acts as supporting FLO to ensure there is always FLO coverage on hand, which will be important particularly during offshore survey operations and future construction activities. Wolfgang joined Sea Risk as a Partner after nine years managing the marine liaison program for a major cable supplier and ship operator. He has expertise in subsea cable permitting and regulatory issues, AIS monitoring and notification, fault investigation, cable awareness, liaison with maritime authorities, shipping interests, fishermen and others in more than 20 countries in Asia, Europe, Middle East, Africa, India, and the Americas. He has negotiated and served as liaison officer in cable/fishing agreements on the US West Coast. He speaks Spanish, Japanese, Vietnamese, Russian and German. Additional experience includes extensive work as a commercial fisherman in Norway, the Russian Far East and Alaska, as well as international scientific fisheries observer on high seas vessels in the Southern Ocean, Western and North Pacific, and the Bering Sea. He holds a B.S. in Animal Science from Washington State University.

Empire Wind Fisheries Liaison Officer, Elizabeth Marchetti, Sea Risk Solutions

Elizabeth Marchetti also acts as supporting FLO. Elizabeth joined Sea Risk with extensive fisheries experience along the Atlantic seaboard. She started her career within the commercial fishing industry and has been working with the fishing community for over fifteen years. She has served as a Field Scientist aboard fishing vessels researching lobster recovery, fishing gear development, and a broad range of other studies in fisheries science, management, and technology. As a NOAA Port Agent she supported biosampling as well as fishermen's inquiries about management, reporting, and other issues. From 2015 to 2018 she served as Fisheries Liaison during the installation and operation of the Block Island Wind Farm, the first offshore wind farm operating in the USA. In addition to her liaison responsibilities Elizabeth serves on our team of AIS managers, supporting subsea cable awareness and protection. Elizabeth has also supported the Empire Wind project by serving as an OFLR during geophysical, geotechnical and benthic survey activities in the Empire Wind lease area during summer 2018 (Section 12.3.3 for details). She holds a Bachelor of Science Degree in Marine Biology from the University of Rhode Island.

FLO Contact details:

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In addition to supporting Equinor Wind on the Empire Wind offshore wind energy development and entire OCS-A 0512 Lease Area, Sea Risk also supports Equinor Wind in our recently acquired Massachusetts offshore wind energy development lease OCS-A 0520. The fisheries work leading up to and beyond the lease sale provides an increased regional perspective of the fisheries organizations, their key concerns and mitigation options available to developers. Where feasible, fisheries outreach will be combined for both the New York Bight and Massachusetts leases to minimize stakeholder fatigue and maintain consistency, noting that each wind farm project should be treated on a case by case basis, while also recognizing similar regional and fishery-specific considerations.

12.3.2 Fishing Industry Representatives

Fishing Industry Representatives ("FIRs") are essential contacts within the fishing community to ensure flows of information and communications between Equinor Wind, the FLO and the fishing community. Identifying potential impacts and addressing them with mitigation is a two-way process, which relies on stakeholder and developer participation to achieve those goals. Appreciating that stakeholder fatigue can be an impact itself on the fishing industry, using FIRs as main points of contact are a means to mitigate pressures on individual fisher's time from the outset.

FIRs are expected to represent and/or relay the views of the majority of fishers within his or her remit. It is important that the FIRs have the backing and support of the fisheries they represent. The FIRs should be able and willing to disseminate information from the FLO or Equinor Wind to the fishing community and vice versa on a timely and all-inclusive basis. The FIR is normally an individual who has worked extensively within or currently represents the industry in that particular sector, port or region. The primary responsibilities of the FIR are:

- To be the main focal point for liaison with the fisheries under their representation;
- To liaise and cooperate with the FLO to ensure the objectives of the FLP and co-existence strategy are achievable;
- To feedback to the FLO any fishers' concerns, data, or requests for meetings;
- To identify individuals or small groups of fishermen that can contribute to topic-specific technical discussions;
- To support, encourage and facilitate any meaningful discussions on potential impacts and appropriate mitigation measures to support minimizing impacts and coexistence; and
- To assist in the distribution of notices and relevant project information to fisheries under their representation and to follow up that all relevant parties received such notices.

Equinor Wind has identified and engaged multiple FIRs, who were already in place as the main points of contact within several fishing organizations. At this time, Equinor Wind understands that many of the organizations already have trusted and respected representatives and that currently there is no need for Equinor Wind to establish new FIRs. However, Equinor Wind is open to identifying and working with additional FIRs in the event that such a need presents itself. For example, some fishing organizations have nominated RODA as their principal FIR, acting as the main point of contact between Equinor Wind and those fishing organizations. However, Equinor Wind will engage with newly nominated FIRs as well.

[redacted]

- [redacted]
- [redacted]
- [redacted]
- [redacted]
- [redacted]

12.3.3 Offshore Fisheries Liaison Representatives

Where appropriate and feasible, Offshore Fisheries Liaison Representatives ("OFLRs") have been, and will continue to be, present on vessels that are working on behalf of Equinor Wind in wind farm-related activities (*e.g.*, survey vessels and installation vessels). The main purpose of the OFLR is to mitigate impacts to fisheries in the field by avoiding or minimizing disruption to normal fishing practices during surveys, construction and maintenance activities. This is done by (i) ensuring a flow of information on fishing activity from the FLO onshore through to the vessel master; (ii) advising the vessel master of any signs of fishing activity to avoid in the field; (iii) providing a communications link with fishing vessels encountered on site to enquire on activity; (iv) disseminating information to fishing vessels in the field; and (v) observing and recording fishing practices in the field to help inform the project development and related mitigation and impact assessments.

Equinor Wind has selected and will continue to select known and respected OFLRs with experience in the fishing industry, and where possible, current or retired Captains of fishing vessels or fisheries observers. When feasible, the background and experience of the OFLR is matched with the areas and timing of fisheries that may be present when the wind farm vessels are in the lease area. The primary responsibilities of the OFLR are:

- To maintain daily contact with, and keep records of, fishing vessels observed to be within the vicinity of the work areas of wind farm-related vessels;
- To keep the masters and watch officers of wind farm-related vessels informed of fishing vessels in the vicinity of their working area and the gears and modes of operation of such fishing vessels;
- To keep fishing vessels advised of the locations, operations, schedules, and safety zones of wind farm vessels; and
- To provide on-site ad-hoc assistance and advice to wind farm-related vessel officers with the objective of minimizing hindrance to fishing activities, avoiding conflicts, and ensuring the commitments in the co-existence plan are adhered to.

With support from the FLO, Equinor Wind has succeeded in recruiting OFLRs who are known and respected in the fishing industry. The services provided by the OFLRs have contributed to a record of no reported claims or incidents of conflict in Equinor Wind's survey operations spanning March 2018 through December 2018. Equinor Wind continues to actively solicit OFLRs in all states along the east coast with relevant experience. The OFLRs to date include individuals with a broad range of experience and skills, as detailed below:

[redacted]

12.3.4 Identification of Industry Contacts and Interested Parties

Effective consultation is essential for sharing information and soliciting feedback, with the aim of aiding in the identification of potential impacts and potential viable avoidance or mitigation options. Effective consultation is facilitated with the establishment of a comprehensive contact database for local and regional fisheries associations, societies, groups, individual fishers and the various industry organizations. This database is maintained and regularly updated by the FLO in conjunction with Equinor Wind's key project team members.

Equinor Wind appreciates that some fisheries information, such as discrete fishing sites, can be commercially sensitive to those fishers. In these circumstances, Equinor Wind will work with the individual fishing organization/fisher to establish confidentiality agreements for the purpose of sharing information for the objective of using such information to work towards avoiding or minimizing impacts.

Members of the commercial and recreational fishing communities are identified through various different channels and include, but are not limited to:

- Contacting fishing industry leaders known through 25 years of the FLOs' liaison experience, including those contacts gained through acting as FLO for NYSERDA during the development of the New York State Offshore Wind Master Plan;
- Contacting fishing industry association leaders;
- Attending Fishery Management Council ("FMC") meetings;
- Attending meetings about offshore wind and other related topics;
- Manning stands at commercial and recreational fishing forums;
- Recommendations from state fisheries staff and NMFS staff;
- Fisheries Management Council Advisory Panel lists online;
- Public comments and documents online;
- Word of mouth from the fishing community;
- AIS monitoring including ship identification;
- Fishing vessels identified offshore during surveys by the OFLR;
- NMFS permit holder lists online;
- Dock visits; and
- Fisheries contacts information referenced in NYSERDAs New York State Offshore Wind Master Plan Fish and Fisheries Study (2017; Appendix J).

12.3.5 Communication Channels

As previously noted, Equinor Wind intends to reach a wide range of potentially affected parties in order to provide project updates, communicate during offshore activities, and to solicit feedback on the offshore wind energy development. In order to achieve this, Equinor Wind is taking a broad approach to dissemination of information. Equinor Wind will continue to use these practices as the project develops and will add further outlets as appropriate. Equinor Wind has been engaging with the fishing industry since being awarded the OCS-A 0512 Lease, with Equinor Wind's FLO representing Empire Wind and the Lease Area from January 2018 onwards. The FLO has documented over [redacted] contact events when including individual email notices. The comprehensive and inclusive fisheries outreach effort to date can be seen in Attachment 35.

Notices, information and project details have and will be distributed to the fishing community via the following methods and media:

- Contact with FIRs;
- Contact with fisheries associations;
- Directly from the FLO to individual fishermen not represented by an FIR, but identified on the FLO's database;
- USCG Notice to Mariners;
- Electronic email distribution to commercial fishing permit holders (NOAA or state agencies);
- Empire Wind's website- "Fisheries" page;
- Through fisheries-specific websites such as F-TWG and RODA should these developer information pages be developed as planned;
- Local harbor masters;
- State Fisheries mailing lists;
- 3D Simulation Tool demonstrations;
- Survey flyers;
- Statements of Common Ground ("SoCG");
- Fisheries specific newsletters;
- Presentations or networking at fishing conferences and exhibitions; and
- Notices in fishing news publications.

Throughout the consultation process, Equinor Wind will be open to consideration of other means or methods to that would provide for effective and efficient communication with the fisheries stakeholders.

Aid to Communications: 3D Simulation Tool

From experience developing offshore wind farms in Europe, Equinor Wind appreciates that it can be a challenge for the maritime community to offer meaningful feedback when the potential effects of the wind farm are only conceptual. This is even more challenging in the U.S. where there are no existing large offshore wind farms of comparable scope to use as a proxy. As such, Equinor Wind has developed a 3D offshore wind energy development simulation tool to facilitate consultation with the maritime community, building on a model developed for Equinor's Dogger Bank offshore wind energy development in the U.K. The model seeks to provide some perspective on turbine layouts, size and spacing where this is difficult to convey on paper charts. In particular, this can help focus discussions related to the ability to fish and transit between turbines.

The model has been designed for the user to select all weather and sea conditions, times of the day and year, and viewpoints from the bridge of fishing vessels with the ability to transit through the wind farm at user-selected speeds, bearings and environmental conditions. Appreciating the variety of fishing vessel types operating in the northeast U.S., the model includes five representative fishing vessels to select from. See Figures 1-4 for examples of these simulations.

Figure 1: Model Overview of a Wind Farm Layout

Figure 2: Model Simulation of Fishing Vessel Transiting Wind Farm in Clear Conditions.

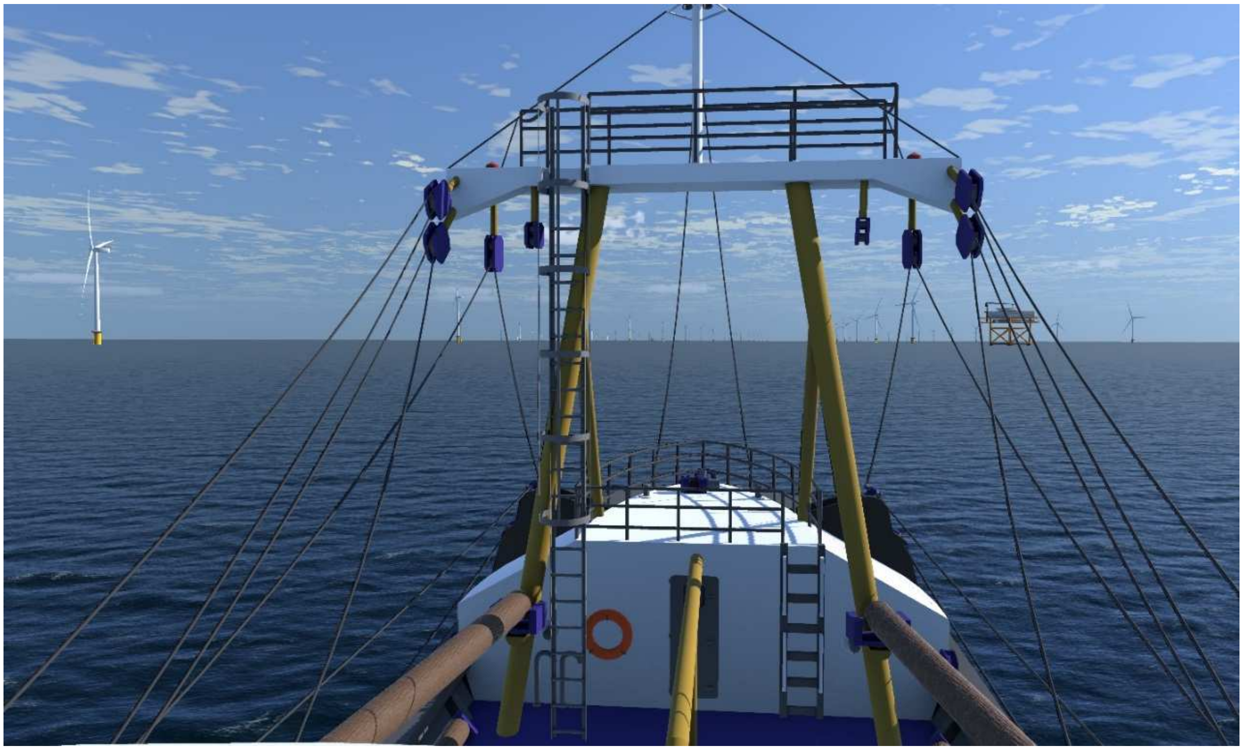


Figure 3: Model Simulation of Fishing Vessel Transiting Wind Farm in Stormy Conditions.

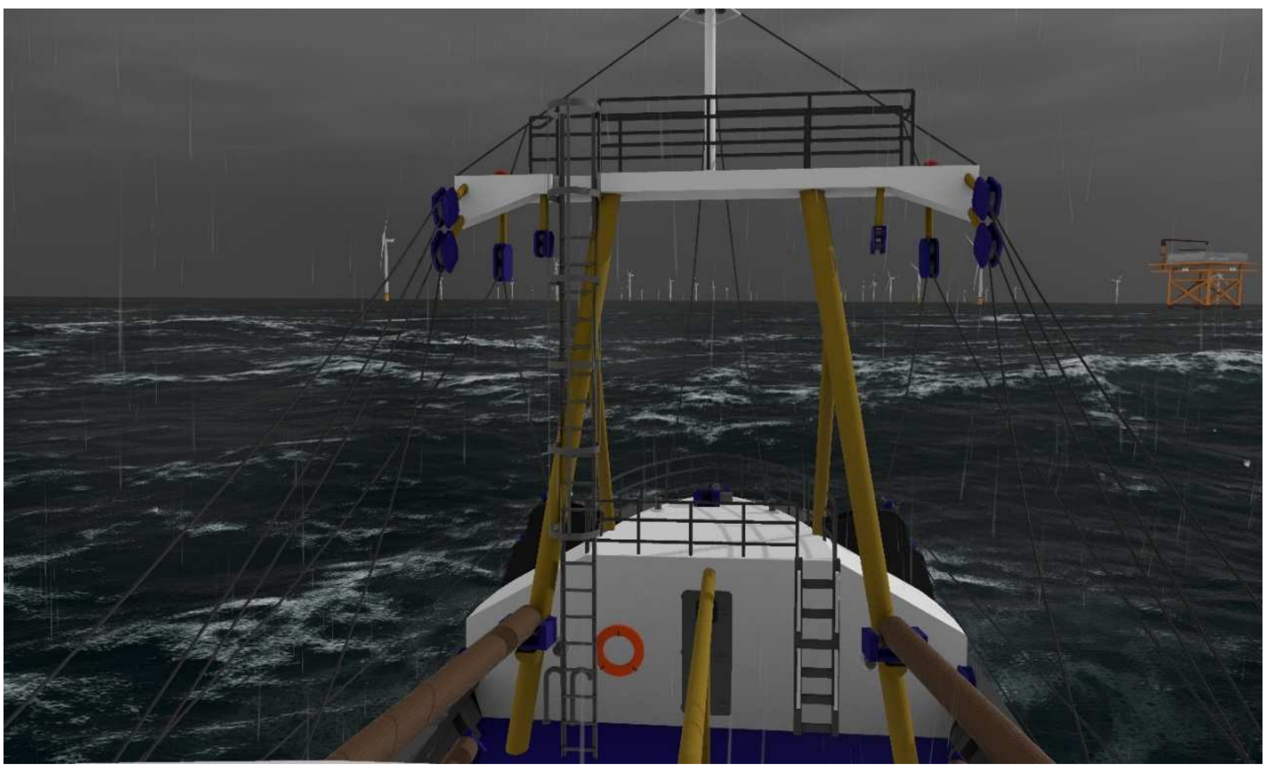


Figure 4: Examples of Types of Fishing Vessels that Can be Applied to the Simulation

The model is also used in consultation with the wider maritime industry to address impacts on maritime navigation safety and to inform layouts that facilitate search and rescue.

Equinor Wind has made the 3D model tool available for use in stakeholder meetings and will consider requests for FIRs to download and use the models to support consultation with their relevant members. Equinor Wind is committed to making the model available in F-TWG meetings to aid discussions on the FMP, as well as making it available for general F-TWG and M-TWG discussion purposes.

The 3D Simulation Tool may also be useful in wider stakeholder engagement, for example in schools, public meetings or awareness campaigns, and as such Equinor Wind is open to considering requests for additional usage.

Aid to Communications: Survey Flyers

Equinor Wind has and will continue to reach multiple fishers to solicit feedback and inform on survey activities via project specific Survey Flyers. The Survey Flyers include information related to survey schedule and activities; contact details for the vessel, OFLR and FLO; contacts in the event of an emergency; and a request for feedback should the information pose a potential conflict.

To date, Equinor Wind has issued hard and digital copies of Survey Flyers to contacts on the contacts database. For example, the Survey Flyer in February 2018 covered the start of offshore geophysical and geotechnical surveys in the Lease area, and the Survey Flyer in November 2018 provided an update on current operations and schedules. Examples of previously issued Survey Flyers can be seen in Attachment 36.

Equinor Wind will continue to issue Survey Flyers for future offshore surveys, with the next planned notice scheduled in advance of the Spring 2019 offshore survey campaign. Equinor Wind intends to adopt the same principle during offshore activities related to the construction, operations and decommissioning phases; that is, issuing flyers as a means of notifications to the fishing community at appropriate intervals/project milestones and in advance of activities.

Aid to Communications: Fisheries Newsletters

Equinor Wind will disseminate information and solicit feedback via project specific newsletters aimed solely at the fishing community. This is an approach that was successfully used by Equinor Wind with positive feedback from the fishing community in Europe. The Fisheries Newsletter includes:

- A project overview and update;
- Permitting, survey and construction schedules;
- Details of upcoming consultation meetings;
- Specific announcements related to requests for information;
- Links to other sources of information; and
- Contact information.

[redacted]

F-TWG Commitment and State Consultations

Equinor Wind is committed to working with organizations representing multiple fisheries groups such as F-TWG and RODA as a means to engage with the fishing industry, regulators and other developers more effectively. These groups will also serve as forums for identifying and collaborating on research needs and disseminating relevant information.

As previously stated, Equinor Wind has made a commitment to continue participation in the F-TWG and E-TWG and is committed to consulting and working with members of the F-TWG on the FMP. Equinor Wind is currently represented on the F-TWG by Martin Goff, who has many years of experience cooperating with the fishing industry in relation to offshore wind energy developments, and Stephen Drew, FLO for Empire Wind, who also comes with over 15 years of experience of collaboration between offshore industries and fisheries. Equinor Wind has attended all F-TWG meetings to date and has attended and contributed to all E-TWG meetings to date.

Should Equinor Wind be awarded a contract to supply offshore wind renewable energy certificates through this solicitation process, Equinor Wind will attend a project specific F-TWG session to present and consult on this FMP. It is beneficial to all parties if this session is held as soon after RFP award as feasible, and as such, Equinor Wind encourages the F-TWG to pre-arrange the session(s). Equinor Wind proposes to present all aspects of this FMP to the F-TWG during an all-day workshop, or as deemed appropriate by the wider F-TWG, soliciting and responding to feedback as it is received. Equinor Wind is committed to attending as many subsequent sessions as required in order to meet the goals of this FMP and the F-TWG coexistence philosophy.

Equinor Wind is also committed to consulting with New York state agencies throughout the offshore wind energy development process. There has already been engagement to date on matters including, but not limited to, the Empire Wind project development updates and schedules, benthic and fisheries resources, fisheries outreach and coexistence, avian and bat studies, onshore ecology, visual assessments and historic properties. Equinor Wind is committed to continue consulting with New York state, as other state agencies as appropriate, as the project continues to develop up to and post submission of all relevant state and federal permits.

Equinor Wind has already submitted a Site Assessment Plan (“SAP”) proposing the installation and operation of several meteorological and oceanographic (“metocean”) buoys and related site assessment activities. The SAP was submitted in June 2018. Equinor’s SAP was deemed complete on August 22, 2018 and approved November 21, 2018. The metocean buoys were installed December 2, 2018. In addition to federal agencies, Equinor Wind consulted with the relevant state agencies during SAP development and prior to SAP submission, including the New York State Department of Environmental Conservation (“NYSDEC”).

The next significant phase of development will be the submission of the Construction and Operation Plan (“COP”) describing all the activities necessary for the construction, operation, and decommissioning of the proposed offshore wind facility. [redacted] At the time of COP submittal, Equinor Wind will provide a copy to the New York Department of State, the NYSDEC, the New York State Office of Parks, Recreation and Historic Preservation, the New York State Department of Public Service, the New York Office of General Services, and NYSERDA so that they may review the COP concurrently with BOEM. In the event that a state agency requests a meeting, Equinor Wind will participate to discuss and attempt to resolve any issues that are identified, as applicable.

Equinor Wind already has been consulting with relevant state agencies and fisheries organizations as it develops the COP, including to inform the baseline characterization for fisheries resource and fishing practices, and for spatial planning and mitigation options of the offshore wind energy development. Equinor Wind has adopted a “no surprises” approach, whereby at COP submission all interested parties will have had opportunities to consult and input into the project. Equinor Wind will continue to consult with state agencies and fisheries organizations up to the point of COP submittal. As such, where feasible, state agencies and the fishing industry will have had opportunities to input into the COP pre-submission.

It is acknowledged that the awardee of the offshore wind energy contract should consult on the FMP post-contract award, with the objective of seeking and applying as much consultation feedback on the FMP as possible before the project advances to a stage where modifications are difficult. Due to the potentially short time period between contract award and COP submittal, Equinor Wind will proactively consult on the FMP, wherever feasible, to ensure there is sufficient time for feedback on fisheries related matters to be addressed prior to COP submission.

Communications During Surveys, Site Design, Construction, and Operations

Details regarding (i) Equinor Wind’s communication with the fishing community in advance of and during offshore site surveys, and (ii) Equinor Wind’s proposal to continue this communication as part of the FMP are covered in Section 12.7.2.

Details regarding how Equinor Wind is communicating with, and proposes to continue to communicate with, the fishing industry on matters related to construction and operations activities are also provided in Section 12.7.2.

Statements of Common Ground

As a means of aiding communications between Equinor Wind and the fishing industry, Equinor Wind proposes establishing Statements of Common Ground (“SoCG”). The principle of SoCGs is adopted from experience of using them during consultation with different stakeholders in the U.K. and Europe, including the fishing industry.

SoCGs are established between developers and stakeholders (in this case fisheries organizations) to set out the areas of agreement, disagreements, and any issues that remain unresolved between the two parties in relation to the proposed development. In particular, a SoCG seeks agreement on the degree to which access to commercial and recreational fisheries will be sufficiently protected during surveys, construction, operation and decommissioning of the project, and sets those out as clear recorded goals that can be referenced. This also helps to focus attention on matters unresolved or highlighted of being of key concern or priority, as well as giving regulatory agencies, for example BOEM and USCG, an insight into the consultation process and progress made for their decision making.

SoCGs are updated at appropriate intervals with the goal of achieving agreement on all matters. Typical contents include:

- A description of the proposed development and affected party (in this case fisheries organization);
- A summary of consultation to date between both parties;
- Matters agreed, disagreed, unresolved relating to:
    - Communication/Consultation;
    - Baseline data;
    - Impact assessments;
    - Mitigation;
    - Wind farm construction and decommissioning;
    - Wind farm design and operation;
    - Matters for further discussion; and
    - Supporting information.

Equinor Wind will solicit the opportunity of establishing an SoCG for each individual fisheries organization, appreciating that impacts and objectives differ based on the fishery location, gear type, season of operation, target commercial species and potential impacts from the offshore wind energy development. An example of an existing executed SoCG from another Equinor offshore wind farm development can be seen in Attachment 38.

12.4 Monitoring and Research (Pre-, During and Post-Construction)

Equinor Wind is committed to collecting and evaluating existing data, conducting research studies, incorporating feedback from the fishing community, and conducting site specific or collaborative regional surveys and research in order to establish a baseline characterization of the lease area's natural habitat, resources and uses. Establishing this baseline data is necessary to identify and quantify potential impacts from the proposed offshore wind energy development, identify mitigation options to avoid or minimize impacts, and establish protocols for monitoring impacts or data gaps where appropriate. Equinor Wind's efforts to establish baseline data and monitor for potential impacts are and will be conducted in accordance with best practices, including BOEM guidance as well as consideration of recommendations for further research from groups such as F-TWG and E-TWG. The purpose of this section is to provide an overview of Equinor Wind's approach to establishing baseline data, monitoring for potential impacts and changes in usage, and assessing and quantifying changes attributable to project activities.

Equinor Wind acknowledges that ongoing research and monitoring at the project site is important to refine the understanding of impacts, potential mitigation options, and for future planning purposes, including facilitating the responsible leasing and development of potential future offshore wind energy areas within the New York Bight in line with New York State's ambitious offshore wind energy targets. As part of the development of the Empire Wind Project, Equinor Wind is committed to exploring appropriate monitoring protocols. These could include, for example, monitoring of potential behavioral responses or changes in spatial and temporal distribution of biological resources or fishing practices as a direct result of the offshore wind energy development. Monitoring is further discussed in Section 12.4.4 and Section 12.5.

A robust data- and evidence-derived baseline characterization is important for identifying potential impacts, avoidance and mitigation options and monitoring protocols. Equinor Wind describes the current and planned efforts towards establishing baselines for benthic and fisheries resources in Section 12.4.2 and fishing activity in Section 12.4.3.

12.4.1 Baseline data

Baseline data may be categorized for use in two distinct areas:

- A baseline dataset that characterizes an area by habitat type, based on the presence, absence, or relative abundance of species, and by spatial and temporal use of the relevant area by receptors that may be impacted positively (positive beneficial) or negatively (negative adverse) by the development of an offshore wind energy development; and

- A baseline dataset used to monitor the impact of an offshore wind energy development before, during and after the development of a project.

Since executing the OCS-A 0512 lease in March 2017, Equinor Wind has been working diligently to understand the characteristics of the Lease Area and the potential environmental and social impacts of the Empire Wind Project. The fisheries baseline studies and information presented in this FMP is the product of numerous studies and analyses that have been conducted to date regarding the potential environmental impacts and benefits of the Empire Wind Project. Because detailed design, site evaluation, and environmental impact assessments remain ongoing, the FMP focuses on the process that has/will be used for identifying environmental receptors, baseline data, effects, and environmental impacts. Baseline data will continue to be refined as the project matures, with additional detail provided in the COP, which Equinor Wind will submit to BOEM in connection with the development of the Lease Area.

As part of the federal and state permitting processes, regulations and guidance are in place to ensure an acceptable baseline is established and that impacts are judged against that baseline. In accordance with these requirements, Equinor Wind has been actively engaging with relevant state and federal regulators and stakeholders regarding its approach to the baseline characterization of the Lease Area. Equinor Wind will continue consulting with the fishing community on baseline data, including via the F-TWG, RODA and through direct outreach.

Baselines can be established by using existing published reports, studies, data or data portals, or by direct data collection through surveys and desktop assessments. Equinor Wind's first step in establishing baseline data for the Lease Area has been a thorough literature review, data mining and gap analysis exercise to establish what information already exists. Equinor Wind evaluated the extent to which existing and publicly available data sources were suitable for characterizing benthic habitat and fisheries resources in the relevant area, including evaluation of NYSERDA's Master Plan Fish and Fisheries Study (2017; Appendix J). In 2018, as part of its survey activities, benthic sampling was conducted which included grab samples and photographs of the benthic habitat at specified intervals within the lease area and along the export cable corridor(s). The survey work will continue in 2019. The benthic information collected will have a direct relationship to the types of fisheries resources expected to be present, based on habitat type (*e.g.*, hard-bottom, soft bottom). The published data in conjunction with the survey data are supporting the preliminary characterization of baseline conditions in accordance with federal and state requirements and guidelines. [redacted]

12.4.2 Benthic and Fisheries Resources

This section describes the benthic and fisheries resources that are associated with Equinor Wind's Project Area. This discussion includes the following information on each resource or receptor:

(1) information currently available; (2) efforts to further collect data; (3) potential effects that are likely to have an impact; and (4) potential mitigation options that Equinor Wind is committing to or can be considered as appropriate to results from further studies and impact assessments. This section on benthic and fisheries resource has also been included in the Environmental Mitigation Plan ("EMP") as part of this proposal.

Regulatory Context

The fisheries of the United States are managed within a framework of overlapping international, federal, state, interstate, and tribal authorities. Individual states and territories generally have jurisdiction over fisheries in marine waters within 3 nautical miles ("nm") (3.5 miles ("mi") or 5.6 kilometers ("km")) of their coasts. Federal jurisdiction includes fisheries in marine waters inside the U.S. Exclusive Economic Zone ("EEZ"), which encompasses the area from 3 to 200 nm (3.5 to 230 mi or 5.6 to 370 km) offshore of any U.S. coastline (NOAA 2016). In addition to the regional fishery management councils ("FMCs"), an array of multi-state fisheries commissions coordinate conservation and management of the common interstate nearshore fishery resources—marine finfish, shellfish, and anadromous fish—for sustainable use. Together with National Marine Fisheries Service ("NMFS"), a division of the National Oceanic and Atmospheric Administration ("NOAA"), these councils maintain fishery management plans for specific species or species groups to regulate commercial and recreational fishing within their geographic regions. NMFS's Highly Migratory Species Division is responsible for tuna, sharks, swordfish, and billfish in the Atlantic Ocean (NMFS 2009). FMCs are required to identify essential fish habitat ("EFH") for each fishery covered under a fishery management plan. EFH is defined as the waters and seafloor necessary for spawning, breeding, or growth to maturity (16 U.S.C. § 1802(10)). "Fish" is defined as "finfish, mollusks, crustaceans, and all other forms of marine animals and plant life other than marine mammals and birds" (16 U.S.C. § 1802(12)). The role of the benthic habitat as a fisheries resource is fundamental to the identification of EFH, as reflected in the emphasis on EFH in BOEM's benthic survey guidance (BOEM 2013a). The guidance recommends that the NMFS EFH mapper tool (http://www.habitat.noaa.gov/protection/efh/habitatmapper.html) be used for species identification and habitat characteristics at any particular location (BOEM 2013a, page 4).

Impacts to benthic habitats and fisheries resources are managed under various federal laws including the Magnuson-Stevens Fishery Conservation and Management Act ("MSA"), Endangered Species Act ("ESA"), and NEPA. In support of the COP and associated evaluations of potential project-related impacts for Federal and State permit applications, BOEM's site characterization requirements in 30 C.F.R. § 585.626 are being applied to the benthic habitat and fisheries resource assessments.

BOEM is required to consult with NMFS as part of the NEPA process and if a proposed project is expected to adversely affect EFH. An adverse effect is defined as "any impact which reduces the quality and/or quantity of essential fish habitat," which includes physical, chemical, and biological impacts (NMFS 2004). Effects may manifest in a number of ways, either directly or indirectly, and on any spatial scale, including areas beyond EFH. For example, changes in water quality, benthic communities, or prey availability may constitute an adverse effect on EFH. BOEM must also consult with NMFS under Section 7 of the ESA for actions described in the COP that may affect anadromous fish species listed under the ESA. State agencies will also be consulted as part of the coastal consistency determination.

Preliminary Resource Characterization

Benthic habitat can be used to support prediction of the presence of fisheries resources, by providing information on sediment size/type, density, presence of submerged vegetation and other characteristics. The offshore lease area and large portions of the proposed export cable corridors are predominantly characterized as sand with isolated patches of gravel-sand. Finer grained sediments are expected within the New York Harbor. Although generally flat, the New York Bight contains sand ridges, filled valleys, shoal-retreat massifs, and paleoshorelines (NYSERDA 2017; Appendix A). In general, benthic habitat throughout the lease area is relatively homogeneous. During the BOEM offshore wind planning process prior to the lease auction, an isolated topographic high, known for its value to commercial and recreational fishing, was identified to the northwest of the lease area; this area, called Cholera Bank, is a sensitive feature that was subsequently removed from the lease area prior to lease sale. The National Centers for Coastal Ocean Science and BOEM are preparing comprehensive seafloor substrate maps of the New York Bight, with a particular focus on the lease area. Information from that study will be incorporated into the COP as appropriate when it becomes available and will be combined with Equinor Wind's site-specific benthic sampling to generate full benthic habitat maps.

A review of available data on seagrasses concluded that neither of the two seagrasses native to the New York Bight region exist within the lease area (NYSERDA 2017; Appendix A). Suitable habitat for seagrasses is limited to water shallower than 39 feet ("ft") (12 meters ("m")). While not present within the lease area, seagrasses are found along coastal areas, including the barrier island systems Long Island, and will, therefore, form part of the assessment for cable landfall locations and onshore cable routing.

Fish and invertebrate species of interest in the lease area fall into three groups based on regulatory status: (1) species managed under the MSA; (2) species listed under the ESA; and (3) non-game fish and invertebrate species that are considered important prey (or shelter, in the case of biogenic habitats) for fish and wildlife. Extensive long-term datasets are available to characterize fisheries resources in the lease area. In 2016, NYSERDA initiated three-year aerial surveys of sharks, rays, and large bony fish in the area (2017; Appendix J). Additional surveys will focus on fish and invertebrate population structure and distribution, and identification of potential impacts on EFH and sensitive habitats. NYSERDA concluded that the combined datasets from Marine-life Data Analysis Team ("MDAT"), the aerial fish surveys, and the Virginia Institute of Marine Science's Northeast Area Monitoring and Assessment Program together provide support for siting decisions for wind energy that would not interfere with fisheries resources.

In NYSERDA's Master Plan, the physical and biological character of the seafloor was described within the New York Bight through analysis of Multibeam Echo Sounder (MBES) and benthic survey data (2017; Appendix A). This in conjunction with the NYSERDA Master Plan Fisheries Study (2017; Appendix J) and additional scientific literature provide additional information to support describing baseline conditions as Equinor Wind develops the baseline conditions for its assessments.

Fish and Invertebrate Species Managed Under the MSA

Virtually all coastal U.S. waters are designated as EFH for at least one managed species. Designated EFH is an indicator of underlying habitat features important to fish. EFH delineates areas where the species may occur based on known occurrence of the species or habitat features important to the species/life stage. Construction, operation, and decommissioning of the project has the potential to directly and indirectly affect managed marine finfish and invertebrates as well as marine and estuarine habitats (including EFH) that support managed species and their prey. Therefore, locations of designated EFH for various life stages of managed species will be foundational to the benthic and fisheries resource assessment.

Just as the location of benthic EFH can serve as an approximate guide to locations of benthic fisheries species, locations of heavy harvests of managed fisheries are often associated with areas of physical impact. In fact, BOEM's benthic guidance recommends that areas affected by bottom-tending mobile fishing gear be identified and suggests that "publicly available commercial fishing data" be used to characterize benthic habitats (BOEM 2013a, page 5). In particular, heavy bottom trawls are known to disturb benthic EFH in many locations. The characterization of baseline benthic habitat conditions will take into account locations where heavy gear is expected to have caused physical injury to bottom habitats. On a similar basis, the location of historic and contemporary anchoring locations of large cargo vessels and tankers will be recorded, for localized disturbance to benthic EFH.

EFH has been designated in the lease area for various life stages of more than two dozen non-migratory managed species, including finfish, sharks and rays, and invertebrates, as provided in Figure 5. Designated EFH for three (3) coastal migratory pelagic and seventeen (17) highly migratory managed fish species also occurs in the lease area, as provided in Figure 6. EFH is designated in the lease area by both the Mid-Atlantic Fishery Management Council ("MAFMC") and the New England Fishery Management Council ("NEFMC") for species that occur in both jurisdictions. EFH for other species and/or life stages may be present along the export cable corridor. On April 9, 2018, the *Federal Register* published NEFMC's Final Rule, which modified the designation of EFH for numerous species that occur in the lease area (NEFMC's Omnibus Essential Fish Habitat Amendment 2; 50 C.F.R. Part 648). In this Final Rule, NMFS approved: (1) all of the updated EFH; (2) all of the recommended habitat area of particular concern ("HAPC"); (3) the majority of the habitat management area recommendations; (4) all of the seasonal spawning area recommendations; and (5) the framework and administrative recommendations.

Figure 5: Non-Migratory Species with Designated EFH within the Lease Area

	Managed Species		Egg	Larval	Juvenile	Adult
	Common Name	*Scientific Name*				
Invertebrates	Atlantic Sea Scallop	*Placopecten magellanicus*	-	-	X	X
	Longfin Inshore Squid	*Doryteuthis (Amerigo) pealeii*	X	-	X	X
	Northern Shortfin Squid	*Illex illecebrosus*	-	-	X	X
	Quahog	*Arctica islandica*	-	-	X	X
	Surfclam	*Spisula solidissima*	-	-	X	X
Elasmo-branchs	Clearnose Skate	*Raja eglanteria*	X		X	X
	Little Skate	*Leucoraja erinacea*	-	-	X	X
	Spiny Dogfish	*Squalus acanthias*	-	-	X	X
	Winter Skate	*Leucoraja ocellata*	-	-	X	X
Finfish	American Plaice	*Hippoglossoides platessoides*	-	X	-	-
	Atlantic Cod	*Gadus morhua*	-	-	-	X
	Atlantic Herring	*Clupea harengus*	-	X	X	X
	Black Sea Bass	*Centropristis striata*	-	X	X	X
	Bluefish	*Pomatomus saltatrix*	X	X	X	X
	Butterfish	*Peprilus triacanthus*	X	X	X	X
	Haddock	*Melanogrammus aeglefinus*	-	X	X	-
	Mackerel	*Scomber scrombus*	X	X	X	X
	Monkfish	*Lophius americanus*	X	X	X	X
	Ocean Pout	*Macrozoarces americanus*	X	X	X	X
	Pollock	*Pollachius virens*	-	-	X	X
	Red Hake	*Urophycis chuss*	X	X	X	X
	Scup	*Stenotomus chrysops*	X	X	X	X
	Silver Hake	*Merluccius bilinearis*	X	X	X	X
	Summer Flounder	*Paralichthys dentatus*	X	X	X	X
	Windowpane Flounder	*Scophthalmus aquosus*	X	X	X	X

	Managed Species		Egg	Larval	Juvenile	Adult
	Common Name	*Scientific Name*				
	Winter Flounder	*Pseudopleuronectes americanus*	X	X	X	X
	Witch Flounder	*Glyptocephalus cynoglossus*	X	X	-	X
	Yellowtail Flounder	*Limanda ferruginea*	X	X	X	X

Note:
X EFH designated in Lease Area
- No EFH designated in Lease Area

Figure 6: Migratory Species with Designated EFH within the Lease Area

	Managed Species		Neonate	Juvenile	Adult	Not Specific
	Common Name	*Scientific Name*				
Coastal Migratory Pelagics	King Mackerel	*Scomberomorus cavalia*	X	X	X	
	Spanish Mackerel	*Scomberomorus maculatus*	X	X	X	
	Cobia	*Rachycentron canadum*	X	X	X	
Tuna	Albacore Tuna	*Thunnus alalunga*	-	X	-	-
	Bigeye Tuna	*Thunnus obesus*	-	X	-	-
	Bluefin Tuna	*Thunnus thynnus*	-	X	-	-
	Skipjack Tuna	*Katsuwonus pelamis*	-	X	X	-
	Yellowfin Tuna	*Thunnus albacres*	-	X	-	-
Sharks	Basking Shark	*Cetorhinus maximus*	-	X	X	-
	Blue Shark	*Prionace glauca*	X	X	X	-
	Common Thresher Shark	*Alopias vulpinus*	-	-	-	X
	Dusky Shark	*Carcharhinus obscurus*	X	X	X	-
	Porbeagle Shark	*Lamna nasus*	-	X	X	-
	Sandbar Shark	*Carcharhinus plumbeus*	X	X	X	-
	Sand Tiger Shark	*Carcharias taurus*	X	-	-	-
	Scalloped Hammerhead Shark	*Sphyrna lewini*	-	X	X	-
	Shortfin Mako Shark	*Isurus oxyrinchus*	-	-	-	X
	Smooth Dogfish	*Mustelus canis*	-	-	-	X
	Tiger Shark	*Galeocerdo cuvier*	-	X	X	
	White Shark	*Carcharodon carcharias*	-	-	-	X

Notes:
X EFH designated in Lease Area
- No EFH designated in Lease Area

Federal & State-Listed Endangered Fish Species

Three federally-listed endangered fish may occur in the lease area: (1) Atlantic salmon (*Salmo salar*); (2) the Atlantic sturgeon (*Acipenser oxyrinchus*); and (3) shortnose sturgeon (*Acipenser brevirostrum*). On August 17, 2017, NOAA NMFS designated critical habitat for the Atlantic sturgeon in certain areas, including the New York Bight (Endangered and Threatened Species; Designation of Critical Habitat for the Endangered New York Bight, Chesapeake Bay, Carolina and South Atlantic Distinct Population Segments of Atlantic Sturgeon and the Threatened Gulf of Main Distinct Population Segment of Atlantic Sturgeon; 50 C.F.R. Part 226). New York classifies the Atlantic sturgeon as protected. Both the manta ray (*Manta birostris*) and the oceanic whitetip shark (*Carcharhinus longimanus*) were recently classified as threatened under the ESA (50 C.F.R. Part 223). The most current official distribution and abundance data on these species are available from NMFS. Independent researchers often publish supplemental data on various aspects of endangered species in localized areas, such as movement patterns, spawning locations, life history traits, and other factors that may be relevant to the impact analysis. New York classifies the shortnose sturgeon (*Acipenser brevirostrum*) as endangered. The shortnose sturgeon is found in the lower portion of the Hudson River from river mile 0 (southern Manhattan) to river mile 152 (the Federal dam at Troy) (NYSDEC Shortnose Sturgeon Fact Sheet, available at: http://www.dec.ny.gov/animals/26012.html). NYSDEC lists a number of other fish species as endangered, most if not all, are associated with fresh water habitat which will be evaluated, as applicable to the export cable route.

It is virtually impossible to demonstrate the absence of a rare species within its historical range; therefore, these three endangered fish species will be assumed present in the lease area, albeit in limited abundance and frequency based on the type of habitat that is present. More details on the spatial and temporal distribution of Atlantic sturgeon is expected to be available soon, resulting from BOEM funded studies carried out by Stony Brook University. Equinor Wind has also made its metocean moorings available to Stony Brook University to attach Atlantic sturgeon receivers to in order to gather more data. This has resulted in three additional sensors being deployed in the lease area in December 2018 and an additional sensor to be installed in spring 2019. Data will be collected from these sensors for approximately another two years, to develop a broader knowledge of Atlantic sturgeon movements in the vicinity of the lease area.

Non-Game Fish and Invertebrate Species

Useful data on the distribution and abundance of non-game fish and invertebrates come from many sources, including fisheries management plans, peer-reviewed literature, and NMFS reports. Although the Estuarine Living Marine Resource database (NOAA 2000) has not been kept current, the descriptions of spatial and temporal distributions of species (by life stage) in Hudson River/Raritan Bay and the Great South Bay provide a framework for describing current conditions in the area of the proposed cable landing(s). NYSERDA recently reviewed the Ocean Biogeographic Information System and confirmed that typical invertebrates of recreational and commercial interest in the lease area include longfin and shortfin squid, lobster, horseshoe crab, blue crab, scallop, ocean quahog, and Atlantic surfclam (NYSERDA Master Plan; 2017; Appendix J). NYSERDA also reviewed the available data on the suitability of habitat and the presence of living coral. Most coral habitat is well to the east of the lease area (near the continental shelf break). However, a small area of coastal Long Island was identified as having habitat suitable to support corals (NYSERDA 2017; Appendix A). The New York Department of State ("NYSDOS") has designated 250 areas within the potential export cable corridors as Significant Coastal Fish and Wildlife Habitats (NYSERDA 2017; Appendix J).

Ongoing and Planned Assessments

BOEM has published recommended approaches for assessing benthic habitat and fisheries resources during the permitting phase of offshore wind projects: (1) *Guidelines for Providing Benthic Habitat Survey Information for Renewable Energy Development on the Atlantic Outer Continental Shelf* (Benthic Guidelines; BOEM 2013a); and (2) *Guidelines for Providing Information on Fisheries for Renewable Energy Development on the Atlantic Outer Continental Shelf* (Fisheries Guidelines; BOEM 2013b). Because fisheries resources are defined by their use as commodities, BOEM has also provided guidance on evaluating the impact of wind projects on the socioeconomic aspects of fishing: *Guidelines for Providing Information on Fisheries Social and Economic Conditions for Renewable Energy Development* (BOEM 2015a), which are further referenced in Section 12.

Existing Data Collection and Monitoring Efforts

Under BOEM funding as part of their efforts to map the lease area during the leasing stage, and subsequently continuing after the Lease was awarded to Equinor Wind, NOAA's National Ocean Service ("NOS") conducted extensive surveys over three years using sonar and sediment grabs using research vessel Research Vessel ("RV") Nancy Foster, adding to data collected earlier in 2013 on RV Ferdinand Hassler (NOAA NOS Survey Report). [redacted]

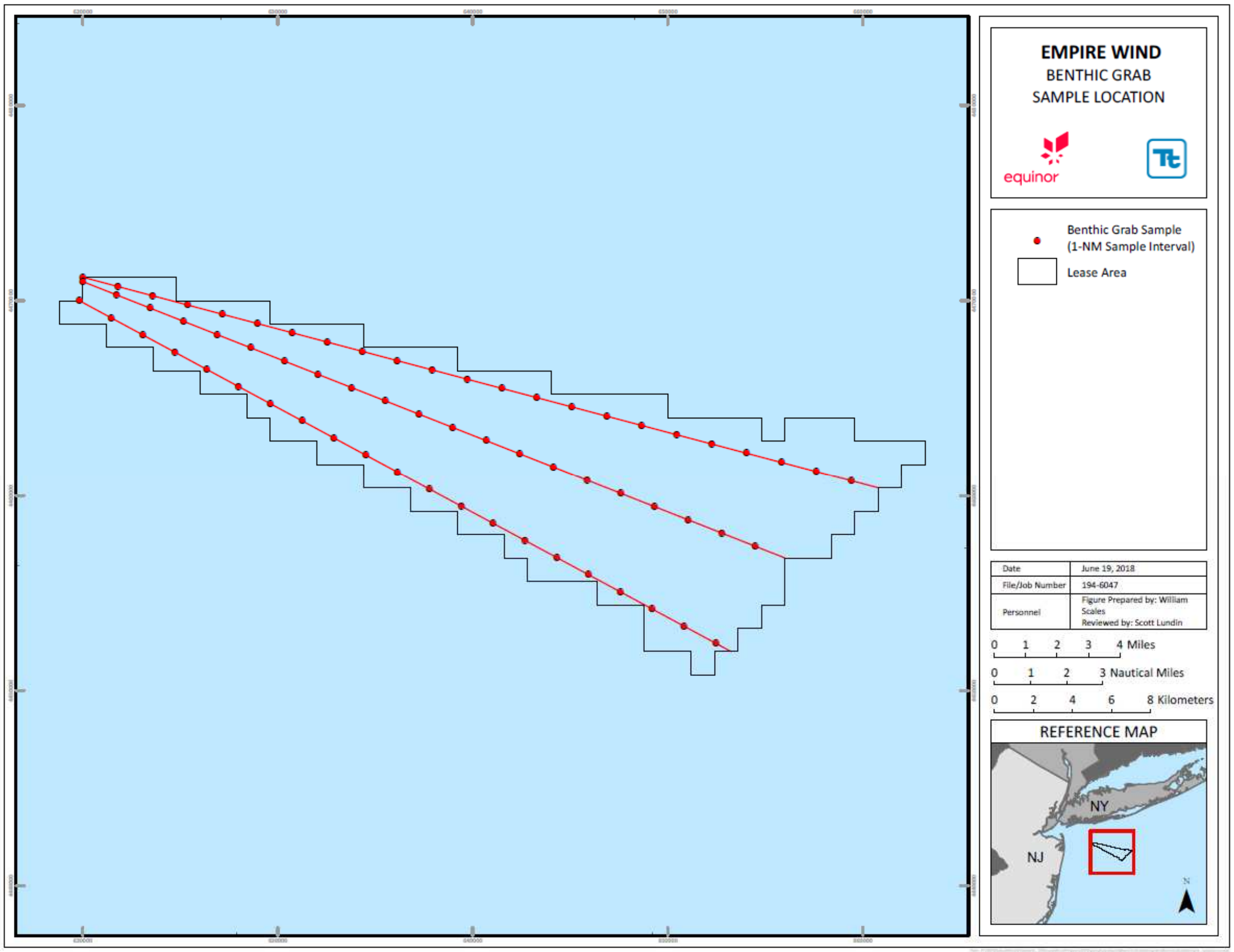
Equinor Wind Data Collection

To support the assessment of benthic and fisheries resources in the lease area, Equinor Wind conducted geophysical, benthic, and geotechnical work from March 2018 to November 2018 across the entire lease area and a large proportion of export cable corridors, with additional geophysical, benthic, and geotechnical surveys planned for 2019 to fill in any data gaps, in particular from landfall to the 65 ft (20 m) depth contour. The plans for the 2018 surveys were submitted to BOEM in November 2017 and subsequently approved in February 2018. An Incidental Harassment Authorization ("IHA") was submitted to NOAA NMFS and issued in April 2018. A High-Resolution Geophysical ("HRG") Survey Plan was also issued. In the spirit of openness and transparency, Equinor Wind has made these documents available for download from the Empire Wind webpage at www.empirewind.com/environmental.

Equinor Wind contracted Alpine Ocean Seismic Survey Inc. ("Alpine") to perform the surveys, using survey vessels RV Shearwater and RV Ocean Researcher from March 18, 2018, to December 2, 2018. The survey equipment and scope included, but was not limited to, the following:

- Gridded survey lines at a spacing of approximately 98 ft by 1,640 ft (30 m by 500 m);
- Depth sounding (multibeam echosounder) to determine site bathymetry and elevations;
- Magnetic intensity measurements (gradiometer) for detecting local variations in the regional magnetic field from geological strata and potential ferrous objects on and below the bottom;
- Seafloor imaging (sidescan sonar survey) for seabed sediment classification purposes, to identify natural and man-made acoustic targets on the seabed, as well as any anomalous features;
- Shallow penetration sub-bottom profiler to map the near-surface stratigraphy (from seabed surface to 16.4 ft (5 m) below seabed) soils below the seabed;
- Medium penetration sub-bottom profiler to map deeper subsurface stratigraphy as needed (soils down to 75-100 m below seabed);
- CPTs and Vibracores in the lease area and along the export cable corridors;
- Sediment grab samples and drop-down video images at 67 sampling locations (see Figure 7) to support the interpretation of geophysical data to characterize surficial sediment conditions and benthic habitat, including macrofaunal analysis with samples sieved at 0.5 mm mesh size.

Figure 7: Locations of 2018 Benthic Survey Campaign within Lease Area



Data from the 2018 HRG and benthic surveys will be analyzed and reported on in 2019 to applicable stakeholders. Preliminary and anecdotal results from the survey crew are consistent with descriptions of the expected habitat from previous studies. Full results will inform planning and mitigation with additional survey data in 2019 being added as appropriate and used in the development of the COP and other State and Federal permit applications as required.

Equinor Wind is currently planning and procuring contractors to conduct benthic sampling along the proposed export cable corridors, with sampling expected to take place in spring 2019. Sampling will be as consistent with the benthic sampling conducted within the lease area and will include as a minimum the following:

- Sediment grab samples for grain size analysis;
- Drop-down camera and/or video images;

- Grab samples for macrofauna.

In addition, and as previously noted, BOEM has funded studies that are being carried out by Stony Brook University to monitor the spatial and temporal distribution of Atlantic sturgeon within the New York Bight and Equinor Wind's lease area. The study is coming to a close at the time of writing. Equinor Wind has made its metocean moorings available to Stony Brook University to attach Atlantic sturgeon receivers to in order to gather more data. This has resulted in three additional sensors being deployed in the lease area in December 2018 and an additional sensor to be installed in spring 2019. Data will be collected from these sensors for approximately an additional two years.

Baseline Summary

Equinor Wind evaluated the extent to which existing, and publicly available data sources are suitable for characterizing benthic habitat and fisheries resources in the lease area. Both published data and ongoing survey efforts in the lease area and surrounding waters support the preliminary characterization of baseline conditions in accordance with Federal and State requirements and guidelines.

Furthermore, Equinor Wind presented the list of data sets proposed to be utilized for the baseline characterization of benthic and fisheries resources to NOAA NMFS in March 2018 and August 2018. NOAA NMFS provided feedback, including additional data sets to use, and agreed with the conclusion that there is sufficient existing data for a baseline characterization in the lease area.

As such, additional benthic and fisheries surveys are not deemed to be required within the lease area for the purpose of the COP impact assessments, spatial planning or mitigation, however Equinor Wind will consult with E-WTG, F-TWG, RODA, and the fishing industry, including fisheries scientists and managers on requirements for further surveys for targeted fisheries monitoring and research.

12.4.3 Commercial and Recreational Fishing

Both commercial and recreational fishing are important activities in the waters in and surrounding the Lease Area. Commercial fishing typically consists of either fixed or mobile fishing gear. Fixed gear fisheries use static gear such as lobster pots, fish traps, and gillnets, which are set in one location and then checked or retrieved later. Mobile gear fisheries use dynamic, mobile fishing gear such as otter trawls, mid-water trawls, purse seines, dredges, and rod and reel which are deployed while in motion aboard a vessel.

Recreational fishing in the region involves fishing vessels operating out of numerous ports located in New Jersey, New York, Connecticut, Rhode Island, and southeastern Massachusetts, including the Elizabethan Islands, Nantucket and Martha's Vineyard (RIDEM 2017). Recreational fishing occurs year-round but is most intensive from April through November. There are three types of saltwater recreational fishing activities common offshore and along the coasts of the New York Bight; shore-based fishing, fishing by private vessels and fishing by charter vessels.

The marine aquaculture industry, which is predominantly focused on shellfish, is also present along the coast from New Jersey to Massachusetts.

Regulatory Framework

Regionally, fishing in US federal waters of specific species is governed, under the MSA, 16 U.S.C. § 1801 et seq., through eight Regional Fishery Management Councils that develop species-specific FMPs. These FMPs establish specific fishing quotas, seasons, and closed areas. NOAA NMFS works in partnership with Regional Fishery Management Councils to assess and predict the status of fish stocks, set catch limits, ensure compliance with fisheries regulations, and reduce bycatch. NOAA Fisheries Highly Migratory Species Office manages highly migratory species, such as tuna, sharks, swordfish, and billfish, in U.S. Atlantic Ocean, Gulf of Mexico, and Caribbean waters that travel long distances, crossing domestic and international boundaries. Specific to the Lease Area, the NEFMC, MAFMC, and the Atlantic States Marine Fisheries Commission ("ASMFC") manage the multiple species and fisheries in federal waters. While the NEFMC is principally managing the fishery resources of New England (Maine, New Hampshire, Massachusetts, Rhode Island, Connecticut), there is considerable overlap with the Mid-Atlantic Council concerning species with ranges that span between the two councils.

The ASMFC supplements state regulations and fisheries management within federal waters. In particular, since 1996 the ASMFC has managed the lobster fishery within state waters from Maine to Virginia. This fishery is currently managed under Amendment 3, Addenda I-XXVI. Since 2015, the ASFMC has also managed the Jonah crab fishery within this same range under the Interstate Fishery Management Plan and Addenda I-III. Under the Jonah crab fishery management plan, participation in the directed fishery for this species is tied to a lobster permit. Lobsters are managed under three separate stocks: Gulf of Maine, Georges Bank, and Southern New England. The stocks are divided into seven management areas.

Within individual state waters and potentially directly affected by project activities, commercial and recreational fisheries are managed by NYSDEC. Coastal cities and towns within these states manage the residential shellfisheries in all waters within their boundaries that are not closed by respective state agencies for public health or other reasons, with the exception of the commercial harvests that remain under respective state control.

The NYSDEC Division of Marine Resources manages and maintains the state's living marine, estuarine and anadromous resources, (marine fish 6 NYCRR Part 40; lobster and crabs 6 NYCRR Part 44) and protects and enhances the habitat upon which these resources depend. NYSDEC works in cooperation with adjoining states and U.S. federal agencies concerning marine fisheries regulations.

Additionally, New York has established CMPs as part of the National Coastal Zone Management Program which addresses coastal issues, including sustainable and resilient coastal community planning, ocean planning, and planning for energy facilities and development. These programs are a voluntary partnership between the federal government and U.S. coastal and Great Lakes states and territories authorized by the CZMA of 1972 and administered by NOAA.

In 2009 the Governors of New Jersey, New York, Delaware, Maryland, and Virginia signed the Mid-Atlantic Governors' Agreement on Ocean Conservation. The Agreement established the MARCO as a partnership to address new ocean challenges and opportunities through agreed upon shared regional priorities. MARCO leverages existing state and federal resources, knowledge, and partnerships to build a stronger base of information and experience to make well-informed decisions in the best interest of the states and their constituents on these priorities.

Within this comprehensive regulatory framework, commercial and recreational fishing remains an important segment of regional economies. The seafood product preparation and packaging and wholesale and retail seafood sales sectors are major parts of the commercial fishing industry. Marinas, Navigational Services, Port & Harbor Operations, and Ship & Boat Building sectors provide goods and services to both commercial and recreational fisheries. Recreational anglers also support sales and employment for fishing equipment retailers, purchase goods from bait and tackle shops, rent or buy boats, or pay for charter vessels. Additional expenditures can also include food and drink purchases from local restaurants, gas for vessels, and lodging at local hotels for fishing trips. While vessels from as far away as North Carolina and Florida make use of the infrastructure present in the region to unload and sell fish (RI Ocean SAMP 2010), local ports potentially impacted by the project mainly range from New Jersey to through southeastern Massachusetts.

Preliminary Resource Characterization, Ongoing and Planned Assessments – Fishing

Equinor Wind is gathering data on both commercial and recreational fishing practices within the Lease Area and adjacent waters through multiple sources and approaches, including referencing the work of others. For example, New York State's Master Plan Fish and Fisheries Study (2017; Appendix J) provides an excellent overview of fishing areas throughout the NY Bight based on input from various stakeholders, including valuable summary figures of commercial fishery intensity, recreational fishing area. Other sources include BOEM's New York Bight leasing efforts; federal efforts by NOAA NMFS; and additional state efforts NYSDEC and Rhode Island Department of Environmental Management ("RIDEM"). In addition, emphasis has been on seeking and verifying fisheries use through direct consultation with the commercial and recreational communities. To date most of this information has been used for the purpose of identifying potential impacts and then attempting to avoid or reduce potential impacts through thoughtful spatial planning, layouts and best practices during surveys.

The key data sources referenced for the purpose of understanding the fisheries use baseline are summarized, but not limited to the following:

- BOEM's 2017 Study entitled, Socio-Economic Impact of Outer Continental Shelf Wind Energy Development on Fisheries in the U.S. Atlantic;
- State by State analyses of public, commercial fisheries statistics as published by the NOAA Office of Science and Technology;
- NOAA Fisheries Marine Recreational Information Program (MRIP) data on recreational fishing;
- Rhode Island Department of Environmental Management - Division of Marine Fisheries' paper entitled, Spatiotemporal and economic analysis of vessel monitoring system data within wind energy areas in the greater North Atlantic;
- The Mid-Atlantic Regional Ocean Council ("MARCO") Data Portal;
- The BOEM & NOAA Marine Cadastre National Viewer for geospatial data; and
- The Northeast Regional Ocean Council's ("NROC") spatial data portal.

As previously described, direct engagement with the fishing community is key to understanding the fisheries use in the Lease Area and waters of adjacent areas. This has been an extensive part of Equinor Wind's efforts towards understanding fisheries use in the Lease Area and adjacent waters. The consultation with the fishing community can be seen in Attachment 35

As well as using existing data sources and gathering data through consultation, Equinor Wind is also collecting data on fisheries in the field. [redacted]. Although AIS data is picked up by onshore antennas, the quality and spatial and temporal coverage in parts of the Lease Area may be occasionally negatively affected by atmospheric conditions. [redacted]

However, not all fishing vessels are required to have AIS installed or transmitting, and not all vessels have AIS switched on or transmit correct details. As such, AIS cannot be solely relied on as a proxy for fishing effort. [redacted]

[redacted]

Other efforts to build on the understanding of existing fishing effort include:

- Taking nautical charts to recreational and commercial fishers and asking them to mark fished areas and hang ups. Equinor Wind has included Long Range Navigation ("LORAN") to help aid positioning.
- Requesting navigation plotter/logger data of tows, for example these have been provided by a number of trawlers and used for planning purposes
- General discussions with fishers.
- Using fisheries resource baseline and in particular commercial species, as a proxy to areas that are or may be fished.
- Using long term purchased AIS datasets, real-time AIS data and collecting AIS in the field.
- [redacted]
- Visual and radar observations in the field, conducted by the OFLR.
- Observations from the Equinor Wind digital aerial avian surveys, where vessel images were an opportunistic data point.

[redacted]

12.4.4 Monitoring and Research Opportunities

As described previously, Equinor Wind acknowledges that ongoing research and monitoring at the project site is important to refine the understanding of impacts, potential mitigation options, and for future planning purposes, including facilitating the responsible leasing and development of future offshore wind energy areas within the New York Bight in line with New York State's ambitious offshore wind energy targets. As part of the development of the Empire Wind offshore wind energy development, Equinor Wind is committed to exploring appropriate monitoring protocols, for example monitoring of potential behavioral responses or changes in spatial and temporal distribution of biological resources or fishing practices as a direct result of the offshore wind energy development.

In addition, Equinor Wind is in favor of developing and supporting research initiatives that focus on addressing coexistence; that is, research that improves the opportunities for continued and improved access for recreational and commercial fishing in the operational offshore wind energy developments. This may include research aimed at innovative technical approaches to issues such as turbine spacing, impacts on navigation equipment, trawling equipment and information dissemination options.

As the operator of three offshore wind farms in the U.K. (Sheringham Shoal 317 MW, Dudgeon Offshore Wind Farm, 402 MW and the world's first commercial floating offshore wind farm Hywind Scotland, 30 MW), [redacted]

Equinor Wind is also enthusiastic about the possibility of exploring collaborative research and monitoring efforts. Where common approaches to studies can be made, for example related to access to fishing grounds or common benthic and fish species. Equinor Wind is open to collaborate with other offshore wind energy developers on matters such as funding and providing suitable locations and operational support. Equinor Wind has successfully worked with other offshore wind energy developers on collaborative research and can continue to build on these established relationships.

Likewise, Equinor Wind is also open to collaborative research and monitoring opportunities with other organizations as appropriate. Equinor Wind would advocate for groups such as F-TWG, E-TWG and RODA as being the forums for which these research opportunities are explored and addressed.

Equinor Wind is also committed to making nonproprietary data available that can support fisheries research. As an example, Equinor Wind will be making the following fisheries related studies and/or data publicly available either through the COP process or directly on the Empire Wind webpage:

- 2018 benthic survey report covering the "SAP" related survey locations within the Lease Area (benthic grab samples with grain size and macro fauna analysis, drop down video stills, habitat description);

- 2018 benthic survey report covering "COP" related survey locations within the Lease Area totaling 67 sample locations (benthic grab samples with grain size and macro fauna analysis, drop down video stills, habitat description);

- 2019 benthic survey report covering "COP" related survey locations within the proposed export cable corridors (benthic grab samples with grain size and macro fauna analysis, drop down video stills, habitat description);

- 2017 to 2018 digital aerial survey images, monthly and quarterly reports of avian species, marine mammals, sea turtles and data of large bony fish assemblages as observed from the 12 x monthly digital aerial surveys carried out from November 2017 to October 2018; and

- Oceanographic data not deemed proprietary, for example seawater temperature and salinity, from the "Metocean Facilities" deployed within the Lease Area.

Additional publicly available datasets for other non-fisheries resources and studies are described further in the Environmental Mitigation Plan (Section 13).

Equinor Wind is willing to make non-commercially sensitive data from its metocean buoys available for research, for example into how oceanographic variability affects species abundance and spatial and temporal variability. Equinor Wind is currently in discussions with Rutgers University Department of Marine and Coastal Sciences on sharing the seawater temperature data to help support the understanding of the "cold pool" effect driving spatial and temporal distribution of marine life in the New York Bight. The cold pool phenomenon was frequently raised in New York State's State of the Science Workshop (November 2018) as well as BOEM's NY Bight Task Force Meeting (November 2018). In this regard, it is Equinor Wind's belief that understanding physical and biological drivers on biological resource spatial and temporal distribution is essential in order to identify and robustly design effective and meaningful future research and monitoring.

Equinor Wind is open to exploring other outlets for sharing information, for example Equinor Wind can upload fisheries related datasets and reports to the F-TWG webpage and/or RODA webpage. Version control is important however, and it is essential that stakeholders have access to the most recent studies. As such, the issue of version control and key repositories for this data will be further discussed and agreed in F-TWG and E-TWG.

Additional details related to the existing collaborations, and potential future collaborations designed to support other research opportunities can be found in Section 16.

Fisheries Resource

Further research and monitoring is important where data and knowledge gaps remain that may present uncertainties over potential adverse impacts attributable to the effects of offshore wind farm development. It is important that these effects are better understood in order to more accurately quantify impacts, identify potential mitigation options, and reduce uncertainty and conservatism built into impact assessments. This may also help to avoid or reduce impacts through adaptive management in future offshore wind energy leases and developments.

Where feasible, monitoring and research should ideally be targeted towards interactions between offshore wind energy developments and the receptors it is being judged against. From the outset, any research and monitoring should be statistically robust, such that changes in spatial and temporal distribution, and/or behavior pre, during and post construction can be detected at levels statistically attributable to the effects. For some biological monitoring, this level of robustness is not always possible as many outside factors can influence these variations with much greater significance than the factors that can be attributed to causes from offshore wind energy developments. This may be especially true in a dynamic environment such as the New York Bight. For example, attributing changes in a target commercial fish species abundance to offshore wind energy development presents challenges as abundance and distribution can vary spatially and temporally due to outside factors and pressures such as fishing quotas, oceanographic conditions (seawater temperature, nutrients), and distribution and availability of that receptors food resource. As such, for highly variable receptors there has been a shift away from pre, during and post construction monitoring of abundance and distribution of wildlife in Europe, and a focus towards behavioral responses associated with different phases of offshore wind energy developments. Equinor Wind has been involved in this work in Europe and would advocate for similar initiatives in the northeast U.S. These experiences have been and can continue to be shared via the F-TWG and E-TWG.

As a means to determine the statistical power of proposed studies, Equinor Wind advocates that technical experts conduct statistical power analyses up front in the planning process before implementing any future studies. In addition, F-TWG and/or E-TWG are appropriate forums to focus on the development of such analyses and should be part of this planning process. Finally, the fishing industry, fisheries managers and fisheries scientists all have an ability to input into potential monitoring requirements and methodologies, and where appropriate, may also have an opportunity to conduct the monitoring.

Equinor Wind has already participated in and funded novel research and monitoring for offshore wind energy developments and in offshore oil and gas developments where results have relevance to offshore wind energy developments. For example, Equinor collaborated in the UK Carbon Trust ORJIP One Bird Collision Avoidance Study (ORJIP One), UK Carbon Trust ORJIP Four Acoustic Deterrent Devices (ORJIP Four), and the developer led DEPONS (Disturbance Effect on the Harbour Porpoise in the North Sea, DEPONS, 2015).

Equinor Wind has also conducted novel research and monitoring on our existing offshore wind energy developments, for example the tagging of breeding Sandwich terns with GPS loggers to monitor foraging patterns in relation to the Equinor operated Dudgeon Offshore Wind Farm, U.K. Equinor is also part of the Sound and Marine Life joint industry program, which supports research to help increase the understanding of the effect of sound on marine life generated by oil and gas exploration and production activity, with some aspects being directly relatable to offshore wind energy developments, for example offshore seismic surveys and impact pile driving. Equinor Wind would be pleased to provide more details on these studies in F-TWG and/or E-TWG to support future study design.

Fishing

Equinor Wind advocates for monitoring and research initiatives that focus on addressing coexistence and continued and improved access for recreational and commercial fishing in the operational wind farm. This involves a more technical approach to issues such as turbine spacing, impacts on navigation equipment and information dissemination requirements for safe fishing, as demonstrated by discussions with stakeholders to date.

Equinor is committed to working with the F-TWG and wider fishing community, as well as relevant state and federal authorities up to and post RFP contract award to establish the key fisheries coexistence data gaps, the potential studies that can better inform these gaps or impacts, to agree on methodologies and conduct meaningful studies.

Monitoring changes in pre and post construction fishing effort due to the presence of an offshore wind energy development can be challenging. Many factors dictate fishing effort within a given area on a seasonal and year by year basis which make statistically detecting “change” difficult. For example, fishing effort may be influenced by factors such as quota, presence of a mobile species, market prices, fuel prices and fisheries closures. As such, due to the complexities and the need to design a methodology that has both industry and fisheries support, Equinor Wind proposes that such studies be discussed as part of the F-TWG. In addition, Equinor Wind will consult on potential monitoring and research via other fisheries groups such as RODA and FLOWW. The first step may be to carry out a study on comparing fishing effort in the Lease Area and adjacent waters year to year over the past five years prior to offshore wind energy development to test variability and whether further change can be statistically detected.

Equinor Wind is committed to studying if and why fishing activity may be affected by its offshore wind energy development, and where relevant, then determining what measures can be implemented to avoid or reduce the likelihood of negative adverse effects through design and mitigation. All efforts have been addressing this upfront in the early design phase; however, should impacts present themselves during later development, including into the operations phase, Equinor Wind can consider several options; (i) explore whether further mitigation can be applied to reduce impacts (*e.g.*, improved access through technical solutions to fishing practices and/or navigation equipment); (ii) using adaptive management by applying mitigation in the spatial planning and layouts of later phases of the Lease development; and (iii) sharing the results so that they can be used in adaptive management on a wider scale, for development of future lease areas in the New York Bight and wider offshore wind energy space.

12.5 Supporting Other Research

As described in Section 12.4, Equinor Wind is committed to collaborate with the fishing community, F-TWG, E-TWG and RODA, other offshore wind energy developers and third-party groups to conduct robust and relevant research studies that relate to fisheries resource or fishing practices in relation to offshore wind energy developments.

As described in Section 12.4.4, as well as making the Empire Wind offshore wind energy area available for monitoring and research when it can be done in a safe and practical manner, Equinor Wind is also willing to consider proposal requests to access existing Equinor's operating offshore wind energy developments in Europe. We acknowledge that some of the research opportunities that can facilitate coexistence may need to be conducted in operational offshore wind farms. Equinor Wind is currently the operator of three offshore wind farms in the U.K. (Sheringham Shoal 317 MW, Dudgeon Offshore Wind Farm, 402 MW and Hywind Scotland, 30 MW). Due to potential differences in biological resources, this research may be best suited to studies related to fishing feasibility within operational wind farms. Options can be discussed through the F-TWG, E-TWG, RODA or in direct consultation with the fishing industry.

Equinor Wind is also willing to make data available that can support wider fisheries research that may not be directly linked to offshore wind farm developments, but can inform future fisheries practices. For example, Equinor Wind is willing to make non-commercially sensitive data from the metocean data buoys available for research into how oceanographic variability affects species abundance and spatial and temporal variability. Commercially sensitive data is deemed to be for example, but not limited to, wind resource data and operational availability estimates, but can be clarified further with the F-TWG at the time of consulting on research opportunities.

[redacted]

[redacted] Equinor Wind is also committed to working with the F-TWG and E-TWG to (i) prioritize key research needs and data gaps; and (ii) establish best practices for evaluating techniques and proposals;.

In addition to the financial commitment, Equinor Wind will, where feasible, consider making existing wind farm related vessels or buoys available for research opportunities where this does not materially impact existing objectives of those resources. For example, Equinor Wind will consider proposals for adding additional or third-party self-contained sensors on survey vessels, construction vessels, O&M vessels, wind farm structures or wind farm related buoys and metocean moorings. As a demonstration of this commitment, Equinor Wind has already provided this opportunity to SUNY Stony Brook ("Stony Brook") so that they could attach three receiver gates to the metocean moorings that were deployed in December 2018. [redacted]

As further demonstration of Equinor Wind's commitment to novel and collaborative research and monitoring, Equinor Wind is collaborating with the Wildlife Conservation Society ("WCS") and Woods Hole Oceanographic Institute ("WHOI") on real-time large whale detection and notification buoys in a minimum 2-year monitoring program. [redacted]

12.6 Avoiding, Mitigating and Minimizing Impacts- Benthic & Fisheries Resources

Benthic and fisheries resource characterization has been described in Section 12.4.2. This section describes the potential impact producing factors on those resources that have been identified to date, and how Equinor Wind intends to avoid or mitigate those effects during surveys, construction, operations and decommissioning to minimize the impacts where feasible.

12.6.1 Potential Impacting Factors

An understanding of the potential effects from offshore wind energy developments that have the potential to impact benthic and fisheries resources, either positively or negatively, have come from experience, literature on the subject and from New York State's Offshore Wind Master Plan Fish & Fisheries Report (2017; Appendix J). The potential impact producing factors identified that are relevant to benthic habitats and fisheries resources are as follows:

- Short-term temporary physical disturbance to habitats and species resulting from seabed preparation, anchor spreads, jack-up barge footings and the installation of subsea cables during construction, decommissioning and limited maintenance periods;
- Short-term temporary habitat loss resulting from seabed preparation, anchor spreads, jack-up barge footings and the installation of subsea cables during construction, decommissioning and limited maintenance periods;
- [redacted]
- Short-term temporary increased suspended sediment concentration and deposition (smothering) resulting from seabed preparation and the installation of subsea cables during construction and decommissioning, and from short duration scouring events during operations;
- Temporary exposure to accidental spills, pollution or trash from project related vessels;
- Long-term temporary habitat loss or modification resulting from the presence of foundations, scour material and surface cable protection during operations;
- Long-term temporary changes to existing physical oceanographic conditions during operations due to the presence of structures; and
- Potential exposure to Electromagnetic Fields ("EMF") during operations.

12.6.2 Potential Mitigation

The baseline characterization and assessment of future potential impacts on benthic habitats and fisheries resources from the construction, operation, and decommissioning of the project must satisfy the requirements of various regulations and jurisdictional agencies. As such, collaboration and coordination with BOEM, NOAA NMFS, NYSDEC and relevant stakeholders throughout the development and planning process, will be critical to the success of the project. In order to mitigate for the potential impacts to benthic habitats and fisheries resources associated with the construction, operations, and decommissioning of the project, Equinor Wind is implementing the following mitigation measures:

- Avoiding, to the extent possible, siting structures (wind turbines, offshore substations, and submarine cables) in areas of sensitive habitat;
- Using best management practices and timing during cable installation activities to minimize sediment resuspension and dispersal in areas of known historically contaminated sediments;
- [redacted]
- A commitment to sufficiently bury electrical cables where feasible, minimizing seabed habitat loss and reducing the effects of EMF;
- Consideration of the timing of construction activities; working with the fishing industry and fisheries agencies on sensitive spawning and fishing periods to actively avoid or reduce interaction with receptors, where feasible;
- Using industry Best Practices for vessel operation, and implementing an Oil Spill Response Plan ("OSRP").

More confidence in the type and level of impacts to benthic and fisheries resources will be determined as the project matures and on submission of the COP. However, certain assumptions can be made at this stage for the purpose of the bid, based on preliminary information and experience, as described in further sections.

Surveys

Equinor Wind is following BOEM best practice guidance for surveys and submitting survey plans for review and approval prior to survey activity, which addresses potential impacts to benthic and fisheries resources during survey activities, for example exposure to noise through geophysical surveys or disturbance to habitats and species through benthic and geotechnical sampling. Where there is potential for impacts on threatened or endangered species, NOAA NMFS is included in the survey plan review in coordination with BOEM.

Sensitive benthic habitats are actively avoided where feasible, by taking this into consideration in the planning phase, for example routing export cable corridors to avoid sensitive habitats and therefore avoid the need for intrusive surveys there. This practice will be continued as the Empire Wind project develops. In addition, real-time avoidance is and will continue to be applied for seabed intrusive sampling by the use of drop down cameras to inspect the seabed prior to taking samples. For the summer 2018 geotechnical and benthic sampling, the team of Environmental Scientists onboard the survey vessel provided this real-time monitoring.

As such, and where feasible, sensitive benthic habitats will be avoided to the greatest extent possible when conducting seabed intrusive surveys through a combination of avoidance through spatial planning pre-survey, then avoidance during surveys through real-time monitoring.

Construction

Habitat Loss

With embedded mitigation in place, including project siting to avoid sensitive habitats, Equinor Wind expects that impacts to sensitive benthic habitats and fisheries resources resulting from seabed disturbance and temporary habitat loss will be avoided or reduced to as low as feasible. With expected high recoverability rates of immobile species and the return of mobile species following the disturbing activity, Equinor Wind does not expect significant adverse impacts. Disturbance to the seabed habitat during construction is expected to recover within a relatively short time period, with recolonization expected within several years for most species. The level of disturbance from construction activities is likely to be consistent with seabed disturbance and recovery resulting from existing anthropogenic pressures in the lease area and adjacent waters, such as bottom contacting commercial fishing activities and commercial vessel anchoring.

With highly sensitive habitats being avoided through spatial planning and micro siting, the potentially affected areas are therefore expected to be of the relatively homogenous sand or sandy gravel habitat type. The overall affected area during construction activities is expected to be an insignificant proportion of the overall available habitat in context to the Empire Wind offshore wind energy development, full lease area, and available similar habitats and species in adjacent waters. Equinor Wind will calculate actual affected areas and habitat loss and will share those results with the E-TWG and F-TWG, as well as publishing as part of the COP.

Suspended Sediments and Deposition

Exposure to increased suspended sediment concentration and potential smothering of benthic organisms and fish larvae resulting from cable installation and seabed preparation is expected to be short-term in duration and within the timescales of a tidal cycle. Sediments in the lease area are of a sand to gravelly sand nature and settlement rates are relatively fast. The suspended sediment concentrations generated through construction activity are also expected to be within the background levels of wave-induced suspended sediments from natural storm events, such as "nor-easters" typical of the region. In this instance the affected areas are expected to be localized and significantly smaller than affected areas from natural storm events. Equinor Wind will be carrying out sediment transport modeling to quantify the suspended sediment concentrations, durations and affected areas and will share these results with the F-TWG, as well as publishing as part of the COP.

Water Quality

The routing of the export cable corridor has taken into consideration existing and historic dumping grounds (charted) and has actively avoided them where feasible. As stated, much of the routing is in areas that are characterized as sand, where larger grain-sizes reduces the potential for contamination to be present. More information on sediment properties and potential impacts will become available as data from the 2018 surveys is analyzed and reported and as Equinor Wind completes additional nearshore surveys and sediment sampling in 2019, where chemical characterization will occur in areas of grain-size <90%. The information gathered will inform a sediment transport analysis. If contaminants are present, any release of contaminants will be of a short-term temporary nature and of limited spatial coverage. Additionally, Best Management Practices will be defined to further mitigate these effects.

Underwater Noise

[redacted]

Operations

Electromagnetic Fields

Equinor Wind intends to mitigate for potential EMF effects by burying cables to sufficient burial depths based upon existing fishing practices and cable burial risk assessments. Where target burial depth is not feasible, for example, due to challenging seabed conditions or cable crossings, the cables will be sufficiently protected with surface cable protection. The likelihood for receptor-effect interaction will be reduced, with impacts not expected to be significant adverse. The UK National Policy Statement for Renewable Energy Infrastructure EN-3 (DECC, 2011) states that for offshore wind, electrical cables that are sufficiently protected or buried will not result in significant impacts on sensitive species. It is however appreciated that species within the lease area will be different to those in U.K. waters and, therefore, Equinor Wind is open to discussing further monitoring and research to fill any data gaps through the E-TWG and F-TWG. Equinor Wind will carry out EMF modeling and assessments as part of the COP submission.

Suspended Sediments and Deposition

Existing information indicates the subsurface currents within the lease area and adjacent waters are expected to be typically less than 0.32 ft/s (0.10 m/s). To better understand the physical environment, Equinor Wind has installed current meters in the lease area as of December 2, 2018 to collect site-specific measurements and will also be performing sediment transport modeling as part of the COP assessments. Based on the existing information, the relatively low near-bed current speeds are not expected to generate significant quantities of suspended sediments and deposition from scouring. Equinor Wind is conducting further studies to identify where scour protection may be required, which will further reduce the magnitude of suspended sediments affecting receptors. Similar to construction activities, the suspended sediment concentrations generated through scour in the operations phase are also expected to be within the background levels of wave-induced suspended sediments during natural storm events, such as '"nor-easters" typical of the region. In this instance the affected areas are expected to be localized and significantly smaller than affected areas from natural storm events.

Loss of Habitat

The seabed in the lease area and adjacent areas surrounding is relatively homogenous, made up of sand and sandy gravel. More detailed information on the habitat type and benthic community will become available as data from the 2018 and 2019 surveys become available and NOAA NOS Survey Report referenced in Section 13.6.3 is published.

[redacted]

The introduction of hard structures to an otherwise sandy mobile seabed may be considered a positive beneficial impact, as the hard structures offer a new habitat type for colonizing based on the associated 'reef' effect (see BOEM "Rigs to Reefs" at https://www.bsee.gov/what-we-do/environmental-focuses/rigs-to-reefs). The change to habitat type and potential change to species may be topic for further monitoring and research in consultation with F-TWG and E-TWG.

Decommissioning

Impacts resulting from decommissioning activities are not expected to exceed impacts resulting from construction. Moreover, with requirements expected for the removal of structures at or just below the seabed level, Equinor Wind expects the seabed will recover to its pre-construction condition within a relatively short timeframe. Decommissioning impacts and mitigation will require further consideration and should form part of future E-TWG and F-TWG discussion points. Approaches and requirements will likely further be refined as European offshore wind energy developments near closer to decommissioning and as US offshore wind energy development matures. Equinor Wind will use those experiences to apply to decommissioning best practices to avoid and minimize impacts associated with the Empire Wind Project, as appropriate.

12.7 Avoiding, Mitigating and Minimizing Impacts- Fishing

This section summarizes Equinor Wind's intentions and efforts towards identifying potential impacts to the fishing industry and how those impacts have been or will be addressed through avoidance or mitigation. Consideration is given to the period covering survey activities; activities up to and including the construction phase; the operational life of the offshore wind energy development(s); and decommissioning.

Further details of impact assessments for commercial and recreational fisheries will be developed as the project matures towards COP submission, and through continued engagement with the fishing community. Equinor Wind believes there are opportunities to reduce impacts on recreational and commercial fisheries to as low as practical, where additional mitigation options still to be explored as part of ongoing consultation, information gathering, and project design. As such, Equinor Wind believes that there are opportunities to ensure significant adverse impacts can be avoided, and where these cannot be avoided, potentially offset.

12.7.1 Potential Impacting Factors

The potential impact producing factors relevant to commercial and recreational fishing have been identified through previous experience, referencing literature and best practice guidelines on fisheries, for example in NYSERDA's Fish and Fisheries Study (2017; Appendix J), and direct feedback from the fishing community. This has also been a subject of study by NOAA NMFS, as presented in NY's State of the Science conference (November 2018) and BOEM's NY Bight Task Force Meeting (November 2018). Equinor Wind will continue to consult with the fishing community to ensure that all relevant potential impacts or concerns are identified and addressed as appropriate. The identified impact producing factors and/or concerns are as follows:

- Adverse impacts to target commercial fish species resulting from offshore wind energy development surveys, construction activities, operations and decommissioning.
- Positive beneficial increases in species biodiversity and abundance during operations.
- Short term temporary displacement or restricted access to traditional fishing grounds during surveys and construction and decommissioning.
- Long term temporary displacement or restricted access to traditional fishing grounds during operations.
- Navigational safety concerns during construction due to partially constructed infrastructure.
- Navigational safety concerns during surveys, construction, operations and decommissioning due to increased project related vessel traffic.
- Navigational safety concerns during operations due to changes in existing vessel patterns, for example displacement of existing vessels.
- Navigational safety concerns while transiting due to the presence of structures (*e.g.,* allision and impacts on navigation equipment during operations.

- Navigational safety concerns while fishing due to the presence of structures, subsea cables, cable protection, scour protection, furrows and dropped objects during operations.
- Positive beneficial increase in search and rescue capabilities at sea during operations (as seen in Forewind's SoCG; see Attachment 38).
- Increased transit times due to the presence of structures and/or restricted access during operations.
- Increased resource pressure on existing commercial fisheries due to the attraction of other fisheries, for example an increase in recreational fisheries and fixed gear fisheries.
- Navigational safety concerns for existing commercial fisheries due to the attraction of other fisheries, for example an increase in recreational fishing vessels and fixed gear.
- Increased pressures on existing fisheries in adjacent waters due to fisheries displaced from the project area.
- Navigational safety concerns due to the presence of partially removed structures at decommissioning.

Each of these identified potential impacts are addressed in the following sections, either with in built mitigation being applied, commitments to mitigation, or suggestions for mitigation that should be considered as part of the F-TWG consultation and as the project matures.

12.7.2 Potential Mitigation

Surveys

Equinor Wind has committed to minimizing adverse impacts to fisheries during Empire Wind's project related offshore surveys by pro-actively avoiding potentially conflicting activities with fishing. Where feasible, Equinor Wind will avoid areas being fished at the time of survey activities and take steps to survey alternative areas. This has been achieved so far through thoughtful spatial planning and scheduling, applying consultation feedback, notifications of planned surveys, fisheries liaison during surveys, fisheries liaison and observations in the field during surveys, real-time monitoring of potentially conflicting activities, and adaptive management approaches.

Equinor Wind's commitments to avoid or mitigate impacts during surveys are described below, including examples of where these commitments have been put into practice already.

Pre-Survey Avoidance through Spatial Planning

Measures to minimize impacts started at the early design stage and it is Equinor Wind's intention to continue to follow this process going forward. Through the use of pre-survey consultation, Equinor Wind tries to first reduce the risk of potential conflicting activities in the planned areas for surveys and development.

For example, when planning export cable corridors, Equinor Wind consulted with the fishing industry on areas between the Lease Area and potential landfalls, so that the export cable corridors could be routed to avoid apparent high use, high value, and high sensitivity areas. This ensured surveys could proactively plan to avoid fishing activity, but also avoid future impacts during cable installation and in operations where feasible. In addition to consultation, Equinor Wind utilized available fisheries data, habitat data, information on existing subsea telecommunication cables and pipelines and the company's own extensive experience in developing offshore wind farms and offshore oil and gas platforms (with associated pipelines and/or electrical cables) for planning the proposed export cable route(s).

This pre-survey consultation with fisheries also gave Equinor Wind valuable information related to cable burial requirements and concerns over surface cable protection, should burial not be feasible. For example, feedback from the clam dredge industry on dredge penetration provided valuable information regarding requirements for sufficient burial depths. Survey methodologies were adjusted accordingly to ensure sufficient data was collected to be able to inform cable burial feasibility to these depths. Likewise, feedback on the concerns of cable surface protection, in particular concrete mattresses, led to planning routes where feasible cable burial is a primary objective.

Pre-Survey Planning: Timing

Where feasible, Equinor Wind has and will continue to plan the timing of offshore surveys to avoid or reduce the risk of conflicting with fishing activity. As an example, pre-survey consultation with the squid fishery and data reviews indicated that in some years the squid fishery can be concentrated in the Lease Area in the months of May through September, most likely in the western section of the Lease Area around a feature known as Cholera Bank, which lies directly west and outside of the Lease Area. As a means to mitigate impacts on the squid fishery, Equinor Wind adapted the survey line plan to cover the Cholera Bank area in May and June so that the survey vessel could be clear of the area if the squid fishing was present later that season. As such, there have been no reports of impacts on the squid fishery through Equinor Wind's survey activities.

This practice will be continued for future offshore surveys where feasible and in consultation with the fishing community.

Notifications

Equinor Wind is committed to disseminating information related to offshore survey activities to the fishing community in advance of surveys. This can be achieved using several different approaches or media and is in addition to the wider project notification (see Section 12.3.5). The purpose of early and often notifications is to; (i) solicit feedback if the proposed activities have the potential for impacts so that mitigating actions can be considered presurvey; (ii) warn of increased vessel activity; (iii) provide contact details for the FLO, OFLR and vessel should contact need to be made; (iv) keep the fishing community updated on the project related activities in general; and (v) advise when survey activities have finished.

To date, Equinor Wind has contacted approximately [redacted], survey flyers, and calls related to survey activity. In addition, some of the survey information has been re-broadcasted by state agencies and fishermen's organizations that have agreed to distribute the materials to their members, and has been included in notifications through USCG Notices to Mariners.

The inclusion of OFLRs when appropriate and feasible also means notifications can be provided in "real-time." For example, if the OFLR observes a fishing vessel in the field, the OFLR has the ability to contact that fisher via radio to disseminate information.

In addition to notifications, Equinor Wind will regularly solicit feedback on fishing activity during surveys, through a combination of direct outreach to the fishing community, state fisheries agencies and federal fisheries agencies. As an example, Equinor Wind's FLO actively sought additional sources of information on the location of fishing activity through periodic inquiries to NOAA NMFS regarding general fleet movements, and through monitoring non-confidential data available through VMS. During the summer 2018 geophysical surveys, emphasis was on monitoring the squid fishery fleet movements leading up to and during the period when they are known to fish within the lease area. [redacted]

Adaptive Management: Survey Areas and Export Cable Routes

Equinor Wind has incorporated flexibility into the offshore survey schedule and spatial planning for the offshore wind energy area and export cable corridors so that an adaptive management approach can be taken as more information is collected during surveys and stakeholder outreach. This has been applied through several practices.

First, the team onboard the survey vessels had the mandate to modify planned survey areas. For example, surveyors had a mandate to alter planned routes in favor of alternate areas that had not been identified in pre-survey consultation or data if they determined the planned route was likely to be of high importance to the fisheries.

Further, during the summer 2018 geophysical survey, real-time side scan sonar data identified areas of potentially hard ground in sections of the export cable corridor in an otherwise predominantly sandy seabed. The harder ground can be associated with crab & lobster fishing, or recreational fishing. The OFLR also observed surface marker buoys associated with fixed gear. A decision was subsequently made in real time to avoid this area, modify the survey plan for the export cable corridor and then survey alternative areas deemed to be of lower potential conflict.

Equinor Wind will continue to use this form of adaptive mitigation going forward as remaining or additional sections of export cable routes are surveyed in 2019.This same technique may also be used at the time of detailed design surveys, should they be required pre-installation.

Adaptive Management: Timing of Surveys

If certain areas cannot be avoided altogether through spatial planning due to a lack of technically and commercially feasible alternatives, the timing of surveys can be planned to avoid or minimize disturbance to fishing activity. As an applied example, during the summer 2018 geophysical surveys, a short section of the export cable corridor from the Lease Area to landfall contained a high density of fixed lobster fishing gear. An appraisal of alternative cable routes to the north and south of this section did not provide any suitable alternatives without significant deviation and increased technical and commercial challenges. As such, avoidance through adaptive spatial planning was not feasible and the section was upheld, subject to exploring further mitigation to deconflict the section in the construction and operations phase with the relevant fishery. The presence of the experienced OFLR onboard meant the OFLR would be able to advise the vessel master on safely navigating through the section, avoiding fishing gear. However, a conservative decision was made by the project team to avoid potential conflict from the survey activity altogether and cease surveys in this area until a time when less fishing gear was present, and risks were reduced. Through the FLO, Equinor Wind learned this particular area closes to fixed gear fishing during the month of May. Equinor Wind plans to complete the survey of this section of the route in May 2019, if feasible due to scheduling and other considerations, which will reduce the potential risk of disruption and potential impacts to this fishery. If, during survey work, it is determined this area cannot be avoided during active fishing, Equinor Wind is committed to work with the fisheries to determine the best methods to conduct the survey work and minimize disturbance.

Adaptive Management: Real-Time Monitoring

Equinor Wind has adopted a real-time monitoring approach to improve its ability to apply the adaptive management options previously described during surveys; that is, to pro-actively avoid surveying areas being fished to avoid potential conflicts.

Many northeastern fishing vessels broadcast their information with the Automated Identification System (“AIS”). Requirements for AIS on fishing vessels are limited, but it can be a valuable source of information on vessel movements in some areas and under certain conditions. Sea Risk, the company providing Equinor Wind’s FLO, has years of experience using AIS in relation to subsea cable damage prevention in the U.S. and overseas, monitoring AIS in real-time with specialized software on a 24/7 basis.

As an example of this approach being trialed and then implemented for the full survey period, during the summer 2018 geophysical survey the FLO was tasked with operating AIS software loading real-time vessel movements in the New York Bight 24/7. Every morning during the survey, Sea Risk reviewed and recorded a 24-hour visual record of vessel movements for distribution by email to the survey vessel, OFLR, onshore survey manager and Equinor Wind. Although there can be issues with AIS data quality, and not all fishing vessels broadcast, it nonetheless provided valuable information about fleet movements and activity of larger vessels. The daily AIS snapshot provided the survey and other project participants a preview of vessels heading in their direction, transiting and working nearby. Although no fishing vessels were observed within areas of potential conflict that required modifications to the survey plans, it provided the tools to make modifications to planned efforts in advance, should there have been a need.

This system also facilitates data collection of fishing practices and transits within the Lease Area and export cable corridors for use in identifying potential impacts and addressing with mitigation. For example, detailed movements of different mobile gear types in the area, including scallop and clam dredges and bottom trawls, are being used to consider maneuverability, speed, towing areas, and water depths of fishing vessels active in the lease as input to the design of turbine layouts, orientation, and spacing.

Equinor Wind is committed to having the real-time AIS monitoring approach as a tool to be considered for future surveys, where appropriate.

Adaptive Management: Consultation During Surveys

In addition to the efforts described above, the FLO actively sought additional sources of information including periodic inquiries to NOAA NMFS regarding general fleet movements, and non-confidential data that can be gained with the VMS. Where potential conflicts with fishermen have become apparent, the survey vessel has moved away.

Summary of Proposed Mitigation for Future Survey Activity

Based on the experience of applying mitigation to avoid or reduce impacts on fisheries during surveys to date, Equinor Wind intends to apply the following mitigation during future survey activities:

- The outset philosophy of purposefully avoiding fishing activity, where feasible;
- Using adaptive management to avoid fishing activity during surveys;
- Pre-survey consultation on proposed survey areas to inform spatial planning to avoid high sensitivity areas;
- Pre-survey consultation on proposed survey areas to inform the planning and scheduling of surveys to avoid fishing activity;
- Real-time adaptive management of the location of export cable corridors and project areas that survey data and visual observations shows to have the potential to impact fisheries during the operations phase;
- Use of an OFLR where appropriate and feasible;

- Real-time monitoring of fishing activity to pro-actively direct survey vessels away from fishing;
- Ongoing consultation during survey activity to seek information of intentions to fish in areas being surveyed; and
- Regular dissemination of survey activity information to the fishing and maritime communities via media including survey flyers, email mailshots, USCG Notice to Mariners ("NTMs"), information posted on the project-specific website, and making survey activity information available on fisheries targeted websites such as the F-TWG operations page and/or RODA.

Construction

Equinor Wind will approach construction activity with a similar philosophy to those employed for survey activities; that is to avoid conducting construction activity at times and in locations where active fishing is underway. However, due to the complexity, schedule and costs associated with construction activities in comparison to surveys, this requires different approaches to reach the same outcome. Some of the details of how construction will take place, when and in what areas is still being determined as the project matures, and as such estimates described within are based on experience and literature. Commitments for the construction phase will be discussed and agreed upon as part of the consultation of the FMP with the F-TWG and other applicable parties.

The type of construction activity and impact to the project through implementing mitigation needs consideration. Mitigation needs to be both effective and proportionate to the reduction in impact that mitigation will have. In some circumstances, if impacts to fishers remain significant and adverse, alternative mitigation or offsets may be a preferred and a more appropriate option.

Equinor Wind is familiar with certain types of avoidance or mitigation measures that can be employed based on previous experience of developing offshore wind energy projects. Additional measures may be identified and explored in consultation with the fishing community. These are addressed on an impact-by-impact basis, as described in Section 12.7.1. Potential construction related-impacts are summarized again below:

- Adverse impacts to specific commercial fish species, resulting from offshore wind energy development construction activities;
- Short-term temporary displacement or restricted access to traditional fishing grounds during offshore wind energy development construction;
- Navigational safety concerns during offshore wind energy development construction due to partially built infrastructure (*e.g.*, as a result of foundations being installed a season before wind turbines); and
- Navigational safety concerns during due to increased project related construction vessel traffic.

Impacts on fisheries resources, in particular target commercial species is covered in Section 12.6.2 and is therefore not repeated in this section. However, some of the commitments and mitigation options aimed at avoiding or minimizing impacts to fisheries resources will have direct applicability on fishing access. This is covered further below.

As with surveys, Equinor Wind will, where feasible, plan to avoid construction activities in areas and/or at times when fishing activity is likely to be present or is present. This requires two distinct approaches; pre-planning of timing and location to avoid conflicting activities; and, adaptive management during construction activities. In addition, Equinor Wind can consider "rolling construction zones," whereby discrete areas of construction activity are closed to other vessels for safety reasons, without restricting larger areas (*e.g.*, within the boundaries of the entire offshore wind development area). These approaches are discussed further below.

Pre-Planning Timing and Location

As with surveys, where feasible, Equinor Wind will determine sensitive timing and locations of fishing activity to help plan avoidance measures (*e.g.*, avoidance of the squid fishery that data and consultation has shown can be concentrated in the Lease Area from May to September). As previously mentioned, it is not always possible to avoid conflicting activities during construction, as some timing is limited by other external factors such as construction vessel availability, seasonal restrictions, weather and schedule delays; however, Equinor Wind can use information like this to minimize the "likelihood" of interaction. For example planning for construction activities, such as foundation installation or inter-array cable laying, in this area outside an area of potential peak squid fishery. Equinor Wind understands that the location of focused squid fishing may vary year to year; therefore, continuous consultation with these stakeholders will allow for effective construction scheduling.

In addition, consultation can offer alternative options for fisheries less subject to spatial and temporal fluctuations and seasonality of target species. Equinor Wind will share as much scheduling information as early as possible so that fishers can also plan around construction activities. For example, sharing a set start date, duration and locations of construction activity may provide the scallop fishery an opportunity plan longer term fishing areas, with the option to fish conflicting areas prior to or after that particular construction activity. It is possible that temporary displacement from a traditional ground may still occur, but with pre-warning and the ability to make alternative plans, the effects of that impact can be reduced.

Equinor Wind will commit to provide as much notice as possible to facilitate consultation and pre-planning for both parties through the suite of options described in Section 12.3.5, including but not limited to:

- Survey/Construction Flyers;
- Through email shots and notifications sent via the FLO direct to fishing contacts, FIRs and state fisheries agencies;

- Through direct communication in meetings;
- Notifications on Equinor Wind's webpage and fisheries webpages such as F-TWG and RODA, as appropriate;
- In Fisheries Newsletters; and
- USCG NTMs.

In addition, Equinor Wind is committed to exploring the following pre-planning timing and location options with the F-TWG and fishing industry:

- Protocols for regular two-way dissemination of information related to fishing and construction activity to aid timing and location planning; and
- Consideration of planned or expected timing, location and type of fishing activity when planning construction locations and timing.

Adaptive Management Timing and Location

With the challenges associated with accurate timing of construction activity and equally challenging nature of predicting the spatial and temporal presence of some highly mobile fish species, it may not always be possible to avoid conflicting activities as planned. Best practices to reduce the likelihood of conflicting activities may fail if a mobile commercial species appears at a different location or construction timing accelerated is modifed. In these circumstances adaptive management must be considered.

If, for example, a high number of fishing vessels are already fishing for, or have opportunities to start fishing for, squid Equinor Wind can consider, in consultation with representatives of that fishery, options to move some pre-planned construction activity to an alternative location. If there is flexibility to do this without significant and disproportionate impacts to the construction activity, then this can be considered.

The use of real-time monitoring with AIS, visual observations from the OFLR and regular updates on the fleet movements from the FLO and FLO sources can all contribute toward understanding (i) fleet movements, (ii) where and when potential conflicts may arise, and (iii) how to avoid or mitigate any such potential conflicts.

Equinor Wind will commit to have an OFLR on board project related construction vessels, where appropriate and feasible to aid with adaptive management and to help with the dissemination of information to/from the FLO to/from the vessel master and/or fishers in the field.

In summary, the adaptive management options Equinor Wind is committing to explore further with the F-TWG and the fishing industry are:

- Protocols for regular two-way dissemination of information related to fishing and construction activity to aid adaptive project construction location decision making;

- Use of real-time monitoring of fishing activity, such as AIS, to aid adaptive project construction location decision making;
- Protocols and situations in which the project can consider modifying construction timing and location within short notice periods; and
- Use of an OFLR onboard project related construction vessels to aid communications and monitoring of fishing activity.

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Advanced and continued notifications to the fishing community are essential for all options described in this section to be effective. As such, and if implemented, Equinor Wind will establish notification protocols in consultation with F-TWG and the fishing industry for the use of fixed, partially fixed or rolling construction and safety zones. Should these options be applied, Equinor Wind will commit to having an OFLR onboard the project related construction vessels to further aid communications in the field.

The options Equinor Wind is committing to explore further with the F-TWG and the fishing industry to avoid or reduce short term temporary impacts from temporary displacement during construction activity are:

- Advanced dissemination of planned construction schedules and locations to aid alternate planning for fishers;
- Advanced and continued communications and notifications related to the timing and location (for example implementation and lifting) of construction and safety zones; and
- Rolling construction and safety zones.

Navigational Safety: Partially Built Structures

Potential risks identified through consultation with the fishing and maritime communities, from experience and from relevant literature, include, but are not limited to:

- Allisions with or snagging of fishing gear on installed wind turbine foundations prior to tower and wind turbine installation due to lack of visual reference;
- Allisions with or snagging of fishing gear on installed offshore substation foundations prior to topside installation due to lack of visual reference;
- Snagging of fishing gear on electrical cables laid on the seabed awaiting burial or protection; and
- Snagging of fishing gear on areas of seabed preparation prior to foundation installation.

Equinor Wind is committed to safety and proposes the following mitigation measures to reduce the likelihood of fishing vessels encountering the risks identified above. The mitigation is a combination of effective communications and dissemination of information and effective marking, lighting and safety measures in line with federal and international regulations (*e.g.*, USCG and COLREGS). Navigational safety in itself is being assessed as part of the COP and forms part of Equinor Wind's Navigation Safety Risk Assessment ("NSRA"). Mitigation measures will be consulted on with USCG, F-TWG and the fishing industry, as well as with the wider maritime community. Equinor Wind proposes to present the NSRA at the F-TWG during consultation on the FMP. Mitigation measures, include but are not limited to:

- Marking & lighting of partially built structures following Private Aids to Navigations ("PATONS");
- Dissemination of charted locations of partially built structures to the fishing community via the previously described notifications channels;
- Provision of locations of partially built structures in digital formats that can be uploaded to typical navigation equipment, for example navigation plotters;
- USCG NTMs;
- Provision of locations of partially built structures for updating NOAA Nautical Charts, as well as USCG Local Notices to Mariners at more frequency (*i.e.*, weekly);
- Consultation with the fishing community with the potential to establish temporary safety exclusion zones around partially installed wind farm electrical cables;
- Provision of safety vessels around high risk structures, including utilizing vessels in the fishing fleet to act as safety vessels; and
- Prescribed transit routes for offshore wind energy development construction and support vessels to/from port to/from the offshore wind energy development;
- Real-time monitoring and notifications to fishing vessels approaching areas of potential risk.

Navigational Safety: Increased Construction Vessel Traffic

Increased vessel traffic due to the offshore wind energy development related construction and support vessels has been identified by the fishing industry as a potential navigation safety risk, with concerns over an increased likelihood of collision between a fishing vessel and construction vessel. Navigational safety and associated mitigation options will be covered as part of Equinor Wind's NSRA, which Equinor Wind will share with the fishing industry for consultation, and can present to the F-TWG while consulting on the FMP. Equinor Wind will seek to minimize the likelihood of a vessel to vessel encounter through planning and mitigation. Mitigation options that Equinor Wind is open to explore with the fishing industry include, but are not limited to:

- Advanced and regular dissemination of information of planned construction activities, timing, locations, transit routes, vessel details, vessel contact details and project contacts to the fishing community via the suite of notifications options previously described;
- Prescribed transit routes for offshore wind energy development construction and support vessels to/from port to/from the offshore wind energy development;
- Offshore wind energy development construction and support vessels to following best practice guidance, including COLREGS;

- A commitment that Equinor Wind will make all offshore wind energy development construction and support vessels aware of the final FMP and prescribed mitigation measures;
- A commitment that Equinor Wind will, where appropriate and feasible, have an OFLR onboard at least one offshore wind energy development construction and support vessels in the field to aid communications; and
- Potential real-time monitoring of fishing vessel activity to monitor for and avoid through contact, potential conflicting activities.

Operations

Equinor Wind has set out with the objective to coexist with the fishing community, with particular emphasis on applying thoughtful planning and mitigation measures that enable continued access to traditional fishing grounds during the operational phase, while also balancing technically and commercially feasible offshore wind energy developments that offer value to the New York rate payer and meet New York State's ambitious offshore wind targets.

The planning and mitigation options that will be considered for minimizing impacts to fisheries are described in this section. These measures are in direct response to the concerns and potential impacts identified in consultation with the fishing community, from direct experience from developing offshore wind energy developments and from recommendations in literature such as NYSERDA's Fish and Fisheries Study (2017).

Potential impacts from the offshore wind energy development, as a whole for all phases of development, are covered in Section 12.7.1. The potential impacts attributable to the operations phase are summarized again below:

- Adverse impacts to target commercial fish species resulting from offshore wind energy developments;
- Positive beneficial increases in species biodiversity and abundance;
- Long-term temporary displacement or restricted access to traditional fishing grounds;
- Navigational safety concerns due to increased offshore wind energy development related vessel traffic;
- Navigational safety concerns due to changes in existing vessel patterns, for example displacement of existing vessels;
- Navigational safety concerns while transiting due to the presence of structures (*e.g.,* allision and impacts on navigation equipment);
- Navigational safety concerns while fishing due to the presence of structures, subsea cables, cable protection, scour protection, furrows and dropped objects;
- Positive beneficial increase in search and rescue capabilities at sea with Equinor Wind's operations equipment/staff;

- Increased transit times due to the presence of structures and/or restricted access during operations;
- Increased resource pressure on existing commercial fisheries during operations due to the attraction of other fisheries, for example an increase in recreational fisheries and fixed gear fisheries;
- Navigational safety concerns for existing commercial fisheries due to the attraction of other fisheries, for example an increase in recreational fishing vessels and fixed gear; and
- Increased pressures on existing fisheries in adjacent waters due to displaced fisheries from the offshore wind energy development area.

Initial Feedback for Design Parameters

Thoughtful spatial planning and project design can be one of the most effective means of avoiding or reducing impacts on fisheries during the operations phase.

The approach Equinor Wind has taken to establish design parameters that foster coexistence includes; (i) solicitation of early feedback from the fishing community on concerns and design requirements; (ii) use of that feedback to set high level spatial constraints to feed into survey plans; (iii) use of that feedback to set design rules that foster coexistence and can be used to generate initial site planning and wind farm layouts; (iv) consultation with the fishing community on plans and draft layouts; and (v) use of that feedback on draft layouts to modify as appropriate and feasible for COP submission. Equinor Wind started this process early, with the goal of having mitigation plans and layouts included in the COP submission that have been generated through consultation, consensus and where available, based on data and evidence.

[redacted] However, Equinor Wind is progressing on the basis of a successful RFP award and is currently at stage (iv) as noted above; that is, Equinor Wind is seeking feedback from the fishing industry on draft layouts having been through steps (i) to (iii). Equinor Wind expects to be at a mature stage (iv) and progressing to stage (v) when consulting with F-TWG on the FMP.

The first step in Equinor Wind's approach has been to solicit and gather as much information as possible on existing and likely future fishing practices in the Lease Area and adjacent areas, from: concerns raised and risks identified from direct engagement with the fishing industry; past experience developing offshore wind farms; referencing the New York State Master Plan Fish and Fisheries Study (Chapter 5.2; 2017) and referring to best practice guidance. Some existing concerns and best practice guidance can be applied. However, due to the potential variation in fisheries resources, fishing practices and local conditions varying site by site, and in many instances within a site, it is Equinor Wind's view that each wind farm project should be assessed and planned on a case by case basis. As such, site-specific feedback via direct consultation with the fishing community has been the most effective method.

Meaningful and targeted feedback at the very early stages of project development can be limited where the absence of specific details on project design and site-specific survey data limits what project specific feedback the fishing community can provide above and beyond what exists in best practice guidance. Feedback Equinor Wind received in those early stages was still incredibly useful and applied in the early design process. Information gained from the period from OCS-A 0512 Lease award (April 2017) through spring 2018 was used to set early design constraints so that spatial planning, wind farm design, and layouts took into account fishing at the earliest stage possible.

Based on inputs from the fishing and maritime communities, and experience developing offshore wind farms in Europe, Equinor Wind established a set of "Layout Rules" within which initial designs have been based. The intention being that Equinor Wind can plan survey activities and further mature designs around the Layout Rules, with follow up consultation with the fishing and maritime communities on site plans, wind farm layouts, and export cable corridors generated from these.

As an example, feedback from the fishing community, which was based on the entire OCS-A 0512 Lease Area, included, but was not limited to:

- The northwestern part of the Lease Area and adjacent waters of the Cholera Bank supports a highly mobile squid fishery, which can be intensively fished for periods of 1-3 months in some years (anecdotal reports of up to 60 vessels at a time), and may be elsewhere for several years.
- The Lease Area supports some scallop fishing. The larger fleet tends to prefer waters of 25 fathoms and deeper, while the greatest depth in the lease area is approximately 23 fathoms. However, some "day boats" may work in the area, as well as boats of any size in case of rough weather offshore, or a particularly large localized set of scallops. The scallop fishing seen in the Lease Area tends to concentrate in the eastern, deeper section.
- The Lease Area supports some monkfish gillnetting, spread out across the Lease Area in some seasons and years. It tends to focus in the southeast section of the Lease Area.
- The northwest tip of the Lease Area and adjacent waters of the Cholera Bank supports a small lobster fishery, where there are patches of harder seabed compared to predominantly sand and gravel elsewhere in the Lease Area.
- The clam dredge fishery has concerns related to the export cable routes, wind turbine spacing and sufficient cable burial.
- Fisheries have requested Equinor Wind to:
    - Bury all electrical cables;
    - Avoid use of concrete mattresses to protect electrical cables, should sufficient burial not be achieved. Cable protection material should be sympathetic to fishing practices;

- Orient rows of wind turbines in dominant trawling directions; that is to orient rows of wind turbines parallel to the water depth contours, in a southwest to northeast direction;
- Space wind turbines as far apart as possible. Requests have varied from 1nm, 2nm and 4nm;
- Maintain a level of consistency in wind turbine alignment in clear rows;
- Align turbine rows for compatibility with traditional practices that facilitate coexistence of static and mobile gear fishermen, for example on LORAN lines ending in 5.
- Coordinate with the fishing industry during surveys, construction activity and scheduled and unscheduled maintenance;
- Identify measures that minimize effects of wind turbines on radar interference;
- Identify measures that minimize the effects of EMF on fisheries resources;
- Minimize the effects of underwater noise during construction and operations on fisheries resource;
- Provide unrestricted access to traditional fishing grounds;
- Define protocols for snagged or lost gear;
- Provide waivered liability for fishing vessels damaging wind farm assets;
- Define transit corridors for fishing vessels transiting from New Jersey to/from eastern Long Island and New England;
- Define fixed, predictable transit routes for wind farm related construction and maintenance vessels to/from ports and the wind farm area.
- Consult and seek approval for proposed wind farm layouts and export cable corridors before concluding on final designs.

As described in previously in Section 12.3.5, Equinor Wind is seeking to enter into a SoCG with each fishing organization as a means of recording feedback and tracking how those concerns are being addressed.

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As seen in Figure 8, the fishing industry provided plotter tracks from eight trawlers for multiple years. These helped us understand common tow orientations, reinforcing reports of trawling aligned with bathymetry.

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During surveys from March through November 2018, fishing was monitored closely to avoid potential conflict, combining radar, onboard visual, and AIS. Concerning the interest in transit lanes, AIS tracks were recorded for fishing vessels crossing the Lease Area. Figure 11 below depicts the data from one trawler over the period June – October 2018. Straight lines across the lease indicate transits.

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The following sections describe how that feedback has been addressed, to date.

Layout Rules

Feedback from both the fishing and maritime communities resulted in Equinor Wind establishing layout rules from which to apply to the first phase of designing wind farm layouts. The layout rules established for the initial phase of planning are described below. Equinor Wind will consider committing to the principles of final layout rules at COP submission, providing clarity to the fishing and maritime communities as to what layouts could be selected from the design envelope at the final stage of project development.

It should be noted that the layout rules are designed to facilitate safe navigation and access. The layout rules are not designed to replace or supersede other existing primary navigation aids which should be employed and will significantly reduce risk (*e.g.*, vessel bridge navigation equipment). The layout rules used in this initial design phase are:

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Empire Wind Offshore Wind Energy Area, Location

Prior to factoring in fisheries, the technical, commercial and operational constraints dictated the location of the preferred first offshore wind energy development area within the Lease Area, the Empire Wind project area, in order to maximize benefits from the build out of this area. These considerations are described in Section 3 of the RFP submission. The proposed project area was then considered for compatibility with the existing fisheries active in or adjacent to the area. As covered in Sections 12.4.3 and 12.7.4 information on existing fisheries and feedback on the site use came from existing data sources or from direct consultation with the fishing community.

A mitigation and design consideration available to a developer at this stage if there is risk of a significant adverse impact on a fishery that cannot reduced through other planning or mitigation is to "avoid" the area altogether. For example, with Equinor as partner in the Forewind consortium developing the Dogger Bank offshore wind farms in the U.K., a conscious project decision was made to "avoid" a consistent year-to-year sand eel fishery (*i.e.*, sand lance), that supported tens of fishing vessels over sustained seasonal periods, with limited alternative areas in adjacent waters. The fisheries resource also supported marine mammals and avian species as an important prey resource. On that basis, the developable area of what would be an equivalent lease area was reduced to remove the potentially affected area and receptors.

Appreciating that fishing can occur anywhere in the Lease Area, including the proposed Empire Wind project area, consideration was given to distinct areas of significant use that might be consistent with the Dogger Bank example described above. As previously noted, the northwestern part of the Lease Area and adjacent waters of the Cholera Bank was identified as supporting a highly mobile squid fishery, which can be intensively fished for periods of 1-3 months in some years (anecdotal reports of up to 60 vessels at a time). Upon further analysis, it was evident that this fishery was highly mobile and did not show site fidelity on a consistent year-to-year basis, with the fishery sometimes moving to other parts of the Lease Area or to other areas of the adjacent waters and wider New York Bight at varying levels of intensity. With this taken into consideration, it was not deemed proportionately effective to avoid this area, but to explore further mitigation options in project design.

Perimeters and Layout Clarity

The layout rules were followed to ensure that all wind farm structures were placed in a manner that provided consistency and clear line of sight, with no protruding structures that may increase navigation risk. On this basis, the location of the offshore substation, which will be determined following completion of surveys, will be located in the same manner to maintain consistency.

Straight lines of wind turbines on the perimeters have been adopted to provide clarity of the boundary of the wind farm area for vessels' navigation in proximity to the Empire Wind area, for example commercial vessels using the TSS, as well as reducing the effect of disorientation to fishers with a clearer boundary.

Perimeter wind turbines have been placed in a manner that maintains unobstructed rows with a clear entrance, transit and exit into, through and out of the Empire Wind project area without altering course.

Orientation of Wind Turbine Rows

Equinor Wind included at least one line of orientation of wind turbine rows into the layout to facilitate unobstructed straight channels within which to continue towing mobile gear without altering course while under tow. With the Empire Wind proposed layout, this resulted in three distinct lines of orientations, increasing the options for set mobile gear tow headings.

In direct response to feedback that mobile fishing is predominantly along bathymetric contours which generally follow a southwest to northeast direction in the Lease Area, Equinor Wind adjusted the primary turbine rows to be in a southwest to northeast direction. Equinor Wind believes this will support the unobstructed towing of mobile gears in a manner consistent with towing patterns today. As well as supporting existing towing patterns, the additional wind turbine row orientations support options for unobstructed towing of mobile gear in a north to south direction and a north-west to south-east direction. Some fishermen recommend east-west row orientations in the interest of coexistence for potential future increases in static gear with the existing mobile gear fishery. However, as of this draft that seems less practical because; in this Lease Area we have heard of no fishermen's formal or informal agreements for placement of static and mobile gear; static gear here is relatively limited, with some lobster pots on the northwest corners and sporadic monkfish gillnets mainly in the southeast; and a southwest-northeast orientation is more compatible not only with trawl tows but also fishing vessel transits. Equinor Wind believes layouts should be aligned with existing practices, but is willing to engage in further consultations as part of F-TWG, RODA and fishing industry.

It should be noted that the southwest to northeast orientation also facilitates existing fishing vessel transit routes from ports in New Jersey to/from New England.

Wind Turbine Spacing

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Wind Farm Cables

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Proposed Empire Wind Farm Layout – Summary

Equinor Wind has applied fishing industry feedback and best practice guidance to the planning and indicative design and layout of the proposed Empire Wind offshore wind energy area. It is believed that the indicative layout sets out to avoid and reduce impacts where feasible, while balancing the technical, commercial and safety considerations for developing and offshore wind energy development and at the same time meeting New York State's ambitious offshore wind targets. This is achieved through taking into consideration safe navigation through: (i) the fixing of structures in straight or aligned rows, (ii) orienting rows in the dominant mobile gear tow directions, (iii) burying cables, (iv) planning for consistent and clear entrance and exits into and out of the wind farm, and (v) requiring future wind farm phases to be consistent with Empire Wind in design and layouts, but marked, lit and identifiable as a different wind farm to aid orientation. Equinor Wind welcomes feedback on the assumptions, efforts and prosed layouts in the F-TWG and will continue to consult on the layouts with the fishing industry.

Where risks are not completely avoided, further mitigation options are addressed in the following sections to reduce those risks to as low as reasonably practical.

Navigational Safety: Wind Farm Cables

As previously described, Equinor Wind will sufficiently bury inter-array and export electrical cables where feasible. This activity will result in: (i) reducing the likelihood of potential damage to the cables, (ii) ensuring energy security, and (iii) avoiding or reducing the risk of navigational safety to fishers from accidentally snagging on cables with fishing gear or being displaced from traditional fishing areas due to the presence of cables. Equinor Wind will endeavor to bury cables at burial depths targeted as appropriate to the existing fishing practices and cable burial risk assessments within the Empire Wind Project area. Target burial depths along the export cable corridor will be determined in accordance with prevailing identified fishing activities, commercial shipping and anchoring, and state and federal regulations and requirements.

Equinor Wind will coordinate with the fishing industry and F-TWG on cable burial, including using fishing industry input in the project specific Cable Burial Risk Assessment.

Preliminary geological data obtained from desktop studies and site-specific surveys conducted in 2018 suggest that inter-array cable burial is expected to be feasible for the majority of the Empire Wind Project area using existing cable trenching and burial tools. Full survey results are expected to be available to help inform this process by the time Equinor Wind consults with F-TWG on the FMP. However, where cable burial is not feasible, for example due to localized challenging geology or when crossing third-party cables, Equinor Wind will work with the fishing industry to select cable protection materials that are sympathetic to fishing activities. In response to feedback from the fishing industry, Equinor Wind will not select concrete mattresses as a primary option for cable protection. Cable protection requirements will be assessed on a case by case site specific basis taking into consideration cable risk, fishing practices and relevant state and federal requirements.

Equinor Wind further proposes to reduce the likelihood of snagging incidents through post installation surveys, notifications and communications. Equinor Wind will explore the following options with the fishing industry and F-TWG:

- Subject to state and federal approvals, sharing with fishers the “as-laid” inter-array cable positions and sections of surface cable protection for inclusion on NOAA Nautical Charts, navigation plotters, or as hard copy or digital charts
- Post cable lay surveys to determine actual cable burial depth versus target cable burial.
- Site specific periodic cable burial inspection surveys as appropriate to the level of risk of future exposure or intensity of fishing
- Emergency contacts list for fishers to report exposed or suspected exposed cables
- Emergency procedures and protocols, including compensatory measures for snagged or lost gears

- “Trawlability” surveys

Navigational Safety: Wind Farm Structures

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Industry wide concerns have also been raised about fishing vessels transiting through offshore wind energy developments. This is a topic of discussion for offshore wind lease areas in Massachusetts. Based on this issue, Equinor Wind collected information related to transiting fishing vessels with respect to the Empire Wind offshore development area and wider Lease Area. Information was derived from direct feedback through consultation with fishers and through inspection of AIS for fishing vessels traveling at a speed suggesting transit rather than engaged in fishing.

The data showed few vessels that regularly transit through or in adjacent waters to the Lease Area, with most, if not all, transiting from fishing ports in New Jersey to and from fishing grounds in New England.

Consideration is given to the likelihood of an allision with a wind turbine during transit. Fishing vessel Captains use transits as a rest period, handing over the wheelhouse to less experienced second or third mates or crew, with potentially less experience in navigation and seamanship.

However, it is expected that regardless of wind turbines being present within the Lease Area, the most experienced crew member, most likely the Captain, will be at the wheelhouse with a heightened sense of alertness when crossing the Lease Area due to the fact the transit crosses four busy TSS. It is also expected that transits through offshore wind energy developments would also call for experienced crew in the wheelhouse thus reducing the risk of an allision due to a relatively inexperienced crew. However, Equinor Wind is open to exploring funding of further training for all crew for transiting through operational wind farms, which could be done through maritime simulation training schools within the New York Bight should this potential impact require further mitigation.

The setting of wind turbine rows in a southwest to northeast orientation, primarily to aid continued trawling along existing trawl patterns and bathymetric contours, also lends itself to the historic transit pattern, with little or altering of course required to transit through a row a wind turbines.

Due to the shape of the Lease Area, transits through the Lease Area from a general south to north are of a fairly short distance, typically ranging from between 2 to 4 nautical miles. Therefore, the duration of transit is short and combined with the orientation of rows, and the minimum 5 rotor diameter spacing of wind turbines, fishers are expected to be able to transit through in most conditions. Equinor Wind is aware that concerns are also related to transits in very poor weather conditions, with some requests from the fishing industry for between 2 to 4 nautical mile transit lanes to accommodate safe transit in poor weather. In light of the position of the Lease Area, it’s possible that during poor weather, vessels will elect to take a route closer inshore and therefore west of the Lease Area. However, some fishing vessels may prefer to take the transit offshore. Equinor Wind is monitoring BOEM’s leasing efforts in the New York Bight, with clear indications that BOEM intends to accommodate an offshore transit fairway east of the Lease Area. Equinor Wind will commit to work with BOEM, USCG, F-TWG, RODA and the fishing industry, as well as the maritime industry, to work towards offshore transit fairways prior to further lease areas are finalized. On this basis, Equinor Wind believes that potential impacts from transiting in very poor weather will be mitigated by the future implementation of transit fairways east of, and outside of, the Lease Area. Equinor Wind will also offer to facilitate transit discussion by offering use of the 3D Wind Farm Simulation Tool, as described in Section 12.3.5.

Navigational Safety: Increased Vessel Traffic

Empire Wind related vessel traffic during the operations phase is likely to be limited to the Operations and Maintenance (“O&M”) vessels servicing the wind turbines and offshore substation. This will be a Service Operations Vessel (“SOV”) and approximately two support Crew Transfer Vessels (“CTVs”). The increase in vessel traffic compared to background baseline levels is low and as such, the likelihood of collision is still low. However, this risk can be lowered further still to as low as reasonably practical through further mitigation and best practices. Equinor Wind will consider the following mitigation measures:

- Notifications to the fishing and maritime community of any unscheduled O&M different to normal vessel operations, for example Jack-up rigs or cable inspection and maintenance vessels. OFLRs used where appropriate
- A communications plan with key contacts and emergency procedures between the Empire Wind operations base and the fishing industry
- Establishing set transit routes for O&M vessels to/from the shore operations base

It should also be noted that in Europe the presence of offshore wind farm development vessels in the offshore locations has been deemed a positive beneficial impact, in that they offer immediate search and rescue facilities and safe havens to mariners in distress that may otherwise rely on emergency assistance from agencies based farther away.

Operations Impacts on Fisheries Resources

[redacted]

Operations Impacts from Modified Fisheries

A concern that has been raised by the commercial fishing industry is that the positive beneficial impact of the enhancement of biodiversity and abundance of species from the introduction of hard structures (Section 12.6.2) will attract larger numbers of recreational fishing vessels to the area, which may result in conflicting activities with the commercial fishing fleet. In addition, concerns have been raised about existing fisheries being displaced into other fishing grounds. It is too early in the Empire Wind development process to predict or quantify potential modifications to recreational and commercial fisheries, and therefore the potential mitigation measures that can be applied either in the spatial planning and design of the offshore wind facility or during the operations phase. This is an industry wide question that is best addressed through groups such as F-TWG, RODA and FLOWW in a collaborative approach. Equinor Wind will participate and contribute to these discussions as appropriate.

Modifications Post RFP Award

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Decommissioning

Impacts during decommissioning are not expected to exceed those of during construction or operations, and with mitigation in place similar to that proposed as for construction activities, Equinor Wind believes that impacts will not exceed those described for the survey, construction and operations phase for both fisheries resource and fishing (Sections 18.2, 18.3 and 18.4 respectively).

However it is clear that both the offshore wind energy development industry, regulatory agencies and the fishing industry need more information on the effects of decommissioning, and while those effects and associated impacts may become clearer from the eventual decommissioning of offshore wind energy developments in Europe, or from experiences of decommissioning offshore oil and gas platforms in the Gulf of Mexico, Equinor Wind is willing to collaborate on research initiatives via F-TWG and E-TWG to address some of these questions.

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12.9 Additional Considerations

The overall approach for development of this FMP has been to acknowledge the dynamic nature of executing a successful offshore wind energy development off the coast while considering the complex dynamics of the fisheries resources and stakeholders. As such, Equinor Wind has and will continuously evaluate and evolve this FMP so that all the components of the FMP are complete and sufficient. Given the nuance of offshore wind development in the United States, Equinor Wind expects that additional guidance and information will become available throughout the planning process and we will continue to consider its relevance to the FMP. Further, Equinor Wind will continue to rely on experience both from the mature overseas offshore wind industry and any experience that results from other offshore wind developments in the eastern seaboard of the United States.

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Equinor Wind US LLC

Section 13

Environmental Mitigation Plan

Table of Contents

Table of Figures

13 ENVIRONMENTAL MITIGATION PLAN

Proposers must include in their Proposals a detailed Environmental Mitigation Plan that describes how Proposer will mitigate adverse environmental impacts that may be caused by the Project. Elements of the Environmental Mitigation Plan are described in detail in Appendix E. Proposers are advised to review the environmental studies prepared for the New York State Offshore Wind Master Plan with respect to the potential impacts of offshore wind energy development on the environment, and also are advised to include in their mitigation plan the appropriate Best Management Practices described in the Master Plan and supporting studies.

13.1 Summary

Equinor Wind welcomes the opportunity to submit an Environmental Mitigation Plan ("EMP") as part of its application to supply offshore renewable energy certificates ("ORECs") to New York. Equinor Wind is firmly committed to responsibly developing the Empire Wind Project in a manner that avoids or minimizes adverse impacts to the natural environment and resources to the maximum extent possible, while fostering the sustainable growth of offshore wind energy development in the New York Bight.

As part of this commitment, Equinor Wind believes that from the outset measures to avoid or mitigate adverse environmental impacts while maximizing the positive beneficial environmental impacts of an offshore wind energy project should be:

- Identified and developed in consultation and coordination with the relevant stakeholders;
- Based on robust baseline characterization that has been developed in consultation with relevant stakeholders;
- Evidence based and founded on the latest science;
- Where data gaps exist or the receptor-effect interactions are unknown, information gaps are satisfied through targeting data collection, monitoring and/or research;
- Incorporated into spatial planning, for example project siting and design; and
- Applied to how the project is implemented, for example surveys construction methods and operations and maintenance activities.

As such, this EMP sets out to summarize Equinor Wind's approach to: understand the natural and biological environment through baseline characterization; assess potential impacts; identify avoidance; mitigation or enhancement opportunities; understand how these will be considered and applied; identify the steps taken to consult with the relevant stakeholder groups to get feedback and buy in on decisions; and describe how Equinor Wind will conduct monitoring, data collection, and/or collaborative strategic research.

Since executing the lease in March 2017, Equinor Wind has been working diligently to understand the physical and biological characteristics and uses of the lease area. This EMP is the product of numerous studies and analyses that have been conducted to date, including work conducted by others (*e.g.*, NYSERDA's Offshore Wind Master Plan (2017); "Master Plan"). This information is being compiled to understand existing conditions and potential environmental impacts and benefits of the Empire Wind Project and therefore, what mitigation or enhancements can be exercised to reduce negative adverse effects or boost positive beneficial effects.

Detailed design, site evaluation, and environmental impact assessments for the Empire Wind Project remain ongoing. Therefore, this version of the EMP focuses on the process that will be used for identifying environmental receptors, baseline data characterization, potential effects, and the associated potential environmental impacts. The EMP also provides details regarding how potential impacts may be mitigated to the maximum extent possible given the current status of project development, and in further consultation with the relevant stakeholder groups including New York State Environmental Technical Working Group ("E-TWG"). Naturally, this EMP will continue to evolve through consultation and as the project matures, with additional detail and information provided in the Construction and Operation Plan ("COP") that Equinor Wind will submit to the U.S. Department of Interior, Bureau of Ocean Energy Management ("BOEM") in connection with the development of the lease area.

Equinor Wind recognizes the importance of adaptive management for any project, and in particular, a large-scale project such as the Empire Wind offshore wind energy development. Throughout each stage of the Project, Equinor Wind will continue to evolve its procedures for the evaluation and mitigation of environmental resources.

As described, this EMP sets out the intended approaches to responsible development, however some of these efforts are already underway or completed and evident in the approach taken, for example, offshore site surveys, baseline data collection and project design, and are therefore described as part of this EMP.

Similarly, Equinor Wind's approach to responsible development in regards to fisheries resource and fishers is covered in the Fisheries Mitigation Plan ("FMP") (see Section 12).

13.2 Communications and Collaboration

Openness is a core value and cornerstone of Equinor Wind's approach to engaging with and sharing data with stakeholders. Regular, open consultation will be key to ensuring that all interested parties are well informed in order to provide input into data, design, and mitigation options. This will facilitate working towards the joint objective of avoiding or minimizing impacts, while enabling the responsible and sustainable development of offshore wind energy in the lease area. All efforts for the Empire Wind Project will also contribute to successful future lease areas within the New York Bight by sharing experiences and lessons learned throughout this process.

Equinor Wind is approaching project development towards the COP and other state and federal permits on a "no surprises" basis; that is, sharing project updates, plans, results and information regularly and at all stages of the project so that all relevant interested parties have had sufficient opportunities to input into these processes, while also being sensitive to the potential for stakeholder fatigue. Equinor Wind intends to submit the COP and state and federal permits having taken regulatory agencies and stakeholders through the process. If data gaps or deficiencies or opportunities are to be identified, Equinor Wind believes it is best to do this at an early stage so that they can be addressed. This early and often approach has allowed Equinor Wind to identify, validate, and avoid potential negative impacts associated with offshore wind adaptively, to the best of its abilities. In instances where negative impacts cannot be avoided, Equinor Wind has been proactive in identifying appropriate mitigation approaches with input from stakeholders, such that any mitigation decided upon will be appropriate and effective to offset such impacts.

This type of approach has identified opportunities for collaboration in monitoring and research to support characterizing baseline conditions as described in later sections of this EMP. It is expected that additional studies will be identified as the Empire Wind Project progresses that will be appropriate for characterizing changes associated with offshore wind development to inform the stakeholder community through this open and active relationship.

13.2.1 Stakeholder Engagement

Active communication and dialogue with stakeholders begins during the early planning stages of project development, with Equinor Wind using feedback received from stakeholders to tailor the various phases of the Empire Wind Project.

Equinor Wind has been and will continue to engage with regulatory agencies, Environmental NGOs ("ENGOs"), research institutions and relevant stakeholders either via independent meetings or through environmental round tables in order to maximize opportunities to discuss the project and solicit feedback. For example, Equinor Wind has held "Environmental Roundtables" with ENGOs, held "Inter-agency Roundtables" with state and federal agencies, presented project updates and responded to questions at BOEM's New York Bight Task Force Meetings, and has held [redacted] related to environmental and permitting matters since lease award in March 2017 (see Attachment 17. This process will continue throughout the development of the Empire Wind Project, such that stakeholders are well aware of and able to input into planned activities, including pre-construction surveys, construction, operation and decommissioning.

Effective, clear and inclusive communication is required to ensure Equinor Wind can reach as many affected or interested stakeholders as possible in order to share project-related information and solicit feedback. Equinor Wind intends that its outreach will be as inclusive as possible. Additional details on outreach are described in Sections 12 and 14, including tracking tools in use. Examples of stakeholder engagement relevant to the EMP are covered in the following sections.

New York State Environmental Technical Working Group

Equinor Wind has committed to actively participate and contribute to the New York State E-TWG as a means to collaborate on best practices and research for offshore wind energy development, balancing responsible development while fostering opportunities for future offshore wind energy development in the New York Bight. Equinor Wind is represented on the E-TWG by Head of Environment and Permitting for Equinor Wind US, Martin Goff, a Chartered Marine Scientist bringing with him over 6-years of experience developing offshore wind energy developments in Europe and more than 10-years prior to that as a Physical Oceanographer supporting offshore energy and construction projects. Martin has represented Equinor in similar environmental and permitting groups to E-TWG in the U.K., including the Renewables U.K. Consents and Licensing Group ("RUK CLG"), Southern North Sea Offshore Wind Forum ("SNSOWF"), The Carbon Trusts ORJIP group and steering committee and Natural England's/The Crown Estates' Environmental Strategic Monitoring Group. Martin has attended all E-TWG meetings to date.

Martin is supported on the E-TWG by Head of External Affairs, Julia Bovey and Environment and Permitting Manager, Laura Morales. Additional details regarding Martin, Julia and Laura's experience are provided in Section 2.

Equinor Wind is committed to continued presence and participation on E-TWG and sees the group as an effective vehicle for prioritizing and focusing discussions on impacts, mitigation and collaborative research. Equinor Wind considers the ENGOs on E-TWG as a proxy "ENGO steering committee" for engagement with the ENGO community on responsible development.

Equinor Wind also attended and participated in the E-TWG State of the Science Workshop in Long Island, New York (13 – 14 November 2018).

New York State F-TWG, M-TWG and T-TWG

In addition to E-TWG, Equinor Wind is an active participating member of the Fisheries Technical Working Group ("F-TWG"). As such Equinor Wind has a good overview of the different groups and objectives, in particular the E-TWG and F-TWG where there is overlap on matters related to benthic and fisheries resources. Due to the overlap, both E-TWG and F-TWG are represented by the same personnel in Equinor Wind as outlined above.

Federal Agencies

Equinor Wind has been actively engaging with federal agencies since lease award in March 2017. A key part to ensuring a smooth permitting process and soliciting feedback on baseline data requirements has been and will continue to be engaging with the federal agencies, with BOEM as lead agency as a group, as well as individually. In this respect Equinor Wind held an "intra-agency" workshop in December 2017 attended by all federal agencies relevant to the permitting process. This also included state agencies for additional overlap and identification of responsibilities between federal and state permitting jurisdiction and requirements.

In addition, Equinor Wind has attended and presented Empire Wind project updates at New York Bight Task Force meetings, including in Riverhead, NY, Trenton, NJ, and New York City, NY. This has provided opportunities for federal and state agencies to ask questions, direct Equinor Wind towards suitable data sets, highlight potential data gaps and set the scene for follow up one on one agency meetings.

Bureau of Ocean Energy Management ("BOEM")

Equinor Wind is in regular communications with BOEM as lead agency on the Empire Wind offshore wind energy development. In addition to face to face workshops at BOEM offices in Sterling, VA and our office in Washington D.C., Equinor Wind and BOEM have scheduled monthly calls to discuss project updates, data and survey plans. These monthly calls will continue as the project develops. In addition, Equinor Wind and BOEM have unscheduled calls as appropriate to cover specific matters and involving specific subject matter experts.

NOAA National Marine Fisheries Service

Equinor Wind has been in consultation with the NOAA National Marine Fisheries Service ("NMFS") in relation to development of survey plans, baseline characterization data, for example, benthic and fisheries data sources and providing feedback on Equinor Wind's data collection efforts, and strategic advice on threatened and endangered species. Equinor Wind has also coordinated with NMFS on Incidental Harassment Authorizations ("IHAs") for geophysical surveys and the potential future requirements for IHAs in relation to construction activities. Equinor Wind has met with NMFS in meetings on several occasions in addition to conference calls. Equinor Wind expects to work closely with NMFS in the lead up to COP submission and then post COP submission for IHAs.

Other Federal Agencies

As well as BOEM and NMFS, Equinor Wind has been regularly engaging with other federal agencies related to the project, including the Fisheries and Wildlife Service ("FWS"), Environmental Protection Agency ("EPA"), U.S. Coastguard and U.S. Army Corps of Engineers ("USACE") and National Parks Service ("NPS"). Further details of the consultation can be found in Attachment 17.

New York State Agencies

Equinor Wind has actively engaged with New York State agencies through the Empire Wind development process. Equinor Wind intends to continue communications with these groups as the project develops, sharing COP sections prior to COP submission for feedback where feasible, and a commitment to sharing the COP with state agencies at COP submission. Equinor Wind also participated in a state inter-agency meeting to discuss state specific permitting studies necessary above and beyond COP requirements on December 11, 2018, which included New York State Department of Public Services ("NYSDPS"), related to the Article VII process. Additional examples of outreach is provided below, while details on permits and approvals are provided in Section 10.

New York State Department of Environmental Conservation

Equinor Wind has had in person meetings with New York State Department of Environmental Conservation ("NYSDEC") covering project updates and plans, environmental data collection, baseline data and potential mitigation options, fisheries resource and fishing, as well as seeking advice on relevant data sources for fishing and ecological resources in the New York Bight and New York state waters.

New York State Department of State

Equinor Wind has had in person and teleconference meetings with New York State Department of State ("NYSDOS") covering project updates and plans as it relates to the coastal resources and policies. Additionally, NYSDOS has been engaged as part of the consistency determination(s) required for Equinor Wind to complete survey work within three nautical miles of the coastline.

New York State Office of Parks, Recreation and Historic Preservation

New York State Office of Parks, Recreation and Historic Preservation has been contacted for several aspects of the Empire Wind Project. Much of the coastline consists of preserved parks and/or historical sites. First and foremost, NYSOPRHP has been contacted to discuss Equinor Wind's approach to characterizing terrestrial archaeology, underwater archaeology and historic architecture. This was provided in writing on December 13, 2018 and NYSOPRHP provided concurrence on December 19, 2018. In addition, viewshed is a subject of discussion for offshore wind developments. Equinor Wind has been proactive in providing its approach to visual simulations presented within this proposal in writing on November 6, 2018. NYSOPRHP provided concurrence on November 29, 2018. Equinor Wind also provided additional information during an in-person meeting on December 12, 2018. Follow up meetings are planned to present the results of these simulations, as provided in Section 15.

Environmental Non-Governmental Organizations

Equinor Wind recognizes that close coordination with the relevant ENGOs is essential to developing offshore wind energy projects that meet New York State's and Equinor's ambitious offshore wind energy targets, but in a manner that is responsible and maintains continued support from the ENGO community for future offshore wind energy opportunities. Equinor Wind has been engaging with ENGOs in several different forums. For example, Equinor Wind has held two "Environmental Round Tables" aimed specifically at the ENGO community. We chose to locate these on Long Island in order to maximize exposure to New York based or affiliated ENGOs as well as ENGOs at the national level. The roundtables included: project updates, permitting schedule, surveys planned or being conducted, survey results, baseline data assumptions, mitigation options, and open question and answer sessions. Equinor Wind is considering future ENGO Round Tables, with the next roundtable likely to be at a time when Equinor Wind can present relevant environmental chapters of the COP submission, ideally pre-COP submission to incorporate and address feedback as appropriate. As a minimum, Equinor Wind will seek a roundtable to present the COP post submission.

Equinor Wind has also been engaging and will continue to engage directly with individual ENGO groups throughout the project development, including those represented on the E-TWG.

Equinor Wind has entered into collaborative research and monitoring with the Wildlife Conservation Society ("WCS") and Woods Hole Oceanographic Institution ("WHOI"), as described in Section 13.3.1 and further detailed under Section 13.5.3 (see Equinor Wind-WCS Collaboration); has cooperated with the Natural Resource Defense Council ("NRDC"), National Wildlife Federation ("NWF") as detailed in Section 13.5.4; and WCS on observations during seismic surveys in the lease area (see Section 13.5.3 under Protected Species Observer Data).

As previously described, Equinor Wind considers the ENGOs on E-TWG as an appropriate "ENGO steering committee" for future matters related to developing the Empire Wind offshore wind energy project.

Equinor Wind expects to continue close and open communications with the ENGO community going forward, particularly focused on developing avoidance and mitigation measures in relation to future survey, construction and operations activities related to marine mammals and avian species.

Tribal Nations

The regulations under Section 106 of the National Historic Preservation Act require Equinor Wind, via the BOEM NEPA process, to consult not only with the State Historic Preservation Offices ("SHPOs"), but also with representatives of federally recognized Indian tribes. NYSERDA's Offshore Wind Master Plan's Cultural Resources Study (2017; Appendix H; Master Plan Cultural Resources Study) identified that the Shinnecock Indian Nation ("Shinnecock") expressed interest in offshore wind energy projects offshore of New York State. Equinor Wind has been engaging with the Shinnecock during the development of Empire Wind, including in relation to environmental matters. Equinor met with Shinnecock Council to introduce the project and consult on offshore geophysical and geotechnical survey plans and has provided project status updates at appropriate intervals. Equinor Wind and the Shinnecock expect to hold a meeting in the near future, pre-COP submission, to discuss survey results, including results from the benthic surveys, marine mammals data, and archaeological and cultural resources assessments. Additionally, Equinor Wind will consult with the Shinnecock to discuss the results of the visual simulations.

General Public

As with all stakeholder groups, Equinor Wind's approach towards outreach with the general public is covered in the Community Outreach Plan, Section 14 of the RFP. From an environmental perspective, Equinor Wind endeavors to address any feedback or questions raised in relation to environmental concerns the Empire Wind offshore energy development may have, responding to questions directly in open house public meetings where appropriate.

Equinor Wind intends to have a presence at Empire Wind COP related public hearings to address questions and comments and is open to having a presence at New York State public meetings, open houses or webinars as required.

13.3 Environmental Monitoring and Research

Consistent with Equinor Wind's openness policy, Equinor commits to make publicly available any information or data and supporting metadata that is developed throughout the Empire Wind Project that enhances the understanding of environmental characteristics, or use by wildlife, of any offshore, nearshore or onshore areas, so long as it is not considered proprietary in nature. Any data acquired as a result of monitoring required by NYSDOS, NYSDEC, NYSERDA or other regulatory bodies will be made available as soon reasonable after collection and validation on an ongoing and routine basis. The repository of such data will be defined and agreed upon between Equinor Wind and the applicable agency.

Equinor Wind acknowledges that ongoing research and monitoring at the project site is important to refine the understanding of impacts, potential mitigation options, and for future planning purposes, including facilitating the responsible leasing and development of potential future offshore wind energy areas within the New York Bight in line with New York State's ambitious offshore wind energy targets. As part of the development of the Empire Wind offshore wind energy development, Equinor Wind is committed to exploring appropriate monitoring protocols, for example monitoring of potential behavioral responses or changes in spatial and temporal distribution of biological resources as a direct result of the offshore wind energy development.

In addition, Equinor Wind is in favor of developing and supporting research initiatives that focus on addressing coexistence; that is, research that improves the opportunities for continued and improved access for recreational and commercial fishing in the operational offshore wind energy developments. This may include research aimed at innovative technical approaches to issues such as turbine spacing, impacts on navigation equipment, trawling equipment and information dissemination options. Further details can be seen in the Fisheries Mitigation Plan, Section 12.

As the operator of three offshore wind farms in the U.K. (Sheringham Shoal 317 MW, Dudgeon Offshore Wind Farm, 402 MW and the world's first commercial floating offshore wind farm Hywind Scotland, 30 MW), Equinor Wind can also consider exploring collaborative opportunities to conduct research and monitoring in those operational wind farms. Options can be discussed through the E-TWG or in direct consultation with relevant stakeholders.

Equinor Wind is also enthusiastic about the possibility of exploring collaborative research and monitoring efforts. Where common approaches to studies can be made, for example related to avian species and marine mammals. Equinor Wind is open to collaborate with other offshore wind energy developers on matters such as funding and providing suitable locations and operational support. Equinor Wind has successfully worked with other offshore wind energy developers on collaborative research and can continue to build on these established relationships.

Likewise, Equinor Wind is also open to collaborative research and monitoring opportunities with other organizations as appropriate. Equinor Wind would advocate for groups such as E-TWG and F-TWG as being the forums for which these research opportunities are explored and addressed.

Finally, and as previously stated, Equinor Wind is committed to making nonproprietary data available that can support research. Equinor Wind recognizes the value of data-sharing and data transparency to enhance the scientific community's understanding of environmental characteristics, offshore, nearshore or onshore. As an example, Equinor Wind will be making the following studies and/or data publicly available either through the COP process or directly on the Empire Wind webpage:

- 2018 benthic survey report covering the "SAP" related survey locations within the lease area (benthic grab samples with grain size and macro fauna analysis, drop down video stills, habitat description);
- 2018 benthic survey report covering "COP" related survey locations within the lease area totaling 67 sample locations (benthic grab samples with grain size and macro fauna analysis, drop down video stills, habitat description);
- 2019 benthic survey report covering "COP" related survey locations within the proposed export cable corridors (benthic grab samples with grain size and macro fauna analysis, drop down video stills, habitat description);
- 2017 to 2018 digital aerial survey images, monthly and quarterly reports of avian species, marine mammals, sea turtles and large bony fish assemblages as observed from the 12 x monthly digital aerial surveys carried out from November 2017 to October 2018; and
- Oceanographic data, not deemed proprietary, for example seawater temperature and salinity, from the "Metocean Facilities" deployed within the lease area.

Additional publicly available datasets for other resources and studies are described further in this EMP (*e.g.*, Sections 13.5.3 and 13.7.2).

As a further example of sharing data, Equinor Wind is willing to make non-commercially sensitive data from our metocean buoys available for research. Equinor Wind is currently in discussions with Rutgers University Department of Marine and Coastal Sciences on sharing the seawater temperature data to help support the understanding of the "cold pool" effect driving spatial and temporal distribution of marine life in the New York Bight. The cold pool phenomenon was frequently raised in New York State's State of the Science Workshop (November 2018) as well as BOEM's NY Bight Task Force Meeting (November 2018). In this regard, Equinor Wind believes that understanding physical and biological drivers on biological resource spatial and temporal distribution is essential in order to identify and robustly design effective and meaningful future research and monitoring.

Equinor Wind is open to exploring other outlets for sharing information, for example Equinor Wind can upload fisheries related datasets and reports to the F-TWG webpage and/or RODA webpage. Version control is important, however, and it is essential that stakeholders have access to the most recent studies. As such, the issue of version control and key repositories for this data will be further discussed and agreed in E-TWG and F-TWG.

[redacted]

Much of the data collection for this project will become available as a mechanism of the permits and authorizations that are required under the project, which will be subject to public comment. For example, studies that are being conducted in support of the Construction and Operations Plan ("COP") (*e.g.*, benthic, cultural resources, fisheries, marine mammals, sea turtles, birds, and bats) will be included as appendices of the COP, with the exception of any redacted information that meets the requirements of "proprietary", as well as spatial information considered sensitive under the Endangered Species Act or the National Historic Preservation Act.

Equinor is open to sharing field-collected data if it is finalized in advance of COP or other application submittal with other government agencies or public entities and will work with Federal and State agencies and other stakeholders to determine the best method of achieving this goal. As part of its active stakeholder outreach, Equinor Wind is sharing information with various entities, including ENGOs, during on-going stakeholder and special interest meetings. Information that has undergone final quality assurance/quality control ("QA/QC") can be made available upon request to educational institutions, environmental groups or other interested parties. As previously mentioned, Equinor Wind has already made data and reports available including from offshore high resolution aerial surveys of birds and other marine life, which are available on a publicly accessible website, the same website as NYSERDA's aerial survey results.

Equinor Wind is committed to collaboration opportunities for research and/or monitoring with the appropriate agencies, developers or research institutions. We recognize that there is an interest in understanding how the environment responds to the installation of offshore wind structures and activities. We also recognize that these facilities offer additional opportunities to initiate studies not directly considering the offshore wind industry (*e.g.*, installation of oceanographic and climatic monitors further off the coast to what is currently employed). As detailed within this EMP, Equinor Wind is actively cooperating with entities such as WCS, WHOI and SUNY Stony Brook. Discussions have been on-going with other research institutes, such as Rutgers University as noted above. These agreements afford us the opportunity to contribute to peer-reviewed publications (*e.g.*, scientific journals) and other mechanisms to further the scientific knowledge of the offshore environment and how humans interact with it. Equinor Wind also interacts with international institutions, by contributing to organizations such as the Carbon Trust. Equinor Wind makes an effort to meet with any interested parties when contacted to discuss prospective research matters.

13.3.1 Supporting Other Research

Equinor Wind is committed to collaborate with the scientific community, E-TWG, relevant stakeholders, other offshore wind energy developers and third-party groups to conduct robust and relevant research studies that relate to environmental resources and offshore wind energy developments.

In addition to making the Empire Wind offshore wind energy area available for monitoring and research when it can be done in a safe and practical manner, Equinor Wind is also willing to consider requests to access existing Equinor's operating offshore wind energy developments in Europe.

Equinor Wind will, where feasible, consider making existing wind farm related vessels or buoys available for research opportunities. For example, Equinor Wind will consider proposals for adding additional third-party self-contained sensors on survey vessels, construction vessels, O&M vessels, wind farm structures or wind farm related buoys and metocean moorings. As a demonstration of this commitment, Equinor Wind has already provided this opportunity to SUNY Stony Brook so that they could attach three receiver gates to the metocean moorings that were deployed in December 2018. [redacted]

As further demonstration of Equinor Wind's commitment to novel and collaborative research and monitoring, Equinor Wind is collaborating with WCS and WHOI on real-time large whale detection and notification buoys in a minimum 2-year monitoring program. [redacted]

Further research and monitoring is important where data and knowledge gaps remain that present uncertainties over potential significant adverse impacts attributable to the effects of offshore wind farm development. It is important that these effects are better understood in order to more accurately quantify impacts, identify potential mitigation options, and reduce uncertainty and conservatism built into impact assessments. This may also help to avoid or reduce impacts through adaptive management in future offshore wind energy leases and developments.

Where feasible, monitoring and research should ideally be targeted towards interactions between offshore wind energy developments and the receptors it is being judged against. From the outset, any research and monitoring should be statistically robust, such that changes in spatial and temporal distribution, and/or behavior pre, during and post construction can be detected at levels statistically attributable to the effects. For some biological monitoring, this level of robustness is not always possible as many outside factors can influence these variations with much greater significance than the factors that can be attributed to causes from offshore wind energy developments. This may be especially true in a dynamic environment such as the New York Bight. For example, attributing changes in a target commercial fish species abundance to offshore wind energy development presents challenges as abundance and distribution can vary spatially and temporally due to outside factors and pressures such as fishing quotas, oceanographic conditions (seawater temperature, nutrients), and distribution and availability of that receptors food resource. As such, for highly variable receptors there has been a shift away from pre, during and post construction monitoring of abundance and distribution of wildlife in Europe, and a focus towards behavioral responses associated with different phases of offshore wind energy developments. Equinor Wind has been involved in this work in Europe and would advocate for similar initiatives in the northeast U.S. These experiences can be shared via the ETWG and F-TWG.

As a means to determine the statistical power of proposed studies, Equinor Wind advocates that technical experts conduct statistical power analyses up front in the planning process before implementing any future studies. In addition, F-TWF and/or E-TWG are appropriate forums in which to discuss the development of such analyses and should be part of this planning process.

Finally, the fishing industry, fisheries managers and fisheries scientists all have an ability to input into potential monitoring requirements and methodologies, and where appropriate, may also have an opportunity to conduct the monitoring. Equinor Wind has already participated in and funded novel research and monitoring for offshore wind energy developments and in offshore oil and gas developments where results have relevance to offshore wind energy developments. For example, Equinor has funded and collaborated in the UK Carbon Trust ORJIP One Bird Collision Avoidance Study (ORJIP One), UK Carbon Trust ORJIP Four Acoustic Deterrent Devices (ORJIP Four), and the developer led DEPONS (Disturbance Effect on the Harbour Porpoise in the North Sea, DEPONS, 2015).

Equinor Wind has also conducted novel research and monitoring on our existing offshore wind energy developments, for example the tagging of breeding Sandwich terns with GPS loggers to monitor foraging patterns in relation to the Equinor operated Dudgeon Offshore Wind Farm, U.K. Equinor is also part of the Sound and Marine Life joint industry program, which supports research to help increase the understanding of the effect of sound on marine life generated by oil and gas exploration and production activity, with some aspects being directly relatable to offshore wind energy developments, for example offshore seismic surveys and impact pile driving. Equinor Wind would be pleased to provide more details on these studies in E-TWG to support future study design.

Consistency with NYSERDA's Offshore Wind Master Plan

New York State, under the direction of NYSERDA, has been evaluating the potential for offshore wind for New York since 2016. In its development of the New York State Offshore Wind Master Plan ("Master Plan") (NYSERDA Report 17-25; NYSERDA 2017), NYSERDA has summarized the feasibility for offshore wind supporting NY State renewable energy goals by identifying potential locations and mechanisms (*e.g.*, procurement, cost reduction, supply chain). The Master Plan also includes twenty different studies to support responsible and cost-effective development many of which document natural resources that are addressed in this EMP, including:

- Appendix A: Analysis of Multibeam Echo Sounder and Benthic Survey Data;
- Appendix D: Birds and Bats Study;
- Appendix I: Environmental Sensitivity Analysis;
- Appendix J: Fish and Fisheries Study; and
- Appendix L: Marine Mammals and Sea Turtles Study.

In many or all cases, the Empire Wind lease area is completely or mostly included within the study areas for these assessments. Figure 1 provides an example of NYSERDA's Fish and Fisheries Studies Area of Analysis (AoA) within the New York Bight region in relation to the Empire Wind Lease Area.

Figure 1: [redacted]

[redacted]

Many of the studies completed or in progress for the Project to document baseline conditions are following similar methodologies as those utilized in NYSERDA's Master Plan and NYSERDA's ongoing studies (*e.g.*, aerial baseline survey for marine wildlife). It is also important to note that methodologies developed for the Project-specific studies were prepared in consultation with state and federal regulators and the relevant ENGOs. Therefore, it is the expectation that results from the Project studies will provide value to the scientific community in documenting the extent of various resources within the New York Bight. It is also important to note that drawing on the efforts of NYSERDA has allowed the environmental assessment and permitting schedule for the Empire Wind Project to be significantly de-risked, shortened, evaluated within a more regional context, and is overall more efficient in terms of realizing New York State's ambitious goals for renewable energy through offshore wind energy developments.

The NYSERDA natural resources appendices previously referenced identify recommendations for future studies; approaches to surveys and studies; and/or best management practices for mitigation. Some examples are provided in Figure 2. Equinor Wind, has taken these recommendations into consideration as it has developed its studies for documenting baseline conditions, and in many cases have incorporated them. Equinor Wind will also consider these in development of future studies and identification of mitigation techniques. This will facilitate an ability to compare and contrast information gathered by various entities in an "apples to apples" manner. Further, the Empire Wind Project offers the opportunity to broaden the long-term regional understanding of natural resources in the New York Bight and responses of these resources to offshore wind energy development (both direct and indirect) as part of the on-going and future monitoring studies associated with the project.

Figure 2: Examples of NYSERDA Master Plan Appendices Study Recommendations

Benthic (Appendix A)	Birds and Bats (Appendix D)	Fish & Fisheries (Appendix J)	Marine Mammal & Sea Turtles (Appendix L)
Survey collection following BOEM's guidelines (one sample per 1-2 km^2)	Shipboard and/or aerial surveys	Engage multiple interests in development of survey protocols	Consideration of actual presence, use patterns and sensitivity of particular receptors in mitigation and best management practices.
Use of acoustic and optical data	Field surveys for bats using acoustic monitoring and/or radio telemetry	Prioritize studies on species that are commercially or ecologically important	
Use of Coastal and Marine Ecological Classification Standard ("CMECS") Biotic Component classifier	Post-construction monitoring to include evaluation of collision fatalities and displacement	Enhance scientific knowledge for data-poor species	
		Consider the potential to introduce invasive and/or non-native species	

13.4 Baseline Data, Environmental Impacts and Mitigation Approach

This section sets out Equinor Wind's approach to establishing the baseline characterization of existing conditions and receptors within potentially affected areas, potential environmental impacts, and mitigation measures, which are detailed for the various natural resources identified for describing in the New York RFP, in Sections 13.5 through 13.7.

Further details regarding the regulatory requirements for identifying baseline conditions and impact assessments are covered in the Environmental Assessment Permitting Plan in Section 8.

As illustrated in Section 8, Environmental Assessment and Permitting Plan, and Section 10, Project Schedule, at the time of writing, Equinor Wind is currently in the process of collecting baseline data, analyzing data from site specific surveys, conducting assessments and carrying out extensive consultation on baseline data, potential receptors and potential environmental impacts, with the intention to finalize the environmental impact assessments to inform spatial planning and in support of submission of State and Federal permit applications. As such, this EMP sets out what is known about the existing baseline, what the potential impacts could be from the project, and what potential mitigation options Equinor Wind will employ to avoid or reduce impacts where feasible. It also identifies what data gaps require additional effort, or where further monitoring and research is required. This information will also form the basis of the COP under the National Environmental Policy Act ("NEPA") process and any other State and Federal permit applications.

Assessment Inventory

Baselines can be established by using existing published reports, studies, data or data portals, or by direct data collection through surveys and desktop assessments. Equinor Wind's first step in establishing baseline data for the lease area has been a thorough literature review, data mining, and gap analysis exercise to establish what information already exists. Equinor Wind evaluated the extent to which existing and publicly available data sources were suitable for characterizing environmental resources in the relevant area, including evaluation of NYSERDA's Master Plan (2017).

To support the baseline characterization of resources onshore and offshore, Equinor Wind has or is in the process of completing the following assessments, which will consist of both desktop and/or field surveys:

- Offshore site characterization surveys including, oceanographic and meteorological (metocean) measurements, geophysical and geotechnical investigations, sediment & water quality sampling, benthic sampling (physical properties), and marine archaeological resource surveys and reviews;
- Offshore biological baseline resource surveys including avian surveys, bat monitoring, marine mammal and sea turtle surveys, benthic sampling (biological), and fisheries resource assessments;
- Wetlands delineations;
- Terrestrial cultural surveys;
- Terrestrial wildlife assessments;
- Visual and historic properties surveys;
- Onshore acoustic surveys and in-air modeling;
- Onshore traffic analysis;

- Underwater acoustic modeling;
- Air quality modeling;
- Sediment transport analysis;
- Navigation Risk Safety Assessment;
- Aviation Assessments;
- Tourism and recreation;
- Offshore cable burial risk assessments; and
- Electromagnetic Field ("EMF") modeling.

The published data in conjunction with the survey data are supporting the preliminary characterization of baseline conditions in accordance with federal and state requirements and guidelines. Equinor Wind consults with appropriate stakeholders to discuss research that may support the characterization. As an example for one receptor group, Equinor Wind presented the list of data sets proposed to be utilized for the baseline characterization of benthic and fisheries resources to NOAA NMFS in March 2018. NOAA NMFS provided feedback, including additional data sets to use, and agreed with the conclusion that this approach is sufficient for the baseline characterization in the Project Area. Equinor Wind also plans to discuss this approach with NYSDEC in the near future and will continue to consult with E-TWG and F-TWG to understand what new information may become available to support the baseline characterization.

Lastly, Equinor Wind will draw on extensive first-hand experience developing offshore and onshore energy assets around the world, including offshore wind energy developments in Europe. The results of these baseline characterization assessments and an understanding of potential impacts will inform the engineering and design decisions on the project as well as the development of appropriate mitigation and monitoring. This analysis will be presented in the COP and other Federal and State permit applications.

The Design Envelope Approach

As part of the wider lease area development process, Equinor Wind will adopt a design envelope approach, sometimes referred to as the Rochdale Envelope approach. This approach is consistent with BOEM's guidelines for the COP process as detailed in its Draft Design Envelope Guidelines (BOEM, 2018).

Equinor Wind will utilize this approach for permitting given the development approach at this stage of this Project, as well as timing of individual future phased projects within the lease area that are dictated by power offtake auctions. However, it is expected that these uncertainties will be resolved as the project matures. Moreover, developments in offshore wind technology far outpace the permitting process, for example wind turbine size and capacity is evolving at an accelerated rate, and therefore some flexibility is needed to ensure that when the project reaches a Final Investment Decision ("FID") and/or construction, the project can select the best available technology. In general, the latest technology offers the best value for the ratepayer and lower overall environmental impacts. As part of the environmental impact assessments, a worst-case development scenario will be taken from the design envelope into the impact assessment calculation, which may not always reflect the level of impacts from the final design chosen. As such, the design envelope approach limits how much specificity can be placed on the environmental impacts at this stage, but typically provides a conservative assessment.

It is understood that other permits required for offshore wind energy developments making landfall and connecting into New York and therefore New York State Department of Environmental Conservation ("NYSDEC") jurisdiction (onshore to 3 nautical miles) will require a more refined design. As such, activities associated with the export cable landfall, onshore export cable, and substation improvements may take a narrower design envelope approach to support any required applications. Historically, landfall and onshore is less likely to encounter technical advancements at the same pace as offshore, such as the previously provided example of wind turbine size and associated foundations sizes and types.

Impact Producing Factors

A summary of the potential impact producing factors that may occur as a result of the Empire Wind offshore energy development activities are summarized below and addressed in more detail on a receptor-by-receptor basis in later sections, to the extent possible at this time. A full appraisal of effects and potential environmental impacts will be described in the COP and other State and Federal permit applications.

Potential Impact Producing Factors:

- Seafloor Disturbance – the installation/decommissioning of foundations, export cable(s), and scour protection will disturb the seafloor.
- Land Disturbance – the installation/decommissioning of the onshore transmission cable and substation(s) will disturb the onshore land.
- Sediment Suspension and Deposition – during installation and decommissioning activities, sediment will temporarily be suspended into the water column, with the potential for resuspension of sediments from scouring during operations.
- Underwater Noise – survey activities and installation activities have the potential to temporarily generate noise in the lease area, and, to a lesser extent, the surrounding area.
- Noise – onshore and offshore construction activities will temporarily create noise. Onshore substations may generate noise during operation.
- EMFs – during operations EMF fields may be detectable along the offshore and onshore cable routes, and infield cable arrays.
- Spills – during surveys, construction, operations, and decommissioning, there is the potential for accidental releases or discharges of pollutants, oil, trash, etc.
- Vessel and Onshore Traffic – increased vessel traffic during surveys, construction, operations, and decommissioning.

- Air Emissions – during construction, operations, and decommissioning activities, vessels traveling to and from the project site will result in a small amount of emissions. Generators or other equipment used for both onshore and offshore facilities may also result in emissions. There will be a positive overall net reduction in air emissions as a result of the operating wind farm.
- Change in Habitat – during operation, wind turbines, foundations, scour material, and substations will modify existing habitat.
- Disturbance, Displacement and Collision – the presence of wind turbines, substations and vessels may result in the disturbance and displacement of both wildlife and other marine users.
- Lighting – wind farm related vessels, wind turbines, offshore substations, and onshore substations will be equipped with lighting measures which have the potential to disturb.

The baseline characterization, survey efforts, and potential environmental impacts and mitigation are described in Sections 13.5 through 13.7 on a receptor-group basis.

It should also be noted that as part of this RFP submission, Equinor Wind only describes those receptor groups identified in the New York RFP; however Equinor Wind is actively assessing all relevant receptor groups as identified in the New York State Master Plan (NYSERDA, 2017), BOEM's Construction and Operations Plan ("COP") guidance (BOEM, 2016) and those receptors highlighted of being of key concern to interested parties.

Environmental Impact Assessments and Mitigation

Environmental impact assessments can be used as a tool for quantifying potential impacts and identifying if those impacts require further mitigation to bring them to acceptable levels or require further monitoring to quantify impact levels post implementation of a project. This process requires project and site-specific inputs, which generally include:

- Project description, either detailed or within a specified design envelope;
- A description of how the project will be developed;
- A description of the existing baseline environment;
- Baseline evaluation and, where necessary, baseline data collection;
- A description of the likely effects resulting from the proposed development;
- Identification of receptors most likely to be impacted by the project;
- Evaluation of the likely impacts on the receptors;
- Alternatives analysis;
- An appraisal of the quality and certainty of available data, effects, and potential impacts;
- Mitigation measures to avoid, reduce, or offset negative impacts;
- Measures to enhance positive beneficial impacts;
- Monitoring requirements; and
- A consideration of cumulative effects.

For the purposes of offshore wind energy development, an environmental impact is defined as the consequences borne by a receptor, either positive or negative, resulting from an effect produced directly or indirectly by the project. The impact level is a combination of the sensitivity or 'value' of that receptor along with the magnitude and type and duration (*e.g.*, temporary or permanent) of the effects on that receptor. These impacts can be classified as being negative (adverse) or positive (beneficial).

In order to properly assess environmental impacts, it is important to first understand and quantify the receptor. This quantification includes an understanding of the physical presence or absence of a receptor along with its abundance, spatial and temporal boundaries, and sensitivity characteristics. This is carried out through robust baseline assessments, and where required, further project-specific baseline data collection. This process includes referencing existing information on that receptor's sensitivity and protection status. Additionally, it is important to understand a receptor's ability to withstand effects when exposed, such as adaptability, tolerance, recoverability and its value as an overall resource. Finally, the effect must be quantified by considering its magnitude, the temporal and spatial extent of the effect, the level of change of that effect compared to existing baseline conditions, and the likelihood of a receptor-effect interaction.

Mitigation is a means for either reducing adverse impacts or increasing the beneficial impacts on a receptor. These measures typically take two forms: (1) modifying the effects through design, spatial planning, or timing (avoidance and mitigation); or (2) through offsetting unavoidable adverse impacts through compensatory measures. Again, the type and level of mitigation required is dependent on the final project design, the level of impact and the appropriate and proportionate balance of considering mitigation effectiveness and value versus the "cost" of that mitigation to the project, where for example cost can include, but is not limited to a negative impact on project commercial and technical scope, loss of social and environmental opportunities (*e.g.*, health benefits, socio-economic benefits), and indirect increases in impacts on other receptors.

13.5 Marine Mammals and Sea Turtles

This section describes the baseline characterization for marine mammals and sea turtles that Equinor Wind has determined to be associated with the Empire Wind Project Area through a combination of existing data sources and direct survey effort, including identifying where further surveys will be conducted or could be considered as part of a monitoring or research study. Consideration is given to the NYSERDA Master Plan Marine Mammals and Sea Turtles Study (2017; Appendix L)

This section includes the following information on each resource or receptor: (1) information currently available; (2) efforts to further collect data; (3) potential effects that are likely to have an impact; and (4) potential mitigation options that can be employed.

13.5.1 Regulatory Context

Impacts to marine mammals and sea turtles are regulated under various federal laws including the Marine Mammal Protection Act ("MMPA"), ESA, and NEPA. These regulations require consultation between the lead agency (BOEM) and other federal and state agencies with jurisdiction over marine mammals and sea turtles, including NMFS, United States Fish and Wildlife Service ("USFWS"), and NYSDEC.

In support of the COP, marine mammal and sea turtle resources will be assessed to comply with BOEM's site characterization requirements in 30 C.F.R. § 585.626(3). BOEM must also consult with NMFS under Section 7 of the ESA for actions that could affect protected marine species under NMFS's jurisdiction (*e.g.*, various marine mammals, sea turtles, and fish species). Consultation is required for approval of a COP as the activities described in a COP may affect listed marine species. State agencies will also be consulted as part of the coastal consistency determination process.

Underwater noise is considered an activity with the potential to harass or harm protected species, referred to as "take," under the MMPA and ESA; where unauthorized "take" is prohibited. NOAA has established impact criteria referred to as Level A and Level B harassment. Level A harassment is defined as any act of pursuit, torment, or annoyance that has the *potential to injure* a protected species stock in the wild. Level B harassment is defined as any act of pursuit, torment or annoyance that has the *potential to disturb* a protected species stock in the wild by causing a disruption of behavioral patterns, including, but not limited to, migration, breathing, nursing, breeding, feeding, or sheltering. The criteria are further separated for impulsive and non-impulsive (*i.e.*, continuous) sounds.[1] Figure 3 sets out NOAA-established guidance for evaluating noise impacts, which defines harassment thresholds for broad categories of marine species.

[1] Pile driving and High Resolution Geophysical (HRG) equipment are considered impulsive. Dynamic Positioning (DP) thrusters on vessels and the routine operation of a wind turbines are considered a continuous noise source.

Figure 3: NOAA Established Acoustic Criteria and Metrics for Marine Mammals, Fisheries and Sea Turtles

Functional Hearing Group	Estimated Auditory Bandwidth	Representative Animals	Level A Impulsive	Level A Non-Impulsive	Level B Impulsive	Level B Non-Impulsive
Low-Frequency Cetaceans	7 Hz to 35 kHz	Whales	219 dB_{peak} & 183 dB SEL_{cum}	199 dB SEL_{cum}	160 dB re: 1 µPa (RMS)	120 dB re: 1 µPa (RMS)
Mid-Frequency Cetaceans	150 Hz to 160 kHz	Dolphins	230 dB_{peak} & 185 dB SEL_{cum}	198 dB SEL_{cum}		
High-Frequency Cetaceans	275 Hz to 160 kHz	Harbor Porpoise	202 dB_{peak} & 155 dB SEL_{cum}	173 dB SEL_{cum}		
Phocid Pinnipeds	50 to 86 kHz	Seals	218 dB_{peak} & 185 dB SEL_{cum}	201 dB SEL_{cum}		
Sea Turtles	Up to 1.2 kHz	Turtles	207 dB_{Peak} 180 dB re: 1 µPa (RMS)		166 dB re: 1 µPa (RMS)	
ESA-Listed Fish	NA	Atlantic Sturgeon	206 dB_{Peak} & 187 dB SEL_{cum} (fish >2g) 183 dB SEL_{cum} (fish <2g)		150 dB re: 1 µPa (RMS)	

Notes:
dB_{peak} = peak decibel level; dB re: 1 µPa (RMS) = decibels relative to 1 micopascal (root mean square); g = gram; Hz = hertz; kHz = kilohertz; SEL_{cum} = cumulative sound exposure level; NA = Not Applicable

In 2018, NMFS released a revision to its *Technical Guidance for Assessing the Effects of Anthropogenic Sound on Marine Mammal Hearing* (NOAA NMFS 2018). This guidance assigns species of cetaceans and pinnipeds to functional hearing groups based on their hearing characteristics. The hearing groups include low-frequency cetaceans (baleen whales), mid-frequency cetaceans (dolphins, toothed whales, beaked whales, bottlenose whales), high-frequency cetaceans (true porpoises, Kogia, river dolphins, cephalorhynchid, *Lagenorhynchus cruciger, L. australis*), Phocid pinnipeds (true seals), and Otariid pinnipeds (sea lions and fur seals). All but the Otariid pinniped hearing groups have the potential to occur within the lease area. Each group has its own hearing ability and noise threshold, where impacts should be considered (Southall et al. 2007). NOAA uses two measures of potential harassment: peak dB and SELcum. For Level B harassment, NOAA Fisheries uses an interim sound threshold guideline of 160 dB rms 90 percent re 1 micropascal (µPa) for pulsed sound and 120 dB rms re 1 µPa received level (both unweighted) for continuous sound.

There is little information available on the effects of noise on sea turtles, and the hearing capabilities of sea turtles are also poorly understood. Some studies have demonstrated that sea turtles have fairly limited capacity to detect sound, although all results are based on a limited number of individuals and must be interpreted cautiously (Popper et al. 2014). Limited research has shown that the upper limit of the hearing range of sea turtles is generally in the range of 1,000 to 1,200 hertz (Hz) (Tech Environmental 2006, Martin et al. 2012). McCauley et al. (2000) serves as the best available information on the levels of underwater noise that may produce a startle, avoidance, and/or other behavioral or physiological response in sea turtles. McCauley noted that decibel levels of 166 decibels (dB) root mean square (RMS) re: 1 micropascal (µPa) were required before any behavioral reaction (*e.g.*, increased swimming speed) was observed, and decibel levels above 175 dB RMS re: 1 µPa elicited avoidance behavior of sea turtles. NOAA Fisheries (NOAA NMFS GARFO, 2016) provides further guidance with a Level A threshold for sea turtles set at 180 dB RMS re 1 µPa RMS to prevent mortalities, injuries, and most auditory impacts.

Noise injury thresholds have been established by the Fisheries Hydroacoustic Working Group and adopted by NOAA Fisheries. NOAA's Greater Atlantic Regional Fisheries Office has applied these standards for assessing the potential effects of ESA-listed fish species exposed to elevated levels of underwater sound produced during pile driving (NOAA NMFS GARFO 2016). These fish noise thresholds are based on sound levels that have the potential to produce injury or elicit a behavioral response. The metrics used consider both peak level (dB_{Peak}) and cumulative sound exposure level (SEL_{cum}).

13.5.2 Preliminary Resource Characterization

The Empire Wind project area, including the associated offshore export cable corridor and landfall includes coastal beaches, coastal waters, continental shelf waters, and offshore waters. The marine mammal (cetaceans and pinnipeds) and sea turtle species known to occur within the waters of the New York Bight and the lease area are provided in Figure 4, as identified from several sources (identified at the bottom of the figure). These animals include thirty-nine marine mammals and five sea turtles. All thirty-nine marine mammal species identified in Figure 4 are protected by the MMPA, and some are additionally protected by the ESA or by New York state law.

Figure 4: Marine Mammal and Sea Turtle Species Known to Occur Within the Waters of the New York Bight

Common Name	Scientific Name	Federal Status	NY Status	Estimated Population[1]	Known NY Bight Distribution	Occurrence in NY Bight	Seasonal Occurrence
Toothed Whales (Odontoceti)							
Sperm whale	*Physeter macrocephalus*	E	E	2,288	Along and over continental shelf[3,4]; around Montauk Point[4]; Deep ocean waters[4]	Common[4,7]	Unknown[4]
Atlantic spotted dolphin	*Stenella frontalis*	N/A	N/A	44,715	Primarily deeper waters [5]	Common[5]	Seasonal[5]
Atlantic white-sided dolphin	*Lagenorhynchus acutus*	N/A	N/A	48,819	On continental shelf and slope[5]	Common[5]	Seasonal[5]
Blainville's beaked whale	*Mesoplodon densirostris*	N/A	N/A	7,092	Deep ocean waters[5]	Common[5]	Seasonal[5]
Bottlenose dolphin[a]	*Tursiops truncatus*	N/A	N/A	11,548	Coastal and offshore[1]	Common[5]	Year-round[5]
Common dolphin	*Delphinus spp.*	N/A	N/A	70,184	Coastal and offshore[1]	Common[5]	Year-round[5]

Common Name	Scientific Name	Federal Status	NY Status	Estimated Population[1]	Known NY Bight Distribution	Occurrence in NY Bight	Seasonal Occurrence
Clymene dolphin	*Stenella clymene*	N/A	N/A	12,524	Over continental slope and deep ocean waters[7]	Extremely Rare[7]	N/A
Cuvier's beaked whale	*Ziphius cavirostris*	N/A	N/A	6,532	Deep ocean waters[5]	Common[5]	Seasonal[5]
Harbor porpoise	*Phocoena*	N/A	SC	79,833	Great South Bay[3]	Common[5]	Seasonal[3]
Long-finned pilot whale	*Globicephala melas*	N/A	N/A	5,636	Over continental shelf to slope[5]	Common[5]	Year-round[5]
Pantropical spotted dolphin	*Stenella attenuata*	N/A	N/A	3,333	Primarily deeper waters [5]	Common[5]	Seasonal[5]
Rough-toothed dolphin	*Steno bredanensis*	N/A	N/A	271	Over continental slope, shelf, and deep ocean waters[7]	Extremely Rare[7]	N/A
Risso's dolphin	*Grampus griseus*	N/A	N/A	18,250	Along continental slope[5]	Common[5]	Year-round[5]
Sowerby's beaked whale	*Mesoplodon bidens*	N/A	N/A	7,092	Deep ocean waters[5]	Common[5]	Seasonal[5]
Striped dolphin	*Stenella coeruleoalba*	N/A	N/A	54,807	Over continental slope[5]	Common[5]	Seasonal[5]

Common Name	Scientific Name	Federal Status	NY Status	Estimated Population[1]	Known NY Bight Distribution	Occurrence in NY Bight	Seasonal Occurrence
True's beaked whale	*Mesoplodon mirus*	N/A	N/A	7,092	Deep ocean waters[5]	Common[5]	Seasonal[5]
Dwarf sperm whale	*Kogia sima*	N/A	N/A	3,785	Over outer continental shelf[5]	Rare[5,7]	N/A
Gervais' beaked whale	*Mesoplodon europaeus*	N/A	N/A	7,092	Deep ocean waters[5]	Rare[5]	N/A
Killer whale	*Orcinus orca*	E	N/A	Unknown	Over continental shelf and rise[5]; Open sea and offshore waters[4]	Rare[5]	N/A
Northern bottlenose whale	*Hyperoodon ampullatus*	N/A	N/A	Unknown	Deep ocean waters[5]	Rare[5]	N/A
Fraser's dolphin	*Lagenodelphis hosei*	N/A	N/A	492	Over continental slope and deep ocean waters[7]	Extremely Rare[7]	N/A
Pygmy killer whale	*Feresa attenuata*	N/A	N/A	Unknown	Deep ocean waters[5]	Rare[5]	N/A
Pygmy sperm whale	*Kogia breviceps*	N/A	N/A	3,785	Over continental slope[5]	Rare[5,7]	N/A

Common Name	Scientific Name	Federal Status	NY Status	Estimated Population[1]	Known NY Bight Distribution	Occurrence in NY Bight	Seasonal Occurrence
False killer whale	*Pseudorca crassidens*	N/A	N/A	442	Over continental slope and deep ocean waters[5,7]	Extremely Rare[7]	N/A
Short-finned pilot whale	*Globicephala macrorhynchus*	N/A	N/A	21,515	Over continental shelf to slope[5]	Rare[5]	N/A

Common Name	Scientific Name	Federal Status	NY Status	Estimated Population[1]	Known NY Bight Distribution	Occurrence in NY Bight	Seasonal Occurrence
Melon-headed whale	*Peponocephala electra*	N/A	N/A	1,175	Deep ocean waters[7]	Extremely Rare[7]	N/A
Spinner dolphin	*Stenella longirostris*	N/A	N/A	Unknown	Deep ocean waters[5]	Rare[5]	N/A
White-beaked dolphin	*Lagenorhynchus albirostris*	N/A	N/A	2,003	On and over continental shelf[5,7]	Extremely Rare[7]	N/A
Baleen Whales (Mysticeti)							
Minke whale	*Balaenoptera acutorostrata*	N/A	N/A	2,591	On and over continental shelf[5]	Common[1]	Seasonal[1]
North Atlantic Right whale	*Eubalaena glacialis*	E / CE	E	440	Primarily coastal[4]	Common[4]	Seasonal[4]
Humpback whale	*Megaptera novaeangliae*	E	E	Unknown	Becoming more coastal[4]; may be in inlets[4]	Common[4]	Seasonal[4]
Finback whale	*Balaenoptera physalus*	E	E	1,618	Throughout[4]	Common[4]	Year-round[4]
Blue whale	*Balaenoptera musculus*	E	E	Unknown	Not well known[4]; primarily deep waters[4]	Rare[4]	N/A
Sei whale	*Balaenoptera borealis*	E	E	357	Continental shelf and slope waters[5]; throughout[4]	Rare[4]	N/A

Common Name	Scientific Name	Federal Status	NY Status	Estimated Population[1]	Known NY Bight Distribution	Occurrence in NY Bight	Seasonal Occurrence
Bryde's whale	*Balaenoptera edeni*	E	N/A	7	Continental Shelf and slope waters[5,7]	Extremely Rare[7]	N/A
Pinnipeds (Pinnipedia)							
Gray seal	*Halichoerus grypus*	N/A	N/A	Unknown	Coastal and continental shelf waters[5]	Common[5]	Seasonal[5]
Harbor seal	*Phoca vitulina*	N/A	N/A	75,834	Coastal, bays, estuaries, inlets[5]	Common[5]	Seasonal[5]
Harp seal	*Cystophora cristata*	N/A	N/A	Unknown	Continental shelf with pack ice[5]	Rare[5]	N/A
Hooded seal	*Phoca groenlandica*	N/A	N/A	Unknown	Deep ocean water at edge of continental shelf with pack ice[5]	Extremely Rare[9]	N/A
Ringed Seal	*Pusa hipsida*	N/A	N/A	Unknown	Coastal and continental shelf waters[7]	Extremely Rare[7]	N/A
Sea Turtles							

Common Name	Scientific Name	Federal Status	NY Status	Estimated Population[1]	Known NY Bight Distribution	Occurrence in NY Bight	Seasonal Occurrence
Green turtle	*Chelonia mydas*	T	T	Unknown	Juveniles - oceanic waters[5,6] Adults - nearshore areas[5,6]	Common[5]	Seasonal[5]
Kemp's ridley turtle	*Lepidochelys kempii*	E	E	Unknown	Juveniles - oceanic waters and *Sargassum* habitats[5] Adults - nearshore areas[5]	Common[5]	Seasonal[5]
Leatherback turtle	*Dermochelys coriacea*	E	E	Unknown	Juvenile - oceanic waters[5] Adults - mid-ocean to continental shelf and nearshore waters[5]	Common[5]	Seasonal[5]

Common Name	Scientific Name	Federal Status	NY Status	Estimated Population[1]	Known NY Bight Distribution	Occurrence in NY Bight	Seasonal Occurrence
Loggerhead turtle	*Caretta*	T	T	Unknown	Juveniles - oceanic waters[5] Adults - continental shelf and along break[5]	Common[5]	Seasonal[5]
Hawksbill turtle	*Eretmochelys imbricata*	E	E	Unknown	Juveniles - oceanic waters[5] Adults - nearshore areas[5]	Rare[5]	N/A

Notes:
a. Northern migratory coastal stock species
BCC: Bird of Conservation Concern; SC: Special Concern; E: Endangered; T: Threatened; N/A: Not Applicable
Bays: Enclosed or semi-enclosed coastal bays; Coastal: Nearshore waters of NY Bight within sight of land; Pelagic: Offshore waters of NY Bight out of sight of land
Sources:
1. Hayes et al. 2017 2. NYSDEC 2017a 3. NYSDEC 2015a 4. Schlesinger and Bonacci 2014 5. USDON 2005 6. Lowry 2016
7. NYSERDA 2017; Appendix L

Some of the species listed are noted as “extremely rare” (NYSERDA 2017; Appendix L); however, they are included as documented sightings. For most of these species, there are no data on seasonality, density, or abundance. That said, there are several ongoing, multi-year studies and surveys currently being conducted. NYSERDA (2017; Appendix L) reviewed the available data and has provided summaries of “Best Available Data” in the form of comprehensive lists of datasets for marine mammals and sea turtles and notes that current studies will provide reliable species counts when they are complete. These combined studies and models, in addition to studies being conducted by Equinor Wind (further described below), will be useful and likely will provide support for spatial planning, construction and operations decisions, and inform the application of appropriate mitigation.

Ambient sound levels in the lease area are largely influenced offshore by the volume of shipping activity entering and exiting the ports of New York. Ships produce low-frequency noise from engine and propeller cavitation.

13.5.3 Ongoing and Planned Assessments

To support the assessment of marine mammals and sea turtles, BOEM has issued *Guidelines for Providing Information on Marine Mammals and Sea Turtles for Renewable Energy Development on the Atlantic Outer Continental Shelf Pursuant to 30 C.F.R. Part 585 Subpart F* (Marine Mammal and Sea Turtle Guidelines; BOEM 2013c).

Existing Data Collection and Monitoring Efforts

Equinor Wind has evaluated readily available spatial data including ongoing and completed survey efforts. Of particular relevance to the Empire Wind offshore wind energy development are the ongoing and active data collection efforts of: NYSDEC, Schlesinger and Bonacci 2014, NYSERDA, WCS, and the Atlantic Marine Assessment Program for Protected Species (“AMAAPS”) surveys (NOAA NEFSC 2017 and SEFSC 2016). Collectively, these studies provide current and relevant data about the lease area.

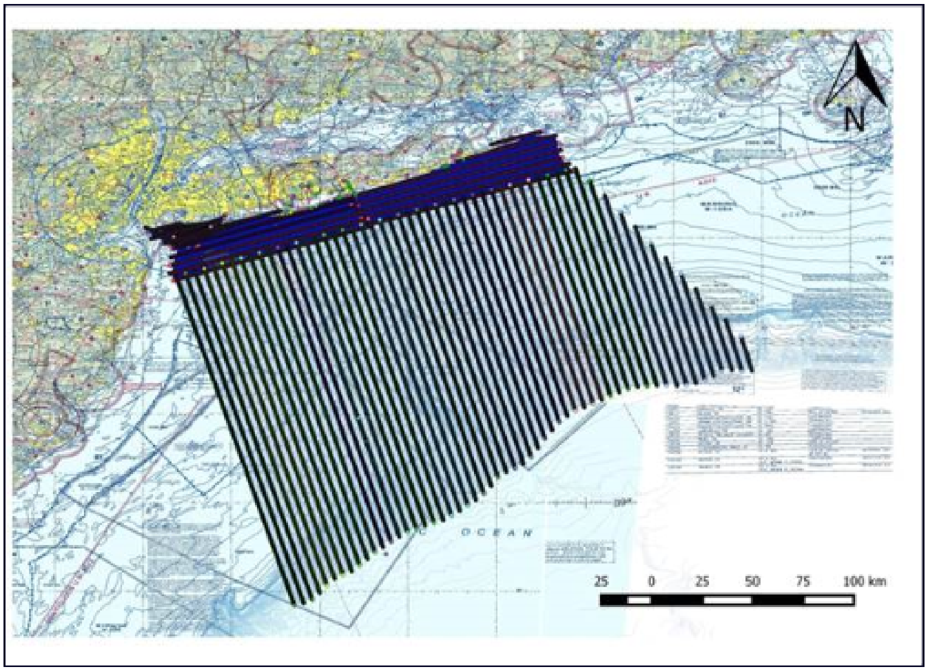
Data collected during NYSDEC’s multi-year, monthly aerial survey data collection effort from March 2017 through February 2020 provides current information on the presence of marine mammals and sea turtles directly in and around the lease area, and where possible (where enough detections have been sighted), will provide density and abundance estimates. Figure 5 illustrates the transect lines for this study developed by NYSDEC with input from NOAA NMFS.

Figure 5: Transect lines for the NYSDEC Aerial Surveys for Whales in the New York Bight[2]

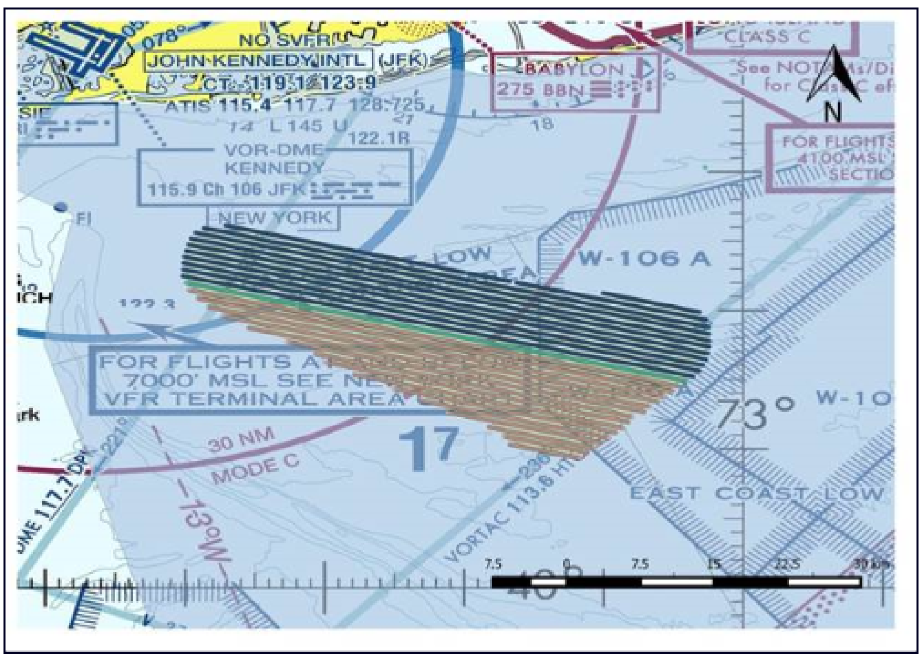
NYSERDA is funding a similar aerial survey program evaluating the New York Bight area, including the Offshore Planning Area ("OPA") and a period covering the Wind Energy Area ("WEA") that overlap with the Empire Wind lease area and associated project area (see Figure 6). These surveys are done on a quarterly basis. Data and information includes maps of each species sighted and all species by season and year; calculation of the relative abundance or density for each species of whale by month, season, and year; inter-annual variability; summary of numbers of whales in each group by sex and age; summary of behavioral observations; summary of sea turtle sightings; and summary of environmental data.

[2] Source: http://www.dec.ny.gov/lands/113818.html

Figure 6: NYSERDA Aerial Surveys for the Offshore Planning Area and Wind Energy Area[3]



New York Offshore Planning Area (OPA) showing transect survey lines.



Wind Energy Area (WEA) and the 4-km buffer showing image capture locations for the grid surveys.

[3] Source: https://remote.normandeau.com/nys_overview.php

WCS in collaboration with Woods Hole Oceanographic Institute ("WHOI") has deployed a passive acoustic monitoring device to the southeast of the lease area that is collecting near real-time acoustic observations of whale species, including North Atlantic right whale, sei whale, humpback whale and fin whale. In addition to providing several years' worth of valuable information on the presence or absence of vocalizing marine mammals, the data buoy is recording the ambient sound environment at the southern end of the lease area.

Other passive acoustic surveying is being conducted by the Bioacoustics Research Program at Cornell University's Lab of Ornithology ("BRP") via their work with NYSDEC. Cornell University is conducting the passive acoustic monitoring survey for 6 large whale species (right, fin, sei, blue, sperm, and humpback) in the New York Bight. The survey consists of 15 autonomous recorders placed in and around the shipping lanes, from the shelf break to the New York Harbor. Acoustic data have been and will be are collected year-round, from October 2017 through September 2020, and downloaded from the recorders every four months. This passive acoustic monitoring within the New York Bight will assist in environmental assessments and in increasing baseline marine mammal data for the area which is part of the approximate 16,000 square mile New York Offshore Planning Area ("OPA"). This roughly 16,000 square mile portion of the New York Bight has been identified as an area of interest for potential development of offshore renewable energy projects. The data are being collected to provide information on the presence, relative distribution, and daily, monthly, and seasonal distribution of these six species. It will also characterize the ambient noise in the shipping lanes and patterns of ambient noise in this region which is expected to provide data on marine mammal acoustic masking potential.

The AMAAPS effort is a collaborative study between NOAA, BOEM, USFWS, and the U.S. Navy with the goal of providing enough information to develop models and other tools which will provide seasonal, spatially-explicit density estimates for marine mammals and sea turtles (and seabirds) in the western North Atlantic Ocean. Broad-scale data are being collected over multiple years as well as the collection of finer-scale data at selected sites. Information is currently available from surveys conducted from 2010-2016. Other data collection efforts include the Georgia Department of Natural Resources' focus on tagging right whales and Geographic Information Gateway, CetMap, and other efforts to collect spatial data.

Equinor Wind Data Collection and Monitoring

APEM Ltd Digital Aerial Surveys

Equinor Wind has contracted APEM Ltd., supported by Normandeau Inc., to conduct monthly digital aerial surveys across the lease area, which includes the capturing digital images and of marine mammals and sea turtles in addition to avian species, large fish assemblages and opportunistic vessel sightings. To ensure the survey methods were consistent with BOEM guidelines, a survey plan, "Avian Survey Protocol", which included marine mammals and sea turtles, was submitted and approved by BOEM and US FWS.

Digital aerial surveys were subsequently carried out from November 2017 to October 2018, with monthly results, monthly reports and quarterly reports made publicly available on the following webpage:

https://remote.normandeau.com/ewind_overview.php.

Equinor Wind is committed to continuing to make this data available in as near real-time as possible, subject to the delay between image capture and the time associated with image processing, species identification and quality control.

APEM and the methodology chosen was influenced by NYSERDA having used APEM and these methods to conduct quarterly digital aerial surveys over the New York Bight and OCS-A 0512 lease area from summer 2016 to summer 2017, then ongoing surveys over the New York Bight continuing into winter 2018/2019 at the time of writing. This included the consistency associated with the public webpage to display results.

A summary of the scope of the Equinor Wind digital aerial survey is as follows:

- Surveys conducted once per month over a 12-month period;
- Image resolution at sea surface of 1.5 cm ground sampling distance (“GSD”);
- Grid survey design;
- Grid imagery footprint of 310 m by 219 m;
- A 2.5-mi (4 km) buffer around the lease area;
- Minimum of 20% of the lease area and buffer imaged, with 10% of area analyzed;
- Monthly results displayed online; and
- Monthly and quarterly reporting, also provided online.

Figure 7: Grid Survey Design Over Lease Area and 2.5-mile Buffer

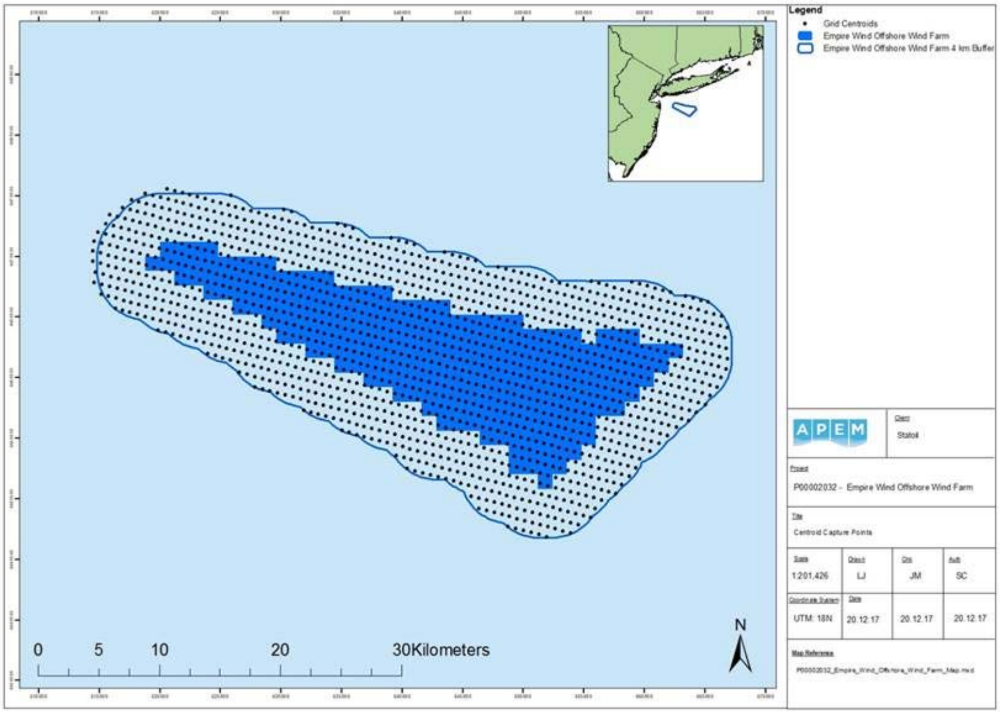
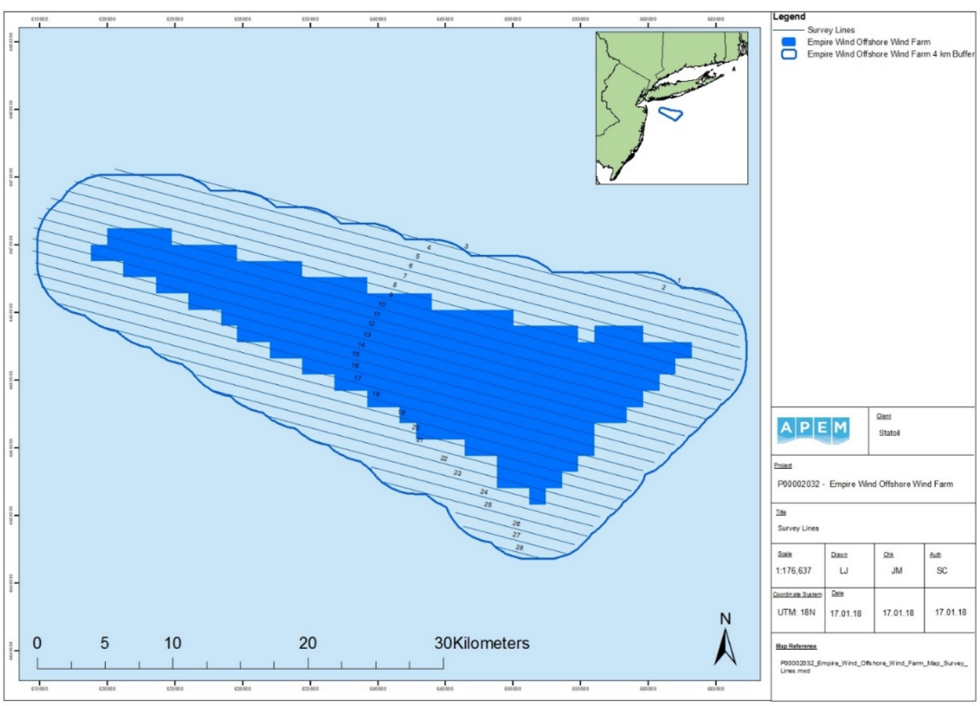


Figure 8: Survey Flight Path Over Lease Area and 2.5-Mile Buffer



As described, the assessment approach and methods were designed to supplement the substantial body of existing data and meet BOEM's data requirements for site characterization studies to evaluate the potential effects of the proposed project. While the primary purpose of this study was to assess the presence of avian species, marine mammal sighting data was also collected, processed and quality controlled across the lease area. The supplemental quarterly digital aerial surveys conducted by APEM Ltd. on behalf of NYSERDA provides an excellent spatial and temporal characterization, providing not only additional data in a common approach and format in the lease area, but a wider regional context that provides more value in the context of assessing impacts.

Avian and marine mammal surveys are historically the longest lead time items for baseline data collection leading up to impact assessments, typically with a minimum of two years of data collection to account for inter-annual variations in spatial and temporal distribution. NYSERDA's early efforts on data collection has meant that Equinor Wind has been able to reduce this time down to one year of data collection to add to the existing effort, effectively bringing the impact assessment process forward by a year, having the ability to apply the results into design decisions at an earlier stage and bringing the COP schedule, and therefore the opportunity for permit approvals, construction and first power to New York forward by approximately a year.

Protected Species Observer Data

Equinor Wind used Protected Species Observers ("PSOs") during offshore geophysical surveys to mitigate against the potential risk of vessel strikes and exposure to noise on marine mammals and sea turtles. (Previous mitigation and proposed future mitigation during surveys is further detailed in Section 13.5.4.) In addition to providing mitigation, the PSOs also served an important function for furthering the understanding of the spatial and temporal distribution of marine mammals from recording observations in the field by recording visual observations and passive acoustic monitoring. Observations covered the period of 11 March 2018 to 3 December 2018 during the 2018 geophysical, geotechnical and benthic survey program. A total of 387 marine mammals and 34 sea turtles observations were made[4], along with geographic position and where possible species identification, behavior, photographs and notes on specific features or marks. The observations also form part of a NOAA NMFS IHA requirement to report on PSO observations at prescribed intervals.

In the spirit of collaboration and data sharing, Equinor Wind will commit to make these PSO reports and data available upon request, but at a minimum will provide the reports to the ENGOs represented on the E-TWG (*e.g.*, WCS), for use in their ongoing research. Equinor Wind will commit to share future PSO observations reports, as appropriate.

[4] Observations included visual and acoustic monitoring. In some instances, the same individual would be identified with both methods (*i.e.*, two observations).

In addition, Equinor Wind requested that the Lead PSO be available for contact with WCS' Ocean Giants survey team in order to share real-time sightings information in the field so that: WCS could apply the information to their own boat-based whale observation surveys and the Lead PSO could apply the information to Equinor Wind's field surveys for areas that may need to be avoided at that specific time. This provided an ability to use an adaptive management approach to survey plans. Equinor Wind will commit to continue this practice for future activities where PSOs are used and where it does not affect the primary role of the Lead PSO.

Equinor Wind – WCS Collaboration

Understanding the potential risks of development of the Empire Wind offshore wind energy project on marine mammals and sea turtles, in particular, the highly vulnerable and endangered North Atlantic right whale, is key to ensuring Equinor Wind can identify potential impacts and then avoid or reduce those impacts where feasible through effective and proportionate mitigation. For example, seasonal timing restrictions on certain survey and construction activities have been raised as mitigation measures developers could adopt as best practice. There is agreement that time and area restrictions offer a means of mitigation in cases where there is limited information or alternative mitigation options; however, time and area restrictions also have limitations and may fail to protect 'pioneers' or late departing animals that may be present before or after a seasonal restriction is applied. In addition, opportunities for conducting these survey and construction activities may be lost if for example, no animals are present in the area in what could be deemed a closed period. Equinor Wind believes that avoidance and mitigation measures should therefore be data and evidence based where there is an opportunity to collect that data.

As such, Equinor Wind is pleased to announce a collaborative Grant Agreement with WCS and WHOI to develop and install two more real-time whale detection and monitoring buoys within the lease area for at least two-years, complimenting and adding to the existing WCS "Blue York" buoy on the eastern boundary of the Lease. The buoys will help to further understand the spatial and temporal distribution of the four large whale species: North Atlantic right whale, Fin whale, Sei whale and Humpback whale, within the lease area, and when added to existing arrays of passive acoustic detection moorings around the New York Bight, will also provide an understanding of the wider regional context.

The buoys are expected to be installed summer 2019, with a minimum of 2 years data collection up to summer 2021. The location of the buoys will be subject to avoiding anchoring in sensitive seabed habitats, permitting requirements and in consultation with the fishing industry to avoid conflicting activities.

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

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[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

Underwater Noise Measurements

Impact assessments will require the estimation of harassment zones based on anticipated source levels. The distance to Level A/B harassment thresholds will be calculated for noise emitting activities (*e.g.*, geophysical surveys [redacted]). Assessments will be based upon best available information, which may be derived from equipment providers or field measurements.

The lease area conditions require acoustic measurements for High Resolution Geophysical ("HRG") and geotechnical equipment operating at or below 200 kilohertz (kHz) at a minimum of two reference locations and in a manner that is sufficient to establish the following: source level (peak, SEL, and RMS sound levels at 3.28 ft (1 m)), a pattern of spreading loss, and the sound-exposure distance for ear injury for each marine mammal hearing group, sea turtles, and fish. The distance to the 166, 160, and 150 dB RMS behavioral thresholds (Level B harassment) must also be reported. The first location must be at a distance of 200 m from the sound source, and the second location must be as close to the sound source as technically feasible. These sound measurements should be taken at the reference locations at two depths (*i.e.*, a depth at mid-water and a depth at approximately 3.28 ft (1 m) above the seafloor). Equinor Wind has already conducted sound source Field Verification Trials ("FVT") for the 2018 geophysical surveys, with data presented to NOAA NMFS and BOEM to support distance thresholds for mitigating against and recording Level B take during survey operations.

Some data covering several years of timeseries currently exists on the ambient underwater sound levels within or near to the lease area, collected from noise sensors installed by WCS as part of their 'Blue York' real-time whale monitoring buoy. Additional measurements will be obtained from the collaborative work between WCS and Equinor Wind to provide further spatial context to ambient noise levels within or adjacent to the lease area.

Baseline Summary

Based on the four comprehensive marine resource surveys being conducted currently, Equinor Wind's monthly digital aerial surveys across the lease area, and the breadth of existing data, Equinor Wind has concluded that there are sufficient data to appropriately characterize and assess impacts to marine mammals and sea turtles in support of project development. During an August 2018 meeting with NOAA NMFS, Equinor Wind received confirmation that this baseline characterization approach would be sufficient to assess impacts to marine mammals and sea turtles. The further studies, monitoring and collaborations will further build on this existing baseline data and facilitate more effective, targeted mitigation and avoidance options.

13.5.4 Potential Impacts and Mitigation

The potential impact producing factors relevant to marine mammals and sea turtles during surveys, construction, operations, and decommissioning are as follows:

- Short-term temporary increases in underwater noise from geophysical survey activity in the pre-construction, construction and operations phases;
- [redacted]
- Long-term temporary increases in background underwater noise from operational wind turbines and operations and maintenance ("O&M") vessels during operations;
- Short-term temporary collisions from offshore wind energy project related vessels during construction and decommissioning;
- Long-term temporary collisions from offshore wind energy project related vessels operations; and
- Changes to prey resources during construction and operations.

Equinor Wind will have more confidence in the type and level of impacts to marine mammals and sea turtles as the Empire Wind offshore wind energy project matures, including upon submission of the COP. At which time, subsequent NOAA NMFS IHA or Letter of Intent assessment and applications would be filed, as appropriate. Equinor Wind's ongoing monitoring and studies will facilitate refining impact assessments and further monitoring during and post construction, or research aimed at behavioral responses, will provide additional insight into the receptor-effect relationship. Certain assumptions can be made at this stage for the purpose of this proposal, based on preliminary information assessed by Equinor Wind to date; experience from developing offshore wind energy develops; and sources such as Section 3 of NYSERDA's Master Plan: Marine Mammals and Sea Turtles Study (2017; Appendix L).

The approach to developing a baseline and assessment of future potential impacts on marine mammals and sea turtles from the effects from construction, operations and decommissioning of an offshore wind energy development must satisfy the requirements of various regulations and jurisdictional agencies. As such, collaboration and coordination with BOEM, NOAA NMFS, NYSDEC, E-TWG, ENGOs and relevant stakeholders throughout the development and planning process will be critical to the success of the Empire Wind offshore wind energy development. Equinor Wind is committed to this collaboration and coordination.

Equinor Wind is applying the following mitigation measures to avoid or mitigate potential impacts to marine mammals and sea turtles associated with the construction, operations and decommissioning of the offshore wind energy development:

- Consultation with regulatory agencies and ENGOs on potential requirements for time-of-year and time-of-day restrictions for survey activities with potentially impacting noise levels;
- [redacted]
- Exclusion and monitoring zones, enforced by qualified protected species observers ("PSOs") for survey activities with potentially impacting noise levels;
- [redacted]
- Soft starts to noise emitting survey equipment where technically feasible;
- [redacted]
- Real-time monitoring systems as appropriate (*e.g.*, visual observations by PSOs, passive acoustic monitoring, use of night vision and infrared during nighttime activities) to facilitate exclusion and monitoring zones;
- [redacted]
- Vessel collision avoidance mitigation measures for project related vessels working in or in transit to/from the offshore wind energy area; and

- Measures to avoid or reduce potential impacts to marine mammal and sea turtle prey resources (see Section 13.6, Benthic and Fisheries Resources).

A more detailed account of how these avoidance or mitigation measures will be applied or considered on a project specific and evidence basis, and in consultation with the relevant regulatory agencies, E-TWG, ENGOs and stakeholders, are described in the following sections.

Offshore Geophysical Surveys

Equinor Wind has already demonstrated a high level of commitment towards avoiding or reducing the likelihood and magnitude of impacts on marine mammals and sea turtles during offshore geophysical surveys to date and will continue to adopt mitigation measures in future surveys, as appropriate to the equipment being used, time of year, area being surveyed and potential presence of receptors. The main potential impacts to marine mammals and sea turtles from geophysical survey activities can be attributed to: increased underwater noise; and vessel strikes.

Survey Equipment Noise

For geophysical surveys carried out to date on the lease area and export cable corridors, Equinor Wind has adopted the following mitigations measures to avoid or reduce impacts from noise:

- Monitoring and applying exclusion zones as appropriate to the noise source and level and receptor, with noise sources and exclusion zones evidence based and determined by infield measurements and/or modeling where feasible;
- "Soft-starts" ramping up of survey equipment power/noise levels for specific equipment that has the potential for impact producing noise levels. Subject to being technically feasible for certain types of equipment;
- NOAA NMFS approved Protected Species Observers ("PSOs") for exclusion zone monitoring pre and during survey equipment operation, and monitoring during vessel transits; and
- Passive Acoustic Monitoring System ("PAMS") and PAMS operators and nighttime visual observation equipment.

[redacted]

[redacted]

In addition, Equinor Wind also accommodated the testing of new PAMS technology developed by [redacted] with potential for improved detection of low frequency cetaceans, in particular, North Atlantic right whales. Equinor Wind facilitated this equipment being tested alongside the existing PAMS equipment, with results expected to inform its effectiveness in future applications. In this regard, Equinor Wind has an is committed to exploring future opportunities to facilitate the trialing of new or novel third-party technologies where feasible.

In preparation of conducting surveys, all required mitigation and monitoring measures were compiled into a single document and provided to all crew members, PSOs and PAMS operators prior to commencement of survey operations. This "Protected Species Mitigation Protocol" is considered a "living document" that will be updated accordingly as Equinor Wind continues its survey activities in 2019 and forward.

Equinor Wind has a policy whereby every employee and contractor has the power to stop a job if that practice is deemed unsafe, without fear of repercussions. Equinor Wind applied the same principle during the 2018 surveys, whereby PSOs, vessel crew and survey crew were briefed at survey kick-off meetings that they had the power to request a power shutdown of noise emitting survey equipment via the Lead PSO should they believe a species of marine mammals was within that species exclusion zone, regardless of whether it had been observed by a PSO or detected on PAMS. It was also made clear that it was better to be on side of caution and that there would be no repercussions for this practice. Lead PSOs also had full mandate to request immediate power shutdowns of survey equipment on a "shutdown first, explain why later" basis, so that any discussions related to survey equipment power shutdown requests could be handled after the event and not potentially impact on asserting that mitigation. Equinor Wind will continue to adopt this approach of empowering all personnel onboard via the Lead PSO and giving the Lead PSO full mandate for mitigation decisions.

Vessel Strike Avoidance

Equinor Wind's vessel strike avoidance measures will (and have been) consistent with: (1) NOAA NMFS guidance to avoid ship collision with marine mammals and sea turtles; (2) conditions within the lease area; (3) and any Incidental Take Authorizations issued by NOAA NMFS. Vessel strike avoidance measures will include, but are not limited to, the following, except under extraordinary circumstances when complying with these requirements would put the safety of the vessel or crew at risk:

- During transit to and from the lease area, all vessels will use dedicated shipping lanes
- All vessel operators and crew will maintain vigilant watch for cetaceans and pinnipeds, and slow down or stop their vessel to avoid striking these protected species

- All vessel operators will comply with 10 knots or less speed restrictions in any Seasonal Management Area per NOAA guidance. This applies to all vessels operating from November 1 through April 30
- All vessel operators will reduce vessel speed to 10 knots or less when any large whale, any mother/calf pairs, whale or dolphin pods, or larger assemblages of non-delphinoid cetaceans are observed nearby an underway vessel (within 330 ft or 100 m).
- All vessels will maintain a separation distance of 1,640 ft (500 m) or greater from any sighted North Atlantic right whale
- If underway, vessels must steer a course away from any sited North Atlantic right whale at 10 knots or less until the 1,640 ft (500 m) minimum separation distance has been established. If a North Atlantic right whale is sited in a vessel's path, or within 330 ft (100 m) to an underway vessel, the underway vessel must reduce speed and shift the engine to neutral. Engines will not be engaged until the North Atlantic right whale has moved outside of the vessel's path and beyond 330 ft (100 m). If stationary, the vessel must not engage engines until the North Atlantic right whale has moved beyond 330 ft (100 m)
- All vessels will maintain a separation distance of 330 ft (100 m) or greater from any sighted non-delphinoid cetacean. If sighted, the vessel underway must reduce speed and shift the engine to neutral, and must not engage the engines until the non-delphinoid cetacean has moved outside of the vessel's path and beyond 330 ft (100 m). If a survey vessel is stationary, the vessel will not engage engines until the non-delphinoid cetacean has moved out of the vessel's path and beyond 330 ft (100 m)
- All vessels will maintain a separation distance of 164 ft (50 m) or greater from any sighted delphinoid cetacean. Any vessel underway will remain parallel to a sighted delphinoid cetacean's course whenever possible and avoid excessive speed or abrupt changes in direction. Any vessel underway must reduce vessel speed to 10 knots or less when pods (including mother/calf pairs) or large assemblages of delphinoid cetaceans are observed. Vessels may not adjust course and speed until the delphinoid cetaceans have moved beyond 164 ft (50 m) and/or are abeam of the underway vessel
- All vessels underway will not divert or alter course in order to approach any whale, delphinoid cetacean, or pinniped. Any vessel underway will avoid excessive speed or abrupt changes in direction to avoid injury to the sighted cetacean or pinniped
- All vessels will maintain a separation distance of 164 ft (50 m) or greater from any sighted pinniped
- All vessels will maintain a separation distance of 164 ft (50 m) or greater from any sighted sea turtle
- If NMFS should establish a Dynamic Management Area ("DMA") in the area of the work, within 24 hours of the establishment of the DMA, Equinor Wind will work with NMFS to shut down and/or alter project activities to avoid the DMA as appropriate

Vessel crew members responsible for navigation duties have and will continue to receive site-specific training on marine mammal sighting/reporting and vessel strike avoidance measures. Through this training, Equinor Wind will ensure that vessel operators and crew maintain a vigilant watch for cetaceans and pinnipeds and enact appropriate speed restrictions, including slowing down or stopping activity as appropriate to avoid striking these protected species. As appropriate, training programs will be provided to NOAA NMFS for review and approval prior to the start of activities. Confirmation of the training and understanding of the requirements will be documented on a training course log sheet. Signing the log sheet will certify that the crew members understand and will comply with the necessary requirements throughout the survey event.

Offshore Survey Summary

Equinor Wind has already demonstrated a commitment to minimizing impacts to marine mammals and sea turtles during pre-construction surveys. In accordance with a BOEM-approved survey plan and an IHA issued by NOAA NMFS, Equinor Wind completed extensive marine surveys in 2018 without any vessel strike incidents. Exclusion zones were established consistent with NOAA NMFS requirements, and throughout the pre-construction surveys, Equinor Wind has documented the required information for transmittal to the applicable stakeholders.

Equinor Wind will continue to consult with NOAA NMFS and other key stakeholders throughout the project development process in order to determine if any alternative or additional appropriate and proportionate mitigation measures may be necessary.

Based on a commitment and application of the avoidance and mitigation measures described in this section, impacts to marine mammals and sea turtles resulting from Empire Wind project-related geophysical survey noise or survey vessel collisions are not expected to be significant adverse. Additional marine mammals and sea turtles data collection from PSO observations, collaboration with other third-party survey efforts on sightings, and the facilitation for testing and research of new monitoring and mitigation equipment is deemed to have positive beneficial impacts.

Construction Activities

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

Soft Starts

Equinor Wind is committed to the use of a soft starts for offshore survey activity where there is noise emitting survey equipment with potential impact producing levels, [redacted]

[redacted]

[redacted]

[redacted]

[redacted]

Vessel Strikes – Construction Vessels

Relevant vessel strike avoidance measures as described previously in this section will be adopted for Empire Wind project related vessels during construction activities.

Construction Summary

With vessel strike avoidance mitigation in place, the likelihood and magnitude of impacts to marine mammals from vessel collisions will be reduced to as low as feasible.

[redacted]

Operations

Potential impacts associated with the operations phase have been identified to include an increase in potential collisions from project-related vessels carrying out O&M or survey operations, changes to prey resources as a direct result of the offshore wind energy development, or potential impacts due to noise from operations vessels.

Vessel Strike Avoidance

[redacted] On this basis, the likelihood for an interaction between an Empire Wind vessel and marine mammal or sea turtle is reduced and with vessel speeds predominantly lower transiting from wind turbine to wind turbine, the magnitude of the effect is decreased. In addition, Equinor Wind will adopt vessel speed restrictions associated with seasonal management areas ("SMA") and dynamic management areas ("DMA") relevant to the size of the vessels used and other vessel strike avoidance measures, such as those described previously in Section 13.5.3, if applicable. Equinor Wind is open to consulting with relevant agencies, ENGOs and E-TWG on further appropriate and proportionate mitigation options, for example, real-time monitoring or observations of marine mammals when in transit and commitments to monitor daily reports on marine mammal sightings and DMAs.

Prey Resource

As described in Section 13.6, with sensitive spatial planning and siting of structures, impacts on fisheries resources that could serve as a source of prey for marine mammals and sea turtles are not expected to be significant adverse during the operations phase. Therefore, significant adverse impacts from reduced prey resource are not expected; however, Equinor Wind will consider whether this requires further monitoring in consultation with E-TWG, BOEM and relevant stakeholders.

Moreover, anecdotal evidence from Equinor's operational offshore wind farms in the U.K. suggests that the increase in species abundance and diversity caused by the introduction of hard structures and the subsequent 'reef effect' has had positive beneficial impacts on marine mammals associated with that particular prey resource.

Operational Noise

As described in New York State Offshore Wind Master Plan: Marine Mammals and Sea Turtles Study (2017; Appendix L), noise associated with operational offshore wind energy developments is likely to be of low risk, with operational noise levels expected to be within or around ambient noise levels. Operational noise measurements from existing operational offshore wind farms have resulted in noise levels that would not result in death or physical injury to marine mammals and sea turtles, with little or no displacement effect. It is also expected that marine mammals and sea turtles in this region are expected to have some level of tolerance to the level of noise generated by operational wind farms due to the potential existing natural and anthropogenic (shipping) background noise in the region. On this basis, no additional mitigation is prescribed, however Equinor Wind is open to engaging on this matter should potential impacts be presented.

Decommissioning

Impacts resulting from the decommissioning activities are not expected to exceed impacts resulting from the worst-case scenarios associated with construction. Moreover, it is expected that as monitoring during operations provides a better understanding of the spatial and temporal presence of marine mammals and sea turtles within the lease area, mitigation measures can be more tailored and effective at further reducing the likelihood and level of impacts.

The operations period can be seen as an opportunity for developers, agencies and stakeholders to collaborate on further research into the effects and potential impacts associated with decommissioning, using the experiences in Europe to help inform that process.

13.6 Benthic and Fisheries Resources

This section describes the benthic and fisheries resources that are associated with Equinor Wind's Project Area. This discussion includes the following information on each resource or receptor: (1) information currently available; (2) efforts to further collect data; (3) potential effects that are likely to have an impact; and (4) potential mitigation options that Equinor Wind is committing to or can be considered as appropriate to results from further studies and impact assessments. This section on benthic and fisheries resource has also been included in the Fisheries Mitigation Plan ("FMP") as part of this proposal.

In addition to the information below, Equinor Wind has provided the FMP setting out the proposed process for identifying baseline conditions and addressing potential impacts to commercial and recreational fisheries and Equinor Wind's coexistence strategy.

13.6.1 Regulatory Context

The fisheries of the United States are managed within a framework of overlapping international, federal, state, interstate, and tribal authorities. Individual states and territories generally have jurisdiction over fisheries in marine waters within 3 nautical miles ("nm") (3.5 miles ("mi") or 5.6 kilometers ("km")) of their coasts. Federal jurisdiction includes fisheries in marine waters inside the U.S. Exclusive Economic Zone ("EEZ"), which encompasses the area from 3 to 200 nm (3.5 to 230 mi or 5.6 to 370 km) offshore of any U.S. coastline (NOAA 2016). In addition to the regional fishery management councils ("FMCs"), an array of multi-state fisheries commissions coordinate conservation and management of the common interstate nearshore fishery resources—marine finfish, shellfish, and anadromous fish—for sustainable use. Together with National Marine Fisheries Service ("NMFS"), a division of the National Oceanic and Atmospheric Administration ("NOAA"), these councils maintain fishery management plans for specific species or species groups to regulate commercial and recreational fishing within their geographic regions. NMFS's Highly Migratory Species Division is responsible for tuna, sharks, swordfish, and billfish in the Atlantic Ocean (NMFS 2009). FMCs are required to identify essential fish habitat ("EFH") for each fishery covered under a fishery management plan. EFH is defined as the waters and seafloor necessary for spawning, breeding, or growth to maturity (16 U.S.C. § 1802(10)). "Fish" is defined as "finfish, mollusks, crustaceans, and all other forms of marine animals and plant life other than marine mammals and birds" (16 U.S.C. § 1802(12)). The role of the benthic habitat as a fisheries resource is fundamental to the identification of EFH, as reflected in the emphasis on EFH in BOEM's benthic survey guidance (BOEM 2013a). The guidance recommends that the NMFS EFH mapper tool (http://www.habitat.noaa.gov/protection/efh/habitatmapper.html) be used for species identification and habitat characteristics at any particular location (BOEM 2013a, page 4).

Impacts to benthic habitats and fisheries resources are managed under various federal laws including the Magnuson-Stevens Fishery Conservation and Management Act ("MSA"), Endangered Species Act ("ESA"), and NEPA. In support of the COP and associated evaluations of potential project-related impacts for Federal and State permit applications, BOEM's site characterization requirements in 30 C.F.R. § 585.626 are being applied to the benthic habitat and fisheries resource assessments.

BOEM is required to consult with NMFS as part of the NEPA process and if a proposed project is expected to adversely affect EFH. An adverse effect is defined as "any impact which reduces the quality and/or quantity of essential fish habitat," which includes physical, chemical, and biological impacts (NMFS 2004). Effects may manifest in a number of ways, either directly or indirectly, and on any spatial scale, including areas beyond EFH. For example, changes in water quality, benthic communities, or prey availability may constitute an adverse effect on EFH. BOEM must also consult with NMFS under Section 7 of the ESA for actions described in the COP that may affect anadromous fish species listed under the ESA. State agencies will also be consulted as part of the coastal consistency determination.

13.6.2 Preliminary Resource Characterization

Benthic habitat can be used to support prediction of the presence of fisheries resources, by providing information on sediment size/type, density, presence of submerged vegetation and other characteristics. The offshore lease area and large portions of the proposed export cable corridors are predominantly characterized as sand with isolated patches of gravel-sand. Finer grained sediments are expected within the New York Harbor. Although generally flat, the New York Bight contains sand ridges, filled valleys, shoal-retreat massifs, and paleoshorelines (NYSERDA 2017; Appendix A). In general, benthic habitat throughout the lease area is relatively homogeneous. During the BOEM offshore wind planning process prior to the lease auction, an isolated topographic high, known for its value to commercial and recreational fishing, was identified to the northwest of the lease area; this area, called Cholera Bank, is a sensitive feature that was subsequently removed from the lease area prior to lease sale. The National Centers for Coastal Ocean Science and BOEM are preparing comprehensive seafloor substrate maps of the New York Bight, with a particular focus on the lease area. Information from that study will be incorporated into the COP as appropriate when it becomes available and will be combined with Equinor Wind's site-specific benthic sampling to generate full benthic habitat maps.

A review of available data on seagrasses concluded that neither of the two seagrasses native to the New York Bight region exist within the lease area (NYSERDA 2017; Appendix Aa). Suitable habitat for seagrasses is limited to water shallower than 39 feet ("ft") (12 meters ("m")). While not present within the lease area, seagrasses are found along coastal areas, including the barrier island systems Long Island, and will, therefore, form part of the assessment for cable landfall locations and onshore cable routing.

Fish and invertebrate species of interest in the lease area fall into three groups based on regulatory status: (1) species managed under the MSA; (2) species listed under the ESA; and (3) non-game fish and invertebrate species that are considered important prey (or shelter, in the case of biogenic habitats) for fish and wildlife. Extensive long-term datasets are available to characterize fisheries resources in the lease area. In 2016, NYSERDA initiated three-year aerial surveys of sharks, rays, and large bony fish in the area (2017; Appendix J). Additional surveys will focus on fish and invertebrate population structure and distribution, and identification of potential impacts on EFH and sensitive habitats. NYSERDA concluded that the combined datasets from Marine-life Data Analysis Team ("MDAT"), the aerial fish surveys, and the Virginia Institute of Marine Science's Northeast Area Monitoring and Assessment Program together provide support for siting decisions for wind energy that would not interfere with fisheries resources.

In NYSERDA's Master Plan, the physical and biological character of the seafloor was described within the New York Bight through analysis of Multibeam Echo Sounder (MBES) and benthic survey data (2017; Appendix A). This in conjunction with the NYSERDA Master Plan Fisheries Study (2017; Appendix J) and additional scientific literature provide additional information to support describing baseline conditions as Equinor Wind develops the baseline conditions for its assessments.

Fish and Invertebrate Species Managed Under the MSA

Virtually all coastal U.S. waters are designated as EFH for at least one managed species. Designated EFH is an indicator of underlying habitat features important to fish. EFH delineates areas where the species may occur based on known occurrence of the species or habitat features important to the species/life stage. Construction, operation, and decommissioning of the project has the potential to directly and indirectly affect managed marine finfish and invertebrates as well as marine and estuarine habitats (including EFH) that support managed species and their prey. Adverse effects on habitat or species could secondarily affect the commercial and recreational fishing industries that these resources support. Therefore, locations of designated EFH for various life stages of managed species will be foundational to the benthic and fisheries resource assessment.

Just as the location of benthic EFH can serve as an approximate guide to locations of benthic fisheries species, locations of heavy harvests of managed fisheries are often associated with areas of physical impact. In fact, BOEM's benthic guidance recommends that areas affected by bottom-tending mobile fishing gear be identified and suggests that "publicly available commercial fishing data" be used to characterize benthic habitats (BOEM 2013a, page 5). In particular, heavy bottom trawls are known to disturb benthic EFH in many locations. The characterization of baseline benthic habitat conditions will take into account locations where heavy gear is expected to have caused physical injury to bottom habitats. On a similar basis, the location of historic and contemporary anchoring locations of large cargo vessels and tankers will be recorded, for localized disturbance to benthic EFH.

EFH has been designated in the lease area for various life stages of more than two dozen non-migratory managed species, including finfish, sharks and rays, and invertebrates, as provided in Figure 10. Designated EFH for three (3) coastal migratory pelagic and seventeen (17) highly migratory managed fish species also occurs in the lease area, as provided in Figure 11. EFH is designated in the lease area by both the Mid-Atlantic Fishery Management Council ("MAFMC") and the New England Fishery Management Council ("NEFMC") for species that occur in both jurisdictions. EFH for other species and/or life stages may be present along the export cable corridor. On April 9, 2018, the *Federal Register* published NEFMC's Final Rule, which modified the designation of EFH for numerous species that occur in the lease area (NEFMC's Omnibus Essential Fish Habitat Amendment 2; 50 C.F.R. Part 648). In this Final Rule, NMFS approved: (1) all of the updated EFH; (2) all of the recommended habitat area of particular concern ("HAPC"); (3) the majority of the habitat management area recommendations; (4) all of the seasonal spawning area recommendations; and (5) the framework and administrative recommendations.

Figure 10: Non-Migratory Species with Designated EFH within the Lease Area

	Managed Species		Egg	Larval	Juvenile	Adult
	Common Name	*Scientific Name*				
Invertebrates	Atlantic Sea Scallop	*Placopecten magellanicus*	-	-	X	X
	Longfin Inshore Squid	*Doryteuthis (Amerigo) pealeii*	X	-	X	X
	Northern Shortfin Squid	*Illex illecebrosus*	-	-	X	X
	Quahog	*Arctica islandica*	-	-	X	X
	Surfclam	*Spisula solidissima*	-	-	X	X
Elasmo-branchs	Clearnose Skate	*Raja eglanteria*	X		X	X
	Little Skate	*Leucoraja erinacea*	-	-	X	X
	Spiny Dogfish	*Squalus acanthias*	-	-	X	X
	Winter Skate	*Leucoraja ocellata*	-	-	X	X
Finfish	American Plaice	*Hippoglossoides platessoides*	-	X	-	-
	Atlantic Cod	*Gadus morhua*	-	-	-	X
	Atlantic Herring	*Clupea harengus*	-	X	X	X
	Black Sea Bass	*Centropristis striata*	-	X	X	X
	Bluefish	*Pomatomus saltatrix*	X	X	X	X
	Butterfish	*Peprilus triacanthus*	X	X	X	X
	Haddock	*Melanogrammus aeglefinus*	-	X	X	-
	Mackerel	*Scomber scrombus*	X	X	X	X
	Monkfish	*Lophius americanus*	X	X	X	X
	Ocean Pout	*Macrozoarces americanus*	X	X	X	X
	Pollock	*Pollachius virens*	-	-	X	X
	Red Hake	*Urophycis chuss*	X	X	X	X
	Scup	*Stenotomus chrysops*	X	X	X	X
	Silver Hake	*Merluccius bilinearis*	X	X	X	X
	Summer Flounder	*Paralichthys dentatus*	X	X	X	X
	Windowpane Flounder	*Scophthalmus aquosus*	X	X	X	X

	Managed Species		Egg	Larval	Juvenile	Adult
	Common Name	*Scientific Name*				
	Winter Flounder	*Pseudopleuronectes americanus*	X	X	X	X
	Witch Flounder	*Glyptocephalus cynoglossus*	X	X	-	X
	Yellowtail Flounder	*Limanda ferruginea*	X	X	X	X

Note:
X EFH designated in Lease Area
- No EFH designated in Lease Area

Figure 11: Migratory Species with Designated EFH within the Lease Area

	Managed Species		Neonate	Juvenile	Adult	Not Specific
	Common Name	*Scientific Name*				
Coastal Migratory Pelagics	King Mackerel	*Scomberomorus cavalia*	X	X	X	
	Spanish Mackerel	*Scomberomorus maculatus*	X	X	X	
	Cobia	*Rachycentron canadum*	X	X	X	
Tuna	Albacore Tuna	*Thunnus alalunga*	-	X	-	-
	Bigeye Tuna	*Thunnus obesus*	-	X	-	-
	Bluefin Tuna	*Thunnus thynnus*	-	X	-	-
	Skipjack Tuna	*Katsuwonus pelamis*	-	X	X	-
	Yellowfin Tuna	*Thunnus albacres*	-	X	-	-
Sharks	Basking Shark	*Cetorhinus maximus*	-	X	X	-
	Blue Shark	*Prionace glauca*	X	X	X	-
	Common Thresher Shark	*Alopias vulpinus*	-	-	-	X
	Dusky Shark	*Carcharhinus obscurus*	X	X	X	-
	Porbeagle Shark	*Lamna nasus*	-	X	X	-
	Sandbar Shark	*Carcharhinus plumbeus*	X	X	X	-
	Sand Tiger Shark	*Carcharias taurus*	X	-	-	-
	Scalloped Hammerhead Shark	*Sphyrna lewini*	-	X	X	-
	Shortfin Mako Shark	*Isurus oxyrinchus*	-	-	-	X
	Smooth Dogfish	*Mustelus canis*	-	-	-	X
	Tiger Shark	*Galeocerdo cuvier*	-	X	X	
	White Shark	*Carcharodon carcharias*	-	-	-	X

Notes:
X EFH designated in Lease Area
\- No EFH designated in Lease Area

Federal & State-Listed Endangered Fish Species

Three federally-listed endangered fish may occur in the lease area: (1) Atlantic salmon (*Salmo salar*); (2) the Atlantic sturgeon (*Acipenser oxyrinchus*); and (3) shortnose sturgeon (*Acipenser brevirostrum*). On August 17, 2017, NOAA NMFS designated critical habitat for the Atlantic sturgeon in certain areas, including the New York Bight (Endangered and Threatened Species; Designation of Critical Habitat for the Endangered New York Bight, Chesapeake Bay, Carolina and South Atlantic Distinct Population Segments of Atlantic Sturgeon and the Threatened Gulf of Main Distinct Population Segment of Atlantic Sturgeon; 50 C.F.R. Part 226). New York classifies the Atlantic sturgeon as protected. Both the manta ray (*Manta birostris*) and the oceanic whitetip shark (*Carcharhinus longimanus*) were recently classified as threatened under the ESA (50 C.F.R. Part 223). The most current official distribution and abundance data on these species are available from NMFS. Independent researchers often publish supplemental data on various aspects of endangered species in localized areas, such as movement patterns, spawning locations, life history traits, and other factors that may be relevant to the impact analysis. New York classifies the shortnose sturgeon (*Acipenser brevirostrum*) as endangered. The shortnose sturgeon is found in the lower portion of the Hudson River from river mile 0 (southern Manhattan) to river mile 152 (the Federal dam at Troy) (NYSDEC Shortnose Sturgeon Fact Sheet, available at: http://www.dec.ny.gov/animals/26012.html). NYSDEC lists a number of other fish species as endangered, most if not all, are associated with fresh water habitat which will be evaluated, as applicable to the export cable route.

It is virtually impossible to demonstrate the absence of a rare species within its historical range; therefore, these three endangered fish species will be assumed present in the lease area, albeit in limited abundance and frequency based on the type of habitat that is present. More details on the spatial and temporal distribution of Atlantic sturgeon is expected to be available soon, resulting from BOEM funded studies carried out by Stony Brook University. Equinor Wind has also made its metocean moorings available to Stony Brook University to attach Atlantic sturgeon receivers to in order to gather more data. This has resulted in three additional sensors being deployed in the lease area in December 2018 and an additional sensor to be installed in spring 2019. Data will be collected from these sensors for approximately and additional two years, to develop a broader knowledge of Atlantic sturgeon movements in the vicinity of the lease area.

Non-Game Fish and Invertebrate Species

Useful data on the distribution and abundance of non-game fish and invertebrates come from many sources, including fisheries management plans, peer-reviewed literature, and NMFS reports. Although the Estuarine Living Marine Resource database (NOAA 2000) has not been kept current, the descriptions of spatial and temporal distributions of species (by life stage) in Hudson River/Raritan Bay and the Great South Bay provide a framework for describing current conditions in the area of the proposed cable landing(s). NYSERDA recently reviewed the Ocean Biogeographic Information System and confirmed that typical invertebrates of recreational and commercial interest in the lease area include longfin and shortfin squid, lobster, horseshoe crab, blue crab, scallop, ocean quahog, and Atlantic surfclam (NYSERDA Master Plan; 2017; Appendix J). NYSERDA also reviewed the available data on the suitability of habitat and the presence of living coral. Most coral habitat is well to the east of the lease area (near the continental shelf break). However, a small area of coastal Long Island was identified as having habitat suitable to support corals (NYSERDA 2017; Apppendix A). The New York Department of State ("NYSDOS") has designated 250 areas within the potential export cable corridors as Significant Coastal Fish and Wildlife Habitats (NYSERDA 2017; Appendix J).

13.6.3 Ongoing and Planned Assessments

BOEM has published recommended approaches for assessing benthic habitat and fisheries resources during the permitting phase of offshore wind projects: (1) *Guidelines for Providing Benthic Habitat Survey Information for Renewable Energy Development on the Atlantic Outer Continental Shelf* (Benthic Guidelines; BOEM 2013a); and (2) *Guidelines for Providing Information on Fisheries for Renewable Energy Development on the Atlantic Outer Continental Shelf* (Fisheries Guidelines; BOEM 2013b). Because fisheries resources are defined by their use as commodities, BOEM has also provided guidance on evaluating the impact of wind projects on the socioeconomic aspects of fishing: *Guidelines for Providing Information on Fisheries Social and Economic Conditions for Renewable Energy Development* (BOEM 2015a), which are further referenced in Section 12.

Existing Data Collection and Monitoring Efforts

Under BOEM funding as part of their efforts to map the lease area during the leasing stage, and subsequently continuing after the Lease was awarded to Equinor Wind, NOAA's National Ocean Service ("NOS") conducted extensive surveys over three years using sonar and sediment grabs using research vessel Research Vessel ("RV") Nancy Foster, adding to data collected earlier in 2013 on RV Ferdinand Hassler (NOAA NOS Survey Report). [redacted]

Equinor Wind Data Collection

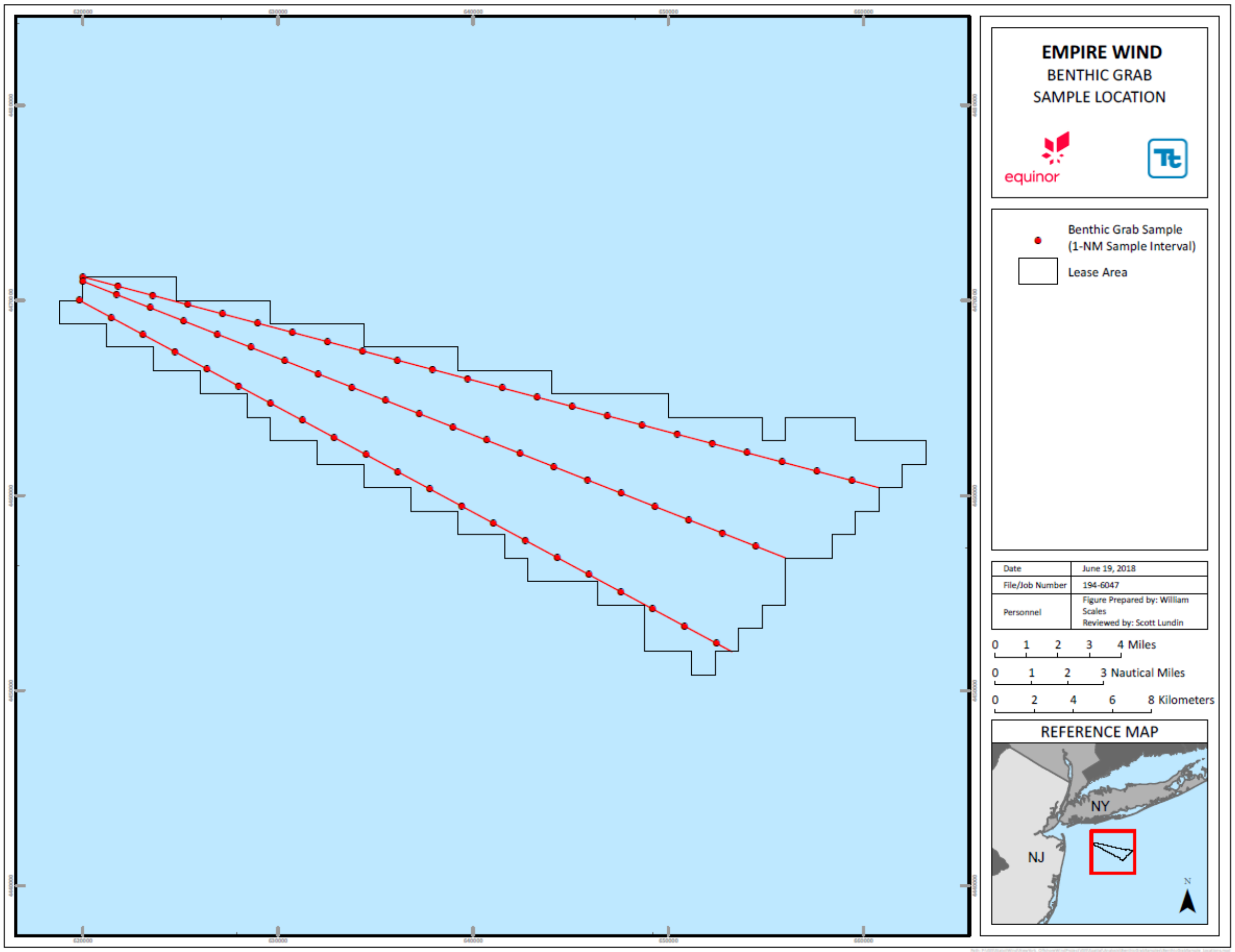
To support the assessment of benthic and fisheries resources in the lease area, Equinor Wind conducted geophysical, benthic, and geotechnical work from March 2018 to November 2018 across the entire lease area and a large proportion of export cable corridors, with additional geophysical, benthic, and geotechnical surveys planned for 2019 to fill in any data gaps, in particular from landfall to the 65 ft (20 m) depth contour. The plans for the 2018 surveys were submitted to BOEM in November 2017 and subsequently approved in February 2018. An

Incidental Harassment Authorization ("IHA") was submitted to NOAA NMFS and issued in April 2018. A High-Resolution Geophysical ("HRG") Survey Plan was also issued. In the spirit of openness and transparency, Equinor Wind has made these documents available for download from the Empire Wind webpage at www.empirewind.com/environmental.

Equinor Wind contracted Alpine Ocean Seismic Survey Inc. ("Alpine") to perform the surveys, using survey vessels RV Shearwater and RV Ocean Researcher from March 18, 2018, to December 2, 2018. The survey equipment and scope included, but was not limited to, the following:

- Gridded survey lines at a spacing of approximately 98 ft by 1,640 ft (30 m by 500 m);
- Depth sounding (multibeam echosounder) to determine site bathymetry and elevations;
- Magnetic intensity measurements (gradiometer) for detecting local variations in the regional magnetic field from geological strata and potential ferrous objects on and below the bottom;
- Seafloor imaging (sidescan sonar survey) for seabed sediment classification purposes, to identify natural and man-made acoustic targets on the seabed, as well as any anomalous features;
- Shallow penetration sub-bottom profiler to map the near-surface stratigraphy (from seabed surface to 16.4 ft (5 m) below seabed) soils below the seabed;
- Medium penetration sub-bottom profiler to map deeper subsurface stratigraphy as needed (soils down to 75-100 m below seabed);
- CPTs and Vibracores in the lease area and along the export cable corridors;
- Sediment grab samples and drop-down video images at 67 sampling locations (see Figure 12) to support the interpretation of geophysical data to characterize surficial sediment conditions and benthic habitat, including macrofaunal analysis with samples sieved at 0.5 mm mesh size.

Figure 12: Locations of 2018 Benthic Survey Campaign within Lease Area



Data from the 2018 HRG and benthic surveys will be analyzed and reported on in 2019 to applicable stakeholders. Preliminary and anecdotal results from the survey crew are consistent with descriptions of the expected habitat from previous studies. Full results will inform planning and mitigation with additional survey data in 2019 being added as appropriate and used in the development of the COP and other State and Federal permit applications as required.

Equinor Wind is currently planning and procuring contractors to conduct benthic sampling along the proposed export cable corridors, with sampling expected to take place in spring 2019. Sampling will be as consistent with the benthic sampling conducted within the lease area and will include as a minimum the following:

- Sediment grab samples for grain size analysis;
- Drop-down camera and/or video images;
- Grab samples for macrofauna.

In addition, and as previously noted, BOEM has funded studies that are being carried out by Stony Brook University to monitor the spatial and temporal distribution of Atlantic sturgeon within the New York Bight and Equinor Wind's lease area. The study is coming to a close at the time of writing. Equinor Wind has made its metocean moorings available to Stony Brook University to attach Atlantic sturgeon receivers to in order to gather more data. This has resulted in three additional sensors being deployed in the lease area in December 2018 and an additional sensor to be installed in spring 2019. Data will be collected from these sensors for approximately an additional two years.

Baseline Summary

Equinor Wind evaluated the extent to which existing, and publicly available data sources are suitable for characterizing benthic habitat and fisheries resources in the lease area. Both published data and ongoing survey efforts in the lease area and surrounding waters support the preliminary characterization of baseline conditions in accordance with Federal and State requirements and guidelines.

Furthermore, Equinor Wind presented the list of data sets proposed to be utilized for the baseline characterization of benthic and fisheries resources to NOAA NMFS in March 2018 and August 2018. NOAA NMFS provided feedback, including additional data sets to use, and agreed with the conclusion that there is sufficient existing data for a baseline characterization in the lease area.

As such, additional benthic and fisheries surveys are not deemed to be required within the lease area for the purpose of the COP impact assessments, spatial planning or mitigation, however Equinor Wind will consult with E-WTG, F-TWG, RODA and the fishing industry, including fisheries scientists and managers on requirements for further surveys for targeted fisheries monitoring and research.

A discussion of impact producing factors, potential impacts and how Equinor Wind proposes to avoid or mitigate to reduce those impacts to benthic and fisheries resource during surveys, construction, operations and decommissioning is provided in the following sections.

13.6.4 Potential Impacts and Mitigation

An understanding of the potential effects from offshore wind energy developments that have the potential to impact benthic and fisheries resources, either positively or negatively, have come from experience, literature on the subject and from New York State's Offshore Wind Master Plan Fish & Fisheries Report (2017; Appendix J). The potential impact producing factors identified that are relevant to benthic habitats and fisheries resources are as follows:

- Short-term temporary physical disturbance to habitats and species resulting from seabed preparation, anchor spreads, jack-up barge footings and the installation of subsea cables during construction, decommissioning and limited maintenance periods;

- Short-term temporary habitat loss resulting from seabed preparation, anchor spreads, jack-up barge footings and the installation of subsea cables during construction, decommissioning and limited maintenance periods;
- [redacted]
- Short-term temporary increased suspended sediment concentration and deposition (smothering) resulting from seabed preparation and the installation of subsea cables during construction and decommissioning, and from short duration scouring events during operations;
- Temporary exposure to accidental spills, pollution or trash from project related vessels;
- Long-term temporary habitat loss or modification resulting from the presence of foundations, scour material and surface cable protection during operations;
- Long-term temporary changes to existing physical oceanographic conditions during operations due to the presence of structures; and
- Potential exposure to Electromagnetic Fields ("EMF") during operations.

Potential Mitigation

The baseline characterization and assessment of future potential impacts on benthic habitats and fisheries resources from the construction, operation, and decommissioning of the project must satisfy the requirements of various regulations and jurisdictional agencies. As such, collaboration and coordination with BOEM, NOAA NMFS, NYSDEC and relevant stakeholders throughout the development and planning process, will be critical to the success of the project. In order to mitigate for the potential impacts to benthic habitats and fisheries resources associated with the construction, operations, and decommissioning of the project, Equinor Wind is implementing the following mitigation measures:

- Avoiding, to the extent possible, siting structures (wind turbines, offshore substations, and submarine cables) in areas of sensitive habitat;
- Using best management practices and timing during cable installation activities to minimize sediment resuspension and dispersal in areas of known historically contaminated sediments;
- [redacted]
- A commitment to sufficiently bury electrical cables where feasible, minimizing seabed habitat loss and reducing the effects of EMF;
- Consideration of the timing of construction activities; working with the fishing industry and fisheries agencies on sensitive spawning and fishing periods to actively avoid or reduce interaction with receptors, where feasible;
- Using industry Best Practices for vessel operation, and implementing an Oil Spill Response Plan ("OSRP").

More confidence in the type and level of impacts to benthic and fisheries resources will be determined as the project matures and on submission of the COP. However, certain assumptions can be made at this stage for the purpose of the bid, based on preliminary information and experience, as described in further sections.

Mitigation for recreational and commercial fishing practices is described in the FMP, Section 12.4.3 of this submission.

Surveys

Equinor Wind is following BOEM best practice guidance for surveys and submitting survey plans for review and approval prior to survey activity, which addresses potential impacts to benthic and fisheries resources during survey activities, for example exposure to noise through geophysical surveys or disturbance to habitats and species through benthic and geotechnical sampling. Where there is potential for impacts on threatened or endangered species, NOAA NMFS are included in the survey plan review in coordination with BOEM.

Sensitive benthic habitats are actively avoided where feasible, by taking this into consideration in the planning phase, for example routing export cable corridors to avoid sensitive habitats and therefore avoid the need for intrusive surveys there. This practice will be continued as the Empire Wind project develops. In addition, real-time avoidance is and will continue to be applied for seabed intrusive sampling by the use of drop down cameras to inspect the seabed prior to taking samples. For the summer 2018 geotechnical and benthic sampling, the team of Environmental Scientists onboard the survey vessel provided this real-time monitoring.

As such, and where feasible, sensitive benthic habitats will be avoided to the greatest extent possible when conducting seabed intrusive surveys through a combination of avoidance through spatial planning pre-survey, then avoidance during surveys through real-time monitoring.

Construction

Loss of Habitat

With embedded mitigation in place, including project siting to avoid sensitive habitats, Equinor Wind expects that impacts to sensitive benthic habitats and fisheries resources resulting from seabed disturbance and temporary habitat loss will be avoided or reduced to as low as feasible. With expected high recoverability rates of immobile species and the return of mobile species following the disturbing activity, Equinor Wind does not expect significant adverse impacts. Disturbance to the seabed habitat during construction is expected to recover within a relatively short time period, with recolonization expected within several years for most species. The level of disturbance from construction activities is likely to be consistent with seabed disturbance and recovery resulting from existing anthropogenic pressures in the lease area and adjacent waters, such as bottom contacting commercial fishing activities and commercial vessel anchoring.

With highly sensitive habitats being avoided through spatial planning and micro siting, the potentially affected areas are therefore expected to be of the relatively homogenous sand or sandy gravel habitat type. The overall affected area during construction activities is expected to be an insignificant proportion of the overall available habitat in context to the Empire Wind offshore wind energy development, full lease area, and available similar habitats and species in adjacent waters. Equinor Wind will calculate actual affected areas and habitat loss and will share those results with the E-TWG and F-TWG, as well as publishing as part of the COP.

Suspended Sediments and Deposition

Exposure to increased suspended sediment concentration and potential smothering of benthic organisms and fish larvae resulting from cable installation and seabed preparation is expected to be short-term in duration and within the timescales of a tidal cycle. Sediments in the lease area are of a sand to gravelly sand nature and settlement rates are relatively fast. The suspended sediment concentrations generated through construction activity are also expected to be within the background levels of wave-induced suspended sediments from natural storm events, such as “nor-easters” typical of the region. In this instance the affected areas are expected to be localized and significantly smaller than affected areas from natural storm events. Equinor Wind will be carrying out sediment transport modeling to quantify the suspended sediment concentrations, durations and affected areas and will share these results with the F-TWG, as well as publishing as part of the COP.

Water Quality

The routing of the export cable corridor has taken into consideration existing and historic dumping grounds (charted) and has actively avoided them where feasible. As stated, much of the routing is in areas that are characterized as sand, where larger grain-sizes reduces the potential for contamination to be present. More information on sediment properties and potential impacts will become available as data from the 2018 surveys is analyzed and reported and as Equinor Wind completes additional nearshore surveys and sediment sampling in 2019, where chemical characterization will occur in areas of grain-size <90%. The information gathered will inform a sediment transport analysis. If contaminants are present, any release of contaminants will be of a short-term temporary nature and of limited spatial coverage. Additionally, Best Management Practices will be defined to further mitigate these effects.

Underwater Noise

[redacted]

Operations

Electromagnetic Fields

Equinor Wind intends to mitigate for potential EMF effects by burying cables to sufficient burial depths based upon existing fishing practices and cable burial risk assessments. Where target burial depth is not feasible, for example, due to challenging seabed conditions or cable crossings, the cables will be sufficiently protected with surface cable protection. The likelihood for receptor-effect interaction will be reduced, with impacts not expected to be significant adverse. The UK National Policy Statement for Renewable Energy Infrastructure EN-3 (DECC, 2011) states that for offshore wind, electrical cables that are sufficiently protected or buried will not result in significant impacts on sensitive species. It is however appreciated that species within the lease area will be different to those in U.K. waters and, therefore, Equinor Wind is open to discussing further monitoring and research to fill any data gaps through the E-TWG and F-TWG. Equinor Wind will carry out EMF modeling and assessments as part of the COP submission.

Suspended Sediments and Deposition

Existing information indicates the subsurface currents within the lease area and adjacent waters are expected to be typically less than 0.32 ft/s (0.10 m/s). To better understand the physical environment, Equinor Wind has installed current meters in the lease area as of December 2, 2018 to collect site-specific measurements and will also be performing sediment transport modeling as part of the COP assessments. Based on the existing information, the relatively low near-bed current speeds are not expected to generate significant quantities of suspended sediments and deposition from scouring. Equinor Wind is conducting further studies to identify where scour protection may be required, which will further reduce the magnitude of suspended sediments affecting receptors. Similar to construction activities, the suspended sediment concentrations generated through scour in the operations phase are also expected to be within the background levels of wave-induced suspended sediments during natural storm events, such as '"nor-easters" typical of the region. In this instance the affected areas are expected to be localized and significantly smaller than affected areas from natural storm events.

Loss of Habitat

The seabed in the lease area and adjacent areas surrounding is relatively homogenous, made up of sand and sandy gravel. More detailed information on the habitat type and benthic community will become available as data from the [redacted]

[redacted] Micrositing to avoid sensitive habitats will be employed. Habitat loss can therefore be deemed long-term temporary, with the habitat expected to recover to existing conditions and benthic species expected to recolonize the area after decommissioning.

The introduction of hard structures to an otherwise sandy mobile seabed may be considered a positive beneficial impact, as the hard structures offer a new habitat type for colonizing based on the associated 'reef' effect (see BOEM "Rigs to Reefs" at https://www.bsee.gov/what-we-do/environmental-focuses/rigs-to-reefs). The change to habitat type and potential change to species may be topic for further monitoring and research in consultation with F-TWG and E-TWG.

Decommissioning

Impacts resulting from decommissioning activities are not expected to exceed impacts resulting from construction. Moreover, with requirements expected for the removal of structures at or just below the seabed level, Equinor Wind expects the seabed will recover to its pre-construction condition within a relatively short timeframe. Decommissioning impacts and mitigation will require further consideration and should form part of future E-TWG and F-TWG discussion points. Approaches and requirements will likely further be refined as European offshore wind energy developments near closer to decommissioning and as US offshore wind energy development matures. Equinor Wind will use those experiences to apply to decommissioning best practices to avoid and minimize impacts associated with the Empire Wind Project, as appropriate.

13.7 Avian and Bat Species

This section describes the avian and bat species associated with the Equinor Wind's Project Area. This discussion includes the following information on each resource or receptor: (1) information currently available; (2) efforts to further collect data; (3) potential effects that are likely to have an impact; and (4) potential mitigation options that can be employed.

13.7.1 Regulatory Context

Impacts to avian and bat species are regulated under various federal laws including ESA, NEPA, and the Migratory Bird Treaty Act. These regulations require consultation between the lead agency (BOEM) and other agencies, including USFWS and NYSDEC. New York also protects certain bird and bat species under the Endangered and Threatened Species Regulations at 6 NYCRR Part 182.

BOEM requires that a baseline assessment of avian and bat species and potential impacts be completed in support of the COP (30 C.F.R. § 585.626(a)(3)) and associated consultations under Section 7 be conducted with the USFWS. Consultation with USFWS is required for approval of a COP as the activities described in a COP may affect listed species. As the lead federal agency, BOEM is responsible for initiating and completing necessary consultations among federal and state agencies.

13.7.2 Preliminary Resource Characterization

A large number of bird species occur in or potentially fly over the New York Bight (and the lease area) as detailed in Figure 13. Of these potential bird species that may occur in the lease area, certain species are listed under the ESA and/or 6 NYCRR 182 as endangered or threatened.

Figure 13: Avian and Bat Species Known to Occur Within the Waters of the New York Bight

Family Common Name	Scientific Name	Fed. Status[4]	NY Status[5]	Known NY Bight Distribution	Occurrence in NY Bight	Seasonal Occurrence
Birds						
Ducks (Anatidae)						
Brant	*Branta bernicla*	N/A	N/A	Scattered, non-breeding, transient[1]	Rare[1]	Seasonal[1]
Canada Goose	*Branta canadensis*	N/A	N/A	Scattered, non-breeding, transient[1]	Rare[1]	Seasonal[1]
Mallard	*Anas platyrhynchos*	N/A	N/A	Scattered, non-breeding, transient[1]	Rare[1]	Seasonal[1]
American Black Duck	*Anas rubripes*	N/A	N/A	Scattered, non-breeding, transient[1]	Rare[1]	Seasonal[1]
Common Eider	*Somateria mollissima*	N/A	N/A	Winter migrant; Coastal, Bays[3]; near coastlines and islands, throughout Lease Area[1]	Common[1]	Seasonal[1]
King Eider	*Somateria spectabilis*	N/A	N/A	Winter; Coastal[3]	Rare[3]	Seasonal[1]
Harlequin Duck	*Histrionicus histrionicus*	N/A	N/A	Winter; Coastal[3]	Rare[3]	Seasonal[1]
Surf Scoter	*Melanitta perspicillata*	N/A	N/A	Winter migrant; Coastal[3]; near coastlines and islands, throughout Lease Area[1]	Common[1]	Seasonal[1]
White-winged Scoter	*Melanitta fusca*	N/A	N/A	Winter migrant; Coastal, Bays[3]; near coastlines and islands, throughout Lease Area[1]	Common[1]	Seasonal[1]
Black Scoter	*Melanitta nigra*	N/A	N/A	Winter migrant; Coastal, Bays[3]; near coastlines and islands, throughout Lease Area[1]	Common[1]	Seasonal[1]

Family Common Name	Scientific Name	Fed. Status[4]	NY Status[5]	Known NY Bight Distribution	Occurrence in NY Bight	Seasonal Occurrence
Long-tailed Duck (was Oldsquaw)	*Clangula hyemalis*	N/A	N/A	Winter migrant; Coastal, Bays[3]; near coastlines and islands, throughout Lease Area[1]	Common[1]	Seasonal[1]
Bufflehead	*Bucephala albeola*	N/A	N/A	Scattered, non-breeding, transient[1]	Rare[1]	Seasonal[1]
Red-breasted Merganser	*Mergus serrator*	N/A	N/A	Winter migrant; Coastal, Bays[3]; near coastlines and islands, throughout Lease Area[1]	Common[1]	Seasonal[1]
Grebes (Podicipedidae)						
Pied-billed Grebe	*Podilymbus podiceps*	BCC	T	Migrant[3]	Rare[3]	Seasonal[1]
Horned Grebe	*Podiceps auritus*	BCC	N/A	Winter migrant; Coastal, Bays[3]; non-breeding[2]	Rare[3]	Seasonal[1]
Red-necked Grebe	*Podiceps grisegena*	N/A	N/A	Winter migrant; Coastal, Bays, Shallow open water[3]; non-breeding[2]	Rare[3]	Seasonal[1]
Plovers (Charadriidae)						
American Oystercatcher	*Haematopus palliatus*	BCC	N/A	Migrant; breeder along coastal beaches and marshlands	Common[6]	Seasonal[6]
Black-bellied Plover	*Pluvialis squatarola*	N/A	N/A	Migrant and rare winter resident	Common[6]	Seasonal[6]
Semipalmated Plover	*Charadrius semipalmatus*	N/A	N/A	Migrant	Common[6]	Seasonal[6]
Piping Plover	*Charadrius melodus*	T	E	Breeding; Open sandy beaches; not well known migratory patterns[3]	Common[3]	Seasonal[3]
Phalaropes (Scolopacidae)						
Upland Sandpiper	*Bartramia longicauda*	BCC	T	Breeding and migrant; beach dunes and grasslands	Rare[6]	Seasonal[6]

Family Common Name	Scientific Name	Fed. Status[4]	NY Status[5]	Known NY Bight Distribution	Occurrence in NY Bight	Seasonal Occurrence
Red Knot	*Calidris canutus*	T	T	Migrant; Primarily coastal shorelines, rare winter resident[3]	Rare[1]	Seasonal[1]
Sanderling	*Calidris alba*	N/A	N/A	Migrant and winter resident; Primarily coastal shorelines	Common[6]	Seasonal[6]
Dunlin	*Calidris alpina*	N/A	N/A	Migrant and winter resident; Primarily coastal shorelines	Common[6]	Seasonal[6]
Purple Sandpiper	*Calidris maritima*	BCC	N/A	Migrant and winter resident; Primarily rocky coastal shorelines	Common[6]	Seasonal[6]
Least Sandpiper	*Calidris minutilla*	N/A	N/A	Migrant; Primarily coastal shorelines	Common[6]	Seasonal[6]
Semipalmated Sandpiper	*Calidris pusilla*	BCC	N/A	Migrant and rare winter resident; Primarily coastal shorelines	Common[6]	Seasonal[6]
Short-billed Dowitcher	*Limnodromus griseus*	BCC	N/A	Migrant and rare winter resident; Primarily coastal shorelines	Common[6]	Seasonal[6]
Red Phalarope	*Phalaropus fulicaria*	N/A	N/A	Migrant; Primarily pelagic shelf breaks, some inshore[3]	Common[1]	Seasonal[1]
Red-necked Phalarope	*Phalaropus lobatus*	N/A	N/A	Migrant; Pelagic shelf breaks[3]	Common[1]	Seasonal[1]
Skuas/Jaegers (Stercorariidae)						
South Polar Skua	*Stercorarius maccormicki*	N/A	N/A	Scattered, non-breeding, transient[1]	Rare[1]	Seasonal[1]
Great Skua	*Stercorarius skua*	N/A	N/A	Winter migrant; Pelagic[3]	Rare[3]	Seasonal[3]
Pomarine Jaeger	*Stercorarius pomarinus*	N/A	N/A	Migrant; Pelagic[3]; most abundant along shelf edge[1]	Rare[1]	Seasonal[1]
Parasitic Jaeger	*Stercorarius parasiticus*	N/A	N/A	Migrant; Pelagic, Seacoasts, Inland Coasts[3]	Rare[3]	Seasonal[3]

Family Common Name	Scientific Name	Fed. Status[4]	NY Status[5]	Known NY Bight Distribution	Occurrence in NY Bight	Seasonal Occurrence
Long-tailed Jaeger	*Stercorarius longicaudus*	N/A	N/A	Migratory, Pelage (less than 20 mi [32 km] offshore), Seacoasts, Inland waterbodies[3]	Rare[3]	Seasonal[3]
Alcids (Alcidae)						
Dovekie	*Alle alle*	N/A	N/A	Winter; Pelagic, Seacoasts[3]	Common[1]	Seasonal[3]
Atlantic Puffin	*Fratercula arctica*	N/A	N/A	Pelagic, Winter	Rare[1]	Seasonal[3]
Common Murre	*Uria aalge*	N/A	N/A	Wintering; Pelagic, Cliffs, Rocky Seacoasts (30 to 90 mi [48 to 145 km] offshore)[3]	Rare[1]	Seasonal[3]
Thick-billed Murre	*Uria lomvia*	N/A	N/A	Winter; Pelagic (less than 100 mi [161 km] offshore), Cliffs, Seacoasts[3]	Rare[1]	Seasonal[3]
Razorbill	*Alca torda*	N/A	N/A	Winter; Pelagic, Cliffs, Islands, Rocky Shores[3]	Rare[1]	Seasonal[3]
Gulls/Terns (Laridae)						
Black-legged Kittiwake	*Rissa tridactyla*	N/A	N/A	Winter migrant; Pelagic (less than 15 mi [24 km] offshore), Bays, Islands, Seacoasts[3]	Common[1]	Seasonal[1]
Bonaparte's Gull	*Larus philadelphia*	N/A	N/A	Wintering; Bays, Seacoasts, Pelagic (less than 15 mi [24 km] offshore)[3]	Rare[1]	Seasonal[1]
Little Gull	*Larus minutus*	N/A	N/A	Scattered, non-breeding, transient[1]	Rare[1]	Seasonal[1]
Laughing Gull	*Larus atricilla*	N/A	N/A	Breeding; Bays, Seacoasts, Islands[3]; Lease Area is close to northern limit	Common[1]	Seasonal[1]
Ring-billed Gull	*Larus delawarensis*	N/A	N/A	Winter migrant; Bays, Seacoasts, Fields[3]	Rare[1]	Year-round[1]

Family Common Name	Scientific Name	Fed. Status[4]	NY Status[5]	Known NY Bight Distribution	Occurrence in NY Bight	Seasonal Occurrence
Herring Gull	*Larus argentatus smithsonianus*	N/A	N/A	Winter breeding migrant; Bays, Coastal, Pelagic (inter/subtidal, less than 20 mi [32 km] offshore)[3]	Common[1]	Year-round[1]
Iceland Gull	*Larus glaucoides*	N/A	N/A	Scattered, non-breeding, transient[1]	Rare[1]	Seasonal[1]
Lesser Black-backed Gull	*Larus fuscus*	N/A	N/A	Winter migrant; Bays, Rocky or sandy coast[3]	Rare[1]	Seasonal[3]
Glaucous Gull	*Larus hyperboreus*	N/A	N/A	Wintering; Coastal, Pelagic, Inland waterbodies, intertidal, cliffs[3]	Rare[1]	Seasonal[3]
Great Black-backed Gull	*Larus marinus*	N/A	N/A	Winter breeding migrant; Bays, Coastal, Pelagic (less than 60 mi (97 km) offshore, intensely less than 15 mi [24 km])[3]	Common[3]	Year-round[3]
Sooty Tern	*Onychoprion fuscatus*	N/A	N/A	Summering, Breeding; less than 30 mi (48 km) offshore[1]	Common[1]	Seasonal[1]
Bridled Tern	*Sterna anaethetus*	N/A	N/A	Summering, Breeding; less than 30 mi (48 km) offshore[1]	Common[1]	Seasonal[1]
Least Tern	*Sterna antillarum*	E/BCC	T	Breeding, Migratory; Bays, Estuaries, Coastal, Rivers/Lakes, Beaches, Shallow Open Water[3]	Common[1]	Seasonal[1]
Black Tern	*Chlidonia niger*	BCC	E	Migratory; Bays, Seacoasts (off Long Island coast)[3]	Rare[3]	Seasonal[3]
Roseate Tern	*Sterna dougallii*	E	E	Breeding, Migratory; Bays, Seacoasts, Islands, Offshore waters[3]	Common[1]	Seasonal[1]

Family Common Name	Scientific Name	Fed. Status[4]	NY Status[5]	Known NY Bight Distribution	Occurrence in NY Bight	Seasonal Occurrence
Common Tern	*Sterna hirundo*	BCC	T	Breeding; Bays, Seacoasts, Beaches, Sandbars, Islands[3]; largest colony off Great Gull Island at east end of Long Island[1]	Common[1]	Seasonal[1]
Artic Tern	*Sterna paradisaea*	BCC	N/A	Summering, Breeding; less than 30 mi (48 km) offshore[1]	Common[1]	Seasonal[1]
Forster's Tern	*Sterna forsteri*	N/A	N/A	Breeding; Bays, Seacoasts, Closer to shore[3]	Common[1]	Seasonal[1]
Royal Tern	*Sterna maxima*	N/A	N/A	Migratory; Open sandy beaches, Seacoasts, Estuaries, primarily forage close to shore[3]	Common[1]	Seasonal[1]
Black Skimmer	*Rynchops niger*	BCC	SC	Breeding (nest on Long Island); Bays, Estuaries, Islands, Sandy Beaches, Shell Banks, Mudflats, forage near beaches, bays and calm inshore waters[3]	Common[3]	Seasonal[2]
Loons (Gaviidae)						
Common Loon	*Gavia immer*	N/A	SC	Winter migrant; Coastal, Pelagic, Bays, Islands[3] Abundant in New York Bay, Long Island	Common[1]	Seasonal[1]
Red-throated Loon	*Gavia stellata*	BCC	N/A	Winter migrant; Coastal, Pelagic, Bays[3]; near coastlines and islands, throughout Lease Area[1]	Common[1]	Seasonal[1]
Shearwaters (Diomedeidae)						

Family Common Name	Scientific Name	Fed. Status[4]	NY Status[5]	Known NY Bight Distribution	Occurrence in NY Bight	Seasonal Occurrence
Northern Fulmar	*Fulmarus glacialis*	N/A	N/A	Winter migrant; Pelagic, rarely more than 60 mi (97 km) offshore[3]	Common[1]	Seasonal[1]
Cory's Shearwater	*Calonectris diomedea*	N/A	N/A	Summering, Winter; Pelagic[3]; occur in center of Lease Area[1]	Common[1]	Seasonal[1]
Sooty Shearwater	*Puffinus griseus*	N/A	N/A	Summering migrant; Pelagic[3]; abundant south of central Long Island[1]	Common[1]	Seasonal[1]
Great Shearwater	*Puffinus gravis*	BCC	N/A	Summering migrant; Pelagic[3]; occur in center of Lease Area[1]	Common[1]	Seasonal[1]
Manx Shearwater	*Puffinus*	N/A	N/A	Summering migrant; Pelagic, Coastal inshore[3]	Rare[1]	Seasonal[1]
Audubon's Shearwater	*Puffinus lherminieri*	BCC	N/A	Wintering; Pelagic[3]	Rare[1]	Seasonal[1]
Storm-Petrels (Hydrobatidae)						
Wilson's Storm-Petrel	*Oceanites oceanicus*	N/A	N/A	Summering migrant; Pelagic[3]; abundant nearshore in summers, beyond shelf in spring and fall[1]	Common[1]	Seasonal[1]
Leach's Storm-Petrel	*Oceanodroma leucorhoa*	N/A	N/A	Summering migrant; Pelagic, primarily forages between 30 to 130 mi (48 to 209 km] offshore; Breeds on islands[3]	Common[1]	Seasonal[1]
Band-rumped Storm-Petrel	*Oceanodroma castro*	BCC	N/A	Summer offshore along shelf edge[1]	Rare[1]	Seasonal[1]
White-faced Storm-Petrel	*Pelagodroma marina*	N/A	N/A	Offshore along shelf edge[1]	Rare[1]	Seasonal[1]

Family Common Name	Scientific Name	Fed. Status[4]	NY Status[5]	Known NY Bight Distribution	Occurrence in NY Bight	Seasonal Occurrence
Gannets (Sulidae)						
Northern Gannet	*Morus bassanus*	N/A	N/A	Winter migrant; Pelagic (forages less than 40 mi [64 km offshore), Coastal[3]; aggregate near fishing activity[1]	Common[1]	Seasonal[1]
Cormorants (Phalacrocoracidae)						
Double-crested Cormorant	*Phalacrocorax auritus*	N/A	N/A	Wintering; Coastal (less than 20 mi [32 km] offshore)[3]; near east end of Long Island, New York Bay[1]	Common[1]	Seasonal[1]
Great Cormorant	*Phalacrocorax carbo*	BCC	N/A	Wintering; Coastal, Cliffs[3]; near east end of Long Island, New York Bay[1]	Common[1]	Seasonal[1]
Pelicans (Pelecanidae)						
Brown Pelican	*Pelecanus occidentalis*	N/A	N/A	Winter breeding migrant; Coastal (less than 50 mi [80 km] offshore), Bays[3]	Common[3]	Seasonal[3]
Herons (Ardeidae)						
American Bittern	*Botaurus lentiginosus*	BCC	SC	Migrant[3]	Rare[3]	Seasonal[3]
Least Bittern	*Ixobrychus exilis*	BCC	T	Migrant; Marshes[3]	Rare[3]	Seasonal[3]
Ospreys (Pandionidea)						
Osprey	*Pandion haliaetus*	N/A	SC	Breeding, Migratory; May forage offshore, may migrate through Lease Area[3]	Common[3]	Seasonal[3]
Accipiters (Accipitridae)						

Family Common Name	Scientific Name	Fed. Status[4]	NY Status[5]	Known NY Bight Distribution	Occurrence in NY Bight	Seasonal Occurrence
Bald Eagle	*Haliaeetus leucocephalus*	BCC	T	Migrant and local breeder along coastal areas.	Common[6]	Year-round[6]
Northern Harrier	*Circus cyaneus*	N/A	T	Breeding, Migratory; May migrate through Lease Area[3]	Common[3]	Seasonal[3]
Golden Eagle	*Aquila chrysaetos*	N/A	E	Migrant, winter resident along coastal beaches	Rare[6]	Seasonal[6]
Falcons (Falconidae)						
Peregrine Falcon	*Falco peregrinus*	BCC	E	Breeding, Migratory; May migrate through Lease Area, may forage offshore[3]	Common[3]	Seasonal[3]
Bats						
Eastern red bat	*Lasiurus borealis*	N/A	N/A	Coastal migrant[3]	Rare[3]	Seasonal[3]
Silver-haired bat	*Lasionycteris noctivagans*	N/A	N/A	Coastal migrant[3]	Rare[3]	Seasonal[3]
Hoary bat	*Lasionycteris cinereus*	N/A	N/A	Coastal migrant[3]	Rare[3]	Seasonal[3]

Family Common Name	Scientific Name	Fed. Status[4]	NY Status[5]	Known NY Bight Distribution	Occurrence in NY Bight	Seasonal Occurrence
Notes: BCC: Bird of Conservation Concern; SC: Special Concern; E: Endangered; T: Threatened; N/A: Not Applicable Bays: Enclosed or semi-enclosed coastal bays; Coastal: Nearshore waters of NY Bight within sight of land; Pelagic: Offshore waters of NY Bight out of sight of land Sources: 1. Kinlan et al. 2012 2. Rodewald 2015 3. NYSERDA 2010a, NYSERDA 2017b 4. USFWS 2008, USFWS 2017a, Ecology and Environment 2017 5. NYSDEC 2015a 6. eBird 2012						

Information on threatened and endangered species and/or their habitat is also available through USFWS IPaC (https://ecos.fws.gov/ipac/) and NYSDEC Environmental Resource Mapper (https://www.dec.ny.gov/animals/38801.html). These sources have identified the following species that may be present in the Empire Wind Project Area:

- Piping plover;
- Rufa red knot;
- Roseate tern;
- Peregrine falcon;
- Upland sandpiper; and
- Northern long-eared bat.

According to recent assessments and studies, the lease area provides habitat for approximately forty waterbird species, including seaducks, loons, gulls, scoters, terns, alcids, gannets, and shorebirds (NYSERDA 2010a, Kinlan et al. 2012, Kinlan et al. 2016, NYSERDA 2017d). With the exception of gulls, use of the lease area by most waterbird species is seasonal with the majority wintering within the sheltered inlets and bays found along the New York Bight. The lease area is located within the Atlantic Flyway and migratory birds are likely to pass through the lease area during spring and fall migration (NYSERDA 2010a, Kinlan et al. 2012, Kinlan et al. 2016).

Some passerine species (songbirds from the order Passeriformes), especially passerines that are long-distance migrants, may occur in offshore waters and may migrate through the lease area (NYSERDA 2010a, Kinlan et al. 2012, Kinlan et al. 2016, NYSERDA 2017d). Robinson Willmott et al. (2013)) reported that when migrating over offshore waters, passerines spend less than five percent of their time flying within the heights (65 to 656 ft or 19-199 m) that reach a wind turbine's rotor-swept zone at the time (see NYSERDA's Offshore Wind Study; 2017; Appendix D). As such, most passerines received a low collision sensitivity score, and all received low risk of displacement scores since open oceans do not provide habitat for passerines (NYSERDA 2017d). Equinor Wind notes that contemporary typical rotor swept zones extend to 850 ft and are increasing, and will make an assessment based on future developments in wind turbine size. Three passerines received a "medium" collision sensitivity score: barn swallow (*Hirundo rustica*), Kirtland's warbler (*Setophaga kirtlandii*), and Bicknell's thrush (*Catharus bicknelli*) (Robinson Willmott et al. 2013, NYSERDA 2017d). Kirtland's warbler is listed as a federally endangered species and winters in the Bahamas Islands. Kirtland's warbler is unlikely to pass through the lease area as the species' known migration route passes over Florida, Georgia and the Carolinas, well south of the lease area (Bocetti et al. 2014). Barn swallows are diurnal migrants that are common in North America (Brown and Brown 1999) but are likely to be rare occurrences far offshore in the lease area. Based on scant migratory data of Bicknell's thrush (state-listed as Special Concern), fall migration may occur over water while spring migration appears to be a more coastal land-route east of the Rocky Mountains (Townsend et al. 2015); therefore, it would be a rare migrant in the lease area.

The federally-listed threatened piping plover (*Charadrius melodus*) and red knot (*Calidris canutus ssp. rufa*), and the federally-listed endangered roseate tern (*Sterna dougallii dougallii*) are known to occur or migrate through the lease area (NYSERDA 2010a, Kinlan et al. 2012, Kinlan et al. 2016). The piping plover is also a state-endangered species that breeds in New York along sandy beaches and forages along tidal areas. Piping plovers tend to stay within narrow coastal margins during migration and are not expected to occur in the lease area (NYSERDA 2010a, Kinlan et al. 2012, Kinlan et al. 2016). The roseate tern is considered a state-listed endangered species and has nesting colonies on coastal areas in proximity to the lease area. Roseate terns may use the lease area to forage and/or migrate, but little activity is expected from roseate terns in the lease area during nesting and post-breeding staging periods (NYSERDA 2010a, Kinlan et al. 2012, Kinlan et al. 2016). The red knot is also a state-Threatened species. Red knots breed in the Arctic, and generally migrate along the Atlantic coast with little activity expected in the lease area.

Migrating raptors utilize barrier beaches for migration, most notably falcons, which are known to cross open water. Peregrine falcons (*Falco peregrinus*), a state-listed endangered species, migrate along the coast and over open water, and likely use the lease area (NYSERDA 2017; Appendix D). Breeding peregrine falcons may also be associated with the export cable route. Bald eagles (*Haliaeetus leucocephalus*) (state Threatened) and golden eagles (*Aquila chrysaetos*) (state Endangered) migrate and forage over land, inland water bodies, and bays, but generally do not migrate or forage over open ocean (NYSERDA 2017; Appendix D). The bald eagle was removed from the Endangered Species list by the U.S. Department of Interior in 2007. Per NYSDEC, the golden eagle is extirpated from New York state (*i.e.*, no longer occurs in the wild).

Bat occurrence patterns in the lease area, and offshore in general, are poorly understood. Bats that are known to currently or historically occur in New York include the big brown bat (*Eptesicus fuscus*), eastern red bat (*Lasiurus borealis*), hoary bat (*L. cinereus*), tri-colored bat (*Perimyotis subflavus*), silver-haired bat (*Lasionycteris noctivagans*), eastern small-footed bat (*Myotis leibii*), little brown bat (*M. lucifugus*), Indiana bat (*M. sodalis*), and northern long-eared bat (*M. septentrionalis*) (NYSDEC 2015b). The Indiana bat is both federally- and state-listed as endangered. Northern long-eared bats are a federally-listed and state-listed threatened species. The small-footed bat is a state-listed species of special concern. Long Island has areas documented as confirmed summer roosting habitat for the northern long-eared bat, which may be associated with the onshore export cable route, where removal of trees within a 150-foot buffer around known occupied maternity roost trees during the pup season (June 1 through July 31) will require a federal Incidental Take Permit under Section 4(d) of the Endangered Species Act. Big brown bat, tri-colored bat, eastern small-footed bat, little brown bat, northern long-eared bat and Indiana bat are all cave-dwelling species that do not migrate over the ocean, and thus are not expected to be in the lease area. Little is known about bat migration or foraging patterns offshore. Recent studies, however, have acoustically detected bats offshore (Peterson 2016; Tetra Tech unpublished data). Bats with the greatest potential to migrate through the lease area on their way between breeding and wintering grounds in the spring and fall are the three migratory tree species: eastern red bat, hoary bat, and silver-haired bat. Based on this information, it is expected that bat activity would likely be greater in uplands, and near the coastal beach and islands than farther offshore.

13.7.3 Ongoing and Planned Assessments

BOEM indicates that the level of surveys required will be assessed on a project-by-project basis. In its *Guidelines for Providing Avian Survey Information for Renewable Energy Development on the Atlantic Outer Continental Shelf Pursuant to 30 C.F.R. Part 585* (Avian Guidelines; BOEM 2017a), BOEM provides guidelines for the design and execution of such surveys.

Currently, in the United States, much is known about birds in estuarine, coastal, and inland habitats but less information is available for offshore habitats (Kinlan et al. 2012). One of the earliest attempts at collecting offshore data was the Manomet Bird Observatory's (now called Manomet Inc.) Cetacean and Seabird Assessment Program ("CSAP") from 1980 to 1988 (Kinlan et al. 2012). Spatially, temporally, and taxonomically, the CSAP database was the most comprehensive information source on seabird distribution in the northeastern United States. NYSERDA used the CSAP dataset to assess potential avian impacts of a proposed New York Bight offshore wind project (NYSERDA 2010a).

Since the development of the CSAP database, other specific regional baseline avian studies for projects have been conducted in the northeastern United States including coastal New Jersey studies for the NJDEP (NJDEP 2010a), the Rhode Island Block Island Wind Farm, and the Massachusetts Cape Wind Project. BOEM has also funded other baseline offshore and nearshore avian studies in nearby regions such as Massachusetts, Rhode Island, and in the Mid-Atlantic region (Paton et al. 2010, Williams et al. 2015, Veit et al. 2016). Sampling and avian survey protocols for the New Jersey Baseline Studies were developed using some of the methods in Camphuysen et al. (2004) and Gould and Forsell (1989) that used a combination of both aerial and boat-based surveys. The Block Island Wind Farm, which was developed approximately 3 mi (5 km) off of Block Island, employed multiple onshore and offshore survey methods for three years including the use of Merlin and Vesper Radar, boat-based and onshore avian surveys, aerial photography surveys, and passive acoustical bird and bat monitoring (Svedlow et al. 2012). Similarly, for the Cape Wind project, the developer and the Massachusetts Audubon Society conducted studies over a five-year period in the lease area, including boat and aerial work during all seasons from 2002 to 2006 (USDOI MMS 2009). Of particular significance to BOEM survey guidelines is the Mid-Atlantic Ocean Data Portal's relevance as a baseline confirmation of temporal use, abundance, and species distribution by avian species or groups in the lease area. The modeling data can also be used to potentially identify species that are high risk for collision or displacement, and species that are protected by federal and/or state laws.

To support the assessment of avian and bat species resources in the lease area, Equinor Wind evaluated readily available spatial data including ongoing and completed survey efforts. The assessment approach and methods were designed to supplement the substantial body of existing data already collected in the lease area. NYSERDA's Master Plan Birds and Bats Study also provides a summary of available information on birds and bats within the New York Bight Region (NYSERDA 2017; Appendix D). As described in Section 13.5.3 and associated figures, Equinor Wind has contracted APEM Ltd, supported by Normandeau Inc. to conduct monthly digital aerial surveys across the lease area, which includes the principal objective of capturing digital images of avian species , with supplimental marine mammals and sea turtles, large fish assemblages and opportunistic vessel sightings, following similar methodology to NYSERDA's ongoing surveys. To ensure the survey methods were consistent with BOEM guidelines, a survey plan, "Avian Survey Protocol", which included marine mammals and sea turtles, was submitted to BOEM and FWS.

Digital aerial surveys were subsequently carried out from November 2017 to October 2018, with monthly results, monthly reports and quarterly reports made publicly available on the following webpage:

https://remote.normandeau.com/ewind_overview.php.

Equinor Wind is committed to continuing to make this data available in as near real-time as possible, subject to the delay between image capture and the time associated with image processing, species identification and quality control.

APEM and the methodology chosen was influenced by NYSERDA having used APEM and these methods to conduct quarterly digital aerial surveys over the New York Bight and OCS-A 0512 lease area from summer 2016 to summer 2017, then ongoing surveys over the New York Bight continuing into winter 2018/2019 at the time of writing. This included the consistency associated with the public webpage to display results.

A summary of the scope of the digital aerial survey is as follows:

- Surveys conducted once per month over a 12-month period;
- Image resolution at sea surface of 1.5 cm ground sampling distance ("GSD");
- Grid survey design;
- Grid imagery footprint of 310 m by 219 m;
- A 2.5-mi (4 km) buffer around the lease area;
- Minimum of 20% of the lease area and buffer imaged, with 10% of area analyzed;
- Monthly results displayed online; and
- Monthly and quarterly reporting, also provided online.

As described, the assessment approach and methods were designed to supplement the substantial body of existing data and meet BOEM's data requirements for site characterization studies to evaluate the potential effects of the proposed project. The supplemental quarterly digital aerial surveys conducted by APEM Ltd. on behalf of NYSERDA provides an excellent spatial and temporal characterization, providing not only additional data in a common currency and format in the lease area, but a wider regional context that provides more value in the context of assessing impacts.

Avian surveys are historically the longest lead time items for baseline data collection leading up to impact assessments, typically with a minimum of two years of data collection to account for inter-annual variations in spatial and temporal distribution. NYSERDA's early efforts on data collection has meant that Equinor Wind has been able to reduce this time down to one year of data collection to add to the existing effort, effectively bringing the impact assessment process forward by a year, having the ability to apply the results into design decisions at an earlier stage and bringing the COP schedule, and therefore the opportunity for permit approvals, construction and first power to New York forward by approximately a year.

Bats

[redacted]

Tagging

[redacted]

Figure 14: [redacted]

[redacted]

Figure 15 [redacted]

[redacted]

Equinor also co-funded and sat on the steering committee of the Carbon Trust ORJIP One Bird Collision Avoidance Study (Skov et al. 2018), looking at collision avoidance behavior of key seabird species around and within an operating offshore wind farm. Many of the species observed in the study are present in the lease area, and therefore those behavioral responses can be directly applied to assessments in the lease area.

As part of its onshore evaluation, Equinor Wind will continue desktop studies and stakeholder discussions for avian and bat species. During field studies, Equinor Wind will complete appropriate surveys to further characterize the project area and determine presence/absence of habitat within proposed project activities.

13.7.4 Potential Impacts and Mitigation

The potential impact producing factors relevant to avian and bat species are as follows:

- Short-term temporary disturbance and displacement resulting from project related vessels and plant during offshore and onshore construction activity;
- Short-term temporary disturbance and displacement from project related vessels during regular offshore maintenance activities during operations;
- Long-term temporary displacement through habitat loss resulting from the presence of wind turbines during operations;
- Collisions with operating wind turbines during operations;
- Barrier effects to migrating receptors resulting from the presence of the offshore wind farm during operations; and
- Indirect impacts resulting from changes to prey resources due to the offshore wind facilities during construction, operations, and decommissioning.

Potential Mitigation

The approach to developing a baseline and an assessment of future potential impacts on avian and bat species from construction, operations and decommissioning of the Empire Wind offshore wind energy development must satisfy the requirements of various regulations and jurisdictional agencies. As such, collaboration and coordination with BOEM, USFWS, NYSDEC, and relevant stakeholders throughout the development and planning process will be crucial to the success of the project. In order to mitigate for the potential impacts to avian and bat species associated with the construction, operations and decommissioning of the project, Equinor Wind is evaluating, and where feasible applying, the following mitigation measures:

- Siting of onshore cables along existing (cleared) rights-of-way, thereby minimizing tree clearing and disturbance of onshore habitat;
- Sympathetic lighting of onshore and offshore structures, vessels and plant to minimize disturbance and displacement (see Section 9.2 for additional details);

[redacted]

- Preparation of an OSRP;
- Trenchless cable installation methods for the export cable at landfall and onshore to avoid sensitive areas;
- Consideration of measures for discouraging and/or provision of alternative roosting;
- Considerate vessel movements in the vicinity of rafting bird; and
- Limiting onshore land disturbance measures to non-nesting seasons for sensitive species (time-of-year restrictions).

As part of on-going consultation with USFWS and NYSDEC, Equinor Wind will determine appropriate measures to address potential protected species associated with the onshore components of the project (*e.g.*, seasonal restrictions).

Construction

The lease area is regularly utilized by a variety of vessels, and as such, the addition of project-related construction vessels is not anticipated to significantly alter the existing baseline vessel effect already impacting the receptors in this area. With adequate mitigation for sympathetic lighting and protocols for construction vessels for the avoidance of large groups of resting birds, impacts resulting from project-related vessels during surveys and construction are not expected to be significant adverse.

Mitigation measures will be implemented to avoid sensitive avian sites during installation of the electrical cables at landfall and onshore. These measures include: avoiding sensitive areas through project siting in consultation with the relevant agencies and stakeholders, and where required, survey data; Horizontal Directional Drilling ("HDD"); and seasonal timing of construction activities to avoid sensitive periods, for example the nesting season. Therefore, impacts associated with onshore cable installation activities can be sufficiently avoided where feasible, and when not feasible, the mitigation options described above are likely to mean impacts to avian and bat species are not expected to be significant adverse.

Operations

The operations phase is deemed to have the highest likelihood for potential impacts on avian and bat species. This is due to the long term physical presence of offshore wind turbines creating a risk of avian and bat collisions, displacement, diversion through barrier effects, and changes to prey resources. Different species are impacted to varying degrees by the effects already identified. As such, it would not be appropriate to specify anticipated impacts on each receptor group, particularly as baseline data is still being analyzed and assessments are still underway.

Nonetheless, Equinor Wind maintains that impacts to avian and bat species will be sufficiently examined as part of BOEM's NEPA process as part of the COP, through state permitting processes and in consultation with USFWS and relevant stakeholders, and that, where appropriate, mitigation will be implemented to reduce impacts to as low as practicable.

Equinor Wind recommends best practice for the avoidance and mitigation of impacts on avian and bird species is discussed as part of the E-TWG.

Decommissioning

Impacts associated with the decommissioning of the project are not expected to exceed those resulting from the construction and operations of the project, with any displaced bird species likely to return soon after the removal of wind turbines.

13.8 Additional Considerations

The overall approach for development of this EMP has been to acknowledge the dynamic nature of executing a successful offshore wind energy development off the coast while considering the complex dynamics of the natural resources and stakeholders. Furthermore, as Equinor Wind continues to gather information on existing conditions, it will be used to further understand and develop the impact assessments associated with the proposed project. As such, Equinor Wind has and will continuously evaluate and evolve this EMP so that all the components of the EMP are complete and sufficient. Given the nuances of offshore wind development in the United States, Equinor Wind expects that additional guidance and information will become available throughout the planning process and we will continue to consider its relevance to the EMP. Further, Equinor Wind will continue to rely on experience both from the mature overseas offshore wind industry and any experience that results from other offshore wind developments on the eastern seaboard of the United States.

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Attachment 1

Resumes

REDACTED

equinor

Attachment 2

Lease OCS-A 0512

equinor

RECEIVED
MAR 10 2017
Office of Renewable Energy Programs

UNITED STATES DEPARTMENT OF THE INTERIOR BUREAU OF OCEAN ENERGY MANAGEMENT **COMMERCIAL LEASE OF SUBMERGED LANDS FOR RENEWABLE ENERGY DEVELOPMENT ON THE OUTER CONTINENTAL SHELF**	Office Sterling, VA	Renewable Energy Lease Number OCS-A 0512
	Cash Bonus and/or Acquisition Fee $42,469,725.00	Resource Type Wind
Paperwork Reduction Act of 1995 statement: *This form does not constitute an information collection as defined by 44 U.S.C. § 3501 et seq. and therefore does not require approval by the Office of Management and Budget.*	Effective Date April 1, 2017	Block Number(s) See Addendum A

This lease, which includes any addenda hereto, is hereby entered into by and between the United States of America, ("Lessor"), acting through the Bureau of Ocean Energy Management ("BOEM"), its authorized officer, and

Lessee	**Interest Held**
Statoil Wind US LLC	100%

("Lessee"). This lease is effective on the date written above ("Effective Date") and will continue in effect until the lease terminates as set forth in Addendum "B." In consideration of any cash payment heretofore made by the Lessee to the Lessor and in consideration of the promises, terms, conditions, covenants, and stipulations contained herein and attached hereto, the Lessee and the Lessor agree as follows:

Section 1: Statutes and Regulations.

This lease is issued pursuant to subsection 8(p) of the Outer Continental Shelf Lands Act ("the Act"), 43 U.S.C. §§ 1331 *et seq.* This lease is subject to the Act and regulations promulgated pursuant to the Act, including but not limited to, offshore renewable energy and alternate use regulations at 30 CFR Part 585 as well as other applicable statutes and regulations in existence on the Effective Date of this lease. This lease is also subject to those statutes enacted (including amendments to the Act or other statutes) and regulations promulgated thereafter, except to the extent that they explicitly conflict with an express provision of this lease. It is expressly understood that amendments to existing statutes, including but not limited to the Act, and regulations may be made, and/or new statutes may be enacted or new regulations promulgated, which do not explicitly conflict with an express provision of this lease, and that the Lessee bears the risk that such amendments, regulations, and statutes may increase or decrease the Lessee's obligations under the lease.

Section 2: Rights of the Lessee.

(a) The Lessor hereby grants and leases to the Lessee the exclusive right and privilege, subject to the terms and conditions of this lease and applicable regulations, to: (1) submit to the Lessor for approval a Site Assessment Plan (SAP) and Construction and Operations Plan (COP) for the project identified in Addendum "A" of this lease; and (2) conduct activities in the area identified in Addendum "A" of this lease ("leased area"), and/or Addendum "D" of this lease ("project easement(s)"), that are described in a SAP or COP that has been approved by the Lessor. This lease does not, by itself, authorize any activity within the leased area.

(b) The rights granted to the Lessee herein are limited to those activities described in any SAP or COP approved by the Lessor. The rights granted to the Lessee are limited by the lease-specific terms, conditions, and stipulations required by the Lessor per Addendum "C."

(c) This lease does not authorize the Lessee to conduct activities on the Outer Continental Shelf (OCS) relating to or associated with the exploration for, or development or production of, oil, gas, other seabed minerals, or renewable energy resources other than those renewable energy resources identified in Addendum "A."

Section 3: Reservations to the Lessor.

(a) All rights in the leased area and project easement(s) not expressly granted to the Lessee by the Act, applicable regulations, this lease, or any approved SAP or COP, are hereby reserved to the Lessor.

(b) The Lessor will decide whether to approve a SAP or COP in accordance with the applicable regulations in 30 CFR Part 585. The Lessor retains the right to disapprove a SAP or COP based on the Lessor's determination that the proposed activities would have unacceptable environmental consequences, would conflict with one or more of the requirements set forth in subsection 8(p)(4) of the Act (43 U.S.C. § 1337(p)(4)), or for other reasons provided by the Lessor pursuant to 30 CFR 585.613(e)(2) or 30 CFR 585.628(f)(2). Disapproval of plans will not subject the Lessor to liability under this lease. The Lessor also retains the right to approve with modifications a SAP or COP, as provided in applicable regulations.

(c) The Lessor reserves the right to suspend the Lessee's operations in accordance with the national security and defense provisions of section 12 of the Act and applicable regulations.

(d) The Lessor reserves the right to authorize other uses within the leased area and project easement(s) that will not unreasonably interfere with activities described in an approved SAP and/or COP, pursuant to this lease.

Section 4: Payments.

(a) The Lessee must make all rent payments to the Lessor in accordance with applicable regulations in 30 CFR Part 585, unless otherwise specified in Addendum "B."

(b) The Lessee must make all operating fee payments to the Lessor in accordance with applicable regulations in 30 CFR Part 585, as specified in Addendum "B."

Section 5: Plans.

The Lessee may conduct those activities described in Addendum "A" only in accordance with a SAP or COP approved by the Lessor. The Lessee may not deviate from an approved SAP or COP except as provided in applicable regulations in 30 CFR Part 585.

Section 6: Associated Project Easement(s).

Pursuant to 30 CFR 585.200(b), the Lessee has the right to one or more project easement(s), without further competition, for the purpose of installing gathering, transmission, and distribution cables, pipelines, and appurtenances on the OCS, as necessary for the full enjoyment of the lease, and under applicable regulations in 30 CFR Part 585. As part of submitting a COP for approval, the Lessee may request that one or more easement(s) be granted by the Lessor. If the Lessee requests that one or more easement(s) be granted when submitting a COP for approval, such project easements will be granted by the Lessor in accordance with the Act and applicable regulations in 30 CFR Part 585 upon approval of the COP in which the Lessee has demonstrated a need for such easements. Such easements must be in a location acceptable to the Lessor, and will be subject to such conditions as the Lessor may require. The project easement(s) that would be issued in conjunction with an approved COP under this lease will be described in Addendum "D" to this lease, which will be updated as necessary.

Section 7: Conduct of Activities.

The Lessee must conduct, and agrees to conduct, all activities in the leased area and project easement(s) in accordance with an approved SAP or COP, and with all applicable laws and regulations.

The Lessee further agrees that no activities authorized by this lease will be carried out in a manner that:

(a) could unreasonably interfere with or endanger activities or operations carried out under any lease or grant issued or maintained pursuant to the Act, or under any other license or approval from any Federal agency;

(b) could cause any undue harm or damage to the environment;

(c) could create hazardous or unsafe conditions; or

(d) could adversely affect sites, structures, or objects of historical, cultural, or archaeological significance, without notice to and direction from the Lessor on how to proceed.

Section 8: Violations, Suspensions, Cancellations, and Remedies.

If the Lessee fails to comply with (1) any of the applicable provisions of the Act or regulations, (2) the approved SAP or COP, or (3) the terms of this lease, including associated Addenda, the Lessor may exercise any of the remedies that are provided under the Act and applicable regulations, including, without limitation, issuance of cessation of operations orders, suspension or cancellation of the lease, and/or the imposition of penalties, in accordance with the Act and applicable regulations.

The Lessor may also cancel this lease for reasons set forth in subsection 5(a)(2) of the Act (43 U.S.C. § 1334(a)(2)), or for other reasons provided by the Lessor pursuant to 30 CFR 585.437.

Non-enforcement by the Lessor of a remedy for any particular violation of the applicable provisions of the Act or regulations, or the terms of this lease, will not prevent the Lessor from exercising any remedy, including cancellation of this lease, for any other violation or for the same violation occurring at any other time.

Section 9: Indemnification.

The Lessee hereby agrees to indemnify the Lessor for, and hold the Lessor harmless from, any claim caused by or resulting from any of the Lessee's operations or activities on the leased area or project easement(s) or arising out of any activities conducted by or on behalf of the Lessee or its employees, contractors (including Operator, if applicable), subcontractors, or their employees, under this lease, including claims for:

a. loss or damage to natural resources,
b. the release of any petroleum or any Hazardous Materials,
c. other environmental injury of any kind,
d. damage to property,
e. injury to persons, and/or
f. costs or expenses incurred by the Lessor.

Except as provided in any addenda to this lease, the Lessee will not be liable for any losses or damages proximately caused by the activities of the Lessor or the Lessor's employees, contractors, subcontractors, or their employees. The Lessee must pay the Lessor for damage, cost, or expense due and pursuant to this section within 90 days after written demand by the Lessor. Nothing in this lease will be construed to waive any liability or relieve the Lessee from any penalties, sanctions, or claims that would otherwise apply by statute, regulation, operation of law, or could be imposed by the Lessor or other government agency acting under such laws.

"Hazardous Material" means

1. Any substance or material defined as hazardous, a pollutant, or a contaminant under the *Comprehensive Environmental Response, Compensation, and Liability Act* at 42 U.S.C. §§ 9601(14) and (33);
2. Any regulated substance as defined by the Resource Conservation and Recovery Act ("RCRA") at 42 U.S.C. § 6991 (7), whether or not contained in or released from underground storage tanks, and any hazardous waste regulated under RCRA pursuant to 42 U.S.C. §§ 6921 *et seq.*;

3. Oil, as defined by the Clean Water Act at 33 U.S.C. § 1321(a)(1) and the Oil Pollution Act at 33 U.S.C. § 2701(23); or
4. Other substances that applicable Federal, state, tribal, or local laws define and regulate as "hazardous."

Section 10: Financial Assurance.

The Lessee must provide and maintain at all times a surety bond(s) or other form(s) of financial assurance approved by the Lessor in the amount specified in Addendum "B." As required by the applicable regulations in 30 CFR Part 585, if, at any time during the term of this lease, the Lessor requires additional financial assurance, then the Lessee must furnish the additional financial assurance required by the Lessor in a form acceptable to the Lessor within 90 days after receipt of the Lessor's notice of such adjustment.

Section 11: Assignment or Transfer of Lease.

This lease may not be assigned or transferred in whole or in part without written approval of the Lessor. The Lessor reserves the right, in its sole discretion, to deny approval of the Lessee's application to transfer or assign all or part of this lease. Any assignment will be effective on the date the Lessor approves the Lessee's application. Any assignment made in contravention of this section is void.

Section 12: Relinquishment of Lease.

The Lessee may relinquish this entire lease or any officially designated subdivision thereof by filing with the appropriate office of the Lessor a written relinquishment application, in accordance with applicable regulations in 30 CFR Part 585. No relinquishment of this lease or any portion thereof will relieve the Lessee or its surety of the obligations accrued hereunder, including but not limited to, the responsibility to remove property and restore the leased area and project easement(s) pursuant to section 13 of this lease and applicable regulations.

Section 13: Removal of Property and Restoration of the Leased Area and Project Easement(s) on Termination of Lease.

Unless otherwise authorized by the Lessor, pursuant to the applicable regulations in 30 CFR Part 585, the Lessee must remove or decommission all facilities, projects, cables, pipelines, and obstructions and clear the seafloor of all obstructions created by activities on the leased area and project easement(s) within two years following lease termination, whether by expiration, cancellation, contraction, or relinquishment, in accordance with any approved SAP, COP, or approved Decommissioning Application, and applicable regulations in 30 CFR Part 585.

Section 14: Safety Requirements.

The Lessee must:

a. maintain all places of employment for activities authorized under this lease in compliance with occupational safety and health standards and, in addition, free from recognized hazards to employees of the Lessee or of any contractor or subcontractor operating under this lease;

b. maintain all operations within the leased area and project easement(s) in compliance with regulations in 30 CFR Part 585 and orders from the Lessor and other Federal agencies with jurisdiction, intended to protect persons, property and the environment on the OCS; and

c. provide any requested documents and records, which are pertinent to occupational or public health, safety, or environmental protection, and allow prompt access, at the site of any operation or activity conducted under this lease, to any inspector authorized by the Lessor or other Federal agency with jurisdiction.

Section 15: Debarment Compliance.

The Lessee must comply with the Department of the Interior's non-procurement debarment and suspension regulations set forth in 2 CFR Parts 180 and 1400 and must communicate the requirement to comply with these regulations to persons with whom it does business related to this lease by including this requirement in all relevant contracts and transactions.

Section 16: Equal Opportunity Clause.

During the performance of this lease, the Lessee must fully comply with paragraphs (1) through (7) of section 202 of Executive Order 11246, as amended (reprinted in 41 CFR 60-1.4(a)), and the implementing regulations, which are for the purpose of preventing employment discrimination against persons on the basis of race, color, religion, sex, or national origin. Paragraphs (1) through (7) of section 202 of Executive Order 11246, as amended, are incorporated in this lease by reference.

Section 17: Certification of Nonsegregated Facilities.

By entering into this lease, the Lessee certifies, as specified in 41 CFR 60-1.8, that it does not and will not maintain or provide for its employees any segregated facilities at any of its establishments and that it does not and will not permit its employees to perform their services at any location under its control where segregated facilities are maintained. As used in this certification, the term "facilities" means, but is not limited to, any waiting rooms, work areas, restrooms and washrooms, restaurants and other eating areas, timeclocks, locker rooms and other storage or dressing areas, parking lots, drinking fountains, recreation or entertainment areas, transportation, and housing facilities provided for employees. Segregated facilities include those that are segregated by explicit directive or those that are in fact segregated on the basis of race, color, religion, sex, or national origin, because of habit, local custom, or otherwise; provided, that separate or single-user restrooms and necessary dressing or sleeping areas must be provided to assure privacy as appropriate. The Lessee further agrees that it will obtain identical certifications from proposed contractors and subcontractors prior to awarding contracts or subcontracts unless they are exempt under 41 CFR 60-1.5.

Section 18: Notices.

All notices or reports provided from one party to the other under the terms of this lease must be in writing, except as provided herein and in the applicable regulations in 30 CFR Part 585. Written notices and reports must be delivered to the Lessee's or Lessor's Lease Representative, as specifically listed in Addendum "A," either electronically, by hand, by facsimile, or by United States first class mail, adequate postage prepaid. Each party must, as soon as practicable, notify the other of a change to their Lessee's or Lessor's Contact Information listed in Addendum "A" by a written notice signed by a duly authorized signatory and delivered by hand or United States first class mail, adequate postage prepaid. Until such notice is delivered as provided in this section, the last recorded contact information for either party will be deemed current for service of all notices and reports required under this lease. For all operational matters, notices and reports must be provided to the party's Operations Representative, as specifically listed in Addendum "A," as well as the Lease Representative.

Section 19: Severability Clause.

If any provision of this lease is held unenforceable, all remaining provisions of this lease will remain in full force and effect.

Section 20: Modification.

Unless otherwise authorized by the applicable regulations in 30 CFR Part 585, this lease may be modified or amended only by mutual agreement of the Lessor and the Lessee. No such modification or amendment will be binding unless it is in writing and signed by duly authorized signatories of the Lessor and the Lessee.

Statoil Wind US LLC	United States of America
Lessee	Lessor
(Signature of Authorized Officer)	(Signature of Authorized Officer)
Meagan Keiser	James F. Bennett
(Name of Signatory)	(Name of Signatory)
Secretary	Program Manager, Office of Renewable Energy Programs
(Title)	(Title)
March 9, 2017	MAR 15 2017
(Date)	(Date)

U.S. DEPARTMENT OF THE INTERIOR
BUREAU OF OCEAN ENERGY MANAGEMENT

ADDENDUM "A"

DESCRIPTION OF LEASED AREA AND LEASE ACTIVITIES

Lease Number OCS-A 0512

I. Lessor and Lessee Contact Information

Lessee Company Number: 15058

(a) Lessor's Contact Information

	Lease Representative	Operations Representative
Title	Program Manager	Same as Lease Representative
Address	U.S. Department of the Interior Bureau of Ocean Energy Management 45600 Woodland Road Mail Stop VAM-OREP Sterling, VA 20166	
Phone	(703) 787-1300	
Fax	(703) 787-1708	
Email	renewableenergy@boem.gov	

(b) Lessee's Contact Information

	Lease Representative	Operations Representative
Name	Alyssa Karotkin	Same as Lease Representative
Title	Commercial Negotiator	
Address	2107 CityWest Blvd. Suite 100 Houston, TX 77042	
Phone	(713) 425-9338	
Fax	(713) 918-8290	
Email	alyka@statoil.com	

II. Description of Leased Area

The total acreage of the leased area is approximately 32,112 hectares (79,350 acres)

This area is subject to later adjustment, in accordance with applicable regulations (e.g., contraction, relinquishment).

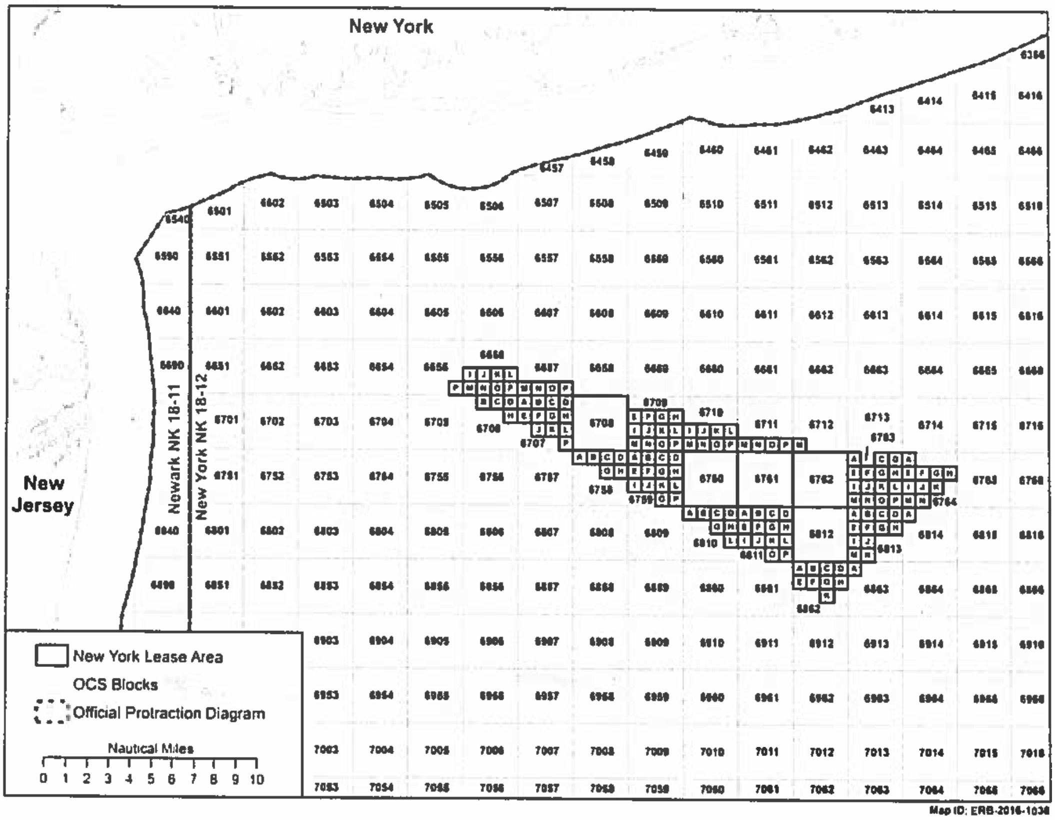
Lease OCS-A 0512

The following Blocks or portions of Blocks lying within Official Protraction Diagram New York NK18-12 are depicted on the map below and comprise 32,112 hectares (79,350 acres), more or less.

Official Protraction Diagram New York NK18-12

1) Block 6655 SE1/4 of SE1/4
2) Block 6656, S1/2
3) Block 6657, S1/2 of S1/2
4) Block 6706, N1/2 of NE1/4, SE1/4 of NE1/4, NE1/4 of NW1/4
5) Block 6707, N1/2, NE1/4 of SW1/4, N1/2 of SE1/4, SE1/4 of SE1/4
6) Block 6708, All of Block
7) Block 6709, S1/2 of N1/2, S1/2
8) Block 6710, S1/2
9) Block 6711, S1/2 of S1/2
10) Block 6712, SW1/4 of SW1/4
11) Block 6758, NE1/4, N1/2 of NW1/4
12) Block 6759, N1/2, , N1/2 of SW1/4, SE1/4
13) Block 6760, All of Block
14) Block 6761, All of Block
15) Block 6762, All of Block
16) Block 6763, NE1/4, NW1/4 of NW1/4, S1/2 of NW1/4, S1/2 ,
17) Block 6764, S1/2 of NE1/4, NW1/4 of NW1/4, S1/2 of NW1/4, SW1/4, NW1/4 of SE1/4
18) Block 6810, NE1/4, N1/2 of NW1/4, NE1/4 of SE1/4
19) Block 6811, N1/2, N1/2 of SW1/4, SE1/4
20) Block 6812, All of Block
21) Block 6813, N1/2, SW1/4
22) Block 6814, NW1/4 of NW1/4
23) Block 6862, N1/2, NW1/4 of SE1/4
24) Block 6863, NW1/4 of NW1/4

For the purposes of these calculations, a full Block is 2,304 hectares. The acreage of a hectare is 2.471043930.



Map of Lease OCS-A 0512

III. Renewable Energy Resource

Wind

IV. Description of the Project

A project to generate energy using wind turbine generators and any associated resource assessment activities, located on the OCS in the leased area, as well as associated offshore substation platforms, inner array cables, and subsea export cables.

V. Description of Project Easement(s)

Once approved, the Lessor will incorporate Lessee's project easement(s) in this lease as ADDENDUM "D."

U.S. DEPARTMENT OF THE INTERIOR
BUREAU OF OCEAN ENERGY MANAGEMENT

ADDENDUM "B"

LEASE TERM AND FINANCIAL SCHEDULE

Lease Number OCS-A 0512

I. Lease Term

The duration of each term of the lease is described below. The terms may be extended or otherwise modified in accordance with applicable regulations in 30 CFR Part 585.

Lease Term	Duration
Preliminary Term	1 year
Site Assessment Term	5 years
Operations Term	25 years

Schedule: ADDENDUM "C" includes a schedule and reporting requirements for conducting site characterization activities.

Renewal: The Lessee may request renewal of the operations term of this lease, in accordance with applicable regulations in 30 CFR Part 585. The Lessor, at its discretion, may approve a renewal request to conduct substantially similar activities as were originally authorized under this lease or in an approved plan. The Lessor will not approve a renewal request that involves development of a type of renewable energy not originally authorized in the lease. The Lessor may revise or adjust payment terms of the original lease as a condition of lease renewal.

II. Definitions

"Available for Commercial Operations" means the status of an individual wind generation turbine on or after the first day that it engages in Commercial Operations on the lease until the day when it is permanently decommissioned. These dates are determined by the COP.

"Commercial Operations" means the generation of electricity or other energy product for commercial use, sale, or distribution.

"Commercial Operation Date," or "COD," refers to the date on which the Lessee first begins Commercial Operations on the lease.

"Delivery Point" is the meter identified in the COP where the Lessee's facility interconnects with the electric grid to deliver electricity for sale.

"Lease Issuance Date" refers to the date on which this lease has been signed by *both* the Lessee and the Lessor.

"Effective Date" has the same meaning as "effective date" in BOEM regulations provided in 30 CFR 585.237.

"End Date" refers to the earlier of a) the last calendar day of the last month of the Operations Term; or b) the date on which the lease terminates in the event of a lease termination.

"Lease Anniversary" refers to the anniversary of the Effective Date of the lease.

III. Payments

Unless otherwise authorized by the Lessor in accordance with the applicable regulations in 30 CFR Part 585, the Lessee must make payments as described below.

(a) ***Rent.*** The Lessee must pay rent as described below:

Rent payments prior to the COD, or prior to the lease End Date in the event that the lease terminates prior to the COD, are calculated by multiplying the acres in the leased area by the rental rate per acre as follows:

Lease OCS-A 0512
- Acres in Leased Area: 79,350
- Annual Rental Rate: $3.00 per acre or fraction thereof
- Rental Fee for Entire Leased Area: $3.00 x 79,350 = $238,050

The first year's rent payment of $238,050 is due within 45 days of the date that the lease is received by the Lessee for execution, in accordance with 30 CFR 585.503. Rent for the entire leased area for the next year and for each subsequent year is due on or before each Lease Anniversary through the year in which the COD occurs. The rent for each year subsequent to the COD on the imputed portion of the lease not authorized for Commercial Operations is due on or before each Lease Anniversary. The imputed portion of the lease that is not authorized for Commercial Operations at each Lease Anniversary in year t, S_t, and the corresponding Adjusted Annual Rent Payment will be determined as follows:

(A) $S_t = \left(1 - \frac{M_t'}{MAX(M_t' : for\ all\ t \geq 2)}\right)$

(B) $Adjusted\ Annual\ Rent\ Payment = S_t * Rental\ Fee\ for\ Entire\ Leased\ Area$

Where:
S_t = Portion of the lease not authorized for Commercial Operations in year *t* based on the definition of *t* in Section III (b) (4) below.

M_t' = Actual Nameplate capacity expressed in megawatts (MW) rounded to the nearest second decimal in year t of Commercial Operations on the lease as defined in Section III (b)(4) below, prior to any adjustments as specified in the most recent approved COP for turbine maintenance, replacements, repowering, or decommissioning. For our purposes nameplate capacity is the maximum rated electric output the turbines of the wind farm facility under commercial operations can produce at their rated wind speed designated by the turbine's manufacturer.

$MAX(M_t')$ = Highest value of M_t' projected in the most recent approved version of the COP to be achieved in any year of Commercial Operations on the lease.

The Adjusted Annual Rent Payment calculated in Equation (A) herein, will be rounded up to the nearest dollar. The annual rent payments will be set forth in ADDENDUM "E" when the COP is initially approved or subsequently revised.

Consider an example of a 1,000 MW project on a lease with an Effective Date of January 1, 2017 and a COD of January 1, 2025 on a lease area consisting of 100,000 acres as follows:

Payment (Jan. 1st)	M_t' (MW)	$MAX(M_t')$ (MW)	$\left(1 - \frac{M_t'}{MAX(M_t')}\right)$	Rental Fee for Entire Area	Payment Amount
2017	0	1,000	1.0	$300,000	$300,000
...	...		...		...
2024	0		1.0		$300,000
2025	500		0.5		$150,000
2026	500		0.5		$150,000
2027	500		0.5		$150,000
2028	800		0.2		$60,000
2029	800		0.2		$60,000
2030	800		0.2		$60,000
2031	1,000		0.0		$0

In the event a revised COP is approved by BOEM with an alternative installation schedule that differs from the previously-approved COP, the Lessee must make subsequent payments based on the revised installation schedule. In addition, the Lessee must make a payment equal to the sum of any incremental annual rent payments that would have been due at the Lease Anniversary of prior years based on the differences between the Initial Installation Schedules specified in the previously-approved COP and the revised COP, plus interest on the annual balances, in accordance with 30 CFR 1218.54.

Consider an example whereby the initial COP specified an installation schedule with all 1,000 MW online at the COD, i.e., M_t' is 1,000 MW at COD. The following table demonstrates how the back rent payments would be calculated if the project was initially scheduled as a single phase, but then later determined to be the three-phase project as shown in the previous example in a revised COP approved prior to the payment due on January 1, 2026.

Payment (Jan. 1st)	Initial M_t^I (MW)	Revised M_t^I (MW)	Single-Phase Payment Amount	Three-Phase Payment Amount	Back Rent Payment Amount	Subsequent Rent Payment Amount
2017	0	0	$300,000	$300,000	$0	$0
...	...	...	...	...	...	...
2024	0	0	$300,000	$300,000	$0	$0
2025	1,000	500	$0	$150,000	$150,000	$0
2026	1,000	500	$0	$150,000	$0	$150,000
2027	1,000	500	$0	$150,000	$0	$150,000
2028	1,000	800	$0	$60,000	$0	$60,000
2029	1,000	800	$0	$60,000	$0	$60,000
2030	1,000	800	$0	$60,000	$0	$60,000
2031	1,000	1,000	$0	0	$0	$0

The last rent payment prior to Commercial Operations being authorized on the entire lease area, i.e., the year in which the value of S_t is equal to zero, or prior to the lease End Date, in the event that the lease terminates prior to Commercial Operations being authorized on the entire lease area, will represent the final rent payment, unless a revised COP identifying an alternative maximum initial capacity is approved by BOEM. All rent payments, including the last rent payment, are payable for the full year and will not be prorated to the COD or other installation milestones. The COD is equivalent to the authorization date for the first phase of development on the lease, to be updated based on the initial or revised approved COP documentation. The schedule of rent payments on the lease is defined in ADDENDUM "E". All rent payments must be made as required in 30 CFR 1218.51. Late rent payments will be charged interest in accordance with 30 CFR 1218.54.

(1) ***Project Easement.***

Rent for any project easement(s) is described in ADDENDUM "D".

(2) ***Relinquishment.***

If the Lessee submits an application for relinquishment of a portion of the leased area within the first 45 calendar days following the date that the lease is received by the Lessee for execution, and the Lessor approves that application, no rent payment will be due on that relinquished portion of the leased area. Later relinquishments of any leased area will reduce the Lessee's rent payments due the year following the Lessor's approval of the relinquishment, through a reduction in the Acres in Leased Area, the corresponding Rental Fee for the Entire Leased Area, and any related Adjusted Annual Rent Payments.

(b) ***Operating Fee.*** The Lessee must pay an operating fee as described below:

(1) **Initial Operating Fee Payment.**

The Lessee must pay an initial prorated operating fee within 45 calendar days after the COD. The initial operating fee payment covers the first year of Commercial Operations on the lease and will be calculated in accordance with the following subsection (4), using an operating fee rate of 0.02 and a capacity factor of 0.4.

(2) **Annual Operating Fee Payments.**

The Lessee must pay the operating fee for each subsequent year of Commercial Operations on or before each Lease Anniversary following the formula in subsection (4). The Lessee must calculate each operating fee annually subsequent to the initial operating fee payment using an operating fee rate of 0.02 through the twenty-five year operations term of the lease. The capacity factor of 0.4 will remain in effect until the Lease Anniversary of the year in which the Lessor adjusts the capacity factor.

(3) **Final Operating Fee Payment.**

The final operating fee payment is due on the Lease Anniversary prior to the End Date. The final operating fee payment covers the last year of Commercial Operations on the lease and will be calculated in accordance with the formula in subsection (4) as follows.

(4) **The formula for calculating the operating fee in year *t*.**

F_t	=	M_t	*	H	*	c_p	*	P_t	*	r_t
(annual operating fee)		(nameplate capacity)		(hours per year)		(capacity factor)		(power price)		(operating fee rate)

Where:

t =	the year of Commercial Operations on the lease starting from each Lease Anniversary, where *t* equals 1 represents the year beginning on the Lease Anniversary prior to, or on, the COD.
F_t =	the dollar amount of the annual operating fee in year *t*.
M_t =	the nameplate capacity expressed in megawatts (MW) rounded to the nearest second decimal place in year *t* of Commercial Operations on the lease. The value of M_t, reflecting the availability of turbines, will be determined based on the COP. This value will be adjusted to reflect any modifications to the COP approved by BOEM as of the date each operating fee payment is due, in accordance with the calculation in Equation 1, for each year of Commercial Operations on the lease. (1) $M_t = \sum_{w=1}^{W_t}\left(N_w * \left[\frac{\left(\sum_{d=1}^{D} E_{w,t,d}\right)}{D}\right]\right)$ Where:

W_t = Number of individual wind generation turbines, *w*, that will be available for Commercial Operations during any day of the year, *t*, per the COP.

N_w = Nameplate capacity of individual wind generation turbine, *w*, per the COP expressed in MW.

$E_{w,t,d}$ = Indicates whether individual wind generation turbine, *w*, will be available for Commercial Operations on day *d* of year *t*. The value is set to 1 for any day in year *t* for which the condition is true, i.e., the wind turbine will be available for Commercial Operations, and zero for any day in year *t* for which the condition is false, i.e., the wind turbine will not be available for Commercial Operations. The month of February is always assumed to have 28 days for purposes of this calculation, where March 1st will be counted as the first day of Commercial Operations if Commercial Operations commence on February 29th of a leap year.

D = Days in the year set equal to 365 in all years for purposes of this calculation.

M_t may be reduced only in the event that installed capacity is permanently decommissioned per the COP. M_t will not be changed in response to routine or unplanned maintenance of units, including the temporary removal of a nacelle for off-site repair or replacement with a similar unit.

EXAMPLE: Assume that the Lease Anniversary is January 1st, the COD is July 1, 2025, that the facility will ultimately have 100 individual wind generation turbines with a nameplate capacity of 5.0 MW each, and that the COP specifies the following, cumulative installation schedule for wind turbines to become available for Commercial Operations:

- July 1, 2025 (COD): 20 turbines (20 new units);
- October 1, 2025: 45 turbines (25 new units);
- January 1, 2026: 50 turbines (5 new units);
- July 1, 2026: 65 turbines (15 new units);
- January 1, 2027: 95 turbines (30 new units);
- February 29, 2027: 100 turbines (5 new units).

Further assume that the COP calls for 50 of the turbines to be decommissioned after September 30, 2046 (t = 22), and that the remaining turbines are decommissioned at the End Date of March 15, 2047 (t = 23).

The value of M_t would be estimated as demonstrated in Table 1a for each year of Commercial Operations on the lease in this example.

Table 1a: Example of M_t Calculations for Installation and Decommissioning

t	Turbines	MW	Commercial Operations Period	Comm. Ops. Days	Days in Year	Share of Days	MW	M_t
1	20	100	Jul. 1st to Dec. 31st	184	365	50.41%	50.41	81.92
	25	125	Oct. 1st to Dec. 31st	92		25.21%	31.51	
2	50	250	Jan. 1st to Dec. 31st	365		100.00%	250.00	287.81
	15	75	Jul. 1st to Dec. 31st	184		50.41%	37.81	
3	95	475	Jan. 1st to Dec. 31st	365		100.00%	475.00	495.96
	5	25	Mar. 1st to Dec. 31st	306		83.84%	20.96	
4	100	500	Jan. 1st to Dec. 31st	365		100.00%	500.00	500.00
...	...	...	...	...		...	...	...
21	100	500	Jan. 1st to Dec. 31st	365		100.00%	500.00	500.00
22	50	250	Jan. 1st to Dec. 31st	365		100.00%	250.00	436.98
	50	250	Jan. 1st to Sep. 30th	273		74.79%	186.98	
23	50	250	Jan. 1st to Mar. 15th	74		20.27%	50.68	50.68

To illustrate the impact of decommissioning a portion of the individual wind generation turbines and replacing them with units of greater capacity on the calculation of M_t, assume that at the end of March 31, 2029, 10 units are to be made unavailable due to decommissioning, and that the incremental units have a capacity of 7.0 MW and are expected to be made available for Commercial Operations on September 15, 2029. The impact on M_t in 2029 and in subsequent years starting in 2030 and continuing until decommissioning is illustrated in Table 1b.

Table 1b: Example of M_t Calculations for Repowering

t	Turbines	MW	Commercial Operations Period	Comm. Ops. Days	Days in Year	Share of Days	MW	M_t
5	90 (5.0)	450	Jan. 1st to Dec. 31st	365	365	100.00%	450.00	483.04
	10 (5.0)	50	Jan. 1st. to Mar. 31st	90		24.66%	12.33	
	10 (7.0)	70	Sep. 15th to Dec. 31st	108		29.59%	20.71	
6	90 (5.0)	450	Jan. 1st to Dec. 31st	365		100.00%	450.00	520.00
	10 (7.0)	70	Jan. 1st to Dec. 31st	365		100.00%	70.00	

H = the number of hours in the year for billing purposes which is equal to 8,760 for all years of Commercial Operations on the lease.

c_p = the "Capacity Factor" in Performance Period p, which represents the share of anticipated generation of the facility that is delivered to where the Lessee's facility interconnects with the electric grid (i.e. the Delivery Point) relative to its generation at continuous full power operation at the nameplate capacity, expressed as a decimal between zero and one.

The initial Capacity Factor (c_0) will be set to 0.4.

The Capacity Factor will be subject to adjustment at the end of each Performance Period. After the sixth year of Commercial Operations on the lease has concluded, the Lessee will utilize data gathered from years two through six of Commercial Operations on the lease and propose a revised Capacity Factor to be used to calculate subsequent annual payments, as provided for in Table 2 below. A similar process will be conducted at the conclusion of each five-year Performance Period, thereafter.

Table 2: Definition of Performance Periods

Performance Period (p)	Commercial Operation Years (t)	Payments Affected by Adjustment	Capacity Factor (c)	Date End Year (n)
0 (COD)	Not Applicable	Payments 1 to 7	c_0=0.4	--
1	t = 2 to 6	Payments 8 to 12	c_1	n_1=6
2	t = 7 to 11	Payments 13 to 17	c_2	n_2=11
3	t = 12 to 16	Payments 18 to 22	c_3	n_3=16
4	t = 17 to 21	Payments 23 to End Date	c_4	n_4=21

Adjustments to the Capacity Factor

The Actual 5-year Average Capacity Factor (Xp) is calculated for each Performance Period after COD ($p > 0$) per Equation 2 below. Xp represents the sum of actual, metered electricity generation in megawatt-hours (MWh) at the Delivery Point to the electric grid (A_t) divided by the amount of electricity generation in MWh that would have been produced if the facility operated continuously at its full, stated capacity (M_t) in all of the hours (h_t) in each year, t, of the corresponding five-year period.

$$\textbf{(2)}\quad X_p = \frac{\sum_{t=n-4}^{n} A_t}{\left(\sum_{t=n-4}^{n} M_t * h_t\right)}$$

Where:

M_t = Nameplate Capacity as defined above.

n = "Date End Year" value for the Performance Period, p, as defined in Table 2.

p = Performance Period as defined in Table 2.

A_t = Actual generation in MWh associated with each year of Commercial Operations, t, on the lease that is transferred at the Delivery Point; Delivery Point meter data supporting the values submitted for annual actual generation must be recorded, preserved, and timely provided to the Lessor upon request. In the event the Lessor requires the assistance of the Lessee in obtaining information useful in verifying such information, for example by waiving confidentiality with respect to data held by a third party, such assistance must be timely provided.

h_t = Hours in the year on which the Actual Generation associated with each year of Commercial Operations, t, on the lease is based; this definition of "hours in the year" differs from the definition of H in the operating fee equation above. The hours in the year for purposes of calculating the capacity factor must take into account the actual number of hours, including those in leap years.

The value of the Capacity Factor at the outset of Commercial Operations ($p = 0$) is set

	to 0.4 as stated in equation 3: **(3)** $c_0 = 0.4$ The value of the Capacity Factor corresponding to each Performance Period (c_p) is set according to equations 4A, 4B, and 4C as follows for each value of p greater than zero. The Capacity Factor is set equal to the Actual 5-Year Average Capacity Factor provided that the value falls within a range of plus or minus 10 percent of the previous Performance Period's capacity factor. **(4A)** $c_p = X_p$ for $c_{p-1} * 0.90 \leq X_p \leq c_{p-1} * 1.10$ **(4B)** $c_p = c_{p-1} * 0.90$ for $X_p < c_{p-1} * 0.90$ **(4C)** $c_p = c_{p-1} * 1.10$ for $X_p > c_{p-1} * 1.10$ All values for c_p must be rounded to the nearest third decimal place.
P_t =	a measure of the annual average wholesale electric power price expressed in dollars per MW hour. The Lessee must calculate P_t at the time each operating fee payment is due, subject to approval by the Lessor. The Base Price (P_b) must equal the weighted average of the peak and off-peak spot price indices for the selected electric region for the most recent year of data available as reported by the selected source for this information. As part of its COP approval, BOEM will designate both the electric region and the source of the information to be used in determining the Base Price. The electric region will be the region associated with the location(s) where the transmission cable for the project makes landfall. A region may consist of a location (e.g., transmission hub), zone, state or other area. If the cable makes landfall in Zone J of New York, for example, the electric region could be Zone J or the entire New York control area, but not Zone K. The peak and off-peak price indices must be weighted 52.0% and 48.0%, respectively, for purposes of estimating the weighted index value for the Base Price. For example, in the March 12, 2012 State of the Markets Report the peak price index for 2011 was $51.99/MWh and the corresponding off-peak price index for 2011 was $33.94/MWh, resulting in a weighted index value for the Base Price for 2011 (P_{2011}) of $43.33/MWh (=52.0% * $51.99 / MWh + 48.0% *$33.94 / MWh). The calculation of P_b must be rounded up to the nearest, second decimal place. The Base Price must be adjusted for inflation from the year associated with the published spot prices to the year in which the operating fee is to be paid as shown in equations (5A) and (5B):

$$\textbf{(5A)}\quad P_t = P_b * \left(\frac{GDP_g}{GDP_{g-1}}\right)^{y-g} * \left(\frac{GDP_g}{GDP_b}\right) \text{ for } g \geq b$$

$$\textbf{(5B)}\quad P_t = P_b * \left(\frac{GDP_g}{GDP_{g-1}}\right)^{y-b} \quad \text{for } g < b$$

Where:

GDP = Annual Implicit Price Deflators for Gross Domestic Product (GDP deflator index) from Table 1.1.9, line 1, in the Survey of Current Business published by the U.S. Bureau of Economic Analysis (BEA) in the specified period; the latest version of this data is currently available at:

http://bea.gov/iTable/iTable.cfm?ReqID=9&step=1

If BEA stops publishing the data required for this calculation, or the specified location of the data changes over time, the Lessor will specify an alternative source of data and methodology that it considers approximately equivalent.

b = The most recent year for which BOEM's identified source reports the appropriate electricity spot price data expressed as the year, e.g., 2009, as in the illustrative example below.

g = The most recent year for which GDP deflator indices are available from BEA expressed as the year, e.g., 2011, as in the illustrative example below.

y = The year the annual payment is due expressed as the year corresponding to the value of t described above, e.g., 2013, as in the illustrative example below.

The second term on the right-hand side of equation (5A) represents a projected annual change in the index of inflation employing the last year of data available from BEA, while the third term represents the cumulative change in the index of inflation up to the previous year.

Example:

The following hypothetical example is provided to illustrate the methodology using Equation (5A) and the illustrative values provided for b, g, and y above, applied to historical GDP deflator data. If the actual price indices are based on 2009 data and the GDP deflator indices are available for 2011, the inflation-adjusted price index value would be determined from equation (5A) as follows for a payment occurring in y = 2013:

	$P_{t(2013)} = P_{2009} * \left(\frac{GDP_{2011}}{GDP_{2010}}\right)^{2013-2011} * \left(\frac{GDP_{2011}}{GDP_{2009}}\right) = \frac{\$40.69}{MWh} * \left(\frac{113.361}{110.992}\right)^{2} * \left(\frac{113.361}{109.729}\right) = \frac{\$43.85}{MWh}$ Note: The current GDP deflator index is 113.361 for 2011, 110.992 for 2010, and 109.729 for 2009 (last revised by BEA on April 27, 2012); the FERC index price for the year 2009 is \$38.40/MWh (On-peak: \$44.60/MWh; Off-peak: \$31.68/MWh; last revised March 12, 2012). Although 2011 FERC prices are available, the 2009 prices are used in the example to illustrate the concept. The Lessor and the Lessee will use the latest FERC price indices and revised BEA GDP deflator index values at the time the pricing adjustments are made. The source of data used in the calculations must be noted in the Lessee's documentation supporting their estimate of the value of P_t each year for review and approval by the Lessor.
r_t =	the operating fee rate of 0.02 (2%).

(c) ***Reporting, Validation, Audits, and Late Payments.***

The Lessee must submit the values used in the operating fee formula to the Lessor at the time the annual payment based on these values is made. Submission of this and other reporting, validation, audit and late payment information as requested by the Lessor must be sent to the Lessor using the contact information indicated in ADDENDUM "A", unless the Lessor directs otherwise. Failure to submit the estimated values and the associated documentation on time to the Lessor may result in penalties as specified in applicable regulations.

Within 60 calendar days of the submission by the Lessee of the annual payment, the Lessor will review the data submitted and validate that the operating fee formula was applied correctly. If the Lessor validation results in a different operating fee amount, the amount of the annual operating fee payment will be revised to the amount determined by the Lessor.

The Lessor also reserves the right to audit the meter data upon which the Actual 5-year Average Capacity Factor is based at any time during the lease term. If, as a result of such audit, the Lessor determines that any annual operating fee payment was calculated incorrectly, the Lessor has the right to correct any errors and collect the correct annual operating fee payment amount.

If the annual operating fee is revised downward as a result of the Lessee's calculations, as validated by the Lessor, or an audit of meter data conducted by the Lessee or Lessor, the Lessee will be refunded the difference between the amount of the payment received and the amount of the revised annual operating fee, without interest. Similarly, if the payment amount is revised upward, the Lessee is required to pay the difference between the amount of the payment received and the amount of the revised annual operating fee, plus interest on the balance, in accordance with 30 CFR § 1218.54.

Late operating fee payments will be charged interest in accordance with 30 CFR § 1218.54.

IV. Financial Assurance

The Lessor will base the determination for the amounts of all SAP, COP, and decommissioning financial assurance requirements on estimates of the cost to meet all accrued lease obligations. The Lessor determines the amount of supplemental and decommissioning financial assurance requirements on a case-by-case basis. The amount of financial assurance required to meet all lease obligations includes:

- The projected amount of rent and other payments due the Lessor over the next 12 months;
- Any past due rent and other payments;
- Other monetary obligations (e.g., fines, liens); and
- The estimated cost of facility decommissioning.

(a) **Initial Financial Assurance Due Prior to Lease Issuance Date.** In accordance with 30 CFR 585.515, the Lessee must provide an initial lease-specific bond, or other approved means of meeting the Lessor's initial financial assurance requirements in an amount equal to $100,000.

(b) **Additional Financial Assurance.** In addition to the initial lease-specific financial assurance previously discussed and as set forth in 30 CFR 585.516-.517, the Lessee is also required to provide additional supplemental bonds associated with the SAP and COP, or other form of financial assurances and a decommissioning bond or other approved means of meeting the Lessee's decommissioning obligations.

(1) Prior to the Lessor's approval of a SAP, the Lessor will require an additional supplemental bond or other form of financial assurance in an amount determined by the Lessor based on the complexity, number, and location of all facilities involved in the site assessment activities planned in the SAP, and estimates of the costs to meet all accrued obligations, in accordance with applicable BOEM regulations (30 CFR 585.515-537). The supplemental financial assurance requirement is in addition to the initial lease-specific financial assurance in the amount of $100,000. The Lessee may meet these obligations by providing a new bond or other acceptable form of financial assurance, or increasing the amount of its existing bond or other form of financial assurance.

(2) Prior to the Lessor's approval of a COP, the Lessor may require an additional supplemental bond or other form of financial assurance in an amount determined by the Lessor based on the complexity, number, location of all facilities, activities and Commercial Operations planned in the COP, and estimates of the costs to meet

all accrued obligations, in accordance with applicable BOEM regulations (30 CFR 585.515-537). The supplemental financial assurance requirement is in addition to the initial lease-specific financial assurance in the amount of $100,000, and any additional supplemental bond or other form of financial assurance required with the SAP. The Lessee may meet these obligations by providing a new bond or other acceptable form of financial assurance, or increasing the amount of its existing bond or other form of financial assurance.

(3) The Lessor will require a decommissioning bond or other form of financial assurance based on the anticipated decommissioning costs in accordance with applicable BOEM regulations (30 CFR 585.515-537). The decommissioning obligation must be guaranteed through an acceptable form of financial assurance, and will be due on a schedule to be approved by BOEM in accordance with the number of facilities installed or being installed.

(c) **Adjustments to Financial Assurance Amounts.** The Lessor reserves the right to adjust the amount of any financial assurance requirement (initial, supplemental, or decommissioning) associated with this lease and/or reassess the Lessee's cumulative lease obligations, including decommissioning obligations, at any time. If the Lessee's cumulative lease obligations and/or liabilities increase or decrease, the Lessor will notify the Lessee of any intended adjustment to the financial assurance requirements and provide the Lessee an opportunity to comment in accordance with applicable BOEM regulations.

U.S. DEPARTMENT OF THE INTERIOR
BUREAU OF OCEAN ENERGY MANAGEMENT

ADDENDUM "C"

LEASE-SPECIFIC TERMS, CONDITIONS, AND STIPULATIONS

Lease Number OCS-A 0512

The Lessee's rights to conduct activities on the leased area are subject to the following terms, conditions, and stipulations. The Lessor reserves the right to impose additional terms and conditions incident to the future approval or approval with modifications of plans, such as a Site Assessment Plan (SAP) or Construction and Operations Plan (COP).

1 DEFINITIONS

1.1 Definition of "Archaeological Resource": The term "archaeological resource" has the same meaning as "archaeological resource" in BOEM regulations provided in 30 CFR 585.112.

1.2 Definition of "Dynamic Management Area (DMA)": The term "DMA" refers to a temporary area designated by the National Oceanic and Atmospheric Administration (NOAA) National Marine Fisheries Service (NMFS) and a circle around a confirmed North Atlantic right whale sighting. The radius of this circle expands incrementally with the number of whales sighted, and a buffer is included beyond the core area, as designated by NMFS, to allow for whale movement. NOAA NMFS may apply mandatory or voluntary speed restrictions. Information regarding the location and status of applicable DMAs is available from the NMFS Office of Protected Resources.

1.3 Definition of "Effective Date": The term "Effective Date" has the same meaning as "effective date" in BOEM regulations provided in 30 CFR 585.237.

1.4 Definition of "Geological and Geophysical Survey (G&G Survey)": The term "G&G Survey" serves as a collective term for surveys that collect data on the geology of the seafloor and landforms below the seafloor. High resolution geophysical surveys and geotechnical (sub-bottom) exploration are components of G&G surveys.

1.5 Definition of "Geotechnical Exploration": The term "Geotechnical Exploration" is used to refer to the process by which site-specific sediment and underlying geologic data are acquired from the seafloor and the sub-bottom and includes geotechnical surveys utilizing borings, vibracores, and cone penetration tests.

1.6 Definition of "High Resolution Geophysical Survey (HRG Survey)": The term "HRG Survey" means a marine remote-sensing survey using, but not limited to, such equipment as side-scan sonar, magnetometer, shallow and medium (seismic) penetration sub-bottom profiler systems, narrow beam or multibeam echo sounder, or other such equipment employed for the purposes of providing data on geological conditions, identifying shallow hazards, identifying archaeological resources, charting bathymetry, and gathering other site characterization information.

1.7 Definition of "Listed Species": The term "listed species," also referred to in adjective form as "listed," means any species of fish, wildlife, or plant that has been determined to be endangered or threatened under Section 4 of the Endangered Species Act. Listed species are provided in 50 CFR 17.11-17.12.

1.8 Definition of "Plan": The term "plan" means a Site Assessment Plan (SAP) and/or a Construction and Operations Plan (COP).

1.9 Definition of "Protected-Species Observer": The term "protected-species observer" or "PSO" means an individual who is trained in the shipboard identification and behavior of protected species. Protected species include marine mammals (those protected under the Endangered Species Act and those protected under the Marine Mammal Protection Act) and sea turtles.

1.10 Definition of "Ramp-up": The term "ramp-up" means the process of incrementally increasing the acoustic source level of the survey equipment when conducting HRG surveys until it reaches the operational setting.

1.11 Definition of "Site Assessment Activities": The term "site assessment activities" or "site assessment," has the same meaning as "site assessment activities" in 30 CFR 585.112.

1.12 Definition of "Qualified Marine Archaeologist": The term "qualified marine archaeologist" means a person retained by the Lessee who meets the Secretary of the Interior's Professional Qualifications Standards for Archaeology (48 FR 44738-44739), and has experience analyzing marine geophysical data.

1.13 Definition of "Take": The terms "Takes," "Taken," and "Taking" have the same meaning as the term "take" as defined in 16 U.S.C. § 1532(19).

2 SCHEDULE

2.1 Site Characterization

2.1.1 Survey Plan(s). Prior to conducting survey activities in support of the submission of a plan, the Lessee must submit to the Lessor at least one complete survey plan. Each distinct survey effort (e.g., mobilization) must be addressed by a survey plan, although a single survey plan may cover more than one effort. Each survey plan must include details and timelines of the survey activities to be conducted on this lease necessary to support the submission of a plan (i.e., necessary to satisfy the information requirements in the applicable regulations, including but not limited to 30 CFR 585.606, 610, 611, 621, 626, 627). Each survey plan must include a description of historic property identification surveys that will be conducted to gather the information required by BOEM to complete review of a plan under the National Historic Preservation Act (e.g., offshore and onshore archaeological surveys and surveys within the viewshed of proposed renewable energy structures). Each survey plan must be consistent with the Lessee's Fisheries Communication Plan (see 4.1.5) and include a description of the Lessee's intentions to coordinate with the U.S. Coast Guard to prepare a Notice to Mariners for the specific survey activities described in the survey plan.

The Lessee must submit each survey plan to the Lessor at least 30 calendar days prior to the date of the required pre-survey meeting with the Lessor (See 2.1.2). Prior to the commencement of any survey activities described in the survey plan, the Lessee must modify each survey plan to address any comments the Lessor submits to the Lessee on the contents of the survey plan in a manner deemed satisfactory by the Lessor.

2.1.2 Pre-Survey Meeting(s) with the Lessor. At least 60 days prior to the initiation of survey activities in support of the submission of a plan, the Lessee must hold a pre-survey meeting with the Lessor to discuss the applicable proposed survey plan and timelines. The Lessee must ensure the presence at this meeting of a Qualified Marine Archaeologist and/or other relevant subject matter experts (e.g., terrestrial archaeologists, architectural historians) related to the proposed historic property identification surveys described in the survey plan. The Lessor may request the presence of other relevant subject matter experts at this meeting.

2.2 Progress Reporting

2.2.1 Semi-Annual Progress Report. The Lessee must submit to the Lessor a semi-annual (i.e., every six months) progress report through the duration of the site assessment term that includes a brief narrative of the overall progress since the last progress report, or – in the case of the first report – since the Effective Date. The progress report must include an update regarding progress in executing the activities included in the survey plan(s), and include as an enclosure an updated survey plan(s) accounting for any modifications in schedule.

3 NATIONAL SECURITY AND MILITARY OPERATIONS

The Lessee must comply with the requirements specified in stipulations 3.1, 3.2, and 3.3 when conducting site characterization activities in support of plan submittal.

3.1 Hold and Save Harmless

The Lessee assumes all risks of damage or injury to persons or property that occurs in, on, or above the OCS, to any persons or to any property of any person or persons in connection with any activities being performed by the Lessee in, on, or above the OCS, if such injury or damage to such person or property occurs by reason of the activities of any agency of the United States Government, its contractors, or subcontractors, or any of its officers, agents or employees, being conducted as a part of, or in connection with, the programs or activities of the individual military command headquarters (hereinafter "the appropriate command headquarters") listed in the contact information provided as an Enclosure to this lease, whether compensation for such damage or injury might be due under a theory of strict or absolute liability or otherwise.

Notwithstanding any limitation of the Lessee's liability in Section 9 of the lease, the Lessee assumes this risk whether such injury or damage is caused in whole or in part by any act or omission, regardless of negligence or fault, of the United States, its contractors or subcontractors, or any of its officers, agents, or employees. The Lessee further agrees to indemnify and save harmless the United States against all claims for loss, damage, or injury in connection with the programs or activities of the command headquarters, whether the same be caused in whole or in part by the negligence or fault of the United States, its contractors, or subcontractors, or any of its officers, agents, or employees and whether such claims might be sustained under a theory of strict or absolute liability or otherwise.

3.2 Evacuation or Suspension of Activities

3.2.1 General. The Lessee hereby recognizes and agrees that the United States reserves and has the right to temporarily suspend operations and/or require evacuation on this lease in the interest of national security pursuant to Section 3(c) of this lease.

3.2.2 Notification. Every effort will be made by the appropriate military agency to provide as much advance notice as possible of the need to suspend operations and/or evacuate. Advance notice will normally be given before requiring a suspension or evacuation. Temporary suspension of operations may include but is not limited to the evacuation of personnel and appropriate sheltering of personnel not evacuated.

"Appropriate sheltering" means the protection of all Lessee personnel for the entire duration of any Department of Defense activity from flying or falling objects or substances, and will be implemented by an order (oral and/or written) from the BOEM Office of Renewable Energy Programs (OREP) Program Manager, after consultation with the appropriate command headquarters or other appropriate military agency or higher Federal authority. The appropriate command headquarters, military agency or higher authority will provide information to allow the Lessee to assess the degree of risk to, and provide sufficient protection for, the Lessee's personnel and property.

3.2.3 Duration. Suspensions or evacuations for national security reasons will not generally exceed 72 hours; however, any such suspension may be extended by order of the OREP Program Manager. During such periods, equipment may remain in place, but all operations, if any, must cease for the duration of the temporary suspension if so directed by the OREP Program Manager. Upon cessation of any temporary suspension, the OREP Program Manager will immediately notify the Lessee that such suspension has terminated and operations on the leased area can resume.

3.2.4 Lessee Point-of-Contact for Evacuation/Suspension Notifications. The Lessee must inform the Lessor of the persons/offices to be notified to implement the terms of 3.2.2 and 3.2.3.

3.2.5 Coordination with Command Headquarters. The Lessee must establish and maintain early contact and coordination with the appropriate command headquarters (see Contact Information for Reporting Requirements Enclosure), in order to avoid or minimize the potential to conflict with and minimize the potential effects of conflicts with military operations.

3.2.6 Reimbursement. The Lessee is not entitled to reimbursement for any costs or expenses associated with the suspension of operations or activities or the evacuation of property or personnel in fulfillment of the military mission in accordance with 3.2.1 through 3.2.5 above.

3.3 Electromagnetic Emissions

Prior to entry into any designated defense operating area, warning area, or water test area for the purpose of commencing survey activities undertaken to support plan submittal, the Lessee must enter into an agreement with the commander of the appropriate command headquarters to coordinate the electromagnetic emissions associated with such survey activities. The Lessee must ensure that all electromagnetic emissions associated with such survey activities are controlled as directed by the commander of the appropriate command headquarters.

4 STANDARD OPERATING CONDITIONS

4.1 General Requirements

4.1.1 Prior to the start of operations, the Lessee must hold a briefing to establish responsibilities of each involved party, define the chains of command, discuss communication procedures, provide an overview of monitoring procedures, and review operational procedures. This briefing must include all relevant personnel, crew members and PSOs. New personnel must be briefed as they join the work in progress.

4.1.2 The Lessee must ensure that all vessel operators and crew members, including PSOs, are familiar with, and understand, the requirements specified in ADDENDUM "C".

4.1.3 The Lessee must ensure that a copy of ADDENDUM "C" is made available on every project-related vessel.

4.1.4 Marine Trash and Debris Prevention. The Lessee must ensure that vessel operators, employees, and contractors actively engaged in activities in support of plan (i.e., SAP and COP) submittal are briefed on marine trash and debris awareness and elimination, as described in the Bureau of Safety and Environmental Enforcement (BSEE) Notice to Lessees and Operators (NTL) No. 2015-G03 ("Marine Trash and Debris Awareness and Elimination") or any NTL that supersedes this NTL, except that the Lessor will not require the Lessee, vessel operators, employees, and contractors to undergo formal training or post placards. The Lessee must ensure that these vessel operator employees and contractors are made aware of the environmental and socioeconomic impacts associated with marine trash and debris and their responsibilities for ensuring that trash and debris are not intentionally or accidentally discharged into the marine environment. The above-referenced NTL provides information the Lessee may use for this awareness briefing.

4.1.5 Fisheries Communications Plan (FCP) and Fisheries Liaison. The Lessee must develop a publicly available FCP that describes the strategies that the Lessee intends to use for communicating with fisheries stakeholders prior to and during activities in support of the submission of a plan. The FCP must include the contact information for an individual retained by the Lessee as its primary point of contact with fisheries stakeholders (i.e., Fisheries Liaison). If the Lessee develops a project website, the FCP must be posted on the Lessee's project website. If the Lessee does not develop a project website, the FCP must be made available to the Lessor and the public upon request.

4.2 Vessel Strike Avoidance Measures

4.2.1 The Lessee must ensure that all vessels conducting activities in support of plan submittal, including those transiting to and from local ports and the lease area, comply with the vessel-strike avoidance measures specified in Section 4.2, except under extraordinary circumstances when complying with these requirements would put the safety of the vessel or crew at risk.

4.2.2 The Lessee must ensure that vessel operators and crews maintain a vigilant watch for cetaceans, pinnipeds, and sea turtles and slow down or stop their vessel to avoid striking protected species.

4.2.3 The Lessee must ensure that all vessel operators comply with 10 knot (18.5 km/hr) speed restrictions in any DMA.

4.2.4 The Lessee must ensure that vessels 19.8 meters (65 ft) in length or greater, operating from November 1 through April 30, operate at speeds of 10 knots (18.5 km/hr) or less.

4.2.5 The Lessee must ensure that all vessel operators reduce vessel speed to 10 knots or less when mother/calf pairs, pods, or large assemblages of non-delphinoid cetaceans are observed near an underway vessel.

4.2.6 North Atlantic right whales.

4.2.6.1 The Lessee must ensure all vessels maintain a separation distance of 500 meters (1,640 ft) or greater from any sighted North Atlantic right whale.

4.2.6.2 The Lessee must ensure that the following avoidance measures are taken if a vessel comes within 500 meters (1,640 ft) of any North Atlantic right whale:

4.2.6.2.1 If underway, vessels must steer a course away from any sighted North Atlantic right whale at 10 knots (18.5 km/h) or less until the 500-meter (1,640 ft) minimum separation distance has been established (except as provided in 4.2.6.2.2).

4.2.6.2.2 If a North Atlantic right whale is sighted within 100 meters (328 ft) of an underway vessel, the vessel operator must immediately reduce speed and promptly shift the engine to neutral. The vessel operator must not engage engines until the North Atlantic right whale has moved outside the vessel's path and beyond 100 meters (328 ft), at which point the vessel operator must comply with 4.2.6.2.1.

4.2.6.2.3 If a vessel is stationary, the vessel must not engage engines until the North Atlantic right whale has moved beyond 100 meters (328 ft), at which point the Lessee must comply with 4.2.6.2.1.

4.2.7 Non-delphinoid cetaceans other than the North Atlantic right whale.

4.2.7.1 The Lessee must ensure all vessels maintain a separation distance of 100 meters (328 ft) or greater from any sighted non-delphinoid cetacean.

4.2.7.2 The Lessee must ensure that the following avoidance measures are taken if a vessel comes within 100 meters (328 ft) of any sighted non-delphinoid cetacean:

4.2.7.2.1 If any non-delphinoid cetacean is sighted, the vessel underway must reduce speed and shift the engine to neutral, and must not engage the engines until the non-delphinoid cetacean has moved beyond 100 meters (328 ft).

4.2.7.2.2 If a vessel is stationary, the vessel must not engage engines until the sighted non-delphinoid cetacean has moved beyond 100 meters (328 ft).

4.2.8 Delphinoid cetaceans and Pinnipeds.

4.2.8.1 The Lessee must ensure that all vessels underway do not divert to approach any delphinoid cetacean and/or pinniped.

4.2.8.2 The Lessee must ensure that if a delphinoid cetacean and/or pinniped approaches any vessel underway, the vessel underway must avoid excessive speed or abrupt changes in direction to avoid injury to the delphinoid cetacean and/or pinniped.

4.2.9 Sea Turtles.

4.2.9.1 The Lessee must ensure all vessels maintain a separation distance of 50 meters (164 ft) or greater from any sighted sea turtle.

4.3 Archaeological Survey Requirements

4.3.1 Archaeological Survey Required. The Lessee must provide the results of an archaeological survey with its plans.

4.3.2 Qualified Marine Archaeologist. The Lessee must ensure that the analysis of archaeological survey data collected in support of plan submittal and the preparation of archaeological reports in support of plan submittal are conducted by a Qualified Marine Archaeologist.

4.3.3 Tribal Pre-Survey Meeting. The Lessee must invite by certified mail the Shinnecock Indian Nation to a tribal pre-survey meeting. The purpose of this meeting will be for the Lessee and the Lessee's Qualified Marine Archaeologist to discuss the Lessee's survey plan and consider requests to monitor portions of the archaeological survey and the geotechnical exploration activities, including the visual logging and analysis of geotechnical samples (e.g., cores). This meeting must be held subsequent to the pre-survey meeting with the Lessor (see 2.1.2). Invitation to the tribal pre-survey meeting must be made at least 15 calendar days prior to the date of the proposed tribal pre-survey meeting. The meeting must be scheduled for a date at least 30 calendar days prior to the commencement of survey activities performed in support of plan submittal and at a location and time that affords the participants a reasonable opportunity to participate. The anticipated date for the meeting must be identified in the timeline of activities described in the applicable survey plan (see 2.1.1).

4.3.4 Geotechnical Exploration.

4.3.4.1 The Lessee may only conduct geotechnical exploration activities in support of plan submittal in locations where an archaeological analysis of the results of geophysical surveys has been completed. This analysis must include a determination by a Qualified Marine Archaeologist as to whether any potential archaeological resources are present in the area that could be impacted by bottom-disturbing activities.

4.3.4.2 Except as allowed by the Lessor under 4.3.6, the geotechnical exploration activities must avoid potential archaeological resources by a minimum of 50 meters, and the Qualified Marine Archaeologist must calculate the avoidance distance from the maximum discernible extent of the archaeological resource.

4.3.4.3 Upon completion of geotechnical exploration activities, a Qualified Marine Archaeologist must certify, in the Lessee's archaeological report(s) submitted with a plan, that such activities did not impact potential historic properties identified as a result of the HRG surveys performed in support of plan submittal, except as follows: in the event that the geotechnical exploration activities did impact potential historic properties identified in the archaeological surveys without the Lessor's prior approval, the Lessee and the Qualified Marine Archaeologist who prepared the report must instead provide a statement documenting the extent of these impacts.

4.3.5 Monitoring and Avoidance. The Lessee must inform the Qualified Marine Archaeologist that he or she is permitted to be present during HRG surveys and bottom-disturbing activities performed in support of plan submittal to ensure avoidance of potential archaeological resources, as determined by the Qualified Marine Archaeologist (including bathymetric, seismic, and magnetic anomalies; side scan sonar contacts; and other seafloor or sub-surface features that exhibit potential to represent or contain potential archaeological sites or other historic properties). In the event that the Qualified Marine Archaeologist indicates that he or she wishes to be present, the Lessee must facilitate the Qualified Marine Archaeologist's presence, as requested by the Qualified Marine Archaeologist, and provide the Qualified Marine Archaeologist the opportunity to inspect data quality.

4.3.6 No Impact without Approval. The Lessee must not knowingly impact a potential archaeological resource without the Lessor's prior approval.

4.3.7 Post-Review Discovery Clauses. If the Lessee, while conducting site characterization activities in support of plan submittal, discovers a potential archaeological resource, such as the presence of a shipwreck (e.g., a sonar image or visual confirmation of an iron, steel, or wooden hull, wooden timbers, anchors, concentrations of historic objects, piles of ballast rock) or pre-contact archaeological site (e.g., stone tools, pottery) within the project area, the Lessee must:

4.3.7.1 Immediately halt seafloor/bottom-disturbing activities within the area of discovery;

4.3.7.2 Notify the Lessor within 24 hours of discovery;

4.3.7.3 Notify the Lessor in writing via report to the Lessor within 72 hours of its discovery;

4.3.7.4 Keep the location of the discovery confidential and take no action that may adversely affect the archaeological resource until the Lessor conducts an evaluation and instructs the applicant on how to proceed; and

4.3.7.5 Conduct any additional investigations as directed by the Lessor to determine if the resource is eligible for listing in the National Register of Historic Places (30 CFR 585.802(b)). The Lessor will direct the Lessee to conduct such investigations if: (1) the site has been impacted by the Lessee's project activities; or (2) impacts to the site or to the area of potential effect cannot be avoided. If investigations indicate that the resource is potentially eligible for listing in the National Register of Historic Places, the Lessor will tell the Lessee how to protect the resource or how to mitigate adverse effects to the site. If the Lessor incurs costs in protecting the resource, under Section 110(g) of the National Historic Preservation Act, the Lessor may charge the Lessee reasonable costs for carrying out preservation responsibilities under the OCS Lands Act (30 CFR 585.802(c-d)).

4.4 Geological and Geophysical (G&G) Survey Requirements

4.4.1 The Lessee must ensure that all vessels conducting activity in support of a plan (i.e., SAP and COP) submittal comply with the G&G survey requirements specified in 4.4, except under extraordinary circumstances when complying with these requirements would put the safety of the vessel or crew at risk.

4.4.2 Visibility. The Lessee must not conduct G&G surveys in support of plan submittal at any time when lighting or weather conditions (e.g., darkness, rain, fog, sea state) prevent visual monitoring of the high-resolution geophysical (HRG) survey exclusion zone (see 4.4.6) or the geotechnical exploration exclusion zone (see 4.4.7), except as allowed under 4.4.3.

4.4.3 Modification of Visibility Requirement. If the Lessee intends to conduct G&G survey operations in support of plan submittal at night or when visual observation is otherwise impaired, the Lessee must submit to the Lessor an alternative monitoring plan detailing the alternative monitoring methodology (e.g., active or passive acoustic monitoring technologies). The alternative monitoring plan must demonstrate the effectiveness of the methodology proposed to the Lessor's satisfaction. The Lessor may, after consultation with NMFS, decide to allow the Lessee to conduct G&G surveys in support of plan submittal at night or when visual observation is otherwise impaired using the proposed alternative monitoring methodology.

4.4.4 Protected-Species Observer. The Lessee must ensure that the exclusion zone for all G&G surveys performed in support of plan submittal is monitored by NMFS-approved PSOs around the sound source. The number of PSOs must be sufficient to effectively monitor the exclusion zone at all times. In order to ensure effective monitoring, PSOs must be on watch for no more than 4 consecutive hours, with at least a 2-hour break after a 4-hour watch, unless otherwise accepted by the Lessor. PSOs must not work for more than 12 hours in a 24-hour period. PSO reporting requirements are provided in 4.5. Prior to the scheduled start of the surveys performed in support of plan submittal, the Lessee must provide to the Lessor a list of PSOs currently approved by NMFS for G&G surveys. For PSOs not currently approved by NMFS, the Lessee must provide to the Lessor PSO résumés, no later than 45 calendar days prior to the scheduled start of such surveys. If additional PSO approvals are required after this time, the Lessee must provide the additional PSO résumés to the Lessor at least 15 calendar days prior to each PSO's start date. The Lessor will send the PSO résumés to NMFS for approval.

4.4.5 Observation Location and Optical Device Availability. The Lessee must ensure that monitoring occurs from the highest available vantage point on the associated operational platform, allowing for 360-degree scanning. The Lessee must ensure that each PSO has access to reticle binoculars and other suitable equipment to adequately perceive and monitor protected species within the exclusion zone during surveys conducted in support of plan submittal.

4.4.6 High-Resolution Geophysical (HRG) Surveys. The following stipulations are specific to HRG surveys conducted in support of plan submittal where one or more acoustic sound source is operating at frequencies below 200 kilohertz (kHz):

4.4.6.1 Establishment of Default Exclusion Zone. The Lessee must ensure that a PSO monitors a 200-meter default exclusion zone for cetaceans, pinnipeds, and sea turtles. In the case of the North Atlantic right whale, the Lessee must observe a minimum separation distance of 500 meters (1,640 ft), as required under 4.2.6.1.

4.4.6.1.1 If the Lessor determines that the exclusion zone does not encompass the sound-exposure threshold for ear injury to protected species (Level A harassment) calculated for the acoustic source having the highest source level, the Lessor will consult with NMFS and may impose additional, relevant requirements on the Lessee, including, but not limited to, required expansion of this exclusion zone.

4.4.6.2 Field Verification of HRG Survey Exclusion Zone. The Lessee must submit to the Lessor the results of field verification to verify the exclusion zone for the HRG survey equipment operating below 200 kHz. If no applicable data are available, the Lessee must conduct field verification of the exclusion zone for HRG survey equipment operating below 200 kHz. As part of such field verification, the Lessee must take acoustic measurements at a minimum of two reference locations and in a manner that is sufficient to establish the following: source level (Peak, SEL, and RMS sound levels at 1 meter), pattern of spreading loss, and the sound-exposure distance for ear injury for each marine mammal hearing group, sea turtles, and fish. The distance to the 166, 160, and 150 dB RMS behavioral thresholds (Level B harassment) must also be reported. The first location must be at a distance of 200 m from the sound source, and the second location must be as close to the sound source as technically feasible. The Lessee must take these sound measurements at the reference locations at two depths (i.e., a depth at mid-water and a depth at approximately 1 meter (3.28 ft) above the seafloor). The Lessee must report the field verification results to the Lessor in the applicable survey plan(s), unless otherwise authorized by the Lessor.

4.4.6.3 Modification of Exclusion Zone Per Lessee Request. The Lessee may use the field verification results to request modification of the exclusion zone for the specific HRG survey equipment under consideration. The Lessee must base any proposed new exclusion zone radius on the largest safety zone configuration of the target Level A or Level B harassment sound-exposure thresholds as defined by NMFS. The Lessee must use this modified zone for all subsequent use of field-verified equipment. The Lessee may periodically reevaluate the modified zone using the field verification procedures described in 4.4.6.2. The Lessee must obtain Lessor approval of any new exclusion zone before it is implemented.

4.4.6.4 Clearance of Exclusion Zone. The Lessee must ensure that active acoustic sound sources are not activated until the PSO has reported the exclusion zone clear of all marine mammals and sea turtles for at least 60 minutes.

4.4.6.5 HRG Survey Mid-Atlantic Seasonal Management Areas Right Whale Monitoring. The Lessee must ensure that between November 1 and April 30, vessel operators monitor NMFS North Atlantic Right Whale reporting systems (e.g., the Early Warning System, Sighting Advisory System, and Mandatory Ship Reporting System) for the presence of North Atlantic right whales during HRG survey operations.

4.4.6.6 Dynamic Management Area Shutdown Requirement. The Lessee must ensure that vessels cease HRG survey activities within 24 hours of NMFS establishing a DMA in the Lessee's HRG survey area. The Lessee may resume HRG survey activities in the affected area as soon as the DMA has expired.

4.4.6.7 Electromechanical Survey Equipment Ramp-Up. The Lessee must ensure that, when technically feasible, a ramp-up of the electromechanical survey equipment occurs at the start or re-start of HRG survey activities. A ramp-up must begin with the power of the smallest acoustic equipment for the HRG survey at its lowest power output. The power output must be gradually increased and other acoustic sources added in such a way that the source level would rise in steps not exceeding 6 dB per 5-minute period.

4.4.6.8 Shutdown for Non-Delphinoid Cetaceans and Sea Turtles. If a non-delphinoid cetacean or sea turtle is sighted at or within the exclusion zone, the Lessee must immediately shut down all the electromechanical survey equipment. The Lessee must ensure that the vessel operator immediately complies with such a call by the PSO. Any disagreement or discussion must occur only after shutdown. Subsequent restart of the electromechanical survey equipment must use the ramp-up provisions described in 4.4.6.7 and must only occur following clearance of the exclusion zone of all marine mammals and sea turtles for at least 60 minutes as described in 4.4.6.4.

4.4.6.9 Power Down for Delphinoid Cetaceans and Pinnipeds. If a delphinoid cetacean or pinniped is sighted at or within the exclusion zone, the Lessee must immediately power down the electromechanical survey equipment to the lowest power output that is technically feasible. The Lessee must ensure that the vessel operator immediately complies with such a call by the PSO. Any disagreement or discussion must occur only after power-down. Subsequent restart of the electromechanical survey equipment must use the ramp-up procedures described in 4.4.6.7 and may occur only after (1) the exclusion zone is clear of delphinoid cetaceans and pinnipeds or (2) a determination by the PSO after a minimum of 10 minutes of observation that the delphinoid cetacean and/or pinniped is approaching the vessel or towed equipment at a speed and vector that indicates voluntary approach to bow-ride or chase towed equipment.

4.4.6.9.1 Pauses in Electromechanical Survey Sound Source. If the electromechanical sound source shuts down for reasons other than encroachment into the exclusion zone by a non-delphinoid cetacean or sea turtle, including, reasons such as, but not limited to, mechanical or electronic failure, resulting in the cessation of the sound source for a period greater than 20 minutes, the Lessee must ensure that restart of the electromechanical survey equipment commences only after clearance of the exclusion zone, as described in 4.4.6.4, and the implementation of ramp-up procedures, as described in 4.4.6.7. If the shutdown is less than 20 minutes, the equipment may be restarted as soon as practicable at its operational level as long as visual surveys were continued diligently throughout the silent period and the exclusion zone remained clear of marine mammals and sea turtles. If visual surveys were not continued diligently during a shutdown of 20 minutes or less, the Lessee must clear the exclusion zone, as described in 4.4.6.4, and implement ramp-up procedures, as described in 4.4.6.7, prior to restarting the electromechanical survey equipment.

4.4.7 Geotechnical (Sub-bottom) Exploration. Stipulations specific to geotechnical exploration limited to borings and vibracores conducted in support of plan submittal are provided in 4.4.7.1 through 4.4.7.6.

4.4.7.1 Establishment of Default Exclusion Zone. The Lessee must ensure that a PSO monitors a 200-meter (656 ft) default exclusion zone for all marine mammals and sea turtles around any vessel conducting geotechnical surveys.

4.4.7.2 Modification of Default Exclusion Zone Per Lessee Request. If the Lessee wishes to modify the 200 meter (656 ft) default exclusion zone for specific geotechnical exploration equipment, the Lessee must submit a plan for verifying the sound source levels of the specific geotechnical exploration equipment to the Lessor. The plan must demonstrate how the field verification activities will comply with the requirements of 4.4.7.3. The Lessor may require that the Lessee modify the plan to address any comments the Lessor submits to the Lessee on the contents of the plan in a manner deemed satisfactory to the Lessor prior to the commencement of field verification activities. Any new exclusion zone radius proposed by the Lessee must be based on the largest safety zone configuration of the target Level A or Level B harassment sound-exposure thresholds as defined by NMFS. The Lessee must use this modified zone for all subsequent use of field-verified equipment. The Lessee may periodically reevaluate the modified zone using the field verification procedures described in 4.4.7.3. The Lessee must obtain Lessor approval of any new exclusion zone before it is implemented.

4.4.7.3 Field Verification of Geotechnical Exclusion Zone. If the Lessee wishes to modify the existing exclusion zone, the Lessee must submit the results of field verification to verify the exclusion zone for the specific geotechnical exploration equipment being used. If no applicable data are available, the Lessee must conduct field verification of the exclusion zone for the specific geotechnical exploration equipment being used. As part of such field verification, the Lessee must take acoustic measurements at a minimum of two reference locations and in a manner that is sufficient to establish the following: source level (Peak, SEL, and RMS sound levels at 1 meter), pattern of spreading loss, and the sound exposure distance for ear injury for each marine mammal hearing group, sea turtles, and fish. The distance to the 166, 160, and 150 dB RMS behavioral thresholds must also be reported. The first location must be at a distance of 200 m from the sound source and the second location must be as close to the sound source as technically feasible. The Lessee must take these sound measurements at the reference locations at two depths (i.e., a depth at mid-water and a depth at approximately 1 meter above the seafloor). The Lessee must use the results to establish a new exclusion zone, which may be greater than or less than the 200 meter (656 ft) default exclusion zone.

4.4.7.4 Clearance of Exclusion Zone. The Lessee must ensure that the geotechnical sound source is not activated until the PSO has reported the exclusion zone clear of all marine mammals and sea turtles for 60 minutes.

4.4.7.5 Shutdown for Non-Delphinoid Cetaceans and Sea Turtles. If any non-delphinoid cetaceans or sea turtles are sighted at or within the exclusion zone, the Lessee must immediately shut down the geotechnical survey equipment. The vessel operator must comply immediately with such a call by the PSO. Any disagreement or discussion must occur only after shutdown. Subsequent restart of the geotechnical survey equipment must only occur following clearance of the exclusion zone as described in 4.4.7.4.

4.4.7.6 Pauses in Geotechnical Survey Sound Source. If the geotechnical sound source shuts down for reasons other than encroachment into the exclusion zone by a non-delphinoid cetacean or sea turtle, including, but not limited to, mechanical or electronic failure resulting in the cessation of the sound source for a period greater than 20 minutes, the Lessee must ensure that restart of the geotechnical survey equipment commences only after clearance of the exclusion zone, as described in 4.4.7.4. If the shutdown is less than 20 minutes, the equipment may be restarted as soon as practicable as long the Lessee has continued visual surveys diligently throughout the silent period and the exclusion zone remained clear of marine mammals and sea turtles. If visual surveys were not continued diligently during a shutdown of 20 minutes or less, the Lessee must clear the exclusion zone, as described in 4.4.7.4, prior to restarting the geotechnical survey equipment.

4.5 Protected-Species Reporting Requirements

The Lessee must ensure compliance with the following reporting requirements for site characterization activities performed in support of plan submittal, and, where appropriate, must fulfill these requirements using the contact information provided as an Enclosure to this lease, or updated contact information as provided by the Lessor:

4.5.1 Field Verification of Exclusion Zone Preliminary Report for HRG Survey Equipment. The Lessee must report the results of field verification to verify the exclusion zone for the HRG survey equipment operating below 200 kHz to the Lessor and NMFS prior to using the HRG equipment during survey activities conducted in support of plan submittal. The Lessee must include in its report a preliminary interpretation of the results for all sound sources, which will include details of the operating frequencies, SPLs (measured in Peak, SEL, and RMS), the distance to the ear injury and behavior thresholds, frequency bands measured, as well as associated latitude/longitude positions, ranges, depths and bearings between sound sources and receivers.

4.5.2 Reporting Injured or Dead Protected Species. The Lessee must ensure that sightings of any injured or dead protected species (e.g., marine mammals, sea turtles or sturgeon) are reported to the Lessor, NMFS and the NMFS Greater Atlantic (Northeast) Region's Stranding Hotline (866-755-6622 or current) within 24 hours of sighting, regardless of whether the injury or death is caused by a vessel. In addition, if the injury or death was caused by a collision with a project-related vessel, the Lessee must notify the Lessor of the strike within 24 hours. The Lessee must use the form provided in Appendix A to ADDENDUM "C" to report the sighting or incident. If the Lessee's activity is responsible for the injury or death, the Lessee must ensure that the vessel assists in any salvage effort as requested by NMFS.

4.5.3 Reporting Observed Impacts to Protected Species.

4.5.3.1 The Lessee must report any observed takes (as defined in 1.13) of listed marine mammals, sea turtles or sturgeon resulting in injury or mortality within 24 hours to the Lessor and NMFS.

4.5.3.2 The Lessee must report any observations concerning any impacts on Endangered Species Act listed marine mammals, sea turtles or sturgeon to the Lessor and NMFS Northeast Region's Stranding Hotline within 48 hours.

4.5.3.3 The Lessee must record injuries or mortalities using the form provided in Appendix A to ADDENDUM "C".

4.5.4 Protected Species Observer Reports. The Lessee must ensure that the PSO record all observations of protected species using standard marine mammal PSO data collection protocols. The list of required data elements for these reports is provided in Appendix B to ADDENDUM "C".

4.5.5 Reports of G&G Survey Activities and Observations. The Lessee must provide the Lessor and NMFS with reports every 90 calendar days following the commencement of HRG and/or geotechnical exploration activities, and a final report at the conclusion of the HRG and/or geotechnical exploration activities. Each report must include a summary of survey activities, all PSO and incident reports (See Appendices A and B), and an estimate of the number of listed marine mammals and sea turtles observed and/or taken during these survey activities. The final report must contain a detailed analysis and interpretation of the sound source verification data, if such data was collected by the Lessee.

4.5.6 Field Verification Plan for HRG Survey Exclusion Zone. No later than 45 calendar days prior to the commencement of any required field verification activities, the Lessee must submit a plan for verifying the sound source levels of any electromechanical survey equipment operating at frequencies below 200 kHz. The plan must demonstrate how the field verification activities will comply with the requirements of 4.4.6.2. Prior to the commencement of the field verification activities, the Lessor may require the Lessee to modify the plan to address any comments the Lessor submits to the Lessee on the contents of the plan in a manner deemed satisfactory to the Lessor.

4.5.7 Marine Mammal Protection Act Authorization(s). If the Lessee is required to obtain an authorization pursuant to section 101(a)(5) of the Marine Mammal Protection Act prior to conducting survey activities in support of plan submittal, the Lessee must provide to the Lessor a copy of the authorization prior to commencing these activities.

4.6 Avian and Bat Survey and Reporting Requirements

4.6.1 Lighting Requirements. When conducting survey activities in support of plan submittal, the Lessee must use lighting only when necessary, and the lighting must be hooded downward and directed when possible, to reduce upward illumination and illumination of adjacent waters.

4.6.2 Annual Report. The Lessee must provide an annual report to the Lessor and U.S. Fish and Wildlife Service using the contact information provided as an Enclosure to this lease, or updated contact information as provided by the Lessor. This report must document any dead or injured birds or bats found during activities conducted in support of plan submittal. The first report must be submitted within 6 months of the start of the first survey conducted in support of plan submittal, and subsequent reports must be submitted annually thereafter until all surveys in support of plan submittal have concluded and all such birds and bats have been reported. If surveys are not conducted in a given year, the annual report may consist of a simple statement to that effect. The report must contain the following information: the name of species, date found, location, a picture to confirm species identity (if possible), and any other relevant information. In addition to the Annual Report, the Lessee must report carcasses with Federal or research bands to the U.S. Geological Society Bird Band Laboratory, within 30 calendar days, using the following website: https://www.pwrc.usgs.gov/bbl/, or updated contact information as provided by the Lessor.

U.S. DEPARTMENT OF THE INTERIOR
BUREAU OF OCEAN ENERGY MANAGEMENT

APPENDIX A TO ADDENDUM "C"

Lease Number OCS-A 0512

Incident Report: Protected Species Injury or Mortality

Photographs/Video should be taken of all injured or dead animals.

Observer's full name: ____________________

Reporter's full name: ____________________

Species Identification: ____________________

Name and type of platform: ____________________

Date animal observed: ____________ Time animal observed: ____________

Date animal collected: ____________ Time animal collected: ____________

Environmental conditions at time of observation (i.e. tidal stage, Beaufort Sea State, weather):

____

____

Water temperature (°C) and depth (m/ft) at site: ____________________

Describe location of animal and events 24 hours leading up to, including and after, the incident (incl. vessel speeds, vessel activity and status of all sound source use):

____

____

____

____

____

Photograph/Video taken: YES / NO If Yes, was the data provided to NMFS? YES / NO
(Please label *species, date, geographic site* and *vessel name* when transmitting photo and/or video)

Date and Time reported to NMFS Stranding Hotline: ____________________

Sturgeon Information: *(please designate cm/m or inches and kg or lbs)*

Species: ____________________

Fork length (or total length): ____________ Weight: ____________

Condition of specimen/description of animal: ____________________

____

Fish Decomposed: NO SLIGHTLY MODERATELY SEVERELY

Fish tagged: YES / NO If Yes, *please record all tag numbers.*

Tag #(s):____

Genetic samples collected: YES / NO

Genetics samples transmitted to:________________________on____/_____/20....

<u>Sea Turtle Species Information</u>: *(please designate cm/m or inches)*

Species:________________________Weight (kg or lbs):____________

Sex: Male Female Unknown

How was sex determined?:________________________________

Straight carapace length:________________Straight carapace width:__________

Curved carapace length:_________________Curved carapace width:__________

Plastron length:______________________Plastron width:______________

Tail length:_________________________Head width:________________

Condition of specimen/description of animal:________________________

Existing Flipper Tag Information

Left:____________________________Right:____________________

PIT Tag#:____

Miscellaneous:

Genetic biopsy collected: YES NO Photographs taken: YES NO

Turtle Release Information:

Date:____________________________Time:_____________________

Latitude:_________________________Longitude:__________________

State:___________________________County:____________________

Remarks: (note if turtle was involved with tar or oil, gear or debris entanglement, wounds, or mutilations, propeller damage, papillomas, old tag locations, etc.)______________

Marine Mammal information: *(please designate cm/m or ft/inches)*

Length of marine mammal (note direct or estimated): ______

Weight (*if possible, kg or lbs*): ______

Sex of marine mammal (if possible): ______

How was sex determined?: ______

Confidence of Species Identification: SURE UNSURE BEST GUESS

Description of Identification characteristics of marine mammal: ______

______

______

______

______

Genetic samples collected: YES / NO

Genetic samples transmitted to: ______ on ____/____/20....

Fate of marine mammal: ______

______

______

______

Description of Injuries Observed: ______

______

______

______

Other Remarks/Drawings: ______

______

______

U.S. DEPARTMENT OF THE INTERIOR
BUREAU OF OCEAN ENERGY MANAGEMENT

APPENDIX B TO ADDENDUM "C"

Lease Number OCS-A 0512

REQUIRED DATA ELEMENTS FOR PROTECTED SPECIES OBSERVER REPORTS

The Lessee must ensure that the PSO record all observations of protected species using standard marine mammal observer data collection protocols. The list of required data elements for these reports is provided below:

1. Vessel name;
2. PSOs' names and affiliations;
3. Date;
4. Time and latitude/longitude when daily visual survey began;
5. Time and latitude/longitude when daily visual survey ended; and
6. Average environmental conditions during visual surveys including:
    a. Wind speed and direction;
    b. Sea state (glassy, slight, choppy, rough, or Beaufort scale);
    c. Swell (low, medium, high, or swell height in meters); and
    d. Overall visibility (poor, moderate, good).
7. Species (or identification to lowest possible taxonomic level);
8. Certainty of identification (sure, most likely, best guess);
9. Total number of animals;
10. Number of juveniles;
11. Description (as many distinguishing features as possible of each individual seen, including length, shape, color and pattern, scars or marks, shape and size of dorsal fin, shape of head, and blow characteristics);
12. Direction of animal's travel relative to the vessel (preferably accompanied by a drawing);
13. Behavior (as explicit and detailed as possible, noting any observed changes in behavior);
14. Activity of vessel when sighting occurred.

U.S. DEPARTMENT OF THE INTERIOR
BUREAU OF OCEAN ENERGY MANAGEMENT

ADDENDUM "D"

PROJECT EASEMENT(S)

Lease Number OCS-A 0512

This section includes a description of the Project Easement(s), if any, associated with this lease, and the financial terms associated with any such Project Easement(s).

I. <u>Rent</u>

The Lessee must begin submitting rent payments for any project easement associated with this lease commencing on the date that BOEM approves the Construction and Operations Plan (COP) or modification of the COP describing the project easement. Annual rent for a project easement 200 feet wide, centered on the transmission cable, is $70.00 per statute mile. For any additional acreage required, the Lessee must also pay the greater of $5.00 per acre per year or $450.00 per year.

U.S. DEPARTMENT OF THE INTERIOR
BUREAU OF OCEAN ENERGY MANAGEMENT

ADDENDUM "E"

RENT SCHEDULE

Lease Number OCS-A 0512

This section includes a description of the schedule for rent payments that will be determined after the Construction and Operations Plan (COP) has been approved or approved with modifications.

Unless otherwise authorized by the Lessor in accordance with the applicable regulations in 30 CFR Part 585, the Lessee must make rent payments as described below.

U.S. DEPARTMENT OF THE INTERIOR

BUREAU OF OCEAN ENERGY MANAGEMENT

Lease Number OCS-A 0512

CONTACT INFORMATION FOR REPORTING REQUIREMENTS

The following contact information must be used for the reporting and coordination requirements specified in ADDENDUM "C", Stipulation 3.2.5:

United States Fleet Forces (USFF) N46
1562 Mitscher Ave, Suite 250
Norfolk, VA 23551
Phone: (757) 836-6206

The following contact information must be used for the reporting requirements in ADDENDUM "C", Section 4.5:

Reporting Injured or Dead Protected Species

National Marine Fisheries Service
Greater Atlantic Region Stranding Hotline
Phone: 866-755-6622

All other reporting requirements in Section 4.5

Bureau of Ocean Energy Management
Environment Branch for Renewable Energy
Phone: 703-787-1340
Email: renewable_reporting@boem.gov

National Marine Fisheries Service
Greater Atlantic Regional Fisheries Office, Protected Resources Division
Section 7 Coordinator
Phone: 978-281-9328
Email: incidental.take@noaa.gov; Mark.Murray-Brown@noaa.gov

Vessel operators can register for automatic email alerts for Seasonal Management Areas and find additional information on ship strike reduction guidelines and requirements at http://www.nmfs.noaa.gov/pr/shipstrike/#sightings.

The following contact information must be used for the reporting requirements in ADDENDUM "C", Stipulation 4.6.2:

Reporting Dead or Injured Avian and Bat Species

U.S. Fish and Wildlife Office, New York Field Office
3817 Luker Road
Cortland, NY 13045
Phone: 607-753-9334
Email: FW5ES_NYFO@fws.gov

Bureau of Ocean Energy Management
Environment Branch for Renewable Energy
Phone: 703-787-1340
Email: renewable_reporting@boem.gov

Attachment 3

Landfall and Cable Routing Study

REDACTED

equinor

Attachment 4

Wind Resource Assessment (Equinor)

REDACTED

equinor

Attachment 5

Wind Resource Assessment (KVT)

REDACTED

equinor

Attachment 6

Quantification of Losses and Uncertainty for Offshore Wind Farm Energy Assessments

REDACTED

equinor

Attachment 7

Creditor Letters of Support

REDACTED

equinor

Attachment 8

Tax Analysis

REDACTED

equinor

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Attachment 9

Annual Reports

equinor

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2017

Annual Report and Form 20-F

Statoil

Aasta Hansteen topside
arriving Ølensvåg

Table of contents

INTRODUCTION

STRATEGIC REPORT

GOVERNANCE

FINANCIAL STATEMENTS AND SUPPLEMENTS

ADDITIONAL INFORMATION

Introduction

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MESSAGE FROM CHAIR OF THE BOARD

DEAR FELLOW INVESTOR,

2017 has been a good year for Statoil, both operationally and financially. We have seen significant positive impacts from the improvements, and have benefitted from an upturn in the oil and gas market. And we have delivered on the sharpened strategy we launched in February 2017.

The 2017 net operating income ended positive with USD 13.8 billion, up from close to zero in 2016. Statoil continues to deliver on the improvement ambitions, and demonstrates strong operational performance. A free cash flow[1] of USD 3.1 billion made Statoil cash-flow neutral well below 50 USD per barrel.

Strong safety performance is essential to Statoil's license to operate. The serious incident frequency for 2017 improved compared to 2016, however, it is key to remember that safety results must be delivered every day. The board of directors is working closely with the administration to ensure that forceful safety efforts and continued leadership focus are maintained.

We have seen a gradual rebalancing of the oil market and recovering prices. However, we should still be prepared for volatility. Key influencing factors are; geopolitical developments, OPEC policies, US shale response and the price impact of short-term trading activities. For the board of directors, it is essential that Statoil is a robust and resilient company, well equipped for different scenarios.

Statoil remains committed to competitive capital distribution. For the fourth quarter 2017 we propose to the annual general meeting (AGM) a dividend of 0.23 USD per share, an increase of 4.5%. This is in line with the dividend policy of increasing the dividend in line with long-term underlying earnings. In addition, Statoil has ended its two-year scrip programme as planned. We also see an emerging scope for share buy-backs, dependent on macro outlook and portfolio developments. However, the near-term priority is to strengthen the balance sheet.

Statoil has increased its production guiding while at the same time reducing capital expenditures. The improvements delivered over the last years have materially improved the financial position and competitiveness. This is reflected in operations and the next generation portfolio with a break-even price of 21 USD per barrel.

Statoil made 14 discoveries from 28 wells drilled in 2017, and have secured access to attractive new acreage, like in Argentina and Turkey, and strengthened the portfolio with acquisitions like Carcará North, Roncador in Brazil and Martin Linge in Norway.

Statoil is striving to further develop a distinct and competitive portfolio, driven by the strategy always safe, high value, low carbon. Statoil will leverage industrial strengths; operational excellence, world class recovery, leading project delivery, premium market access and digital leader, to develop long-term value on the Norwegian continental shelf, develop new growth options internationally and increase value creation in the marketing and midstream business.

The company continues to build a material industrial position in new energy solutions. Within offshore wind Statoil is competitive and well positioned. Statoil is now the operator of three offshore wind farms, and has also entered its first solar project through the acquisitions of a 43.75% share in the Apodi asset in Brazil.

Responding to the climate challenge and preparing Statoil for a low carbon future is an integrated part of the strategy. Concrete actions to reduce greenhouse gas emissions in the operations have been implemented, and we are taking further steps to gradually build a more carbon resilient portfolio.

The board of directors believes the company is well prepared to deal with the current market situation and has the competence, capacity and leadership capabilities necessary to create new business opportunities and long-term value for our shareholders.

After the closing of the year, the board has decided to recommend to the AGM to change the company name from Statoil to Equinor. Our strategy remains firm, and the change is a natural follow up of the strategic development from a focused oil and gas to a broad energy company. The board sees the new name as a continuation of the company's proud history, and a commitment to value creation also in a low carbon future.

I would like to thank all employees for their dedication and commitment to Statoil and our shareholders for their continued investment.

Jon Erik Reinhardsen
Chair of the board

[1] [illegible]

CHIEF EXECUTIVE LETTER

DEAR FELLOW SHAREHOLDER,

As we have started a new year with new opportunities, it is useful to reflect briefly on the past. In 2017, we presented our strategy: always safe, high value, low carbon, and we set clear ambitions for the future. We have delivered above and beyond our ambitious targets, and Statoil is now a stronger, more resilient and more competitive company.

The safety of our people and integrity of our operations remains our top priority. Over the past decade we have steadily improved our safety results. Following some negative developments in 2016, we reinforced our efforts, and last year we again saw a positive development. For the year as a whole, our serious incident frequency came in at 0.6. We will use this as inspiration and continue our efforts. The "I am safety"-program, launched across the company is an important part of these efforts.

We must always be prepared for volatility in our markets. Our improvement work started when prices were still high, and we have used the downturn to reset the company. Today we are a much more robust and resilient company. We have taken down the break-even price of our next generation portfolio by more than 20% during last year to USD 21 per barrel.

Last year we said we would be cash flow positive at USD 50 per barrel in 2017. We did even better, and were cash flow positive well below USD 50. At an average Brent oil price of 54 per barrel, we generated USD 3.1 billion in free cash flow[2]. We tripled our adjusted earnings to USD 12.6 billion, and our net operating income was up from close to zero in 2016 to USD 13.8 billion last year. A negative net income in 2016 is turned to a positive result of USD 4.6 billion.

The organic capital expenditures ended at USD 9.4 billion[3], well below the USD 11 billion initially guided. The reduction is mainly due to solid improvements and continued strict capital discipline.

We continue to transform our cost base and value creation potential. With USD 1.3 billion in additional improvements in 2017, Statoil has realised annual efficiencies of USD 4.5 billion from 2013. In 2017 we also achieved a record high reserve replacement ratio (RRR) of 150% and all time high production. Looking forward the potential is solid towards 2020, with expected increase in annual production of 3-4%, strong cash generation and growing returns.

We have used the down-turn well, but the real test is taking place now, as prices are recovering. I have seen how easy it is for an organisation to start relaxing when prices recover. In Statoil we are determined and will not allow that to happen. We intend to reduce drilling costs further and sustain the 2017 unit of production costs in 2020.

In Statoil we believe the winners in the energy transition will be the producers which can deliver at low cost and with low carbon emissions. We also believe there are attractive business opportunities in the transition to a low-carbon economy.

Co2-emissions from our oil and gas production were reduced with an additional 10% per barrel last year. In the fall 2017 we started production from Dudgeon, and the floating windfarm Hywind. Today, we operate three offshore wind projects in the UK, delivering competitive returns. Statoil will continue its journey from a focused oil and gas to a broad energy company.

I believe Statoil is set to increase returns and grow our cash flow in the years to come. We are delivering on our strategy, investing in high-return opportunities, strengthening our balance sheet - and have increased the capital distribution. I look forward to further developing Statoil in 2018.

This year's AGM will mark a historic moment for us. The board of directors recommends changing the company name from Statoil to Equinor. "Equi" is the starting point for words like equal, equality and equilibrium. "Nor" is signalling a company proud of its origin.

The name says something important about us as a company. What we stand for, where we come from and how we see the future. How we see people - and how we view energy.

The strategy we presented last year remains firm. And we think the name has potential to strengthen our attractiveness with investors, partners and not the least the new generation of talents we need to realise our strategy and reach our ambitions.

Eldar Sætre
President and Chief Executive Officer
Statoil ASA

[2] See section 5.2 Use and reconciliation of non-GAAP financial measures

Statoil at a glance

Our history

Statoil was founded as Den Norske Stats Oljeselskap AS, the Norwegian State Oil company in 1972. Statoil became listed on the Oslo Børs (Norway) and New York Stock Exchange (US) in June 2001. Statoil merged with Hydro's oil and gas division in October 2007. Statoil is an international energy company present in more than 30 countries around the world, including several of the world's most important oil and gas provinces. Our headquarter is located in Stavanger, Norway and we have 20.245 employees worldwide. We create value through safe and efficient operations, innovative solutions and technology. Statoil's competitiveness is founded on our values-based performance culture, with a strong commitment to transparency, collaboration and continuous efficiency improvements.

The board of directors of Statoil have proposed to change the name of the company to Equinor. The new name supports the company's strategy and development as a broad energy company. The suggested name change will be proposed to the shareholders in a resolution to the annual general meeting on 15 May 2018.

Our vision

Our vision rests on three pillars: Competitive at all times, transforming the oil and gas industry and providing energy for a low-carbon future.

Our strategy

Statoil is an energy company committed to long-term value creation in a low carbon future. Statoil will develop and maximise the value of its unique Norwegian continental shelf position, its international oil and gas business and its growing new energy business; focusing on safety, cost and carbon efficiency. Statoil is a values-based company where empowered people collaborate to shape the future of energy.

Our values

Our values embody the spirit and energy of Statoil at its best. They help us set direction and they guide our decisions, actions and the way we interact with others. Our values express the ideals we strive to live up to every day. Statoil's values are: Open, Collaborative, Courageous and Caring.

Our activities

Statoil is engaged in exploration, development and production of oil and gas in addition to renewables. We are the leading operator on the Norwegian continental shelf and have substantial international activities. We sell crude oil and is a major supplier of natural gas. Processing, refining, offshore wind and carbon capture and storage is also part of our operations. Our activities are managed through eight business areas, staffs and support divisions and we have operations in both North and South America, Africa, Asia, Europe and Oceania, as well as in Norway.

Our shareholders

The Norwegian State is the largest shareholder in Statoil, with a direct ownership interest of 67%. Its ownership interest is managed by the Ministry of Petroleum and Energy. US investors hold 11%, Norwegian private owners hold 8%, other European investors hold 8%, UK investors hold 3% and others hold 2%.

Statoil announces dividends on a quarterly basis. It is Statoil's ambition to grow the annual cash dividend, measured in USD per share, in line with long-term underlying earnings.

Aasta Hansteen mating complete December 2017
Photo: Espen Rønnevik/Woldcam

Key figures

(in USD million, unless stated otherwise)	2017	2016	2015	2014	2013
	For the year ended 31 December				
Financial information					
Total revenues and other income[1)]	**61,187**	45,873	59,642	99,264	108,318
Operating expenses	**(8,763)**	(9,025)	(10,512)	(11,657)	(12,669)
Net operating income/(loss)	**13,771**	80	1,366	17,878	26,572
Net income/(loss)	**4,598**	(2,902)	(5,169)	3,887	6,713
Non-current finance debt	**24,183**	27,999	29,965	27,593	27,197
Net interest-bearing debt before adjustments	**15,437**	18,372	13,852	12,004	9,542
Total assets	**111,100**	104,530	109,742	132,702	145,572
Total equity	**39,885**	35,099	40,307	51,282	58,513
Net debt to capital employed ratio before adjustments[2)]	**27.9%**	34.4%	25.6%	19.0%	14.0%
Net debt to capital employed ratio adjusted[2)]	**29.0%**	35.6%	26.8%	20.0%	15.2%
ROACE[3)]	**8.2%**	(0.4%)	4.1%	8.7%	11.8%
Operational data					
Equity oil and gas production (mboe/day)	**2,080**	1,978	1,971	1,927	1,940
Proved oil and gas reserves (mmboe)	**5,367**	5,013	5,060	5,359	5,600
Reserve replacement ratio (annual)	**1.50**	0.93	0.55	0.62	1.28
Reserve replacement ratio (three-year average)	**1.00**	0.70	0.81	0.97	1.15
Production cost equity volumes (USD/boe)	**4.8**	5.0	5.9	7.6	7.5
Average Brent oil price (USD/bbl)	**54.2**	43.7	52.4	98.9	108.7
Share information[4)]					
Diluted earnings per share (in USD)	**1.40**	(0.91)	(1.63)	1.21	2.14
Share price at Oslo Børs (Norway) on 31 December (in NOK)	**175.20**	158.40	123.70	131.20	147.00
Share price at New York Stock Exchange (USA) on 31 December (in USD)	**21.42**	18.24	13.96	17.61	24.13
Dividend paid per share (in USD)[5)]	**0.88**	0.88	1.07	0.97	1.15
Weighted average number of ordinary shares outstanding (in millions)	**3,268**	3,195	3,179	3,180	3,181

1) Total revenues and other income for 2013 are restated.

2) See section 5.2 Use and reconciliation of non-gaap financial measures for net debt to capital employed ratio.

3) Calculated ROACE based on Adjusted earnings after tax and capital employed. See section 5.2 Use and reconciliation of non-gaap financial measures.

4) See section 5.1 Shareholder information for a description of how dividends are determined and information on share repurchases.

5) Dividends for the third and fourth quarter 2016 and the first and second quarter 2017 were paid in 2017. From and including the third quarter of 2015, dividends were declared in USD. Dividends in previous periods were declared in NOK. Figures for 2015 and earlier periods are presented using the Central Bank of Norway year end rates for Norwegian kroner.

ABOUT THE REPORT

This document constitutes the Statutory annual report in accordance with Norwegian requirements and the Annual report on Form 20-F in accordance with the US Securities and Exchange Act of 1934 applicable to foreign private issuers, for Statoil ASA for the year ended 31 December 2017. A cross reference to the Form 20-F requirements are set out in section 5.10 in this report. The Annual report on Form 20-F and other related documents are filed with the US Securities and Exchange Commission (the SEC). The Annual report and Form 20-F are filed with the Norwegian Register of company accounts.

This report presents the

- Director's report (pages 3-121 and 235-269)
- Consolidated Financial Statements of the Statoil group (pages 125-193)
- Parent company financial statements of Statoil ASA (pages 207-234) according to the Norwegian Accounting Act of 1998
- Board Statement on Corp. Governance according to The Norwegian Code of Practice for Corporate Governance (NUES) (pages 85-121)
- Declaration on remuneration for Statoil's corporate executive committee (pages 111-119)
- Payments to governments report (pages 252-268)

Financial reporting terms used in this report are in accordance with International Financial Reporting Standards (IFRS) as adopted by the European union (EU) and with IFRS as issued by the International Accounting Standards Board (IASB), effective at 31 December 2017. This document should be read in conjunction with the cautionary statement in section 5.7 Forward-looking statement.

Specific requirements for Norway

Section 4.3 Parent company financial statements (pages 207-234), section 5.4 Payments to governments (pages 252-268), chapter 3 Board Statement on Corporate Governance according to The Norwegian Code of Practice for Corporate Governance (NUES)(pages 85-121), section 5.5 Statements on this report comprising the statement of the directors' responsibilities (pages 268-269), the recommendation of the Corporate assembly (page 270), the independent auditor's report issued in accordance with law, regulations and auditing standards and practices generally accepted in Norway (pages 125-130) and the going concern assumption (page 58), do not form part of Statoil's Annual report on Form 20-F as filed with the SEC.

In addition, the following sections of this report do not form part of Statoil's Annual report on Form 20-F as filed with the SEC: this section About this report (which has been modified for the purpose of Statoil's Annual report on Form 20-F), Nomination and elections in Statoil (page 87), disclosures regarding deviation from the code in chapter 3, Introduction within section 3.1 Implementation and reporting (page 88), section 3.2 Business (page 90), section 3.3 Equity and dividends (pages 90-91), section 3.4 Equal treatment of shareholders and transactions with close associates (pages 91-92), section 3.5 Freely negotiable shares (page 92), as indicated in the second paragraph of section 3.12 Remuneration to the corporate executive committee, section 3.13 Information and communications (page 119) and section 3.14 Take-overs (page 119-120).

The Statoil Annual report and Form 20-F may be downloaded from Statoil's website at [Statoil.com/annualreport2017]. References to this document or other documents on Statoil's website are included as an aid to their location and are not incorporated by reference into this document. All SEC filings made available electronically by Statoil may be obtained from the SEC at 100 F Street, N.E., Washington D.CC. 20549, United States or on the SEC's website at www.sec.gov.

Aasta Hansteen substructure float off.
Photo: Espen Rønnevik/Woldcam

Strategic report

Johan Sverdrup

2.1 STRATEGY AND MARKET OVERVIEW

STATOIL'S BUSINESS ENVIRONMENT

Market overview

In 2017 the world economy delivered the highest growth rate of the past six years. The world's major economies are growing close to historical trends or above, and the emerging economies are recovering from their economic deceleration in 2016. The US economy is on a strong footing, with GDP growth estimated at 2.2% in 2017. Consumer spending, supported by higher employment, is the main driver of US growth. The Eurozone also showed robust growth estimated at 2.5%, thanks to private consumption and low inflation. In the UK, growth decelerated, with expected GDP growth at 1.8% due to uncertainty around the Brexit process. Chinese GDP growth has been reported at 6.9% in 2017, based on strong government policy stimulus, delivering an improvement in the growth rate for the first time since 2010. The Japanese economy performed relatively well, with an estimated growth rate of 1.8%, driven by a tight labour market, corporate earnings and a conducive external environment. As a notable exception, India at 6.5% growth, delivered below expectations as the economy had to adapt to the Goods and Services Tax and still felt the effects of demonetisation. Reduced inflationary pressure and appreciating currencies in Russia and Brazil have allowed central banks to cut interest rates, contributing to the countries' economic recovery.

Looking forward, a robust demand picture and solid economic fundamentals should allow the expansion to continue. Among the risks that might affect such growth are geopolitical events and a too-fast monetary policy tightening from the central banks in key economies.

Global oil demand grew by 1.5 mmbbl per day in 2017 and global supply grew by 0.4 mmbbl per day. Decreasing oil prices in the first half of the year triggered both Opec and non-Opec countries to collectively honour their commitments to cut production. This resulted in stock draws and facilitated a gradual rebalancing of the market.

Overall, quarterly average European gas prices are up year-on-year throughout 2017. The first half of 2017 saw a downward trend in gas prices. However, in the second half of 2017, markets strengthened with demand growth in Asia leaving less LNG availability to serve a tight European market.

Oil prices and refining margins

A decreasing oil price in the first half of 2017 was followed by a strong second half with prices moving in an upward trajectory, closing the year at USD 66.5 per barrel. Refinery margins had a solid year fueled by strong demand in most products.

Oil prices

As in the previous two years, high volatility characterised the oil market. The average price for dated Brent crude in 2017 was USD 54.2 per barrel, up USD 10.5 per barrel from 2016. A relatively flat oil price fluctuating around USD 55 per barrel in the first couple of months was followed by a period of high volatility. Lingering worries about oversupply combined with surging output in Libya and Nigeria created a bearish sentiment with dated Brent bottoming out at USD 45 per barrel in late June. However, higher-than-expected demand and moderating global supply during the second half of 2017 put upward pressure on the commodity price. By the end of the third quarter, the price had reached almost USD 57 per barrel. Renewed buying interest in China and falling global stock piles facilitated continued rebalancing of the market throughout the fourth quarter. The upward pressure on the dated Brent oil price was strengthened even further by rising global geopolitical uncertainty, pushing prices to a two-year high of USD 62 per barrel in the first half of November. The Opec meeting in late November concluded with an agreement to extend oil supply cuts throughout 2018, with an option to review the deal in June. This gave support to the oil price through the last month of the year. Dated Brent was USD 66.5 per barrel on 31 December 2017. The futures market for Brent at the International Exchange Rate (ICE) was in contango until September before it shifted to backwardation and remained so for the rest of the year.

Over the course of 2017, global geopolitical unrest has been on the rise and received more attention as the market has become tighter.

US shale oil production has increased throughout 2017 due to continued productivity gains and cost reductions. The US is now delivering about 5 mmbbl per day of shale oil, with the Permian and Eagle Ford shale oil basins accounting for about two-thirds of the volumes. US crude oil exporters started to move cargoes toward high-growth markets in Asia as they capitalised on the favorable price differential. Development of Gulf Coast export capacity and crude price differentials are key determinants for future export levels.

Refining margins

Refining margins in Europe were strong in 2017. The moderate stock build in the first quarter of the year was followed by large draws in the next quarter due to strong demand. On the light end side, gasoline margins saw a moderate increase through the first half of the year. High demand and strong prices for LPG, driven by changes in China's energy mix, made the petrochemical industry take more naphtha, leaving less of the feedstock for making gasoline, eventually pushing prices. Stock draws in the US and strong demand in Europe supported diesel margins. The major impact of hurricane Harvey caused refining margins to peak by the end of the third quarter. A stronger physical crude oil market towards the end of the year put downward pressure on margins.

Natural gas prices

The upward trend in gas prices seen in the second half of 2016 continued into the first quarter of 2017, before taking a dip in second quarter 2017. The fourth quarter of 2017 experienced a robust price recovery.

Gas prices - Europe

NBP prices hit a decade low of USD 3 per mmBtu in August 2016, and increased towards an average of USD 5.7 per mmBtu in fourth quarter 2016. The climb continued into January 2017, averaging USD 6.6 per mmBtu, before falling throughout first and second quarter 2017 to USD 4.5 per mmBtu in June. Pipeline supply from the Norwegian Continental Shelf and Russia were at record highs of 117 bcm and 194 bcm respectively in 2017. However, the North-West Europe gas market has since late September 2017 been driven by a bullish combination of continued French nuclear outages, rallying coal prices, low hydro levels in Southern Europe and lower LNG availability in the Atlantic basin. The market tightened further due to the Rough storage shut-in and the new Groningen output ceiling, closing 2017 at USD 7.8 per mmBtu and resulting in an annual average of USD 5.8 per mmBtu.

Gas prices - North America
The Henry Hub price remained stable throughout 2017, averaging USD 3 per mmBtu for the year. Prices peaked early in the year at USD 3.3 per mmBtu on seasonal uplift, before warmer weather weakened the market. Storage inventories have been consistently lower than levels last year, a main driver as to why prices are up year-on-year. The lack of a significant mid-year cooling related to demand peak left summer prices lower than normal and lower than the spring prices. In fourth quarter 2017, robust production growth has limited upside price risks and put a premium on winter heating loads as the market weighs new pipeline takeaway capacity slowly coming online in the Northeast.

Global LNG prices
LNG prices in Asia ended 2016 at USD 9 per mmBtu. From here, monthly prices fell throughout first quarter 2017 and stabilised at USD 5.5 per mmBtu in second quarter 2017. The second half of the year experienced robust price recovery to an average of USD 9.4 per mmBtu in fourth quarter 2017, resulting in an annual average of USD 7.1 per mmBtu. Despite new LNG supply from Australia and the US, a marked pick-up in consumption across Asia has affected the market. Increased coal-to-gas switching to curb air pollution was seen in China. In South Korea and Taiwan gas stepped in for reduced nuclear capacity.

Statoil's corporate strategy

Statoil is an energy company committed to long-term value creation in a low carbon future. Statoil will develop and maximise the value of its unique Norwegian continental shelf (NCS) position, its international oil and gas business and its growing new energy business, focusing on safety, value and carbon efficiency. Statoil is a values-based company where empowered people collaborate to shape the future of energy.

Statoil's top priority in 2017 continued to be to conduct safe, secure and reliable operations with zero harm to people and the environment.

In 2017 Statoil launched its sharpened strategy. Geopolitical shifts, challenges in liquids resource replenishments, market cyclicality, structural changes to costs and increasing momentum towards low carbon implies uncertainty and volatility. To be prepared, Statoil is focusing on building a more resilient, diverse and option-rich portfolio, delivered by an agile organisation that embraces change and empowers its people. To deliver on the sharpened strategy, "always safe, high value, low carbon", Statoil will continue to build opportunities to optimise its portfolio around the following portfolio areas:

- **Norwegian continental shelf** - Build on unique position to maximise and develop long-term value
- **International oil & gas** - Deepen core areas and develop growth options
- **New energy solutions** - Create a material new industrial position
- **Midstream and marketing** - Secure premium market access and grow value creation through cycles

The following strategic principles guide Statoil in actively shaping its future portfolio:

- **Cash generation capacity at all times** - Generating positive cash flows from operations, even at low oil and gas prices, in order to sustain dividend and investment capacity through the economic cycles
- **Capex flexibility** - Having sufficient flexibility in organic capital expenditure to be able to respond to market downturns and avoid value destructive measures
- **Capture value from cycles** - Ensuring the ability and capacity to act counter-cyclically to capture value through the cycles
- **Low-carbon advantage** - Maintaining competitive advantage as a leading company in carbon efficient oil and gas production, while building a low-carbon business to capture new opportunities in the energy transition

In order to deliver on the strategy, Statoil has identified four key strategic enablers that will continue to support the business's needs:

- **Safe and secure operations**
- **Technology, digitalisation and innovation**
- **Empowered people**
- **Stakeholder engagement**

Statoil has a target to implement CO2 emission reduction measures equivalent to 3 million tonnes annually from its emissions between 2017 and 2030 and continues to make progress towards this goal. A significant portfolio of projects and initiatives has been established through 2017 with variable maturity to accomplish the 2030 commitments. Further communication on this can be found in Statoil's 2017 Sustainability Report.

Norwegian continental shelf - Build on unique position to maximise and develop long-term value
For more than 40 years, Statoil has explored, developed and produced oil and gas from the NCS. Statoil aims to deepen and prolong its position by accessing and maturing opportunities into valuable production. At the same time, Statoil plans to improve the efficiency, reliability, carbon emissions and lifespan of fields already in production. The NCS represents approximately two thirds of Statoil's equity production at 1,334 mboe per day in 2017.

Exploration: Statoil continues to be a committed NCS explorer across mature, growth and frontier areas. In 2017, Statoil participated in 17 exploration wells on the NCS, resulting in 10 commercial discoveries. Statoil was awarded 31 licences in mature areas in Norway's Awards for Predefined Areas (APA) 2017 round (result announced January 2018), 17 as operator and 14 as a non-operating partner

Development: Statoil has submitted five plans for development and operation in 2017: Njord, Bauge and Trestakk in the Norwegian Sea, Johan Castberg in the Barents Sea and Snorre Expansion Project in the North Sea. Johan Sverdrup Phase 1 is proceeding as scheduled and the pre-sanction for Johan Sverdrup Phase 2 was approved by the partners in the first quarter of 2017. The Aasta Hansteen project continued as planned and the Oseberg H Unmanned Wellhead Platform was installed in 2017.

Production: Gina Krog came on-stream in 2017. Statoil opened the Valemon onshore control room, enabling remote control.

Statoil will take over operatorship and equity in the Martin Linge field and Garantiana discovery. Two Cat J rigs, Askeladden and Askepott, were delivered to Statoil ready for digitalised operations at Gullfaks and Oseberg.

International oil and gas – Deepen core areas and develop growth options

International oil and gas production represented approximately one third of Statoil's equity production at 745 mboe per day in 2017. Statoil will continue to explore, develop, and produce oil and gas opportunities outside Norway as part of deepening its international core areas, the US onshore operations and Brazil, and developing future growth options.

Exploration: Statoil continues to explore internationally for oil and gas. Statoil participated in 11 exploration wells internationally, four of which were discoveries. Statoil added exploration acreage in Brazil, South Africa, UK, Suriname and the US Gulf of Mexico and entered one new country, Argentina.

Development: Statoil continued to strengthen its strategic partnership with Petrobras in Brazil, continuing construction on Peregrino Phase II and improving the project economics. Offshore UK, Mariner A has been installed and is currently in the hook-up and commissioning phase.

Production: Alongside operator BP and other partners, Statoil has signed the agreement for a licence extension by 25 years until 2049 for Azeri-Chirag Guneshli (ACG) with the Azerbaijan government and SOCAR. Statoil and BP, with Sonatrach, also extended the In Amenas Production Sharing Contract (PSC) by five years, from 2022 to 2027.

Statoil completed its divestment from the Canadian oil sands.

In Brazil, a 25% share in the producing Roncador field was acquired. Statoil also strengthened its position in the BM-S-8 licence, which includes the Carcara discovery, by acquiring QGEP's interest and successfully bidding on the open acreage to the North, before farming down to ExxonMobil and Petrogal.

In the United States, Statoil continued to focus on increasing and sustaining the profitability of existing assets in the portfolio, which led to continued progress towards the targets of lowering its US portfolio net operating income break-even to below USD 50 per barrel and increasing production by 50% from 2014 to 2018.

New energy solutions – Create a material new industrial position

Statoil's ambition is to maintain its advantage as a leading company in carbon efficient oil and gas production while building a low-carbon business to capture new opportunities in the energy transition. Statoil continues to explore new business opportunities in offshore wind, solar, carbon capture and storage (CCS) as well as other potential new energy markets. Statoil expects 15-20% of its investments to be directed towards new energy solutions by 2030.

Develop opportunities: Progress continues on the Arkona offshore wind farm operated by partner E.On. Statoil continues to evaluate a potential Norwegian carbon and capture storage as well as the feasibility of natural gas-to-hydrogen projects. In the United States, Statoil continues to mature the New York Wind Energy Area lease as "Empire Wind".

Operate assets: In 2017, Statoil completed and opened the Dudgeon Offshore Wind Park. Hywind Scotland, the world's first floating wind farm, also started production.

Statoil completed a re-organisation of the Dogger Bank consortium Forewind in the UK, splitting ownership of three of the four projects 50/50 with partner SSE and with Innogy (RWE) taking sole ownership of the remaining project. In December Statoil submitted a bid in the non-subsidy Dutch offshore wind tender for Hollanse Kust Zuid I & II. Statoil also initiated its first move into solar by acquiring 50% of the ongoing Apodi solar project in Brazil from Scatec Solar.

Midstream and marketing – Secure premium market access and grow value creation through cycles

The prime objective for Statoil's mid- and downstream activities is to process and transport its oil and gas production (including the Norwegian State's petroleum) competitively to premium markets, securing maximum value realisation. The main focus has been on:

- Safe, secure and efficient operations
- Minimising carbon emissions and intensity
- Securing flow assurance and premium market access for Statoil's equity production and the State's Direct Financial Interest (SDFI) volumes
- Building and maintaining resilience through asset backed trading, value chain positioning and counter-cyclical actions
- Focus on regional piped gas value chains and pursue selective trading positions in LNG

In 2017, Statoil chartered the ultra-large crude carrier (ULCC) TI Europe as part of its asset backed trading strategy. Statoil decided to phase out the Mongstad combined heat and power by end 2018 and commissioned the Polarled pipeline. Statoil continued work towards integrating digital solutions into decision making, shipping activities, and energy trading.

Strategy enablers

Safe and secure operations: Safety and security is Statoil's top priority. In 2017, Statoil initiated and continued several measures to reinforce safety work in all areas including continuous co-operation with partners and suppliers. The primary efforts launched in 2017 were focused on safety (I am Safety), security (2020 Security Roadmap), and IT security (New Information Technology Strategy) and are described in the chapter "Safeguarding people, the environment and assets: Safety and security."

Technology, digitalisation and innovation: Statoil's technology strategy provides long-term guidance for technology development and implementation. In 2017, Statoil launched its digital roadmap and established its Digital Centre of Excellence and Digital Academy. Statoil, in partnership with Techstars, established an energy-focused accelerator in Oslo.

Empowered people: Statoil promotes a culture of collaboration, innovation and safety, guided by its values. Statoil has continued to develop its employees and attract talents to deliver on the future-fit portfolio ambition.

Stakeholder engagement: Statoil engages with stakeholders to secure industrial legitimacy, its social contract, trust and strategic support from stakeholders. This engagement extends to internal and external collaboration, partnerships, and other co-operation with suppliers, partners, governments, NGOs and communities in which Statoil operates.

GROUP OUTLOOK

Statoil's plans address the current business environment while continuing to invest in high-quality projects. Statoil continues to reiterate its efforts and commitment to deliver on its priorities of high value creation, increased efficiency and competitive shareholder return.

- Organic capital expenditures[4] for 2018 are estimated at around USD 11 billion
- Statoil intends to continue to mature its large portfolio of exploration assets and estimates a total exploration activity level of around USD 1.5 billion for 2018, excluding signature bonuses
- Statoil's ambition is to keep the unit of production cost in the top quartile of its peer group
- For the period 2017 - 2020, production growth is expected to be around 3-4% CAGR (Compound Annual Growth Rate)
- Production for 2018 is estimated to be 1-2% above the 2017 level
- Scheduled maintenance activity is estimated to reduce equity production by around 30 mboe per day for the full year of 2018

These forward-looking statements reflect current views about future events and are, by their nature, subject to significant risks and uncertainties because they relate to events and depend on circumstances that will occur in the future. Deferral of production to create future value, gas off-take, timing of new capacity coming on stream, operational regularity, activity level, development in the prices of goods, raw materials and services that are used in the development and operation of oil and gas producing assets, contractor performance, as well as uncertainty around the closing of the announced transactions represent the most significant risks related to the foregoing guidance. For further information, see section 5.7 Forward-Looking Statements.

[4] See section 5.2 for non-GAAP measures

2.2 BUSINESS OVERVIEW

HISTORY

On 18 September 1972, Statoil was formed by a decision of the Norwegian parliament and incorporated as a limited liability company under the name Den norske stats oljeselskap AS. Being a company owned 100% by the Norwegian State, Statoil's initial role was to be the government's commercial instrument in the development of the oil and gas industry in Norway. Growing in parallel with the Norwegian oil and gas industry, Statoil's operations have primarily been focused on exploration, development and production of oil and gas on the Norwegian continental shelf (NCS).

During the 1980s, Statoil grew substantially through the development of the NCS. Statoil also became a major player in the European gas market by entering into large sales contracts for the development and operation of gas transport systems and terminals. During the same decade, Statoil was involved in manufacturing and marketing in Scandinavia and established a comprehensive network of service stations. This line of business was fully divested in 2012.

In 2001, Statoil was listed on the Oslo and New York stock exchanges and became a public limited company under the name Statoil ASA, 67% majority owned by the Norwegian State. Since then, substantial investments both on the NCS and internationally, have grown our business. The merger with Hydro's oil and gas division on 1 October 2007 further strengthened Statoil's ability to fully realise the potential of the NCS. Enhanced utilisation of expertise to design and manage operations in various environments have expanded our upstream activities outside our traditional area of offshore production. This includes the development of heavy oil and shale gas projects and projects that focus on other forms of energy, especially on offshore wind, but also on solar and carbon capture and storage.

The board of directors of Statoil have proposed to change the name of the company to Equinor. The new name supports the company's strategy and development as a broad energy company. The suggested name change will be proposed to the shareholders in a resolution to the annual general meeting on 15 May 2018.

ACTIVITIES

Statoil is an international energy company primarily engaged in oil and gas exploration and production activities, organised under the laws of Norway and subject to the provisions of the Norwegian Public Limited Liability Companies Act. In addition to being the leading operator on the NCS, Statoil has also substantial international activities and is present in several of the most important oil and gas provinces in the world. Our activities span operations in more than 30 countries and employs 20,245 employees worldwide.

Our access to crude oil in the form of equity, governmental and third-party volumes makes Statoil a large seller of crude oil, and Statoil is the second-largest supplier of natural gas to the European market. Processing, refining, offshore wind and carbon capture and storage is also part of our operations.

Statoil's registered office is at Forusbeen 50, 4035 Stavanger, Norway and the telephone number of its registered office is +47 51 99 00 00.

OUR COMPETITIVE POSITION

Key factors affecting competition in the oil and gas industry are oil and gas supply and demand, exploration and production costs, global production levels, alternative fuels, and environmental and governmental regulations. When acquiring assets and licences for exploration, development and production and in refining, marketing and trading of crude oil, natural gas and related products, Statoil competes with other integrated oil and gas companies.

Statoil's ability to remain competitive will depend, among other things, on continuous focus on reducing costs and improving efficiency. It will also depend on technological innovation to maintain long-term growth in reserves and production, the ability to seize opportunities in new areas and utilise new opportunities for digitalisation.

The information about Statoil's competitive position in the strategic report is based on a number of sources; e.g. investment analyst reports, independent market studies, and our internal assessments of our market share based on publicly available information about the financial results and performance of market players.

Continuous improvements

Statoil focus on continuously efficiency improvements as a response to the industrial challenge that has emerged over the recent years characterised by reducing prices for our products and declining returns. More specifically, the ambition is to realise positive production effects and capital expenditures and operating costs savings to improve financial results and cash-flows. In 2017, Statoil realised efficiency improvements of USD 1.3 billion on top of the already achieved USD 3.2 billon since 2013.

Establishment of Digital Centre of Excellence

In 2017 Statoil accelerated the digitalisation efforts by establishing a Digital Centre of Excellence and launching a digital road map. The goal is to significantly increase our utilisation of data, sophisticated analytics and robotics. In addition, Statoil aims to improve safety, reduce our carbon footprint and increase profitability. Statoil see potential by utilising data across IT applications and organisational boundaries. Combining data and learning across Statoil's disciplines could provide a better basis for decision-making, new business opportunities, and increased collaboration externally with our partners, suppliers and other lines of business.

CORPORATE STRUCTURE

Business areas

Statoil's operations are managed through the following eight business areas:

Development & Production Norway (DPN)

DPN manages Statoil's upstream activities on the NCS and explores for and extracts crude oil, natural gas and natural gas liquids. The business area's ambition is to continue Statoil's leading position on the NCS and ensure maximum value creation through continuously improved HSE and operational performance.

Development & Production International (DPI)
DPI manages Statoil's worldwide upstream activities excluding the DPN and Development & Production USA (DPUSA) business areas. It explores for and extracts crude oil, natural gas and natural gas liquids. DPI's ambition is to build a large and profitable international production portfolio comprising activities ranging from accessing new opportunities to delivering on profitable projects in a range of complex environments.

Development & Production USA (DPUSA)
DPUSA manages Statoil's upstream activities in the USA and Mexico. DPUSA's ambition is to develop a material and profitable position in the US and Mexico, including the deep-water regions of the Gulf of Mexico and unconventional oil and gas in the US.

Marketing, Midstream & Processing (MMP)
MMP manages Statoil's marketing and trading activities related to oil products and natural gas, transportation, processing and manufacturing, and the development of oil and gas. MMP seeks to maximise value creation in Statoil's midstream and marketing business.

Technology, Projects & Drilling (TPD)
TPD is responsible for the global project portfolio, well delivery, new technologies and sourcing across Statoil. TPD seeks to provide safe and secure, efficient and cost-competitive global well and project delivery, technological excellence, and research and development. Cost-competitive procurement is an important contributory factor for maximising value for Statoil.

Exploration (EXP)
EXP manages Statoil's worldwide exploration activities with the aim of positioning Statoil as one of the leading global exploration companies. This is achieved through accessing high potential new acreage in priority basins, globally prioritising and drilling more significant wells in growth and frontier basins, delivering near-field exploration on the NCS and other select areas, and achieving step-change improvements in performance.

New Energy Solutions (NES)
NES reflects Statoil's long-term goal to complement our oil and gas portfolio with profitable renewable energy and other low-carbon energy solutions. NES is responsible for wind farms and carbon capture and storage as well as other renewable energy and low-carbon energy solutions.

Global Strategy & Business Development (GSB)
GSB develops the corporate strategy and manages business development and merger and acquisition activities for Statoil. The ambition of the GSB business area is to closely link corporate strategy, business development and merger and acquisition activities to actively drive Statoil's corporate development.

Reporting segments

With effect as of the third quarter 2017, segment names have been changed for the reporting segments DPN and DPI. New names are Exploration & Production Norway (E&P Norway) and Exploration & Production International (E&P International), respectively. There are no changes to other reporting segments, and business area's names remain unchanged.

Statoil reports its business in the following reporting segments:

- E&P Norway reporting segment – Exploration & Production Norway – the DPN business area
- E&P International reporting segment – Exploration & Production International, which combines the DPI and the DPUSA business areas
- MMP reporting segment - Marketing, Midstream & Processing – the MMP business area
- Other – which includes activities in NES, TPD, GSB and Corporate and support functions

Activities relating to the EXP business area are fully allocated to - and presented in - the relevant exploration and production reporting segment. Activities relating to the TPD and GSB business areas are partly allocated to - and presented in - the relevant exploration and production reporting segments.

Presentation

In the following sections in the report, the operations are reported according to the reporting segment. Underlying activities or business clusters are presented according to how the reporting segment organises its operations. See note 3 Segments to the Consolidated financial statements for further details.

As required by the SEC, Statoil prepares its disclosures about oil and gas reserves and certain other supplementary oil and gas disclosures based on geographic areas. Statoil's geographical areas are defined by country and continent and consist of Norway, Eurasia excluding Norway, Africa, US and Americas excluding US.

SEGMENT REPORTING

Internal transactions in oil and gas volumes occur between our reporting segments before being sold in the market. The pricing policy for internal transfers is based on estimated market prices. For further information, see section 2.8 Operational performance under Production volumes and prices.

We eliminate intercompany sales when combining the results of reporting segments. Intercompany sales include transactions recorded in connection with our oil and natural gas production in the E&P Norway and the E&P International reporting segments, and also in connection with the sale, transportation or refining of our oil and natural gas production in the MMP reporting segment. Certain types of transportation costs are reported in both the MMP and the DPUSA business areas.

The DPN business area produces oil and natural gas which is sold internally to the MMP business area. A large share of the oil produced by the DPI and DPUSA business areas is also sold through the MMP business area. The remaining oil and gas from the DPI and the DPUSA business areas is sold directly in the market. For intercompany sales and purchases, Statoil has established a market-based transfer pricing methodology for the oil and natural gas that meets the requirements for applicable laws and regulations.

In 2017, the average transfer price for natural gas was USD 4.33 per mmbtu. The average transfer price was USD 3.42 per mmbtu in 2016 and USD 5.17 in 2015. For oil sold from DPN to MMP, the transfer price is the applicable market-reflective price minus a cost recovery rate.

The following table shows certain financial information for the four reporting segments, including intercompany eliminations for each of the years in the three-year period ending 31 December 2017. For additional information, see note 3 Segments to the Consolidated financial statements.

Segment performance (in USD million)	For the year ended 31 December 2017	2016	2015
Exploration & Production Norway			
Total revenues and other income	**17,692**	13,077	17,339
Net operating income/(loss)	**10,485**	4,451	7,161
Non-current segment assets[1]	**30,278**	27,816	27,706
Exploration & Production International			
Total revenues and other income	**9,256**	6,657	8,200
Net operating income/(loss)	**1,341**	(4,352)	(8,729)
Non-current segment assets[1]	**36,453**	36,181	37,475
Marketing, Midstream & Processing			
Total revenues and other income	**59,071**	44,979	58,106
Net operating income/(loss)	**2,243**	623	2,931
Non-current segment assets[1]	**5,137**	4,450	5,588
Other			
Total revenues and other income	**87**	39	354
Net operating income/(loss)	**(239)**	(423)	(129)
Non-current segment assets[1]	**390**	352	690
Eliminations[2]			
Total revenues and other income	**(24,919)**	(18,880)	(24,357)
Net operating income/(loss)	**(59)**	(219)	133
Non-current segment assets[1]	-	-	-
Statoil group			
Total revenues and other income	**61,187**	45,873	59,642
Net operating income/(loss)	**13,771**	80	1,366
Non-current segment assets[1]	**72,258**	68,799	71,458

1) Deferred tax assets, pension assets and non-current financial assets are not allocated to segments.

2) Includes elimination of inter-segment sales and related unrealised profits, mainly from the sale of crude oil and products. Inter-segment revenues are based upon estimated market prices.

The following tables show total revenues by country.

2017 Total revenues and other income by country (in USD million)	Crude oil	Natural gas	Natural gal liquids	Refined products	Other	Total sales
Norway	23,087	9,741	4,948	6,463	1,026	45,264
USA	5,726	1,237	668	1,497	1,237	10,365
Sweden	0	0	0	1,268	10	1,277
Denmark	0	0	0	2,195	12	2,208
Other	706	442	31	0	705	1,884
Total revenues (excluding net income (loss) from equity accounted investments and other income	29,519	11,420	5,647	11,423	2,991	60,999

2016 Total revenues and other income by country (in USD million)	Crude oil	Natural gas	Natural gas liquids	Refined products	Other	Total sales
Norway	20,544	7,973	3,580	4,135	(497)	35,735
US	3,073	957	455	1,110	867	6,463
Sweden	0	0	0	1,379	(53)	1,326
Denmark	0	0	0	1,518	14	1,532
Other	690	272	1	0	(26)	936
Total revenues (excluding net income (loss) from equity accounted investments and other income	24,307	9,202	4,036	8,142	305	45,993

2015 Total revenues and other income by country (in USD million)	Crude oil	Natural gas	Natural gas liquids	Refined products	Other	Total sales
Norway	22,741	10,811	4,932	5,644	1,454	45,582
US	3,718	1,133	532	1,605	933	7,922
Sweden	0	0	0	1,762	115	1,877
Denmark	0	0	0	1,750	8	1,759
Other	1,347	446	17	0	722	2,532
Total revenues (excluding net income (loss) from equity accounted investments and other income	27,806	12,390	5,482	10,761	3,232	59,671

RESEARCH AND DEVELOPMENT

Statoil is a technology-intensive company and research and development is an integral part of our strategy. Our technology strategy is about prioritising technology for value creation that enables us to achieve growth and access, and sets the direction for technology development and implementation for the future. Our focus is on low cost, low carbon solutions and re-using standardised technologies.

We continuously research, develop and deploy innovative technologies to create opportunities and enhance the value of Statoil's current and future assets. Statoil's technology development activities aim to reduce field development, drilling and operating costs, and CO_2 and other greenhouse gas emissions. We utilise a range of tools for the development of new technologies:

- In-house research and development
- Cooperation with academia and research institutes
- Collaborative development projects with our major suppliers
- Project related development as part of our field development activities
- Direct investment in technology start-up companies through our Statoil Technology Invest venture activities
- Invitation to open innovation challenges as part of Statoil Innovate

Research and development expenditures were USD 307 million in 2017, USD 298 million in 2016 and USD 344 million in 2015,

2.3 E&P NORWAY
- EXPLORATION & PRODUCTION NORWAY

OVERVIEW

The Exploration & Production Norway (E&P Norway) reporting segment is responsible for exploration, field development and operations on the NCS which includes the North Sea, the Norwegian Sea and the Barents Sea. E&P Norway aims to ensure safe and efficient operations and to maximise the value potential from the NCS. For proved reserves development see Development of reserves in Proved oil and gas reserves in section 2.8 Operational performance.

For 2017, E&P Norway reports NCS production from 38 Statoil operated fields, 10 partner operated fields, and equity accounted production from Lundin Petroleum AB.

Key events and portfolio developments in 2017:

- In March, the decision was made to proceed with the **Johan Sverdrup phase 2** development, awarding FEED contracts. Investment decision and submission of Plan for Development and Operation is expected in the second half of 2018
- On 26 March, the **Flyndre** field came on stream with Maersk Oil UK Ltd as operator
- On 27 March, Statoil submitted the revised Plan for Development and Operation for the **Njord** field, and Plan for Development and Operation for the **Bauge** field. Both submitted plans were subsequently approved on 20 June 2017
- On 15 April, the Norwegian authorities approved the Plan for Development and Operation of the **Trestakk** discovery on the Halten Bank in the Norwegian Sea
- On 30 June, the **Gina Krog** field went on stream
- On 1 July, Statoil assumed operatorship of the **Sigyn** field in the North Sea
- In July, Statoil and partners decided to develop the **Snefrid Nord** gas discovery. The field will be tied back to Aasta Hansteen
- On 28 July, the **Byrding** field came on stream
- In September, Statoil achieved **NCS climate target** two years ahead of schedule
- In October, Barents drilling campaign concludes with the **Kayak** find of commercial size
- In November, opening of the **Valemon** control room, the first platform in Statoil's portfolio remotely-controlled from land
- On 27 November, Statoil announced the decision to buy Total's equity stakes and to assume the operatorships of the **Martin Linge** field and the **Garantiana** discovery. The transactions are expected to be finalised in late March 2018
- On 5 December, Statoil submitted the Plan for Development and Operation for the **Johan Castberg** field in the Barents Sea
- In December, **Cat J rigs** Askeladden and Askepott preparing arrival at the Gullfaks and Oseberg fields. Drilling is expected to start in early 2018
- On 21 December, Statoil submitted the Plan for Development and Operation of the **Snorre Expansion** project, increasing the recovery from the Snorre field by close to 200 million barrels

Fields in production on the NCS

The table below shows E&P Norway's average daily entitlement production for the years ending 31 December 2017, 2016 and 2015. Production in 2017 increased due to higher flex gas off-take, contributions from new fields and fewer turnarounds.

Average daily entitlement production	For the year ended 31 December								
	2017			2016			2015		
	Oil and NGL	Natural gas		Oil and NGL	Natural gas		Oil and NGL	Natural gas	
Area production	mbbl/day	mmcm/day	mboe/day	mbbl/day	mmcm/day	mboe/day	mbbl/day	mmcm/day	mboe/day
Statoil operated fields	505	100	1,136	511	86	1,049	545	88	1,100
Partner operated fields	70	17	179	70	17	177	50	13	132
Equity accounted production	19	-	19	8	-	8	-	-	-
Total	594	118	1,334	589	103	1,235	595	101	1,232

The following tables show the NCS entitlement production by fields in which Statoil was participating during the year ended 31 December 2017.

Average daily entitlement production Field	Geographical area	Statoil's equity interest in %	On stream	Licence expiry date	Average production in 2017 mboe/day
Statoil operated fields					
Troll Phase 1 (Gas)	The North Sea	30.58	1996	2030	200
Oseberg	The North Sea	49.30	1988	2031	101
Gullfaks	The North Sea	51.00	1986	2036	96
Åsgard	The Norwegian Sea	34.57	1999	2027	93
Visund	The North Sea	53.20	1999	2034	67
Kvitebjørn	The North Sea	39.55	2004	2031	54
Tyrihans	The Norwegian Sea	58.84	2009	2029	54
Grane	The North Sea	36.61	2003	2030	47
Snøhvit	The Barents Sea	36.79	2007	2035	44
Troll Phase 2 (Oil)	The North Sea	30.58	1995	2030	39
Sleipner Vest	The North Sea	58.35	1996	2028	39
Statfjord Unit	The North Sea	44.34	1979	2026	38
Gudrun	The North Sea	36.00	2014	2028	35
Snorre	The North Sea	33.28	1992	2018 1)	28
Valemon	The North Sea	53.78	2015	2031	26
Mikkel	The Norwegian Sea	43.97	2003	2024	21
Fram	The North Sea	45.00	2003	2024	20
Kristin	The Norwegian Sea	55.30	2005	2033 2)	19
Alve	The Norwegian Sea	85.00	2009	2029	17
Gina Krog	The North Sea	58.70	2017	2032	15
Urd	The Norwegian Sea	63.95	2005	2026	12
Heidrun	The Norwegian Sea	13.04	1995	2024 3)	11
Vigdis area	The North Sea	41.50	1997	2024	10
Sleipner Øst	The North Sea	59.60	1993	2028	9
Tordis area	The North Sea	41.50	1994	2024	9
Morvin	The Norwegian Sea	64.00	2010	2027	8
Sigyn	The North Sea	60.00	2002	2022 4)	6
Norne	The Norwegian Sea	39.10	1997	2026	5
Gungne	The North Sea	62.00	1996	2028	4
Statfjord Nord	The North Sea	21.88	1995	2026	2
Heimdal	The North Sea	29.44	1985	2021	2
Veslefrikk	The North Sea	18.00	1989	2020 5)	2
Byrding	The North Sea	70.00	2017	2024	2
Statfjord Øst	The North Sea	31.69	1994	2026 6)	1
Sygna	The North Sea	30.71	2000	2026 7)	1
Fram H Nord	The North Sea	49.20	2014	2024 8)	0
Gimle	The North Sea	65.13	2006	2034 9)	0
Sindre	The North Sea	52.34	2017	2023	0
Total Statoil operated fields					1,136

Average daily entitlement production Field	Geographical area	Statoil's equity interest in %	Operator	On stream	Licence expiry date	Average production in 2017 mboe/day
Partner operated fields						
Ormen Lange	The Norwegian Sea	25.35	A/S Norske Shell	2007	2041 10)	74
Skarv	The Norwegian Sea	36.16	Aker BP ASA	2013	2033 11)	39
Ivar Aasen	The North Sea	41.47	Aker BP ASA	2016	2029 12)	21
Goliat	The Barents Sea	35.00	Eni Norge AS	2016	2042	15
Ekofisk area	The North Sea	7.60	ConocoPhillips Skandinavia AS	1971	2028	14
Marulk	The Norwegian Sea	50.00	Eni Norge AS	2012	2025	10
Vilje	The North Sea	28.85	Aker BP ASA	2008	2021	3
Ringhorne Øst	The North Sea	14.82	Point Resources AS	2006	2030	1
Enoch	The North Sea	11.78	Repsol Sinopec UK Ltd.	2007	2024	0
Flyndre	The North Sea	0.47	Maersk Oil UK Ltd.	2017	2028	0
Total partner operated fields						179
Equity accounted production						
Lundin Petroleum AB		20.10	Lundin Petroleum AB			19
Total E&P Norway including share of equity accounted production						1,334

1) PL089 expires in 2024 and PL057 expires in 2018.
2) PL134D expires in 2027 and PL199 expires in 2033.
3) PL095 expires in 2024 and PL124 expires in 2025.
4) Transfer of operatorship from ExxonMobil to Statoil on 1 July 2017.
5) PL052 expires in 2020 and PL053 in 2031.
6) PL037 expires in 2026 and PL089 expires in 2024.
7) PL037 expires in 2026 and PL089 expires in 2024.
8) PL090G expires in 2024 and PL248E expires in 2035.
9) PL120B expires in 2034 and PL050DS expires in 2023.
10) PL209/250 expires in 2041 and PL208 expires in 2040.
11) PL212/262 expires in 2033 and PL159 expires in 2029.
12) PL001B, PL457BS and PL242 expire in 2036. PL 338BS expire in 2029.

MAIN PRODUCING FIELDS ON THE NCS

Statoil operated fields

Troll is the largest gas field on the NCS and a major oil field. The Troll field regions are connected to the Troll A, B and C platforms. Troll gas is mainly exported and produced at Troll A, while oil is mainly produced at Troll B and C. Fram, Fram H Nord and Byrding are tie-ins to Troll C.

The **Oseberg** area includes the Oseberg Field Centre, Oseberg C, Oseberg East and Oseberg South production platforms. Oil and gas from the satellites are transported to the Oseberg Field Centre for processing and transportation.

Gullfaks was developed with three platforms. Since production started on Gullfaks in 1986, several satellite fields have been developed with subsea wells that are remotely controlled from the Gullfaks A and C platforms.

The **Åsgard** field includes the Åsgard A production and storage ship for oil, the Åsgard B semi-submersible floating production platform for gas and condensate, and the Åsgard C storage vessel for oil and condensate. Åsgard C is also storage for oil produced at Kristin and Tyrihans. In 2015 Statoil started the world first subsea gas compressor train on Åsgard, and the second train was started in February 2016. Mikkel and Morvin are tie-ins to Åsgard. The Trestakk development will be a tie-in to Åsgard A with production start planned for 2019.

Visund is an oil and gas field that includes a floating drilling, production and living quarter unit and two subsea templates.

Kvitebjørn is a gas and condensate field developed with an integrated accommodation, drilling and processing facility with a steel jacket.

Partner-operated fields

Ormen Lange operated by A/S Norske Shell, is a deepwater gas field in the Norwegian Sea. The well stream is transported to an onshore processing and export plant at Nyhamna. Gassco AS became operator of Nyhamna JV from 1 October 2017, with Shell as technical service provider.

Skarv is an oil and gas field located in the Norwegian Sea, with Aker BP ASA as operator. The field development includes a floating production, storage and offloading vessel (FPSO) and five subsea multi-well installations.

Ivar Aasen is operated by Aker BP ASA. It is an oil and gas field located in the North Sea. The development includes a fixed steel jacket with partial processing and living quarters tied in as a satellite to Edvard Grieg for further processing and export.

Goliat is operated by Eni Norge AS. It is the first oil field developed in the Barents Sea. The field consists of subsea wells tied back to a circular floating production, storage and offloading vessel (FPSO). The oil is offloaded to shuttle tankers.

Ekofisk is operated by ConocoPhillips Skandinavia AS. It consists of the Ekofisk, Tor, Eldfisk and Embla fields.

Marulk is operated by Eni Norge AS. It is a gas- and condensate field developed as a tie-back to the Norne FPSO.

Exploration on the NCS

Statoil holds exploration acreage and actively explores for new resources in all three regions on the NCS, the Norwegian Sea, the North Sea and the Barents Sea.

Statoil was awarded 31 licences (17 as operator) in the **Awards for Predefined Areas (APA) round 2017** for mature areas and completed several farm-in transactions with other companies.

Throughout 2017, as part of the industry initiative **Barents Sea Exploration Collaboration** (BaSEC), Statoil and its partners have drilled 6 wells in the Barents Sea and are planning to continue drilling wells in the area also in 2018.

In 2017 Statoil and its partners completed 17 exploratory wells and made 10 commercial and 3 non-commercial discoveries in Norway. In 2018 Statoil expects to complete 25-30 exploration wells on the NCS, with exploration near existing infrastructure to be the core of the activity plan.

	Exploratory wells drilled[1]		
	2017	2016	2015
North Sea			
Statoil operated	5	9	11
Partner operated	1	2	3
Norwegian Sea			
Statoil operated	5	2	5
Partner operated	0	0	1
Barents Sea			
Statoil operated	5	0	0
Partner operated	1	1	1
Total (gross)	**17**	**14**	**21**

1) Wells completed during the year, including appraisals of earlier discoveries.

Fields under development on the NCS

Statoil's major development projects on the NCS as of 31 December 2017:

Oseberg Vestflanken 2 (Statoil 49.3%, operator) is the development of the oil and gas structures Alfa, Gamma and Kappa. The well stream will be routed to the Oseberg field centre through a new pipeline. The discoveries will be developed using an unmanned wellhead platform. Production is expected to start in mid-2018.

Aasta Hansteen (Statoil 51%, operator) is a deep-water gas discovery in the Norwegian Sea. The field development includes three subsea templates tied in to a floating processing unit with gas export through a new pipeline, Polarled, to Nyhamna and further export through the Langeled pipeline. The Aasta Hansteen processing unit can also serve as a hub for other potential discoveries in the area. On 11 November 2017, the drilling of the first well of the **Aasta Hansteen** field development commenced. The topside and substructure were integrated in December 2017 in Norway. Production is expected to start in second half of 2018.

Johan Sverdrup (Statoil 40.03%, operator, with additional 4.54% indirect interest held through Lundin) is an oil discovery in the North Sea. Phase 1 of the development will consist of 35 production and water injection wells and a field centre with four platforms: A living quarter platform, a wellhead platform with permanent drilling facility, a processing platform and a riser and utility platform. Crude oil will be exported to Mongstad through a 274 km designated pipeline, and gas will be exported to the gas processing facility at Kårstø through a 156 km pipeline via a subsea connection to the Statpipe pipeline. As at the end of 2017, eight production wells and nine water injection wells have been drilled. Production is expected to start late fourth quarter 2019.

Utgard (Statoil 38.44% interest in the Norwegian and 38% in the UK sector, operator) is a gas and condensate discovery in the North Sea. The development includes two wells in a standard subsea concept, with one drilling target on each side of the UK-Norwegian maritime border. Gas and condensate will be piped through a new pipeline to the Sleipner field for processing and further transportation to market. **In** January 2017, the Plan for Development and Operation and the field development plan were approved by the Norwegian and UK authorities. Production is expected to start in fourth quarter 2019.

Trestakk (Statoil 59.1%, operator) is an oil discovery with associated gas on Haltenbanken. It will be developed as a subsea tie-back to Åsgard A, comprising one subsea template and one satellite with three producers and two injectors. In March 2017, the Plan for Development and Operation was approved by the Norwegian authorities. Production is expected to start in 2019.

Martin Linge (Statoil 19%, and upon consummation of the acquisition from Total, 70%) is an oil and gas field operated by Total, near the British sector of the North Sea. The reservoir is complex with gas under high pressure and high temperatures. In late November 2017, Statoil and Total announced that Statoil will purchase Total's interest (51%) and assume the operatorship of Martin Linge, with an effective date, upon consummation, of January 1, 2018. The transaction is subject to certain conditions and is expected to close in late March 2018. The development includes a fixed steel jacket platform with processing and export facilities, with electric power to be supplied from Kollsnes. Total, the current operator, expects production to start in 2019.

Njord future (Statoil 20%, operator) is a development to enable safe, reliable and efficient exploitation of the Njord and Hyme oil discoveries through to 2040. The development comprises an upgrade of the Njord A platform, an optimal oil export solution and drilling of 10 new wells. The Plan for Development and Operation was approved on 20 June 2017. Production is expected to start in late 2020.

Snorre expansion (Statoil 33.28%, operator) is a development to produce the remaining commercial oil reserves on the Snorre field. The Plan for Development and Operation of the field was submitted to the Norwegian authorities on 21 December 2017. The concept consists of six subsea templates, with four well slots each. Each slot will have the possibility for either production or injection. 24 wells will be drilled, 12 production wells and 12 injection wells. Production is expected to start in 2021.

Johan Castberg (Statoil 50%, operator) is the development of the three oil discoveries Skrugard, Havis and Drivis, located some 140 kilometres northwest of Hammerfest. The development includes a production vessel and a subsea development with 30 wells, ten subsea templates and two satellite structures. The Plan for Development and Operation of the field was submitted to the Norwegian authorities on 5 December 2017. Production is expected to start in 2022.

Decommissioning on the NCS

Under the Petroleum Act, the Norwegian government has imposed strict procedures for removal and disposal of offshore oil and gas installations. The Convention for the Protection of the Marine Environment of the Northeast Atlantic (OSPAR) stipulates similar procedures.

Huldra ceased production in September 2014, after 13 years in production. The permanent plugging and abandonment of wells was finalised in 2017, and removal of platform is planned for in 2019.

Volve ceased production in September 2016, after more than eight years in production. The permanent plugging of wells was finalised during 2016, and the removal of subsea facilities is expected to be completed in 2018.

During 2017, there were permanent plugging and abandonment operations at **Statfjord, Heidrun, Veslefrikk, Troll, Åsgard, Njord, Visund, Skuld** and **Tune**. The partner-operated fields **Ekofisk and Ormen Lange** also had ongoing plugging and abandonment activities.

For further information about decommissioning, see note 2 Significant accounting policies to the Consolidated financial statements.

2.4 E&P INTERNATIONAL – EXPLORATION & PRODUCTION INTERNATIONAL

E&P International overview

Statoil is present in several of the most important oil and gas provinces in the world. Exploration & Production International (E&P International) reporting segment covers development and production of oil and gas outside the Norwegian continental shelf (NCS).

E&P International is present in nearly 30 countries and had production in 12 countries in 2017. E&P International produced 36% of Statoil's total equity production of oil and gas in 2017. For information about proved reserves development see section 2.8 Operational performance under Proved oil and gas reserves.

The map shows the countries where E&P International has activity.

Key events and portfolio developments in 2017 and early 2018:

- In January 2017, the plan for development and operation for the **Utgard** field was approved by the Norwegian and UK authorities. The Utgard field spans the UK-Norway maritime border. For more information, see Fields under development on the NCS in section 2.3 E&P Norway
- In February, the **In Amenas Gas Compression project** in Algeria came into operation
- On 31 January, the transaction to divest Statoil's 100% owned **Kai Kos Dehseh (KKD)** oil sands projects in the Canadian province of Alberta to Athabasca Oil Corporation (AOC) was completed. The transaction covers the producing Leismer asset and the undeveloped Corner project, along with a number of contracts associated with Leismer's production. Following this transaction, Statoil no longer owns or operates any oil sands assets. As part of the transaction, Statoil will own just below 20% of AOC's shares, and this will be managed as a financial investment. For more information about the transaction see note 4 Acquisitions and divestments to the Consolidated financial statements
- In March, Statoil was awarded 13 leases in US Gulf of Mexico
- In March, Statoil was awarded six new licences, five as operator, in the 29th Offshore Licensing Round in UK
- In April, Statoil acquired an additional 14% working interest in existing Statoil-operated unconventional onshore assets in the **Appalachian** region from Northwood Energy Corporation.
- In April, the **Vito** (Statoil 37%, Shell operator) offshore discovery received approval for its concept development and selection
- In May, the **Stampede** (Statoil 25%, Hess operator) asset's offshore platform was successfully installed; and subsea work was completed and all three wells were ready at year end 2017. Production commenced with first oil in January 2018.
- In June, Statoil signed a swap agreement with BP regarding exploration permits in the Great Australian Bight and became operator and 100% equity interest holder in exploration permits **EPP39** and **EPP40** while Statoils equity interest in **EPP37** and **EPP38** were transferred to BP

- In July, Statoil and Queiroz Galvão Exploração e Produção (QGEP) signed an agreement for Statoil to acquire QGEP's 10% interest in the Statoil operated **BM-S-8** licence in Brazil, thereby increasing Statoil's interest in the licence to 76%. The transaction was completed in December. For more information about the transaction see note 4 Acquisitions and divestments to the Consolidated financial statements
- In September, Statoil completed transactions in South Africa for exploration rights, one with ExxonMobil Exploration and Production South Africa acquiring an interest in **Transkei Algoa** and one with OK Energy Ltd. to acquire interest and operatorship in **East Algoa**.
- In October, Statoil, as part of a consortium with ExxonMobil and Galp, presented the winning bid for the **Carcará North** block in the Santos basin in Brazil. The award closed in December 2017. Statoil is the operator and has 40% interest.
  In addition, Statoil, ExxonMobil and Galp have agreed on subsequent transactions in the adjacent BM-S-8 block to align equity interests across the two blocks that together comprise the Carcará oil discovery. Upon consummation and subject to government approval, Statoil will have a 36.5% interest in BM-S-8 and a 40% interest in Carcará North and will be the operator of the unitised Carcará field development. For more information about the transactions see note 4 Acquisitions and divestments to the Consolidated financial statements
- Statoil and the international partners in the **ACG** licence (Azeri-Chirag-Gunashli fields) in Azerbaijan have secured an extension of oil production of 25 years from 2024 under an extended and amended PSA, which was ratified by the Azeri Parliament on 31 October. As part of the agreement, Statoil's interest in the field has been adjusted from 8.56% to 7.27%, effective from 1 January 2017
- On 27 November, the **Hebron** oil field (Statoil 9%, ExxonMobil operator) offshore Canada started production
- In December, Statoil and Petrobras signed an agreement that Statoil will acquire a 25% interest in **Roncador**, a producing oil field in the Campos Basin in Brazil. Petrobras retains operatorship and a 75% interest. The field produced around 280 mboe per day in 2017. The effective date for the Roncador transaction is 1 January 2018. Closing is subject to government approval. For more information about the transactions see note 4 Acquisitions and divestments to the Consolidated financial statements
- In December, Statoil and the other partners BP and Sonatrach in the **In Amenas** licence in Algeria secured a licence extension of 5 years from 2022 through an amended and restated Production Sharing Agreement (PSA). Closing is subject to government approval

INTERNATIONAL PRODUCTION

Entitlement production volumes are Statoil's share of the volumes distributed to the partners according to production sharing agreement (PSA) (see section 5.6 Terms and abbreviations). For US assets entitlement production is expressed net of royalty interests. For all other countries royalties paid in-cash are included in entitlement production and royalties payable in-kind are excluded. Equity production represent volumes that correspond to Statoil's percentage ownership in a particular field and is larger than Statoil's entitlement production if the field is governed by a PSA.

Statoil's equity production outside Norway was 36% of Statoil's total equity production of oil and gas in 2017. Statoil's entitlement production outside Norway was about 31% of Statoil's total entitlement production in 2017.

The following table shows E&P International's average daily entitlement production of liquids and natural gas for the years ending 31 December 2017, 2016 and 2015.

Average daily entitlement production	For the year ended 31 December								
	2017			2016			2015		
Production area	Oil and NGL mboe/day	Natural gas mmcm/day	mboe/day	Oil and NGL mboe/day	Natural gas mmcm/day	mboe/day	Oil and NGL mboe/day	Natural gas mmcm/day	mboe/day
Americas	186	19	304	189	18	299	177	17	283
Africa	197	6	233	203	5	232	211	5	241
Eurasia	26	3	46	32	3	50	36	1	44
Equity accounted production	5	-	5	10	-	10	12	-	12
Total	415	27	588	435	25	592	436	23	580

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The table below provides information about the fields that contributed to production in 2017. Equity production per field is included in this table.

Field	Country	Statoil's equity interest in %	Operator	On stream	Licence expiry date	Average daily equity production in 2017 mboe/day
Americas						349.5
Appalachian[1) 2)]	US	Varies	Statoil/others	2008	HBP[3)]	128.4
Bakken [1)]	US	Varies	Statoil/others	2011	HBP[3)]	57.0
Peregrino	Brazil	60.00	Statoil	2011	2034	39.9
Eagle Ford [1)]	US	Varies	Statoil/others	2010	HBP[3)]	34.3
Tahiti	US	25.00	Chevron	2009	HBP[3)]	24.9
St. Malo	US	21.50	Chevron	2014	HBP[3)]	18.1
Caesar Tonga	US	23.55	Anadarko	2012	HBP[3)]	11.0
Hibernia/Hibernia Southern Extension[4)]	Canada	Varies	HMDC	1997	HBP[3)]	10.4
Jack	US	25.00	Chevron	2014	HBP[3)]	8.3
Julia	US	50.00	ExxonMobil	2016	HBP[3)]	6.4
Terra Nova	Canada	15.00	Suncor	2002	HBP[3)]	4.6
Heidelberg	US	12.00	Anadarko	2016	HBP[3)]	4.5
Leismer	Canada	100.00	Statoil	2010	HBP[3)]	1.8
Hebron	Canada	9.01	ExxonMobil	2017	HBP[3)]	0.2
Africa						310.0
Block 17	Angola	23.33	Total	2001	2022-34[5)]	139.6
Agbami	Nigeria	20.21	Chevron	2008	2024	47.6
In Salah	Algeria	31.85	Sonatrach/BP/Statoil	2004	2027	39.1
Block 15	Angola	13.33	ExxonMobil	2004	2026-32[5)]	37.4
In Amenas	Algeria	45.90	Sonatrach/BP/Statoil	2006	2022	23.6
Block 31	Angola	13.33	BP	2012	2031	18.9
Murzuq	Libya	10.00	Akakus Oil Operations	2003	2035	3.7
Eurasia						80.8
ACG[6)]	Azerbaijan	7.27	BP	1997	2049	49.1
Corrib	Ireland	36.50	Shell	2015	2031	20.0
Kharyaga	Russia	30.00	Zarubezhneft	1999	2031	9.4
Alba	UK	17.00	Chevron	1994	HBP[3)]	2.3
Total E&P International						740.4
Equity accounted production						
Petrocedeño[7)]	Venezuela	9.67	Petrocedeño	2008	2033	4.9
Total E&P International including share of equity accounted production						745.3

1) Statoil's actual equity interest can vary depending on wells and area.
2) Appalachian basin contains Marcellus and Utica formations.
3) Held by Production (HBP): A company's right to own and operate an oil and gas lease is perpetuated beyond its original primary term, as long thereafter as oil and gas is produced in paying quantities. In the case of Canada, in addition to continuing to be in production, other regulatory requirements must be met.
4) Statoil's equity interests are 5.0% in Hibernia and 9.26% in Hibernia South Extension. Effective 1 May 2017, Statoil's interest in Hibernia South Extension increased from 9.03% to 9.26% due to an equity reset trigger defined in the joint operating agreement.
5) Licence expiry varies by field.
6) As of 1 November 2017, Statoil's share of ACG equity production has been adjusted from 8.56% to 7.27% due to ratified licence extension.
7) As of 30 June 2017, the 9.67% ownership share in the heavy oil project Petrocedeño in Venezuela was reclassified from an equity accounted investment to a non-current financial investment. Statoil has as of this date stopped including production and reserves from Petrocedeño in financial reporting. Petrocedeño project (former Sincor project) was established in 2008. Sincor project started production in 2001.

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Americas

USA

Statoil has had strong growth in production and continues to optimise its portfolio within US shale, through acreage acquisition and divestments, since entering the first play in 2008. DPUSA contributed with 14% of Statoil's equity production in 2017.

Statoil entered the **Marcellus** shale gas play, located in the **Appalachian** region in north east US, in 2008 through a partnership with Chesapeake Energy Corporation. In 2012, Statoil became an operator in the Marcellus, through the purchase of additional acreage in the states of West Virginia and Ohio. In 2016, Statoil divested its operated assets in West Virginia. During 2017, Statoil has continued to develop its operatorship in the Appalachian basin assets in Ohio. Within the operated acreage in this basin, Statoil is developing two formations: **Marcellus** and **Utica**, with special focus on the latter. In addition, on April 2017, Statoil acquired an interest in existing Statoil operated assets in the Appalachian from Northwood Energy Corporation. Statoil's net acreage position in Appalachian at the end of 2017 was around 255,000 net acres.

Statoil entered the **Bakken** tight oil play through the acquisition of Brigham Exploration Company in December 2011. Statoil's net acreage position in **Bakken** and **Three Forks** shale formations at the end of 2017 was around 235,000 net acres. Statoil has a total working interest of approximately 70% in Bakken and is the asset's operator.

Statoil entered the **Eagle Ford** shale formation located in southwest Texas in 2010. In 2013, Statoil became operator for 50% of the Eagle Ford acreage. As part of a global transaction in December 2015 with Repsol, Statoil increased its working interest and became operator of all of the assets in the Eagle Ford Shale. As a result, Statoil has a total working interest of 63%. Our joint venture partner, Repsol, continues to hold 37% working interest. Statoil's net acreage position in Eagle Ford at the end of 2017 was around 70,000 net acres.

US gathering system

Statoil's participates in gathering and facilities for initial processing of oil and gas in the **Bakken**, **Eagle Ford** and **Appalachian Basin** assets in the US. This includes crude and natural gas gathering systems, fresh water supply systems, salt water gathering and disposal wells, oil and gas treatment and processing facilities to provide flow assurance for Statoil's upstream production. Midstream assets in Bakken are owned and operated 100% by Statoil. In Eagle Ford, Statoil is the operator for 100% of the midstream assets outside of the Oak, Karnes, DeWitt and Bee (KDB) area with a working interest of 63%. In the KDB area of Eagle Ford, Statoil has an ownership interest of 25.2% in Edwards Lime Gathering LLC, which is operated by Energy Transfer Partners L.P. For Appalachian Basin, Statoil has operated assets in Appalachian Basin South in Monroe Country Ohio to gather Marcellus production, while Utica production is gathered by Eureka Hunter, a third party. In the Appalachian Basin non-operated areas both in the North and South, Statoil's working interest ranges from 16.25% to 32.5% depending on gathering system and number of JV partners which include Williams Energy and Alta Gas.

In January 2016, the responsibility for the US gathering system was transferred from MMP to E&P International.

Statoil is, also, positioned in the US **Gulf of Mexico** for the following offshore developments:

The **Tahiti** oil field is located in the Green Canyon area and is produced through a floating spar facility. As of 31 December 2017, there were twelve production wells in operation, and additional wells will be phased in over time to fully develop the field.

The **Caesar Tonga** oil field is located in the Green Canyon area. As of 31 December 2017, there were seven producing wells tied back to the Anadarko-operated Constitution spar host, and additional production wells will be phased in over time.

The **Jack** and **St. Malo** oil fields are located in the Walker Ridge area. The fields are subsea tie-backs to the Chevron operated Walker Ridge Regional Host facility. As of 31 December 2017, there were five wells producing on Jack and eight wells producing for St. Malo. Additional production wells will be phased in over time.

The **Julia** oil field is located in the Walker Ridge area of the US Gulf of Mexico near Jack and St Malo. First oil was in April 2016 and four wells are currently online. Additional production wells may be drilled based on reservoir performance.

The **Heidelberg** oil field is located in the Green Canyon area and is produced through a floating spar facility. As of 31 December 2017, there were five producing wells in operation.

In addition to these fields, on December 2016, Statoil became operator of the **Titan** offshore platform, at the request of the U.S Bureau of Safety and Environmental Enforcement (BSEE), following the bankruptcy of Bennu Oil & Gas. In addition to the platform itself, Statoil also purchased the export pipelines with capacity to Shell's Mars system (oil) and William's Discovery Gas system (gas). Production has been shut in since November 2016; however, plans are currently in place to have the Titan platform re-instate production in 2018. Prior to being shut in, Titan was producing approximately 3,000 boepd from three nearby fields: Telemark (AT63), in which Statoil holds no interest; and Mirage (MC941) and Morgus (MC942), both of which Statoil now has operating rights and holds record title. Acquiring the platform and assets allows Statoil to effectively manage its abandonment obligations and capture value.

Canada

Statoil has interests in the Jeanne d'Arc Basin offshore the province of Newfoundland and Labrador in the partner operated producing oil fields **Terra Nova**, **Hebron**, **Hibernia** and **Hibernia Southern Extension**.

The **Hebron** field started production in November 2017. The Hebron field consists of a fixed gravity base structure (GBS) with drilling capabilities and storage for oil. Oil is off-loaded to shuttle tankers.

In January 2017, Statoil completed the transaction to fully divest to Athabasca Oil Corporation the assets and 123,200 net acres of oil sands leases in Alberta which form the **Kai Kos Dehseh** project.

Brazil

The **Peregrino** field is a heavy oil field located in the Campos Basin, about 85 kilometres off the coast of Rio de Janeiro. The oil is produced from two wellhead platforms with drilling capability and it is processed on the Peregrino FPSO and offloaded to shuttle tankers. Statoil holds a 60% ownership interest in the field and is operator.

Africa

Angola

The deep water **blocks 17, 15 and 31** contributed with 36% of Statoil's equity liquid production outside Norway in 2017. Each block is governed by a PSA which sets out the rights and obligations of the participants, including mechanisms for sharing of the production with the Angolan state oil company Sonangol.

Block 17 has production from four FPSOs; CLOV, Dalia, Girassol and Pazflor.

Block 15 has production from four FPSOs: Kizomba A, Kizomba B, Kizomba C-Mondo, and Kizomba C-Saxi Batuque.

Block 31 has production from the PSVM FPSO.

The FPSOs serve as production hubs and each receives oil from more than one field and a large number of wells. In 2017, new wells were added and set into production on blocks 15 and 17.

Nigeria

Statoil has a 20.2% interest in the **Agbami** deep water field which is located 110 km off the coast of the Central Niger Delta region. The field is developed with subsea wells connected to an FPSO. The Agbami field straddles the two licences OML 127 and OML 128 and is operated by Chevron under a Unit Agreement. Statoil has 53.85% interest in OML 128.

For information related to the Agbami redetermination process and the dispute between the Nigerian National Petroleum Corporation and the partners in Oil Mining Lease (OML) 128 concerning certain terms of the OML 128 Production Sharing Contract (PSC), see note 23 Other commitments, contingent liabilities and contingent assets to the Consolidated financial statements.

Algeria

The **In Salah** onshore gas development is a joint operatorship between Sonatrach, BP and Statoil. The Northern fields have been operating since 2004. The **Southern fields project**, which has been led by Statoil, started production from two fields (Garet el Befinat and Hassi Moumene) in March 2016. The remaining two fields (Gour Mahmoud and In Salah) started production in July and November 2017, respectively). The Southern fields are tied back into the Northern fields' existing facilities.

The **In Amenas** onshore development is a gas development which contains significant liquid volumes. The In Amenas infrastructure includes a gas processing plant with three trains. The production facility is connected to the Sonatrach distribution system. The facilities are operated through a joint operatorship between Sonatrach, BP and Statoil. The **In Amenas Gas Compression project**, which was led by BP, came into operation in February 2017. The compressors have made it possible to increase production and thereby utilise the capacity of all three trains.
In December, Statoil and the rest of the In Amenas partners secured a licence extension of 5 years beyond 2022. Extension is subject to government approval.

Separate PSAs including mechanisms for revenue sharing, govern the rights and obligations of the Parties and establish joint operatorships between Sonatrach, BP and Statoil for In Salah and In Amenas.

Eurasia

Production consists mainly of the output from the **Azeri-Chirag-Gunashli (ACG)** oil field in the Caspian Sea, the **Corrib** gas field off Ireland's northwest coast, and the **Kharyaga** oil field onshore in the Timan Pechora basin in north-west Russia.

The ACG licence has in 2017 been extended until the end of 2049 through an amended and restated PSA. The ACG New Platform project is an additional production platform in the ACG contract area and work is ongoing to optimise the chosen concept.

INTERNATIONAL EXPLORATION

Statoil reduced exploration drilling activity outside Norway in 2017 and prioritised new access efforts and prospect maturation to support an increased drilling activity in 2018 and onwards.

Brazil is one of Statoil's core exploration areas. In 2017 Statoil has strengthened its position in the Carcará oil discovery through portfolio transactions and through the second pre-salt offshore licensing round.

In 2017 Statoil has established a position onshore in **Argentina** in the Neuquén Basin through joint exploration venture with YPF regarding the Bajo del Toro block and through 5th bidding round for Bajo del Toro Este block.

In **South-Africa** in 2017 Statoil acquired participating interests in two additional offshore frontier blocks, including one operatorship through a transaction with ExxonMobil Exploration and Production South Africa.

Statoil was awarded 13 leases in US **Gulf of Mexico** in 2017 and is strengthening its position in the area.

In 2017 Statoil has signed agreements to enter two additional offshore exploration licences, Block 59 and 60, in the Guyana basin in **Suriname**. This is in line with our global exploration strategy of accessing early in basins with high exploration potential.

Statoil was awarded six licences, five as operator and one as partner, in the 29th Offshore Licensing Round on **the UK continental shelf**. These awards are a result of a strategic decision by Statoil to explore in prolific but mature basins. Statoil has drilled four exploration wells in the UK in 2017, resulting in one commercial discovery on Verbier.

After fulfilling the study period work program, Statoil has closed its office in Yangon in **Myanmar** and relinquished the AD-10 licence, as it now assesses the potential for commercially viable discovery to be low.

Including the four exploration wells drilled and one commercial discovery in the UK in 2017 Statoil and its partners completed 11 exploratory wells and made a total of four commercial discoveries internationally. In 2018 Statoil's international exploration drilling activity will comprise growth opportunities in basins where Statoil already is established with discoveries and producing fields in Brazil, Turkey and the UK, as well as new frontier opportunities such as

Argentina. Statoil expects to complete 8 to 10 exploration wells internationally in 2018.

	Exploratory wells drilled[1]		
	2017	2016	2015
Americas			
Statoil operated	2	5	8
Partner operated	4	2	2
Africa			
Statoil operated	0	0	3
Partner operated	0	0	3
Other regions			
Statoil operated	4	0	2
Partner operated	1	2	0
Total (gross)	**11**	**9**	**18**

1) Wells completed during the year, including appraisals of earlier discoveries.

FIELDS UNDER DEVELOPMENT INTERNATIONALLY

This section covers all the sanctioned projects.

Americas

USA

The **Stampede** oil field (Statoil 25%, Hess operator) is located in the Green Canyon area of the Gulf of Mexico. The development includes a tension-leg platform (TLP) with downhole gas lift and water injection from start of production. In May, the offshore platform was successfully installed. The preparations for start-up of production progressed: subsea work was completed and all three wells were ready at year end 2017. Production commenced with first oil in January 2018

TVEX (Statoil 25%, Chevron operator) is an extension to Tahiti field, targeting shallower reservoirs above the existing main Tahiti reservoir, which is located in the Green Canyon area of the Gulf of Mexico. Start of production is expected in the fourth quarter of 2018.

The **Big Foot** oil field (Statoil 27.5%, Chevron operator) is located in Walker Ridge area of the Gulf of Mexico. The development includes a dry tree TLP with a drilling rig. The **Big Foot** project's offshore installation was completed on March 2018. First oil estimated date is during the second half of 2018.

US Onshore operations use hydraulic fracturing to recover resources. Despite reduction in investment and activity level in recent years in shale plays **Bakken**, **Eagle Ford** and **Appalachian Basin (Marcellus** and **Utica)**, production growth continues. The increase in onshore production is mainly attributed to higher recovery per well due to enhanced completion and improved operational efficiency.

Brazil

Peregrino phase II (Statoil 60%, operator) includes the Peregrino South and Southwest discoveries. The development consists of one wellhead platform tied back to the existing floating production, storage and offloading vessel. Project execution started in April 2016. In September 2016, the plan for development was formally approved by the Brazilian national agency of petroleum, natural gas and biofuels (ANP). Production is expected to start in late 2020.

Eurasia

United Kingdom

Mariner (Statoil 65.11%, operator) is a heavy oil development in the UK. The field development includes a production, drilling and living quarter platform based on a steel jacket. Oil will be exported by offshore loading from a floating storage unit. The development includes a possible future subsea tie-in of Mariner East, a small heavy oil discovery. Mariner topsides were successfully installed in August 2017, and offshore hook-up and commissioning is currently ongoing. Production from Mariner is expected to start in second half of 2018.

DISCOVERIES WITH POTENTIAL DEVELOPMENT

This section covers selected pre-sanction projects.

Americas

USA

The **Vito** project (Statoil 37%, Shell operator) is a light weight semi-submersible platform with a single eight-well subsea manifold, in the Mississippi Canyon area of the Gulf of Mexico. The deep wells (32,000 feet) will have down hole gas lift to assist the production. Production is estimated to start by the end of the second quarter of 2021. In April 2017, its concept development and selection was approved.

Canada

Statoil has made oil discoveries in the Flemish Pass offshore Newfoundland comprising the **Bay du Nord** project (Statoil 65%, operator), and work is ongoing to assess options for developing Bay du Nord.

Brazil

Statoil is operator with 35% equity interest in **licence BM-C-33** in the Campos basin. We are evaluating options for developing the discoveries in the licence.

The pre-salt oil discovery **Carcará** straddles block BM-S-8 and the Carcara North block in the Santos basis. In 2017 Statoil obtained a 40% interest in Carcara North and Statoil has 76% interest in BM-S-8. Statoil has announced agreements to reduce its interest in BM-S-8 to 36.5% and Statoil will be the operator of both Carcara North and BM-S-8 for a unitised field development. Closing of these transactions and unitization of the field is subject to government approval. This, together with the announced agreement with Petrobras to acquire 25% in the producing oil field **Roncador** in the Campos basin, will strengthen our position in Brazil, one of Statoil's core areas due to its large resource base and excellent fit with our technology and capabilities.

Africa

Tanzania

Statoil has made several large gas discoveries in **Block 2** (Statoil 65%, operator) offshore Tanzania during 2012-2015. The licence is located in the Indian Ocean 100 km off the southern part of

Tanzania. Work is ongoing to assess options for developing the discoveries, including the construction of an onshore LNG plant jointly with the co-venturers in Blocks 1 and 4 which are operated by Shell Tanzania.

Eurasia

Russia

In September 2017, Rosneft and Statoil signed the shareholders and operating agreement (SOA) for the **North Komsomolskoye** project. The parties will establish a Russian limited joint venture company where Statoil will own 33.33%. North Komsomolskoye is a conventional, but complex viscous oil field located onshore Western Siberia in Russia. Statoil and Rosneft have agreed to start test production in North Komsomolskoye with the aim to better understand the reservoir and lay the ground for a potential future full field development decision. For information about risks related to our activity in Russia see section 2.11 Risk review under Risks related to our business.

2.5 MMP - MARKETING, MIDSTREAM & PROCESSING

MMP overview

The Marketing, Midstream & Processing (MMP) reporting segment is responsible for marketing, trading, processing and transporting of crude oil and condensate, natural gas, NGL and refined products, including operation of Statoil operated refineries, terminals and processing plants. In addition, MMP is responsible for power and emissions trading and for developing transportation solutions for natural gas, liquids and crude oil from Statoil assets including pipelines, shipping, trucking and rail. The business activities within MMP are organised in the following business clusters: Marketing and Trading, Asset Management and Processing and Manufacturing.

MMP handles Statoil's and the Norwegian state's direct financial interest (SDFI) equity production of crude oil and NGL, and third-party volumes. This represents approximately 50% of all Norwegian liquids exports. MMP is also responsible for marketing Statoil's and SDFI's gas together with third-party gas. This represents approximately 70% of all Norwegian gas exports. See the Norwegian state's participation and SDFI oil and gas marketing and sale in Applicable laws and regulations in section 2.7 Corporate.

Key events in 2017:

- The export of Statoil piped gas was record high at 41.0 bcm
- Decision to phase out combined heat and power plant at Mongstad was made in February
- Statoil awarded long-term contracts for two offshore loading shuttle tankers and two LPG carriers. The fuel efficiency features built into these vessels will reduce operational costs and climate emissions
- Polarled pipeline was commissioned in May and will transport gas from the NCS to the Nyhamna gas processing plant, which has been upgraded to process and export the new volumes

Marketing and trading of gas and LNG

Statoil's gas marketing and trading business is conducted from Norway and from offices in Belgium, the UK, Germany, the USA and Singapore.

Europe

The major export markets for gas from the NCS are Germany, France, the UK, Belgium, the Netherlands, Italy and Spain. LNG from the Snøhvit field, combined with third party LNG cargoes, allow Statoil to reach global gas markets. The majority of gas is sold to counterparties through bilateral sales agreements and the remaining volumes are sold over the trading desk through all the main European trading hubs. The bilateral sales are mainly carried out with large industrial customers, power producers and local distribution companies. A few of Statoil's long-term gas contracts contain contractual price review mechanisms that can be triggered by the buyer or seller as regulated by the contracts. For the ongoing price-reviews, Statoil provides in its financial statements for probable liabilities based on Statoil's best judgement. For further information, see Note 23 to the Consolidated financial statements.

Statoil is active on both physical and exchange markets such as the Intercontinental Exchange (ICE). Statoil expects to continue to optimise the market value of gas volumes through a mix of bilateral contracts and trading via its production and transportation systems and downstream assets.

USA

Statoil Natural Gas LLC (SNG), a wholly-owned subsidiary, has a gas marketing and trading organisation in Stamford, Connecticut that markets natural gas to local distribution companies, industrial customers and power generators. SNG also markets equity production volumes from the Gulf of Mexico, Eagle Ford and the Appalachian Basin and transports some of the Appalachian production to New York City and to Niagara, providing access to the greater Toronto area.

In addition, SNG has long-term capacity contracts at the Cove Point LNG re-gasification terminal, that enables sourcing of LNG from the Snøhvit LNG facility in Norway. Due to low gas prices in the US compared to global LNG prices over the last years, almost all of Statoil's LNG cargoes have been diverted away from the US and delivered into higher priced markets in Europe, South-America and Asia.

Marketing and trading of liquids

MMP is responsible for the sale of Statoil's and the SDFI's crude oil and NGL, in addition to commercial optimisation of the refineries and terminals. The liquids marketing and trading business is conducted from Norway, the UK, Singapore, the US and Canada. The main crude oil market for Statoil is northwest Europe.

MMP also markets equity volumes from E&P International assets located in Canada, the US, Brazil, Angola, Nigeria, Algeria, Azerbaijan and the UK, as well as third party volumes. Value is maximised through marketing, physical and financial trading and through optimisation of own and leased capacity such as refineries, processing, terminals, storages, pipelines, railcars and vessels.

Manufacturing

Statoil owns and is operator of the Mongstad refinery in Norway including the Mongstad Heat and Power Plant (MHPP). The refinery is a medium sized refinery built in 1975, with a crude oil and condensate distillation capacity of 226,000 barrels per day. The refinery is directly linked to offshore fields through two crude oil pipelines, to the crude oil terminal at Sture and the gas processing plant at Kollsnes through an NGL/condensate pipeline, and to Kollsnes by a gas pipeline. MHPP produces heat and power from gas received from Kollsnes and from the refinery. It has capacity of approximately 280 megawatts of electric power and 350 megawatts of process heat. Following termination of the existing gas agreement between the Troll licence and Statoil Refining Norway AS, the normal operation of the power plant will be phased out.

Statoil has an ownership interest of 34% in Vestprosess, which transports and processes NGL and condensate. The Vestprosess pipeline connects the Kollsnes and Sture plants to Mongstad. Operatorship of Vestprosess is transferred to Gassco 1 January 2018, with Statoil as technical service provider.

Statoil owns and is operator of the Kalundborg refinery in Denmark, which has a crude oil and condensate distillation capacity of

108,000 barrels per day. The refinery is connected via one gasoline and one gas oil pipeline to the terminal at Hedehusene near Copenhagen, and most of its products are sold locally.

Statoil has an ownership interest of 82% in the methanol plant at Tjeldbergodden. It receives natural gas from the Norwegian Sea through the Haltenpipe pipeline. In addition, Statoil holds a 50.9% ownership interest in the air separation unit Tjeldbergodden Luftgassfabrikk DA.

The following table shows operating statistics for the plants at Mongstad, Kalundborg and Tjeldbergodden.

	Throughput[1)]			Distillation capacity[2)]			On stream factor %[3)]			Utilisation rate %[4)]		
Refinery	2017	2016	2015	2017	2016	2015	2017	2016	2015	2017	2016	2015
Mongstad	12.1	9.8	11.9	9.3	9.3	9.3	97.5	94.4	97.6	94.7	93.9	93.4
Kalundborg	5.5	5.0	5.2	5.4	5.4	5.4	99.7	98.0	98.5	90.4	91.0	91.0
Tjeldbergodden	0.94	0.76	0.92	0.95	0.95	0.95	99.4	94.8	98.5	99.4	94.8	98.5

1) Actual throughput of crude oils, condensates, NGL, feed and blendstock, measured in million tonnes.
Throughput may be higher than distillation capacity for plants because volumes of fuel oil, NGL, kero, naphta, gasoil and bio-diesel additive may not go through the crude-/condensate distillation unit.

2) Nominal crude oil and condensate distillation capacity, and methanol production capacity, measured in million tonnes.

3) Composite reliability factor for all processing units, excluding turnarounds.

4) Composite utilisation rate for all processing units, based on throughput and capacity.

Terminals and storage

Statoil has a 65% ownership interest in Mongstad crude oil terminal. Crude oil is landed at Mongstad through pipelines from the NCS and by crude tankers from the market. The Mongstad terminal has a storage capacity of 9.4 million barrels of crude oil.

The Sture crude oil terminal receives crude oil through pipelines from the North Sea. The terminal is part of the Oseberg Transportation System (Statoil interest 36.2%). The processing facilities at Sture stabilise Oseberg crude oil and recover LPG mix (propane and butane) and naphtha.

Statoil operates the South Riding Point Terminal, which is located on Grand Bahamas Island and consists of two shipping berths and ten storage tanks, with a storage capacity of 6.75 million barrels of crude oil. The terminal has facilities to blend crude oils, including heavy oils. The South Riding Point terminal was hit by Hurricane Matthew in 2016 with extensive damage to the Sea Island and the offshore berth unloading/loading facility. The reconstruction work is expected to be finalised in 2018.

Statoil UK holds one third share of the interests in the Aldbrough Gas Storage in UK, which is operated by SSE Hornsea Ltd.

Statoil Deutschland Storage GmbH holds a 23.7% stake in the Etzel Gas Lager in the northern part of Germany which has a total of 19 caverns and secures regularity for gas deliveries from the NCS.

Statoil UK holds a 27.3% stake in the Teesside terminal, which stabilises unstable oil from the Ekofisk area and several other Norwegian and UK fields and recovers NGL.

Pipelines

Statoil is a significant shipper in the NCS gas pipeline system. Most gas pipelines on the NCS that are accessed by third-party customers are owned by a single joint venture, Gassled, with regulated third-party access. The Gassled system is operated by the independent system operator Gassco AS, which is wholly owned by the Norwegian state. Statoil's current ownership share in Gassled is 5%. See Gas sales and transportation from the NCS in section 2.7 Corporate for further information.

Statoil is the technical service provider (TSP) for the Kårstø and Kollsnes gas processing plants in accordance with the technical service agreement between Statoil and Gassco AS, included as Exhibit 4(a)(i) to Form 20-F. Statoil also performs the TSP role for the majority of the Gassco operated gas pipeline infrastructure.

In addition, MMP manages Statoil's ownership in the following pipelines in the Norwegian gas transportation system: Oseberg oil transportation system, Grane oil pipeline, Kvitebjørn oil pipeline, Troll oil pipeline I and II, Edvard Grieg oil pipeline, Utsira High gas pipeline, Valemon rich gas pipeline and the Haltenpipe, Norpipe and Mongstad gas pipeline.

Statoil holds 30.1% interest in the Nyhamna gas processing plant in Aukra via the recently established Nyhamna Joint Venture. The venture is operated by Gassco.

The Polarled pipeline connects fields in the Norwegian Sea with the Nyhamna gas processing plant. Transportation through the pipeline will commence at Aasta Hansteen production start. Statoil transferred the operatorship for the Polarled pipeline to Gassco on 1 May 2017.

The Johan Sverdrup oil and gas export pipelines are under construction and will provide export from the Johan Sverdrup field.

2.6 OTHER GROUP

The Other reporting segment includes activities in New Energy Solutions (NES), Global Strategy & Business Development (GSB), Technology, Projects & Drilling (TPD) and corporate staffs and support functions.

New Energy Solutions (NES)

The NES business area reflects Statoil's aspirations to gradually complement its oil and gas portfolio with profitable renewable energy and other low-carbon energy solutions. Offshore wind, solar and carbon capture and storage have been key strategic focus areas in 2017.

As per end of 2017, Statoil's share of the offshore wind production capacity is around 290 megawatt (MW) in production and around 190 MW under development.

Key events in 2017:

- Construction completed with full capacity for wind production from **Dudgeon wind farm** and **Hywind Scotland** during fourth quarter of 2017.
- Increased UK presence through increasing ownership in the **Dogger Bank** offshore wind projects.
- Assumed role as operator for the **Sheringham Shoal wind farm** in April 2017.
- Acquired 43.75% of the Apodi solar asset in Brazil, operated by Scatec. The acquisition was made through a 40% share from Scatec Solar and 3.75% from ApodiPar. The Apodi solar project started construction during fourth quarter of 2017.
- Awarded the role as operator of the **Carbon capture and storage** project for the FEED study. Partners Shell and Total have 33.33% each.
- The existing 5-year agreement for the **Technology Centre Mongstad** for testing of different CO_2 capture technologies expired in August 2017. Statoil, Total, Shell and Gassnova (Norwegian State-owned entity) have agreed to continue operations for three years. Statoil's equity share has been reduced from 20% to 7.5% (in line with other industrial partners).

The **Sheringham Shoal offshore wind farm** (Statoil 40%, operator) located off the coast of Norfolk, UK, was formally opened in September 2012. The wind farm is in full production with 88 turbines and an installed capacity of 317 MW. The wind farm's annual production is approximately 1.1 terawatt hours (TWh) and it has the capacity to provide power to approximately 220,000 households. Statoil took over the role as operator of Sheringham Shoal from the second quarter of 2017.

The **Dudgeon offshore wind farm** (Statoil 35%, operator) is located in the Greater Wash area off the English east coast, a short distance from Sheringham Shoal. A final investment decision for the 402 MW project was made in July 2014 and the project was inaugurated in November 2017. The wind farm is expected to produce 1.7 TWh yearly from 67 turbines, with the capacity to provide power for around 410,000 households.

Dudgeon Offshore Wind.
Photo: Ole Jørgen Bratland

The **Dogger Bank area** has a total consented capacity of 4.8 GW and is potentially the largest offshore wind farm development in the world. In February and August 2015, the consortium received consent from the UK authorities for four projects, each with a capacity of 1200 MW. Statoil and Statkraft, together with RWE and SSE, were partners in the Forewind consortium, each with a 25% equity stake. The consortium has gone through a major reorganisation during 2017. Statoil and SSE bought Statkraft's shares in March 2017 and a project split followed in August 2017, Innogy (RWE) now owns Project 3 (Teesside B) 100%, and Statoil and SSE have entered into a shareholders' agreement for Projects 1, 2 and 4 with a 50/50 ownership of the Creyke Beck A and B, and Teesside A projects.

The **Arkona offshore wind farm** (Statoil 50%, operated by e.on) is being developed in the German part of the Baltic Sea, and the operations and maintenance base will be located in Sassnitz on the island of Rügen. A final investment decision for the up to 385 MW project was made in April 2016. During 2017 the installation of the substructures was completed, and Arkona is expected to be in full operation in 2019. The wind farm is expected to provide power to approximately 400,000 German households from 60 turbines.

The **Hywind Scotland pilot wind park** (Statoil 75%, operator) is a floating wind pilot park using the Hywind concept, developed and owned by Statoil. The project is located at Buchan Deep, approximately 25 km off Peterhead on the east coast of Scotland. Statoil completed the project during 2017 and has installed 5

Siemens 6 MW turbines. Production is expected to be 0.14 TWh/year, powering around 20,000 households. This is the next step in Statoil's strategy towards deployment of the first utility large scale floating wind farms.

Statoil was the winner of the **New York Wind energy area lease**, following the December 2016 BOEM lease sale, with a winning bid of USD 42.5 million. The lease is 321 km^2, large enough to support one or more offshore wind developments with a total capacity of more than 1 GW. The lease is located approximately 20 km directly south of Long Island. The project has been named "Empire Wind" and is being further matured towards a plan for development during 2018.

Since 1996, Statoil has proven experience in **carbon capture and storage** (CCS) and has continued to develop competence through research engagement at Technology Centre Mongstad, the world's largest facility for testing and improving CO_2 capture. In addition, our offshore oil and gas operations at Sleipner and Snøhvit represent two of the world's largest CCS units. Statoil will seek to deploy its competence and experience in other CCS projects, both to reduce carbon dioxide emissions and to drive new opportunities, including enhanced oil recovery (EOR) possibilities and carbon neutral value chains based on hydrogen. Statoil has, on behalf of the Norwegian Ministry of Petroleum and Energy, performed a feasibility study for establishing a CO_2 storage facility in the Norwegian Sea. In 2017 the Ministry of Petroleum and Energy awarded Statoil the lead role to assess a full CCS value chain project covering both storage and transportation from three industrial sources in Norway. Statoil, Shell and Total are partners in the project with equal shares of one-third each.

In February 2016, Statoil launched the **Statoil Energy ventures fund**, a new energy investment fund dedicated to investing in attractive and ambitious growth companies in low carbon energy, supporting Statoil's strategy of growth in new energy solutions. The Statoil Energy Ventures Fund will invest up to USD 200 million over a period of four to seven years.

As of the date of this report, the fund has utilised less than a quarter of the total Statoil venture fund through four direct investments in four different segments, and is a limited partner in one financial venture capital fund.

Global Strategy & Business Development (GSB)

The Global Strategy & Business Development (GSB) business area is Statoil's functional centre for strategy and business development. GSB is responsible for Statoil's global strategy processes and identifies and delivers inorganic business development opportunities, including corporate mergers and acquisitions. This is achieved through close collaboration across geographic locations and business areas. Statoil's strategy forms the basis for guiding the company's business development focus.

GSB also hosts several corporate functions, including Statoil's Corporate Sustainability function, which is shaping the company's strategic response to sustainability issues and reporting on Statoil's sustainability performance.

Corporate staffs and support functions

Corporate Staffs and support functions comprise the non-operating activities supporting Statoil, and include headquarters and central functions that provide business support such as finance and control, corporate communication, safety, audit, legal services and people and leadership.

Technology, Projects & Drilling (TPD)

The **Technology, Projects & Drilling (TPD)** business area is responsible for global project development, well delivery, technology development and procurement in Statoil.

Research & Technology (R&T) is responsible for research and technology development to meet Statoil's business needs on short and long term, for delivering technical expertise to business development, projects and assets, and for implementing new technologies.

Project development (PRD) is responsible for planning and executing major facilities development, brownfield and field decommissioning projects where Statoil is the operator.

Drilling and Well (D&W) is responsible for providing cost-efficient well delivery and well operations, fit-for-purpose drilling facilities and providing expertise and advice to Statoil's global drilling and well operations.

Procurement and Supplier Relations (PSR) is responsible for global procurement aligned with Statoil's business needs.

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The table below displays major projects operated by Statoil, as well as projects operated by Statoil's licence partners. More information about ongoing projects are given in the E&P Norway, E&P International, MMP and NES sections. In our world-class portfolio, an additional 35-40 projects are in the early phase, maturing towards sanction.

Project startups and completions 2017	Statoil's interest	Operator	Area	Type
Hebron	9.01%	ExxonMobil	Jeanne d'Arc Basin, off coast of Newfoundland and Labrador, Canada	Oil
In Salah Southern fields	31.85%	Sonatrach/BP/Statoil	Algeria	Oil and gas
Dudgeon offshore wind farm	35.00%	Statoil	North Sea, off English coast	Wind
Hywind Scotland pilot wind park	75.00%	Statoil	North Sea, off Scottish coast	Wind
Gina Krog	58.70%	Statoil	North Sea	Oil and gas
Gullfaks C subsea compression	51.00%	Statoil	North Sea	Improved gas recovery
Byrding	70.00%	Statoil	North Sea	Oil and associated gas
Polarled	37.10%	Statoil	Norwegian Sea	Export pipeline for gas

Ongoing projects with expected startups and completions 2018-2022	Statoil's interest	Operator	Area	Type
Tahiti vertical expansion	25.00%	Chevron	Gulf of Mexico	Oil
Stampede	25.00%	Hess	Gulf of Mexico	Oil
Big Foot	27.50%	Chevron	Gulf of Mexico	Oil
Peregrino phase II	60.00%	Statoil	Campos basin, off coast of Rio de Janeiro, Brazil	Oil
Arkona offshore wind farm	50.00%	E.ON	Baltic Sea, off German coast	Wind
Mariner	65.11%	Statoil	North Sea	Oil
Oseberg Vestflanken 2	49.30%	Statoil	North Sea	Oil and gas
Troll B gas module	30.58%	Statoil	North Sea	Increased processing capacity
Martin Linge	19.00%	Total	North Sea	Oil and gas
- Total's share, Statoil to take over in late March 2018	51.00%			
Johan Sverdrup	40.03%	Statoil	North Sea	Oil and associated gas
- held through Lundin	4.54%			
Johan Sverdrup export pipelines, JoSEPP	40.03%	Statoil	North Sea	Oil and gas export pipelines
- held through Lundin	4.54%			
Utgard Norwegian sector	38.44%	Statoil	North Sea	Gas and condensate
UK sector	38.00%			
Trestakk	59.10%	Statoil	North Sea	Oil and associated gas
Huldra decommissioning	19.87%	Statoil	North Sea	Field decommissioning
Njord future	20.00%	Statoil	North Sea	Oil
Snorre expansion	33.28%	Statoil	North Sea	Oil
Aasta Hansteen	51.00%	Statoil	Norwegian Sea	Gas
Snefrid Nord	51.00%	Statoil	Norwegian Sea	Gas
Johan Castberg	50.00%	Statoil	Norwegian Sea	Oil

2.7 CORPORATE

APPLICABLE LAWS AND REGULATIONS

Statoil operates in more than 30 countries and is exposed to, and committed to compliance with, a number of laws and regulations globally.

This article focuses primarily on Norwegian laws specific for Statoil`s core activities, taking into account that the majority of Statoil's production is produced on the NCS, the ownership structure of the company and that Statoil is registered and has its headquarters in Norway.

Norwegian petroleum laws and licensing system

The principal laws governing Statoil's petroleum activities in Norway are the Norwegian Petroleum Act and the Norwegian Petroleum Taxation Act.

Norway is not a member of the European Union (EU), but Norway is a member of the European Free Trade Association (EFTA). The EU and the EFTA Member States have entered into the Agreement on the European Economic Area, referred to as the EEA Agreement, which provides for the inclusion of EU legislation in the national law of the EFTA Member States (except Switzerland). Statoil's business activities are subject to both the EFTA Convention and EU laws and regulations adopted pursuant to the EEA Agreement.

For further information about the jurisdictions in which Statoil operates, see sections 2.2 Business overview and 2.11 Risk review.

Under the Petroleum Act, the Norwegian Ministry of Petroleum and Energy ("MPE") is responsible for resource management and for administering petroleum activities on the NCS. The main task of the MPE is to ensure that petroleum activities are conducted in accordance with the applicable legislation, the policies adopted by the Norwegian Parliament (the Storting) and relevant decisions of the Norwegian State.

The Storting's role in relation to major policy issues in the petroleum sector can affect Statoil in two ways: firstly, when the Norwegian State acts in its capacity as majority owner of Statoil shares and, secondly, when the Norwegian State acts in its capacity as regulator:

- The Norwegian State's shareholding in Statoil is managed by the Ministry of Petroleum and Energy. The MPE will normally decide how the Norwegian State will vote on proposals submitted to general meetings of the shareholders. However, in certain exceptional cases, it may be necessary for the Norwegian State to seek approval from the Storting before voting on a certain proposal. This will normally be the case if Statoil issues additional shares and such issuance would significantly dilute the Norwegian State's holding, or if such issuance would require a capital contribution from the Norwegian State in excess of government mandates. A decision by the Norwegian State to vote against a proposal on Statoil's part to issue additional shares would prevent Statoil from raising additional capital in this manner and could adversely affect Statoil's ability to pursue business opportunities. For more information about the Norwegian State's ownership, see Risks related to state ownership in section 2.11 Risk review and Major shareholders in section 5.1 Shareholder information
- The Norwegian State exercises important regulatory powers over Statoil, as well as over other companies and corporations on the NCS. As part of its business, Statoil or the partnerships to which Statoil is a party, frequently need to apply for licences and other approval of various kinds from the Norwegian State. Although Statoil is majority-owned by the Norwegian State, it does not receive preferential treatment with respect to licences granted by or under any other regulatory rules enforced by the Norwegian State

The principal laws governing Statoil's petroleum activities in Norway and on the NCS are the Norwegian Petroleum Act of 29 November 1996 (the "Petroleum Act") and the regulations issued thereunder, and the Norwegian Petroleum Taxation Act of 13 June 1975 (the "Petroleum Taxation Act"). The Petroleum Act sets out the principle that the Norwegian State is the owner of all subsea petroleum on the NCS, that exclusive right to resource management is vested in the Norwegian State and that the Norwegian State alone is authorised to award licences for petroleum activities as well as determine its terms. Licensees are required to submit a plan for development and operation (PDO) to the MPE for approval. For fields of a certain size, the Storting has to accept the PDO before it is formally approved by the MPE. Statoil is dependent on the Norwegian State for approval of its NCS exploration and development projects and its applications for production rates for individual fields.

Production licences are the most important type of licence awarded under the Petroleum Act and are normally awarded for an initial exploration period, which is typically six years, but which can be shorter. The maximum period is ten years. During this exploration period, the licensees must meet a specified work obligation set out in the licence. If the licensees fulfil the obligations set out in the initial licence period, they are entitled to require that the licence be prolonged for a period specified at the time when the licence is awarded, typically 30 years.

The terms of the production licences are decided by the Ministry of Petroleum and Energy. A production licence grants the holder an exclusive right to explore for and produce petroleum within a specified geographical area. The licensees become the owners of the petroleum produced from the field covered by the licence. Production licences are awarded to group of companies forming a joint venture at the Ministry's discretion. The members of the joint venture are jointly and severally responsible to the Norwegian State for obligations arising from petroleum operations carried out under the licence. The Ministry of Petroleum and Energy decides the form of the joint operating agreements and accounting agreements.

The governing body of the joint venture is the management committee. In licences awarded since 1996 where the state's direct financial interest (SDFI) holds an interest, the Norwegian State, acting through Petoro AS, may veto decisions made by the joint venture management committee, which, in the opinion of the Norwegian State, would not be in compliance with the obligations of the licence with respect to the Norwegian State's exploitation policies or financial interests. This power of veto has never been used.

Interests in production licences may be transferred directly or indirectly subject to the consent of the MPE and the approval of the Ministry of Finance of a corresponding tax treatment position. In most licences, there are no pre-emption rights in favour of the other licensees. However, the SDFI, or the Norwegian State, as appropriate, still holds pre-emption rights in all licences.

The day-to-day management of a field is the responsibility of an operator appointed by the MPE. The operator is in practice always a member of the joint venture holding the production licence, although this is not legally required. The terms of engagement of the operator are set out in the joint operating agreement.

If important public interests are at stake, the Norwegian State may instruct Statoil and other licensees on the NCS to reduce the production of petroleum. The last time the Norwegian State instructed a reduction in oil production was in 2002.

A licence from the MPE is also required in order to establish facilities for the transportation and utilisation of petroleum. Ownership of most facilities for the transportation and utilisation of petroleum in Norway and on the NCS is organised in the form of joint ventures. The participants' agreements are similar to joint operating agreements for production.

Licensees are required to prepare a decommissioning plan before a production licence or a licence to establish and use facilities for the transportation and utilisation of petroleum expires or is relinquished, or the use of a facility ceases. On the basis of the decommissioning plan, the Ministry of Petroleum and Energy makes a decision as to the disposal of the facilities.

For an overview of Statoil's activities and shares in Statoil's production licences on the NCS, see section 2.3 E&P Norway.

Gas sales and transportation from the NCS

Statoil markets gas from the NCS on its own behalf and on the Norwegian State's behalf. Gas is transported through the Gassled pipeline network to customers in the UK and mainland Europe.

Most of Statoil's and the Norwegian State's gas produced on the NCS is sold under gas contracts to customers in the European Union (EU), and changes in EU legislation may affect Statoil's marketing of gas.

The Norwegian gas transport system, consisting of the pipelines and terminals through which licensees on the NCS transport their gas, is owned by a joint venture called Gassled. The Norwegian Petroleum Act of 29 November 1996 and the pertaining Petroleum Regulation establish the basis for non- discriminatory third-party access to the Gassled transport system.

The tariffs for the use of capacity in the transport system are determined by applying a formula set out in separate tariff regulations stipulated by the Ministry of Petroleum and Energy. The tariffs are paid on the basis of booked capacity, not on the basis of the volumes actually transported.

For further information, see section 2.5 MMP - Marketing, Midstream and Processing under Pipelines.

The Norwegian State's participation

The Norwegian State's policy as a shareholder in Statoil has been and continues to be to ensure that petroleum activities create the highest possible value for the Norwegian State.

In 1985, the Norwegian State established the State's direct financial interest (SDFI) through which the Norwegian State has direct participating interests in licences and petroleum facilities on the NCS. As a result, the Norwegian State holds interests in a number of licences and petroleum facilities in which Statoil also hold interests. Petoro AS, a company wholly owned by the Norwegian State, was formed in 2001 to manage the SDFI assets.

SDFI oil and gas marketing and sale

Statoil markets and sells the Norwegian State's oil and gas together with Statoil's own production. The arrangement has been implemented by the Norwegian State.

At an extraordinary general meeting held on 25 May 2001, the Norwegian State, as sole shareholder, approved an instruction to Statoil setting out specific terms for the marketing and sale of the Norwegian State's oil and gas. This resolution is referred to as the Owner's instruction.

Statoil is obliged under the Owner's instruction to jointly market and sell the Norwegian State's oil and gas as well as Statoil's own oil and gas. The overall objective of the marketing arrangement is to obtain the highest possible total value for Statoil's oil and gas and the Norwegian State's oil and gas, and to ensure an equitable distribution of the total value creation between the Norwegian State and Statoil.

The Norwegian State may at any time utilise its position as majority shareholder of Statoil to withdraw or amend the marketing instruction

HSE regulation

Statoil's petroleum operations are subject to extensive laws and regulations relating to health, safety and the environment (HSE).

With business operations in more than 30 countries, Statoil is subject to a wide variety of HSE laws and regulations concerning its products, operations and activities. Laws and regulations may be jurisdiction specific, but also international regulations, conventions or treaties, as well as EU directives and regulations, are relevant.

Statoil continues to monitor and respond to the Trump Administration's ongoing reorganization of regulatory bodies, including potentially the Department of Interior (DOI), an effort which is designed to streamline processes and reduce duplications. Potential implications on Statoil's operations in the US will be assessed as this regulatory review process develops. At this time, Statoil does not consider any of these potential changes to have a material impact on its US activities. Similarly, the effects from implementing the EU offshore Safety Directive in EU-member states' legislation will affect operations in relevant EU member countries. See also section 2.11 Risk review under Risk factors.

Taxation of Statoil

Statoil is subject to ordinary Norwegian corporate income tax and to a special petroleum tax relating to its offshore activities in Norway. Statoil's profits, both from offshore oil and natural gas activities and from onshore activities, are subject to Norwegian corporate income tax. The standard corporate income tax rate has been reduced from 24% in 2017 to 23% in 2018. In addition, a special petroleum tax is levied on profits from petroleum production and pipeline transportation on the NCS. The special petroleum tax rate has been increased from 54% in 2017 to 55% in 2018. The special petroleum tax rate is applied to relevant income in addition to the standard income tax rate, resulting in a 78% marginal tax rate on income subject to the special petroleum tax. For further information, see note 9 Income taxes to the Consolidated financial statements.

Statoil's international petroleum activities are subject to tax pursuant to local legislation. Fiscal regulation of Statoil's upstream operations is generally based on corporate income tax regimes and/or PSAs.

Statoil expects the impact of the recently enacted US tax reform to be favourable to Statoil and its US operations, primarily due to the reduction in the US corporate income tax rate from 35% to 21%. This change in US tax legislation (effective 1 January 2018) will have no impact on Statoil's deferred tax balance as Statoil has not recognised any net deferred tax asset or liability related to our US operations as of 31 December 2017. See note 9 Income taxes and note 10 Property, plant and equipment to the Consolidated financial statements.

SUBSIDIARIES AND PROPERTIES

Significant subsidiaries

The following table shows significant subsidiaries and equity accounted companies within Statoil group as of 31 December 2017.

Name	in %	Country of incorporation	Name	in %	Country of incorporation
Statholding AS (Group)	100	Norway	Statoil Natural Gas LLC	100	USA
Statoil Angola Block 15 AS	100	Norway	Statoil New Energy (Group)	100	Norway
Statoil Angola Block 17 AS	100	Norway	Statoil Nigeria AS	100	Norway
Statoil Angola Block 31 AS	100	Norway	Statoil Nigeria Ltd	100	Nigeria
Statoil Apsheron AS	100	Norway	Statoil North Africa Gas AS	100	Norway
Statoil Brasil Oleo e Gas (Group)	100	Brazil	Statoil North Africa Oil AS	100	Norway
Statoil BTC (Group)	100	Norway	Statoil Oil & Gas Brazil AS	100	Norway
Statoil Canada Ltd (Group)	100	Canada	Statoil OTS AB	100	Sweden
Statoil Colombia B.V.	100	Netherlands	Statoil Petroleum AS	100	Norway
Statoil Coordination Center NV	100	Belgium	Statoil Refining Norway AS	100	Norway
Statoil Danmark (Group)	100	Denmark	Statoil Sverige Kharyaga AB	100	Sweden
Statoil Deutschland GmbH (Group)	100	Germany	Statoil Tanzania AS	100	Norway
Statoil Dezassete AS	100	Norway	Statoil UK Ltd (Group)	100	United Kingdom
Statoil do Brasil Ltda	100	Brazil	Statoil US Holding Inc. (Group)	100	USA
Statoil Energy NL B.V.	100	Netherlands	Sincor Netherlands B.V.	100	Netherlands
Statoil Exploration Ireland Ltd	100	Ireland	South Atlantic Holding B.V.	60	Netherlands
Statoil Forsikring AS	100	Norway	AWE-Arkona-Windpark Entwicklungs-GmbH[1)]	50	Germany
Statoil Holding Netherlands B.V.	100	Netherlands	Naturkraft AS	50	Norway
Statoil International Netherlands B.V.	100	Netherlands	Lundin Petroleum AB[1)]	20	Sweden
Statoil Kharyaga AS	100	Norway			
Statoil Murzuq AS	100	Norway			

1) Equity accounted entities.

Property, plant and equipment

Statoil has interests in real estate in many countries throughout the world. However, no individual property is significant. The largest office buildings are the Statoil's head office located at Forusbeen 50, NO-4035, Stavanger, Norway which comprises approximately 135,000 square meters of office space, and the 65,500 square metre office building located at Fornebu on the outskirts of Norway's capital Oslo. Both office buildings are leased.

For a description of our significant reserves and sources of oil and natural gas, see Proved oil and gas reserves in section 2.8 Operational performance and section 4.2 Supplementary oil and gas information (unaudited) later in this report. For a description of our operational refineries, terminals and processing plants, see section 2.5 MMP - Marketing, Midstream and Processing.

Related party transactions

See note 24 Related parties to the Consolidated financial statements. See also section 3.4 Equal treatment of shareholders and transactions with close associates.

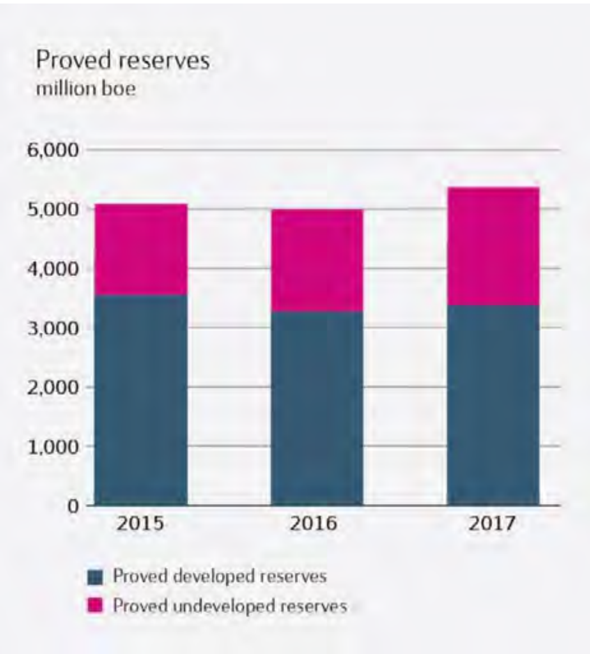
Insurance

Statoil maintains insurance coverage that includes coverage for physical damage to its oil and gas properties, third-party liability, workers' compensation and employers' liability, general liability, sudden pollution and other coverage. See also section 2.11 Risk review under Risk factors.

2.8 OPERATIONAL PERFORMANCE

PROVED OIL AND GAS RESERVES

Proved oil and gas reserves were estimated to be 5,367mmboe at year end 2017, compared to 5,013 mmboe at the end of 2016.



Statoil's proved reserves are estimated and presented in accordance with the Securities and Exchange Commission (SEC) Rule 4-10 (a) of Regulation S-X, revised as of January 2009, and relevant Compliance and Disclosure Interpretations (C&DI) and Staff Accounting Bulletins, as issued by the SEC staff. For additional information, see Proved oil and gas reserves in note 2 Significant accounting policies to the Consolidated financial statements. For further details on proved reserves, see also section 4.2 Supplementary oil and gas information.

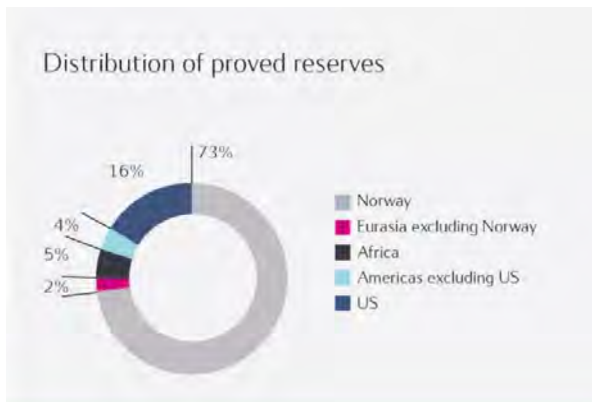
Changes in proved reserves estimates are most commonly the result of revisions of estimates due to observed production performance, extensions of proved areas through drilling activities or the inclusion of proved reserves in new discoveries through the sanctioning of new development projects. These are sources of additions to proved reserves that are the result of continuous business processes and can be expected to continue to add reserves in the future.

Proved reserves can also be added or subtracted through the acquisition or disposal of assets. Changes in proved reserves can also be due to factors outside management control, such as changes in oil and gas prices. Lower oil and gas prices normally allow less oil and gas to be recovered from the accumulations. However, for fields with PSAs and similar contracts, a reduced oil price may result in higher entitlement to the produced volume. These changes are included in the revisions category in the table below.

The principles for booking proved gas reserves are limited to contracted gas sales or gas with access to a robust gas market.

In Norway, the UK and Ireland, Statoil recognises reserves as proved when a development plan is submitted, as there is reasonable certainty that such a plan will be approved by the regulatory authorities. Outside these territories, reserves are generally booked as proved when regulatory approval is received, or when such approval is imminent. Reserves from new discoveries, upward revisions of reserves and purchases of proved reserves are expected to contribute to maintaining proved reserves in future years. Undrilled well locations US onshore are generally booked as proved undeveloped reserves when a development plan has been adopted and the well locations are scheduled to be drilled within five years.

Approximately 91% of our proved reserves are located in OECD countries. Norway is by far the most important contributor in this category, followed by the United States (US), Canada and Ireland. Of Statoil's total proved reserves, 6% are related to PSAs in non-OECD countries such as Azerbaijan, Angola, Algeria, Nigeria, Libya and Russia. Other non-OECD reserves are related to concessions in Brazil, representing 3% of Statoil's total proved reserves. These are included in proved reserves in the Americas.



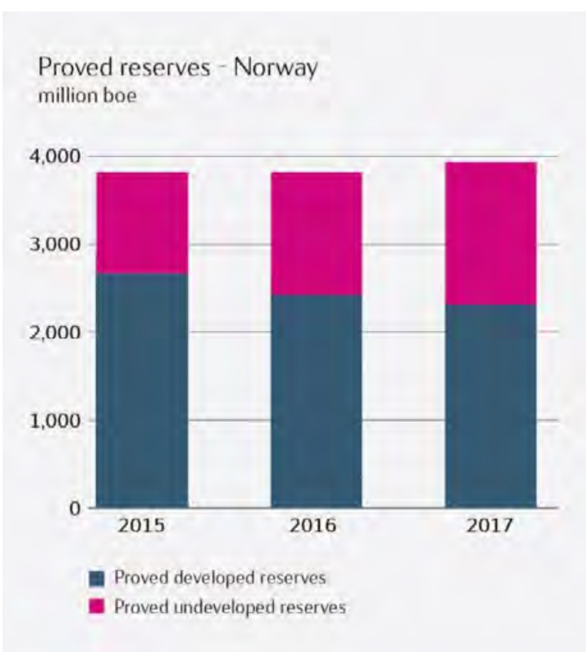
Significant changes in our proved reserves in 2017 were:

- Revisions of previously booked reserves, including the effect of improved recovery, increased the proved reserves by 605 million boe in 2017. Many producing fields have significant positive revisions due to better performance, maturing of new wells and improved recovery projects, as well as reduced uncertainty due to further drilling and production experience. The effect of the increased commodity prices, increasing the proved reserves by approximately 200 million boe through extended economic life time on several fields, is also included in this. The largest revisions are seen in Norway, where many of the larger offshore fields continue to decline less than assumed for the proved reserves, and in the US where continued drilling and production from the onshore plays in the Appalachian basin (Marcellus and Utica), Bakken and Eagle Ford has increased the proved reserves.
- A total of 441 million boe of new proved reserves are added through extensions and new discoveries booking proved reserves for the first time. New field developments in Norway, such as Johan Castberg, Ærfugl and Bauge, and Peregrino Phase 2 in Brazil all contribute to this with a total of 260 million boe. Extensions of the proved areas in the US onshore plays

contribute with167 million boe. The remaining 14 million boe come from other minor extensions on producing fields where new wells have been drilled in previously unproven areas. New discoveries with proved reserves booked in 2017 are all expected to start production within a period of five years.

- A total of 50 million boe of new proved reserves were purchased in 2017 (the Azeri-Chirag-Gunashli PSA extension and transfer of certain ownership shares in the Appalachian basin from Northwood Energy).
- Sale of 38 million boe of proved reserves from the Leismer oil sands development in Canada which was finalised in 2017.
- The 2017 entitlement production was 705 million boe, an increase of 4.7% compared to 2016.

	Proved reserves			
Proved reserves as of 31 December 2017	Oil and Condensate (mmboe)	NGL (mmboe)	Natural Gas (bcf)	Total oil and gas (mmboe)
Developed				
Norway	514	199	8,852	2,290
Eurasia excluding Norway	55	-	159	83
Africa	173	10	273	231
US	252	68	1,675	619
Americas excluding US	118	-	-	118
Total Developed proved reserves	1,112	278	10,958	3,342
Undeveloped				
Norway	919	80	3,501	1,623
Eurasia excluding Norway	42	-	-	42
Africa	12	-	37	19
US	99	21	577	223
Americas excluding US	119	-	-	119
Total Undeveloped proved reserves	1,191	101	4,115	2,025
Total proved reserves	2,302	379	15,073	5,367



Proved reserves in Norway

A total of 3,913 million boe is recognised as proved reserves in 64 fields and field development projects on the NCS, representing 73% of Statoil's total proved reserves. Of these, 53 fields and field areas are currently in production, 42 of which are operated by Statoil.

Four new field development projects added reserves categorised as extensions and discoveries during 2017, Johan Castberg, Bauge, Ærfugl and Alun-Epidot. Production experience, further drilling and improved recovery on several of Statoil's producing fields in Norway also contributed positively to the revisions of the proved reserves in 2017.

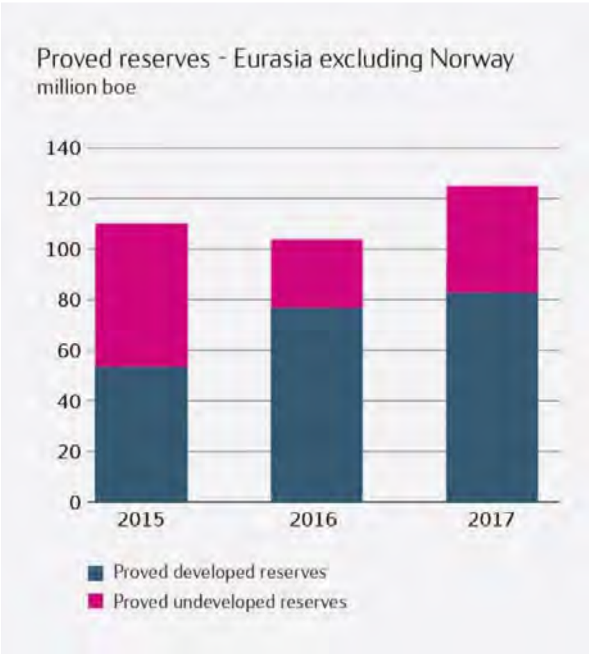
Proved reserves in equity accounted companies in Norway represent Statoil's relative share of Lundin's share in fields carrying proved reserves, only where Statoil as a shareholder has sufficient access to data to be able to estimate proved reserves with reasonable certainty.

Of the proved reserves on the NCS, 2,290 million boe, or 59%, are proved developed reserves. Of the total proved reserves in this area, 56% are gas reserves related to large offshore gas fields such as Troll, Snøhvit, Oseberg, Ormen Lange, Visund, Aasta Hansteen, Åsgard and Tyrihans, and 44% are liquid reserves.

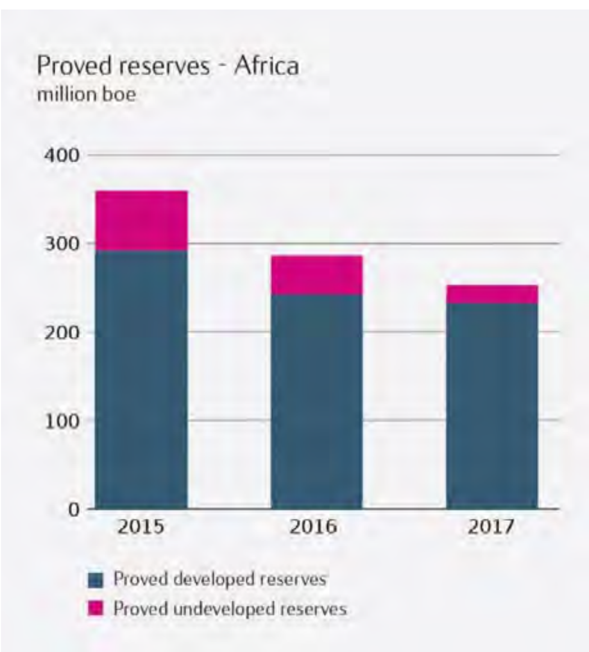
Proved reserves in Eurasia, excluding Norway

In this area, Statoil has proved reserves of 125 million boe related to four fields in Azerbaijan, Ireland, United Kingdom and Russia. Eurasia excluding Norway represents 2% of Statoil's total proved reserves, Azerbaijan being the main contributor with the Azeri-Chirag-Gunashli fields. All fields are producing. Of the proved reserves in Eurasia, 83 million boe or 67% are proved developed reserves.

Of the total proved reserves in this area, 77% are liquid reserves and 23% are gas reserves.



Proved reserves in Africa
Statoil recognises proved reserves of 250 million boe related to 28 fields and field developments in several West and North African countries, including Algeria, Angola, Libya and Nigeria. Africa represents 5% of Statoil's total proved reserves. Angola is the primary contributor to the proved reserves in this area, with 24 of the 28 fields.



In Angola, Statoil has proved reserves in Block 15, Block 17 and Block 31, with production from all three blocks.

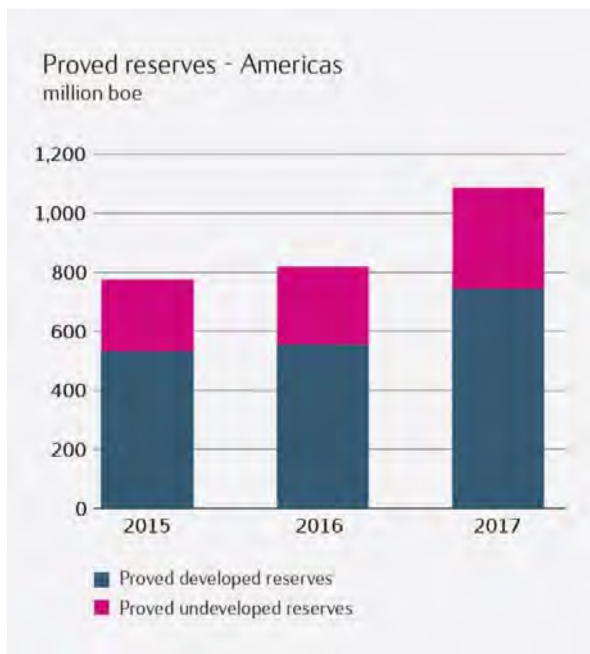
In Algeria and Nigeria, all fields are in production. In Libya, Murzuq started producing again in 2017.

The Agbami equity redetermination in Nigeria implies a reduction of 5.17 percentage points in Statoil's equity interest in the field. Statoil has proceeded to the court of appeal to have the arbitration award set aside. Final approval in the licence was pending at year end 2017, hence the negative effect on the proved reserves, which is estimated to be less than 10 million boe, is not yet included.

In Algeria, an agreement has been signed which will amend the In Amenas Production Sharing Contract by five years, from 2022 to 2027. The effect on the proved reserves will be included once the amended PSA is approved by the authorities and the effect is known.

Most of the fields in Africa are mature and many are on decline or approaching the expiration date of the current PSA. High production in 2017 combined with limited positive revisions and few IOR projects being sanctioned, resulted in further reduction of the proved reserves in this area.

Of the total proved reserves in Africa, 231 million boe, or 93%, are proved developed reserves. Of the total proved reserves in this area, 78% are liquid reserves and 22% are gas reserves.



Proved reserves in the Americas
In North and South America, Statoil has proved reserves equal to 1,079 million boe in a total of 16 fields and field development projects. This represents 20% of Statoil's total proved reserves. Eleven of these fields are located in the US, eight of which are offshore field developments in the Gulf of Mexico and three are onshore tight reservoir assets. Four are located in Canada and one in South America.

As of 30 June 2017, the 9.67% ownership share in the heavy oil project Petrocedeño in Venezuela was reclassified from an equity accounted investment to a non-current financial investment. This has reduced the proved reserves in the Americas by 28 million boe.

In the US, six of the eight fields in the Gulf of Mexico are producing. At year end 2017 field development was still ongoing at Big Foot, and at Stampede which started production in January 2018. The onshore tight reservoir assets in the Appalachian basin, Eagle Ford and Bakken are all in production.

In Canada, proved reserves are related to offshore field developments only.

The increase in proved reserves in this area is mainly due to extensions of the proved areas in the US onshore plays which has added 167 million boe of new proved reserves, positive revisions due to improved operational performance in several assets in the US, and the Peregrino Phase 2 development adding new proved reserves in South America. Proved reserves in the US now represent 16% of total proved reserves and is disclosed as a separate geographic area in the tables.

Of the total proved reserves in the Americas, 737 million boe, or 68%, are proved developed reserves. Of the total proved reserves in this area, 63% are liquid reserves and 37% gas reserves.

Reserves replacement

The reserves replacement ratio is defined as the sum of additions and revisions of proved reserves divided by produced volumes in any given period. The following table presents the changes in reserves including equity accounted entities in each category relating to the reserve replacement ratio for the years 2017, 2016 and 2015. The 2017 reserves replacement ratio excluding equity accounted entities was 1.56 and the corresponding three-year average 1.00. For additional information regarding changes in proved reserves, see section 4.2 Supplementary oil and gas information.

The usefulness of the reserves replacement ratio is limited by the volatility of oil prices, the influence of oil and gas prices on PSA reserve booking, sensitivity related to the timing of project sanctions and the time lag between exploration expenditure and the booking of reserves.

Reserves replacement ratio (including purchases and sales)	For the year ended 31 December 2017	2016	2015
Annual	**1.50**	0.93	0.55
Three-year-average	**1.00**	0.70	0.81

Development of reserves

The total volume of proved reserves increased by 354 million boe in 2017. Positive revisions including improved recovery totalled 605 million boe.

Extensions and discoveries added 441 million boe of new proved reserves in 2017, mainly as undeveloped proved reserves. New development projects such as Bauge, Johan Castberg, Peregrino (Phase 2) and Ærfugl, in addition to several minor extensions on developed assets, added a total of 274 million boe of proved reserves. Further drilling in the Appalachian basin, Bakken and Eagle Ford onshore plays in the US increased the proved areas in these assets and added 167 million boe of new proved reserves.

The net effect of purchases and sales completed in 2017, increased the proved reserves by 12 million boe.

Change in proved reserves (million boe)	For the year ended 31 December 2017	2016	2015
Revisions and improved recovery	**605**	409	(42)
Extensions and discoveries	**441**	179	627
Purchase of petroleum-in-place	**50**	65	13
Sales of petroleum-in-place	**(38)**	(27)	(235)
Total reserve additions	**1,059**	626	363
Production	**(705)**	(673)	(662)
Net change in proved reserves	**354**	(47)	(299)

Development of reserves in 2017 (million boe)	Total	Developed	Undeveloped
At 31 December 2016	5,013	3,268	1,746
Revisions and improved recovery	605	420	185
Extensions and discoveries	441	95	346
Purchase of reserves-in-place	50	26	24
Sales of reserves-in-place	(38)	(33)	(5)
Production	(705)	(705)	-
Moved from undeveloped to developed	-	271	(271)
At 31 December 2017	5,367	3,342	2,025

In 2017, approximately 271 million boe were converted from proved undeveloped to proved developed reserves. The start-up of production from Flyndre and Gina Krog in Norway and Hebron in Canada increased the proved developed reserves by 66 million boe during 2017. The remaining 205 million boe of the converted volume is related to activities on developed assets. Over the last 5 years Statoil has converted 1,931 million boe of proved undeveloped reserves to proved developed reserves.

Net proved developed and undeveloped reserves (million boe)		Oil and Condensate (mmboe)	NGL (mmboe)	Natural gas (bcf)	Total (mmboe)
2017	**Proved reserves end of year**	**2,302**	**379**	**15,073**	**5,367**
	Developed	1,112	278	10,958	3,342
	Undeveloped	1,191	101	4,115	2,025
2016	**Proved reserves end of year**	**2,033**	**372**	**14,637**	**5,013**
	Developed	1,105	277	10,584	3,268
	Undeveloped	928	95	4,054	1,746
2015	**Proved reserves end of year**	**2,091**	**364**	**14,624**	**5,060**
	Developed	1,104	290	11,901	3,515
	Undeveloped	987	74	2,723	1,546

As of 31 December 2017, the total proved undeveloped reserves amounted to 2,025 million boe, 80% of which are related to fields in Norway. The Troll and Snøhvit fields, which have continuous development activities, together with fields not yet in production, such as Johan Sverdrup, Johan Castberg and Aasta Hansteen have the largest proved undeveloped reserves in Norway. The largest assets with respect to proved undeveloped reserves outside Norway are Peregrino in Brazil, ACG in Azerbaijan and the Appalachian basin and Bakken in the US.

All these fields are either producing, or will start production within the next five years. For fields with proved reserves where production has not yet started, investment decisions have already been sanctioned and investments in infrastructure and facilities have commenced. Some development activities will take place more than five years from the disclosure date, but these are mainly related to incremental type of spending, such as drilling of additional wells from existing facilities, in order to secure continued production. There are no material development projects, which would require a separate future investment decision by management, included in our proved reserves. For our onshore plays in the US, the Appalachian basin, Eagle Ford and Bakken, all proved undeveloped reserves are limited to wells that are scheduled to be drilled within five years.

In 2017, Statoil incurred USD 7,729 million in development costs relating to assets carrying proved reserves, USD 5,685 million of which was related to proved undeveloped reserves.

Additional information about proved oil and gas reserves is provided in section 4.2 Supplementary oil and gas information.

Preparation of reserves estimates

Statoil's annual reporting process for proved reserves is coordinated by a central corporate reserves management (CRM) team consisting of qualified professionals in geosciences, reservoir and production technology and financial evaluation. The team has an average of more than 25 years' experience in the oil and gas industry. CRM reports to the vice president of finance and control in the Technology, Projects & Drilling business area and is thus independent of the Development & Production business areas in Norway, North America and International. All the reserves estimates have been prepared by Statoil's technical staff.

Although the CRM team reviews the information centrally, each asset team is responsible for ensuring that it is in compliance with the requirements of the SEC and Statoil's corporate standards. Information about proved oil and gas reserves, standardised measures of discounted net cash flows related to proved oil and gas reserves and other information related to proved oil and gas reserves, is collected from the local asset teams and checked by CRM for consistency and conformity with applicable standards. The final numbers for each asset are quality-controlled and approved by the responsible asset manager, before aggregation to the required reporting level by CRM.

The aggregated results are submitted for approval to the relevant business area management teams and the corporate executive committee.

The person with primary responsibility for overseeing the preparation of the reserves estimates is the manager of the CRM team. The person who presently holds this position has a bachelor's degree in earth sciences from the University of Gothenburg, and a master's degree in petroleum exploration and exploitation from Chalmers University of Technology in Gothenburg, Sweden. She has 32 years' experience in the oil and gas industry, 31 of them with Statoil. She is a member of the Society of Petroleum Engineering (SPE) and vice-chair of the UNECE Expert Group on Resource Classification (EGRC).

DeGolyer and MacNaughton report

Petroleum engineering consultants DeGolyer and MacNaughton have carried out an independent evaluation of Statoil's proved reserves as of 31 December 2017 using data provided by Statoil. The evaluation accounts for 100% of Statoil's proved reserves including equity accounted entities. The aggregated net proved reserves estimates prepared by DeGolyer and MacNaughton do not differ materially from those prepared by Statoil when compared on the basis of net equivalent barrels.

Net proved reserves at 31 December 2017	Oil and Condensate (mmbbls)	NGL/LPG (mmbbl)	Natural Gas (bcf)	Oil Equivalent (mmboe)
Estimated by Statoil	2,302	379	15,073	5,367
Estimated by DeGolyer and MacNaughton	2,363	347	14,404	5,276

A reserves audit report summarising this evaluation is included as Exhibit 15 (a)(iii).

Operational statistics

Developed and undeveloped acreage

The table below shows the total gross and net developed and undeveloped oil and gas acreage, in which Statoil had interests at 31 December 2017.

A gross value reflects the number of wells or acreage in which Statoil owns a working interest. The net value corresponds to the sum of the fractional working interests owned in the same gross wells or acres.

Developed and undeveloped oil and gas acreage at 31 December 2017 (in thousands of acres)		Norway	Eurasia excluding Norway	Africa	US	Americas excluding US	Oceania	Total
Acreage developed	- gross	927	73	796	689	73	-	2,558
	- net	345	16	264	170	19	-	814
Acreage undeveloped	- gross	13,708	40,526	24,958	1,574	37,567	11,749	130,082
	- net	6,016	18,159	9,544	799	15,577	6,928	57,023

The largest concentrations of developed acreage in Norway are in the Troll, Skarv, Oseberg area, Snøhvit and Ormen Lange. In Africa, the Algerian gas development projects In Amenas and In Salah represent the largest concentrations of developed acreage (gross and net). Bakken (onshore US) has the largest developed acreage in Americas.

Statoil's largest undeveloped acreage concentration is in Russia with 15% of the total acreage and 48% of the total acreage in Eurasia excluding Norway. A large part of the net acreage in Russia represents Statoil's share of a joint venture with Rosneft. The largest concentration of undeveloped acreage in the Americas excluding US is Canada, with 25% of the total for this geographic area. In Africa, the largest acreage concentration is in South Africa, representing 69% of the total for this geographic area. In Oceania Statoil holds undeveloped acreage in Australia and New Zealand.

Statoil holds acreage in numerous concessions, blocks and leases. The terms and conditions regarding expiration dates vary significantly from property to property. Work programmes are designed to ensure that the exploration potential of any property is fully evaluated before expiration.

Acreage related to several of these concessions, blocks and leases are scheduled to expire within the next three years. Any acreage which has already been evaluated to be non-profitable may be relinquished prior to the current expiration date. In other cases, Statoil may decide to apply for an extension if more time is needed in order to fully evaluate the potential of the properties. Historically, Statoil has generally been successful in obtaining such extensions.

Most of the undeveloped acreage that will expire within the next three years is related to early exploration activities where no production is expected in the foreseeable future. The expiration of these leases, blocks and concessions will therefore not have any material impact on our reserves.

Productive oil and gas wells

The number of gross and net productive oil and gas wells, in which Statoil had interests at 31 December 2017, are shown in the table below. The total number of productive oil wells in the Americas excluding US has been significantly reduced due to the reclassification of the heavy oil project Petrocdeño from an equity accounted entity to a financial investment.

Number of productive oil and gas wells at 31 December 2017		Norway	Eurasia excluding Norway	Africa	US	Americas excluding US	Total
Oil wells	- gross	874	188	423	2,422	99	4,006
	- net	292.7	27.3	66.4	613.8	29.0	1,029.2
Gas wells	- gross	201	6	104	2,213	-	2,524
	- net	86.7	2.2	40.1	550.0	-	679.0

The total gross number of productive wells as of end 2017 includes 392 oil wells and 11 gas wells with multiple completions or wells with more than one branch.

Net productive and dry oil and gas wells drilled

The following tables show the net productive and dry exploratory and development oil and gas wells completed or abandoned by Statoil in the past three years. Productive wells include exploratory wells in which hydrocarbons were discovered, and where drilling or completion has been suspended pending further evaluation. A dry well is one found to be incapable of producing sufficient quantities to justify completion as an oil or gas well.

Net productive and dry oil and gas wells drilled	Norway	Eurasia excluding Norway	Africa	US	Americas excluding US	Total
Year 2017						
Net productive and dry exploratory wells drilled	8.1	2.6	-	0.7	1.9	13.3
- Net dry exploratory wells drilled	3.5	2.1	-	-	1.9	7.5
- Net productive exploratory wells drilled	4.6	0.5	-	0.7	-	5.8
Net productive and dry development wells drilled	37.5	5.0	4.3	103.2	2.3	152.2
- Net dry development wells drilled	10.1	-	0.1	-	0.1	10.3
- Net productive development wells drilled	27.4	5.0	4.2	103.2	2.2	142.0
Year 2016						
Net productive and dry exploratory wells drilled	5.5	0.7	-	1.6	4.8	12.6
- Net dry exploratory wells drilled	1.4	0.7	-	-	1.9	3.9
- Net productive exploratory wells drilled	4.1	-	-	1.6	3.0	8.7
Net productive and dry development wells drilled	47.4	1.6	5.2	116.6	17.0	187.8
- Net dry development wells drilled	4.2	0.2	0.2	-	-	4.6
- Net productive development wells drilled	43.3	1.5	4.9	116.6	17.0	183.2
Year 2015						
Net productive and dry exploratory wells drilled	10.2	1.0	2.5	1.5	1.1	16.3
- Net dry exploratory wells drilled	4.6	0.4	0.5	0.5	0.4	6.4
- Net productive exploratory wells drilled	5.6	0.7	2.0	1.0	0.7	9.9
Net productive and dry development wells drilled	32.1	4.1	10.6	216.3	12.5	275.6
- Net dry development wells drilled	3.6	-	4.3	0.3	-	8.2
- Net productive development wells drilled	28.6	4.1	6.3	215.9	12.5	267.4

Exploratory and development drilling in process

The following table shows the number of exploratory and development oil and gas wells in the process of being drilled by Statoil at 31 December 2017.

Number of wells in progress at 31 December 2017		Norway	Eurasia excluding Norway	Africa	US	Americas excluding US	Total
Development wells[1]	- gross	39	7	10	362	2	420
	- net	14.2	0.8	2.9	144.7	0.1	162.7
Exploratory wells	- gross	2	3	-	1	-	6
	- net	0.8	1.5	-	0.2	-	2.4

1) Mainly wells related to US onshore developments

Delivery commitments

On behalf of the Norwegian State's direct financial interest (SDFI), Statoil is responsible for managing, transporting and selling the Norwegian state's oil and gas from the Norwegian continental shelf (NCS). These reserves are sold in conjunction with Statoil's own reserves. As part of this arrangement, Statoil delivers gas to customers under various types of sales contracts. In order to meet the commitments, we utilise a field supply schedule that ensures the highest possible total value for Statoil and SDFI's joint portfolio of oil and gas.

The majority of our gas volumes in Norway are sold under long-term contracts with take-or-pay clauses. Statoil's and SDFI's annual delivery commitments under these agreements are expressed as the sum of the expected off-take under these contracts. As of 31 December 2017, the long-term commitments from NCS for the Statoil/SDFI arrangement totaled approximately 278 bcm.

Statoil's total bilateral obligations have been reduced over the past year, as a result of delivering more on existing contracts ending in 2017 than sold on new contracts starting in 2017. This has been a trend in later years. Thus, given a steady gas production in the years to come, Statoil will sell more gas in the spot-market than before.

Statoil and SDFI's delivery commitments, expressed as the sum of expected off-take for the calendar years 2018, 2019, 2020 and 2021, are 47.1, 40.1, 37.9 and 34.9 bcm, respectively. Any remaining volumes after covering our bilateral agreements, will be sold by trading activities at the hubs.

Statoil's currently developed gas reserves in Norway are more than sufficient to meet our share of these commitments for the next four years.

PRODUCTION VOLUMES AND PRICES

The business overview is in accordance with our segment's operations as of 31 December 2017, whereas certain disclosures on oil and gas reserves are based on geographical areas as required by the Securities and Exchange Commission (SEC). For further information about extractive activities, see sections 2.3 E&P Norway and 2.4 E&P International.

Statoil prepares its disclosures for oil and gas reserves and certain other supplemental oil and gas disclosures by geographical area, as required by the SEC. The geographical areas are defined by country and continent. They are Norway, Eurasia excluding Norway, Africa and the Americas.

For further information about disclosures concerning oil and gas reserves and certain other supplemental disclosures based on geographical areas as required by the SEC, see section 4.2 Supplementary oil and gas information (unaudited).

Entitlement production

The following table shows Statoil's Norwegian and international entitlement production of oil and natural gas for the periods indicated. The stated production volumes are the volumes to which Statoil is entitled, pursuant to conditions laid down in licence agreements and production-sharing agreements. The production volumes are net of royalty oil paid in kind, and of gas used for fuel and flaring. Our production is based on our proportionate participation in fields with multiple owners and does not include production of the Norwegian State's oil and natural gas. Production of an immaterial quantity of bitumen is included as oil production. NGL includes both LPG and naphtha. For further information on production volumes see section 5.6 Terms and abbreviations.

Entitlement production (million boe)	Consolidated companies: Norway	Eurasia excluding Norway	Africa	US	Americas excluding US	Subtotal	Equity accounted: Norway	Eurasia excluding Norway	Americas excluding US	Subtotal	Total
Oil and Condensate (mmbbls)											
2015	174	13	75	31	27	319	-	-	4	4	324
2016	169	12	72	34	26	313	2	0	4	6	320
2017	165	10	68	38	21	302	6	0	2	8	310
NGL (mmbbls)											
2015	44	-	3	7	-	54	-	-	-	-	54
2016	46	-	2	9	-	58	0	-	-	0	58
2017	48	-	4	9	0	61	-	-	-	-	61
Natural gas (bcf)											
2015	1,306	16	63	215	0	1,600	-	-	-	-	1,600
2016	1,338	34	60	226	0	1,659	1	0	-	2	1,661
2017	1,515	41	72	240	0	1,868	4	0	-	5	1,873
Combined oil, condensate, NGL and gas (mmboe)											
2015	450	16	88	76	27	658	-	-	4	4	662
2016	454	18	85	83	26	666	3	0	4	7	673
2017	483	17	85	90	21	696	6	0	2	9	705

The only field containing more than 15% of total proved reserves based on oil equivalent barrels is the Troll field.

Entitlement production	2017	2016	2015
Troll field [1)]			
Oil and Condensate (mmbbls)	14	15	14
NGL (mmbbls)	2	2	2
Natural gas (bcf)	384	321	386
Combined oil, condensate, NGL and gas (mmboe)	85	74	85

1) Note that Troll is also included in Norway stated above.

Operational data	For the year ended 31 December 2017	2016	2015	17-16 change	16-15 change
Prices					
Average Brent oil price (USD/bbl)	54.2	43.7	52.4	24%	(17%)
E&P Norway average liquids price (USD/bbl)	50.2	39.4	48.2	27%	(18%)
E&P International average liquids price (USD/bbl)	47.6	35.8	42.9	33%	(17%)
Group average liquids price (USD/bbl)	49.1	37.8	45.9	30%	(18%)
Group average liquids price (NOK/bbl)	405	317	371	28%	(14%)
Transfer price natural gas (USD/mmBtu)	4.33	3.42	5.17	27%	(34%)
Average invoiced gas prices - Europe (USD/mmBtu)	5.55	5.17	7.08	7%	(27%)
Average invoiced gas prices - North America (USD/mmBtu)	2.73	2.12	2.62	28%	(19%)
Refining reference margin (USD/bbl)	6.3	4.8	8.0	31%	(40%)
Entitlement production (mboe per day)					
E&P Norway entitlement liquids production	594	589	595	1%	(1%)
E&P International entitlement liquids production	415	435	436	(5%)	(0%)
Group entitlement liquids production	1,009	1,024	1,032	(1%)	(1%)
E&P Norway entitlement gas production	740	646	637	15%	1%
E&P International entitlement gas production	173	157	144	10%	9%
Group entitlement gas production	913	803	781	14%	3%
Total entitlement liquids and gas production	1,922	1,827	1,812	5%	1%
Equity production (mboe per day)					
E&P Norway equity liquids production	594	589	595	1%	(1%)
E&P International equity liquids production	545	555	569	(2%)	(2%)
Group equity liquids production	1,139	1,144	1,165	(0%)	(2%)
E&P Norway equity gas production	740	646	637	15%	1%
E&P International equity gas production	200	188	170	7%	11%
Group equity gas production	941	834	806	13%	3%
Total equity liquids and gas production	2,080	1,978	1,971	5%	0%
Liftings (mboe per day)					
Liquids liftings	1,012	1,017	1,035	(1%)	(2%)
Gas liftings	936	824	802	14%	3%
Total liquids and gas liftings	1,948	1,842	1,837	6%	0%
MMP sales volumes					
Crude oil sales volumes (mmbbl)	817	811	829	1%	(2%)
Natural gas sales Statoil entitlement (bcm)	52.0	44.3	44.0	18%	1%
Natural gas sales third-party volumes (bcm)	6.4	8.6	8.6	(26%)	0%
Production cost (USD/boe)					
Production cost entitlement volumes	5.2	5.4	6.5	(3%)	(17%)
Production cost equity volumes	4.8	5.0	5.9	(3%)	(17%)

Sales prices

The following tables present realised sales prices.

Realised sales prices	Norway	Eurasia excluding Norway	Africa	Americas
Year ended 31 December 2017				
Average sales price oil and condensate in USD per bbl	54.0	53.6	53.5	46.0
Average sales price NGL in USD per bbl	35.8	-	33.2	20.9
Average sales price natural gas in USD per mmBtu	5.6	5.3	5.2	2.7
Year ended 31 December 2016				
Average sales price oil and condensate in USD per bbl	43.1	42.0	41.4	32.9
Average sales price NGL in USD per bbl	24.4	-	21.9	13.1
Average sales price natural gas in USD per mmBtu	5.2	4.8	4.0	2.1
Year ended 31 December 2015				
Average sales price oil and condensate in USD per bbl	52.2	50.7	49.4	39.4
Average sales price NGL in USD per bbl	30.1	-	26.2	12.5
Average sales price natural gas in USD per mmBtu	7.1	4.6	5.6	2.6

Sales volumes

Sales volumes include lifted entitlement volumes, the sale of SDFI volumes and marketing of third-party volumes. In addition to Statoil's own volumes, we market and sell oil and gas owned by the Norwegian State through the Norwegian State's share in production licences. This is known as the State's Direct Financial Interest or SDFI. For additional information, see section 2.7 Corporate under SDFI oil and gas marketing and sale.

The following table shows the SDFI and Statoil sales volume information on crude oil and natural gas for the periods indicated. The Statoil natural gas sales volumes include equity volumes sold by the MMP segment, natural gas volumes sold by the E&P International segment and ethane volumes.

Sales Volumes	For the year ended 31 December 2017	2016	2015
Statoil[1]			
Crude oil (mmbbls)[2]	**369**	372	378
Natural gas (bcm)	**54.3**	48.0	46.6
Combined oil and gas (mmboe)	**711**	674	671
Third party volumes[3]			
Crude oil (mmbbls)[2]	**302**	294	290
Natural gas (bcm)	**6.4**	8.6	8.6
Combined oil and gas (mmboe)	**342**	348	344
SDFI assets owned by the Norwegian State[4]			
Crude oil (mmbbls)[2]	**147**	148	149
Natural gas (bcm)	**44.0**	39.8	41.8
Combined oil and gas (mmboe)	**424**	398	412
Total			
Crude oil (mmbbls)[2]	**819**	814	816
Natural gas (bcm)	**104.7**	96.4	97.0
Combined oil and gas (mmboe)	**1,477**	1,420	1,427

1) The Statoil volumes included in the table above are based on the assumption that volumes sold were equal to lifted volumes in the relevant year. Volumes lifted by E&P International but not sold by MMP, and volumes lifted by E&P Norway or E&P International and still in inventory or in transit may cause these volumes to differ from the sales volumes reported elsewhere in this report by MMP.

2) Sales volumes of crude oil include NGL and condensate. All sales volumes reported in the table above include internal deliveries to our manufacturing facilities

3) Third party volumes of crude oil include both volumes purchased from partners in our upstream operations and other cargos purchased in the market. The third party volumes are purchased either for sale to third parties or for our own use. Third party volumes of natural gas include third party LNG volumes related to our activities at the Cove Point regasification terminal in the US.

4) The line item SDFI assets owned by the Norwegian State includes sales of both equity production and third party.

2.9 FINANCIAL REVIEW

GROUP FINANCIAL PERFORMANCE

In 2016 and 2015, our **results** were heavily influenced by low oil and gas prices, leading to lower earnings and impairment losses. In 2017, prices have been recovering and we are seeing better results. Operational performance has been solid and production is up by 5% in 2017. Cost discipline and efficiency improvements have contributed to the reduced operating costs. Supported by increasing prices and better operational performance, several previous impairments have been reversed. A negative net income in 2016 of USD 2.9 billion is turned into positive net income of USD 4.6 billion in 2017.

Total equity liquids and gas production was 2,080 mboe, 1,978 mboe, 1,971 mboe per day in 2017, 2016 and 2015, respectively.

The 5% increase in total equity production from 2016 to 2017 was primarily due to start-up and ramp-up on various fields and higher flexible gas offtake on the NCS, partially offset by expected natural decline and divestments.

From 2015 to 2016, the average daily total equity production level was maintained. Increased production from new fields coming on stream, ramp-up on various existing fields and high operational performance, was offset by reduced ownership shares due to divestments, expected natural decline at mature fields and operational challenges.

Total entitlement liquids and gas production was 1,922 mboe per day in 2017 compared to 1,827 mboe in 2016 and 1,812 mboe per day in 2015. In 2017, the total entitlement liquids and gas production was up 5% for the reasons as described above, partially offset by higher negative effect from production sharing agreements (PSA effect) and US royalties, mainly driven by higher prices.

From 2015 to 2016, the total entitlement production was up 1% the reasons as described above. The benefit of a lower effect from production sharing agreements (PSA effect) mainly driven by the reduction in prices, added to the slight increase in entitlement production.

The combined effect of **production sharing agreements (PSA effect) and US royalties** was 158 mboe, 151 mboe and 159 mboe per day in 2017, 2016 and 2015, respectively. Over time, the volumes lifted and sold will equal the entitlement production, but they may be higher or lower in any period due to differences between the capacity and timing of the vessels lifting our volumes and the actual entitlement production during the period.

Income statement under IFRS (in USD million)	For the year ended 31 December 2017	2016	2015	17-16 change	16-15 change
Revenues	**60,971**	45,688	57,900	33%	(21%)
Net income/(loss) from equity accounted investments	**188**	(119)	(29)	N/A	>(100%)
Other income	**27**	304	1,770	(91%)	(83%)
Total revenues and other income	**61,187**	45,873	59,642	33%	(23%)
Purchases [net of inventory variation]	**(28,212)**	(21,505)	(26,254)	31%	(18%)
Operating, selling, general and administrative expenses	**(9,501)**	(9,787)	(11,433)	(3%)	(14%)
Depreciation, amortisation and net impairment losses	**(8,644)**	(11,550)	(16,715)	(25%)	(31%)
Exploration expenses	**(1,059)**	(2,952)	(3,872)	(64%)	(24%)
Net operating income/(loss)	**13,771**	80	1,366	>100%	(94%)
Net financial items	**(351)**	(258)	(1,311)	(36%)	80%
Income/(loss) before tax	**13,420**	(178)	55	N/A	N/A
Income tax	**(8,822)**	(2,724)	(5,225)	>100%	(48%)
Net income/(loss)	**4,598**	(2,902)	(5,169)	N/A	44%

Total revenues and other income amounted to USD 61,187 million in 2017 compared to USD 45,873 million in 2016 and USD 59,642 million in 2015.

Revenues are generated from both the sale of lifted crude oil, natural gas and refined products produced and marketed by Statoil, and from the sale of liquids and gas purchased from third parties. In addition, we market and sell the Norwegian State's share of liquids from the NCS. All purchases and sales of the Norwegian State's production of liquids are recorded as purchases [net of inventory variations] and revenues, respectively, while sales of the Norwegian State's share of gas from the NCS are recorded net. For additional information regarding sales, see the Sales volume table in section 2.8 above in this report.

Revenues were USD 60,971 million in 2017, up 33% compared to 2016. The increase was mainly due to increased prices both for liquids and gas, and increased gas volumes sold. The 21% decrease in revenues from 2015 to 2016 was mainly due to the significant decrease in liquids and gas prices, lower refinery margins and increased losses from reflecting the changes in fair value of derivatives and market value of storage and physical contracts and a reversal of provisions related to our operations in Angola of USD 754 million. For further information, see note 23 Other commitments, contingent liabilities and contingent assets to the Consolidated financial statements.

Net income from equity accounted investments was USD 188 million in 2017, up from a loss in 2016 of USD 119 million due to increased profit from the investment in Lundin Petroleum AB. In 2015, net income from equity accounted investments was a loss of USD 29 million. For further information, please see note 12 Equity accounted investments to the Consolidated financial statements.

Other income was USD 27 million in 2017 compared to USD 304 million in 2016 and USD 1,770 million in 2015. In 2017, other income was insignificant and mainly related to proceeds from minor insurance claims. In 2016, other income was mainly related to gain from sale of the Edvard Grieg field on the NCS and proceeds from an insurance settlement. In 2015, other income mainly consisted of gain from the two step divestments of the ownership interest in the Shah Deniz project in Azerbaijan.

Because of the factors explained above, **total revenue and other income** was up by 33% in 2017. In 2016 and 2015, total revenues and other income decreased by 23% and 40%, respectively.

Purchases [net of inventory variation] include the cost of liquids purchased from the Norwegian State, which is pursuant to the Owner's instruction, and the cost of liquids and gas purchased from third parties. See SDFI oil and gas marketing and sale in section 2.7 Corporate for more details.

Purchases [net of inventory variation] amounted to USD 28,212 million in 2017 compared to USD 21,505 million in 2016 and USD 26,254 million in 2015. The 31% increase in 2017 was mainly related to the increase in prices. The 18% decrease from 2015 to 2016 was mainly related to the decrease in liquids and gas prices.

Operating, selling, general and administrative expenses amounted to USD 9,501 million in 2017 compared to USD 9,787 million in 2016 and USD 11,433 million in 2015. The 3% decrease from 2016 to 2017 was mainly due to divestments and reduced asset retirement provisions, partially offset by net losses from sale of assets and increased costs from new fields coming on stream. Ramp-up on various fields and higher royalty costs also offset the decrease. The 14% decrease from 2015 to 2016 was mainly due to cost improvement initiatives and the NOK/USD exchange rate development. Lower operation and maintenance costs and reduced transportation costs added to the decrease.

Depreciation, amortisation and net impairment losses amounted to USD 8,644 million compared to USD 11,550 million in 2016 and USD 16,715 million in 2015.

The 25% decrease in depreciation, amortisation and net impairment losses in 2017 was mainly due to lower net impairment of assets in 2017 (discussed below), net increased proved reserves estimates on several fields and a lower depreciation basis due to impairments of assets in previous periods. Start-up and ramp-up of production on new fields partially offset the reduction.

Included in the total for 2017 were net impairment reversals of USD 1,055 million, of which impairment reversals amounted to USD 1,972 million mainly related to increased production estimates, cost reductions and increased prices, operational improvements and updated calculation assumptions due to changes in the US tax legislation. The impairment reversals were partially offset by impairment losses of USD 917 million, mainly related to decreased production estimates.

The 31% decrease in 2016 compared to 2015, was mainly due to lower impairment of assets in 2016 and reduced depreciation on mature fields. Higher proved reserves estimate and the NOK/USD exchange rate development in 2016 added to the decrease, partially offset by start-up and ramp-up of production on several fields.

Included in the total for 2016 and 2015, were net impairment losses of USD 1,301 million and USD 5,526 million, respectively, primarily triggered by the reduction in commodity price assumptions and commodity forward prices. The net impairment losses of USD 1,301 million in 2016 were mainly related to impairment of unconventional onshore assets in the USA. The net impairment losses of USD 5,526 million in 2015 were mainly related to both unconventional onshore assets and conventional offshore assets in the E&P International reporting segment, and conventional offshore assets in the development phase in E&P Norway reporting segment.

For further information, please see note 3 Segments and note 10 Property, plant and equipment to the Consolidated financial statements.

Exploration expenses (in USD million)	For the year ended 31 December 2017	2016	2015	17-16 change	16-15 change
Exploration expenditures (activity)	**1,234**	1,437	2,860	(14%)	(50%)
Expensed, previously capitalised exploration expenditures	**73**	808	213	(91%)	>100%
Capitalised share of current period's exploration activity	**(167)**	(285)	(1,151)	(41%)	(75%)
Net impairments / (reversals)	**(81)**	992	1,951	N/A	(49%)
Exploration expenses	**1,059**	2,952	3,872	(64%)	(24%)

In 2017, **exploration expenses** were USD 1,059 million, a 64% decrease compared to 2016 when exploration expenses were USD 2,952 million. Exploration expenses were USD 3,872 million in 2015.

The 64% decrease in exploration expenses in 2017 was mainly due to a lower portion of expenditures capitalised in previous years being expensed in 2017 compared to 2016. Exploration activity was higher in 2017. However, as the exploration wells drilled in 2017 were less expensive due to improved drilling efficiency, exploration expenditures were reduced in 2017 compared to 2016. Net impairment reversals of exploration prospects and signature bonuses in 2017 compared to net impairment charges in 2016, added to the decrease. The decrease was partially offset by a lower capitalisation rate on exploration expenditures incurred in 2017 compared to 2016.

In 2016, exploration expenses were down 24% compared to 2015 mainly due to lower net impairment of exploration prospects and signature bonuses, lower drilling activity and less expensive wells being drilled. The decrease was partially offset by a higher portion of expenditures capitalised in previous years being expensed in 2016 and a lower capitalisation rate on exploration expenditures incurred in 2016 compared to 2015.

Net operating income was USD 13,771 million in 2017 compared to USD 80 million in 2016 and USD 1,366 million in 2015.

With reference to the development in revenues and costs as discussed above, the significant increase in 2017 was primarily driven by higher prices for both liquids and gas, increased gas volumes, significant net impairments reversals in 2017 compared to net impairment charges in 2016 and the reversal of provisions related to our operations in Angola. Reduced depreciation and exploration expenses added to the increase. The decrease in 2016 compared to 2015 was mainly driven by the drop in liquids and gas prices, lower refinery margins and lower gains on sale of assets. Lower net impairment charges in 2016 compared to 2015 and a reduction in operating, depreciation and exploration costs partially offset the decrease.

Net financial items amounted to a loss of USD 351 million in 2017. In 2016 and 2015, net financial items were also a loss of USD 258 million and USD 1,311 million, respectively.

The increased loss of USD 93 million in 2017 was mainly due to loss on derivatives due to increase in EUR and USD interest rates related to our long-term debt portfolio of USD 61 million for 2017, compared to a gain of USD 470 million for 2016, partially offset by a reversal of interest expense of USD 319 million in 2017 previously provided for related to a resolved dispute regarding Statoil's participation offshore Angola in the period 2002 to 2016. For further information, see note 23 Other commitments, contingent liabilities and contingent assets to the Consolidated financial statements.

The reduced loss of USD 1,053 million in 2016 was mainly due to gain on derivatives due to decrease in EUR and GBP interest rates related to our long-term debt portfolio of USD 470 million for 2016, compared to a loss of USD 491 million for 2015.

Income taxes were USD 8,822 million in 2017, equivalent to an effective tax rate of 65.7%, compared to USD 2,724 million in 2016, equivalent to an effective tax rate of more than 100%.In 2015, income taxes were USD 5,225 million, equivalent to an effective tax rate of more than 100%.

The **effective tax rate** in 2017 was primarily influenced by the agreement with the Angolan Ministry of Finance related to Statoil's participation in several blocks offshore Angola. For further information, see note 9 Income taxes to the Consolidated financial statements.

In 2016 and 2015, income before tax was a loss of USD 178 million in 2016 and a profit of USD 55 million in 2015, which both were a combination of large profits in territories with higher statutory tax rates (taking account of Norwegian Petroleum Tax including uplift) and approximately the same amount of losses in territories with lower statutory tax rates. Hence, our effective tax rate is distorted. In addition, the "weighted average statutory tax rate", calculate before taking into account the Norwegian petroleum tax including uplift for comparability, was also distorted.

In 2016, the effective rate of tax on profit earned by E&P Norway, approximated the statutory tax rate (taking account of Norwegian Petroleum Tax including uplift). However, the effective tax rate on E&P International losses was negative due to the inability to currently recognise tax losses and other deferred tax assets arising from losses, primarily in the USA. Overall, this results in a significant income tax charge on a relatively small group loss before tax.

The effective tax rate in 2015 was primarily influenced by losses, mainly caused by impairments recognised in countries where deferred tax assets could not be recognised, partially offset by tax exempted gains on sale of assets including Statoil's interest in the Shah Deniz project. The effective tax rate in 2015 was also influenced by the de-recognition of deferred tax assets within the E&P International segment due to uncertainty related to future taxable income.

The effective tax rate is calculated as income taxes divided by income before taxes. Fluctuations in the effective tax rates from year to year are principally the result of non-taxable items (permanent differences) and changes in the relative composition of income between Norwegian oil and gas production, taxed at a marginal rate of 78%, and income from other tax jurisdictions. Other Norwegian income, including the onshore portion of net financial items, is taxed at 24% (25% in 2016 and 27% in 2015), and income in other countries is taxed at the applicable income tax rates in the various countries.

In 2017, **net income** was USD 4,598 million compared to negative USD 2,902 million in 2016 and negative USD 5,169 million in 2015.

The significant increase in 2017 was mainly a result of the increase in net operating income, partially offset by the increase income taxes and higher loss on net financial items, as explained above. The increase from 2015 to 2016 was mainly due to lower income taxes and lower loss on net financial items, partially offset by the decrease in net operating income.

The board of directors proposes to the annual general meeting (AGM) to increase the dividend by 4.5% to USD 0.23 per ordinary share for the fourth quarter of 2017. The two-year scrip dividend programme ended as planned with the third quarter 2017-dividend.

The **Annual ordinary dividends** for 2017 amounted to an aggregate total of USD 1,586 million, net after scrip dividend of USD 1,357 million. Considering the proposed dividend, USD 2,371 million will be allocated to retained earnings in the parent company.

For 2016 and 2015, annual ordinary dividends amounted to an aggregate total of USD 1,934 million, net after scrip dividend of USD 904 million and USD 2,860 million, respectively.

For further information, see note 17 Shareholders' equity and dividends to the Consolidated financial statements.

In accordance with §3-3a of the Norwegian Accounting Act, the board of directors confirms that the going concern assumption on which the financial statements have been prepared, is appropriate.

SEGMENTS FINANCIAL PERFORMANCE

E&P Norway profit and loss analysis

Net operating income in 2017 was USD 10,485 million, compared to USD 4,451 million in 2016 and USD 7,161 million in 2015. The USD 6,034 million increase from 2016 to 2017 was mainly due to higher liquids and gas prices, and net impairment reversals of USD 905 million in 2017 compared to impairment of USD 829 million in 2016. The USD 2,710 million decrease from 2015 to 2016 was mainly due to lower prices on liquids and gas, partially offset by reduced operating expenses, decreased depreciation and net impairment losses.

The average daily production of liquids and gas was 1,334 mboe, 1,235 mboe and 1,232 mboe per day in 2017, 2016 and 2015, respectively.

The average daily total production level was increased from 2016 to 2017 mainly due to higher flex gas off-take from Troll and Oseberg, contributions from new fields Ivar Aasen and Gina Krog, and fewer turnarounds.

The average daily total production of liquids and gas maintained from 2015 to 2016, mainly due to high operational performance, new fields on stream and new wells from existing fields.

Over time, the volumes lifted and sold will equal entitlement production, but may be higher or lower in any period due to differences between the capacities and timing of the vessels lifting the volumes and the actual entitlement production during the period.

Income statement under IFRS (in USD million)	For the year ended 31 December 2017	2016	2015	17-16 change	16-15 change
Revenues	**17,558**	13,036	17,170	35%	(24%)
Net income/(loss) from equity accounted investments	**129**	(78)	3	N/A	N/A
Other income	**5**	119	166	(96%)	(28%)
Total revenues and other income	**17,692**	13,077	17,339	35%	(25%)
Operating, selling, general and administrative expenses	**(2,954)**	(2,547)	(3,223)	16%	(21%)
Depreciation, amortisation and net impairment losses	**(3,874)**	(5,698)	(6,379)	(32%)	(11%)
Exploration expenses	**(379)**	(383)	(576)	(1%)	(34%)
Net operating income/(loss)	**10,485**	4,451	7,161	>100%	(38%)

Total revenues and other income were USD 17,692 million in 2017, USD 13,077 million in 2016 and USD 17,339 million in 2015.

The 35% increase in revenues from 2016 to 2017 was mainly due to increased liquids and gas prices, and increased gas volumes. The 25% decrease in revenues from 2015 to 2016 was mainly due to reduced liquids and gas prices.

Other income was immaterial in 2017. Other income in 2016 was impacted by gain from sale of Edvard Grieg of USD 114 million. Other income in 2015 was impacted by gain from the sale of certain ownership interests on the NCS to Repsol of USD 142 million.

Operating expenses and selling, general and administrative expenses were USD 2,954 million in 2017, compared to USD 2,547 million in 2016 and USD 3,223 million in 2015. In 2017, expenses increased compared to 2016 mainly due to change in the internal allocation of gas transportation costs between E&P Norway and MMP. The change in internal allocation also increased the revenues due to a higher transfer price. In 2016, expenses decreased compared to 2015 mainly due to cost improvements and exchange rate development (NOK/USD).

Depreciation, amortisation and net impairment losses were USD 3,874 million in 2017, compared to USD 5,698 million in 2016 and USD 6,379 million in 2015. The decrease of 32% from 2016 to 2017 was mainly due to reversal of impairments in 2017 and impairments in 2016. The decrease of 11% from 2015 to 2016 was mainly due to reduced net impairments, exchange rate development (NOK/USD) and increased proved reserves, partially offset by ramp up of new fields in 2016.

Exploration expenses were USD 379 million in 2017, compared to USD 383 million in 2016 and USD 576 million in 2015. The reduction from 2016 to 2017 was mainly due to lower field development activity and lower portion of previously capitalised exploration expenditures being expensed in 2017, partially offset by a lower portion of current exploration expenditures being capitalised. The reduction from 2015 to 2016 was mainly due to lower drilling activity and more expensive wells being drilled in 2015, partially offset by a lower portion of current exploration expenditures being capitalised.

E&P International profit and loss analysis

Net operating income in 2017 was positive USD 1,341 million, compared to negative USD 4,352 million in 2016 and negative USD 8,729 million in 2015. The positive development from 2016 to 2017 was caused primarily by higher oil and gas prices, and by net reversal of impairments in 2017 compared to net impairment losses in 2016. The positive development from 2015 to 2016 was caused primarily by less impairment losses, and also by lower operating expenses.

The average daily equity liquids and gas production (see section 5.6 Terms and abbreviations) was 745 mboe per day in 2017, compared to 743 mboe per day in 2016 and 739 mboe per day in 2015. The minor increase from 2016 to 2017 was due to new wells in the US, particularly at Appalachian, as well as the effect of ramp-up of fields, mainly in Ireland and Algeria. The increase was partially offset by the divestment of Kai Kos Dehseh oil sands and natural decline, primarily at mature fields in Angola. The increase of 0.5% from 2015 to 2016 was driven primarily by the effect of the ramp-up of fields, mainly in Ireland, Algeria, and the US. The increase was partially offset by the divestment of Shah Deniz (Azerbaijan) and natural decline.

The average daily entitlement liquids and gas production (see section 5.6 Terms and abbreviations) was 588 mboe per day in 2017, compared to 592 mboe per day in 2016, and 580 mboe per day in 2015. Entitlement production in 2017 was down by 1% due to higher negative effect from production sharing agreements (PSA effect) and US royalties, mainly driven by higher prices. Entitlement production in 2016 was up by 2% due to the increased equity production as described above and a relatively lower PSA effect. The combined effect of production sharing agreements (PSA effect) and US royalties was 158 mboe, 151 mboe and 159 mboe per day in 2017, 2016 and 2015, respectively.

Over time, the volumes lifted and sold will equal our entitlement production, but they may be higher or lower in any period due to differences between the capacity and timing of the vessels lifting our volumes and the actual entitlement production during the period. See section 5.6 Terms and abbreviations for more information.

Income statement under IFRS (in USD million)	For the year ended 31 December 2017	2016	2015	17-16 change	16-15 change
Revenues	**9,219**	6,623	7,135	39%	(7%)
Net income/(loss) from equity accounted investments	**22**	(100)	(91)	N/A	(10%)
Other income	**14**	134	1,156	(90%)	(88%)
Total revenues and other income	**9,256**	6,657	8,200	39%	(19%)
Purchases [net of inventory]	**(7)**	(7)	(10)	2%	(28%)
Operating, selling, general and administrative expenses	**(2,804)**	(2,923)	(3,391)	(4%)	(14%)
Depreciation, amortisation and net impairment losses	**(4,423)**	(5,510)	(10,231)	(20%)	(46%)
Exploration expenses	**(681)**	(2,569)	(3,296)	(74%)	(22%)
Net operating income/(loss)	**1,341**	(4,352)	(8,729)	N/A	50%

E&P International generated **total revenues and other income** of USD 9,256 million in 2017, compared to USD 6,657 million in 2016 and USD 8,200 million in 2015.

Revenues in 2017 were positively impacted primarily by higher realised liquids and gas prices, in addition to positive effects from reversal of provisions related to our operations in Angola of USD 754 million. The decrease from 2015 to 2016 was mainly caused by lower realised liquids and gas prices, partially offset by lower provisions relating to commercial disputes in 2016 compared to 2015. For information related to the reversal of provisions and disputes, see note 23 Other commitments, contingent liabilities and contingent assets to the Consolidated financial statements.

Other income was USD 14 million in 2017, compared to USD 134 million in 2016 and USD 1,156 million in 2015. In 2017, other income was mainly related to proceeds from minor insurance claims. In 2016, other income was mainly related to proceeds from an insurance settlement. In 2015, other income consisted of gains from sales of assets, related primarily to the sale of ownership interest in the Shah Deniz project and the South Caucasus Pipeline.

As a result of the factors explained above, **total revenues and other income** increased by 39% in 2017. In 2016, total revenues and other income decreased by 19%.

Operating expenses and selling, general and administrative expenses were USD 2,804 million in 2017, compared to USD 2,923 million in 2016 and USD 3,391 million in 2015. The 4% decrease from 2016 to 2017 was mainly due to portfolio changes and reduced provisions related to asset retirement. The decreases were partially offset by net losses from sale of assets in 2017, and higher royalties, costs related to preparation for operation for new fields and transportation expenses. The 14% decrease from 2015 to 2016 was mainly due to lower operating and maintenance costs for various fields, in addition to lower diluent expenses. The decreases were partially offset by operating and transportation costs for the new fields coming on stream.

Depreciation, amortisation and net impairment losses were USD 4,423 million in 2017, compared to USD 5,510 million in 2016 and USD 10,231 million in 2015. The 20% decrease from 2016 to 2017 was caused primarily by net reversal of impairments in 2017, compared to net impairment losses in 2016. Net reversal of impairments amounted to USD 102 million in 2017, with the reversal of impairment related to an unconventional onshore asset in North America, caused by changes in US tax legislation, operational improvements and increased recovery rate, as the main contributor. In addition, depreciations decreased due to higher reserves estimates and effects from previous periods' impairments, partially offset by production ramp-up from new fields.

The 46% decrease from 2015 to 2016 was primarily caused by lower net impairment losses in 2016 compared to 2015. Net impairment losses amounted to USD 541 million in 2016 and resulted mainly from reduced long-term price assumptions with the largest effect being on the unconventional onshore assets in North America. Net impairment losses amounted to USD 5,416 million in 2015, and were mainly related to unconventional onshore assets in North America and certain conventional upstream assets. The impairment losses resulted primarily from reduced short-term forward prices in combination with reduced long-term oil price forecasts. In addition, depreciations decreased due to higher reserves estimates. The decreases were partially offset by start-up and ramp-up of production from new fields.

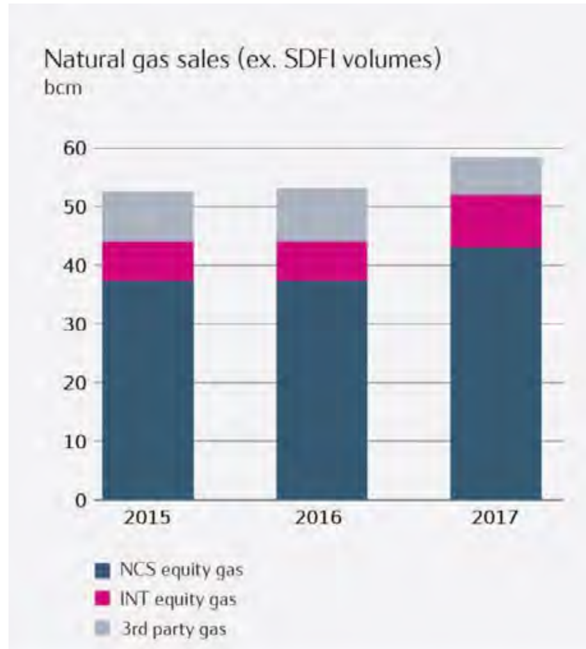
Exploration expenses were USD 681 million in 2017, compared to USD 2,569 million in 2016 and USD 3,296 million in 2015. The reduction from 2016 to 2017 was mainly due to net impairment of exploration prospects and signature bonuses in 2016 of USD 992 million compared with USD 82 million in 2017. Lower portion of capitalised expenditures from earlier years being expensed in 2017 of USD 60 million compared with USD 785 million in 2016 contributed to the reduction, in addition to less expensive wells drilled in 2017 despite higher exploration activity. This was partially offset by lower capitalization rate in 2017. The 22% reduction from 2015 to 2016 was mainly due to lower impairments, lower drilling activity and lower well costs in 2016. Higher portion of wells capitalised in previous periods being expensed this year and a lower capitalisation rate in 2016 partially offset the decrease.

MMP profit and loss analysis

Net operating income was USD 2,243 million, USD 623 million and USD 2,931 million in 2017, 2016 and 2015, respectively. In 2017 net operating income was positively impacted by changes in fair value of derivatives and periodisation of inventory hedging effect of USD 365 million compared to negative impact of USD 1,072 million in 2016. Higher refinery margins and increased production from processing plants added to the total increase of USD 1,620 million from 2016 to 2017.

The decrease of USD 2,308 million from 2015 to 2016 was mainly due to lower fair value of derivatives and periodisation of inventory hedging effect of USD 1,072 million in 2016 compared to negative USD 21 million in 2015. Lower margins from processing and turnarounds in 2016 added to the decrease. The decrease is also impacted by the net reversal of impairment charges of USD 421 million in 2015.

Total natural gas sales volumes were 58.4 bcm in 2017, 52.9 bcm in 2016 and 52.6 bcm in 2015. The 10% increase in total gas volumes sold from 2016 to 2017 was related to higher entitlement production on the NCS and internationally, partially offset by lower sales of third party gas. The chart does not include any volumes sold on behalf of the Norwegian State's direct financial interest (SDFI).

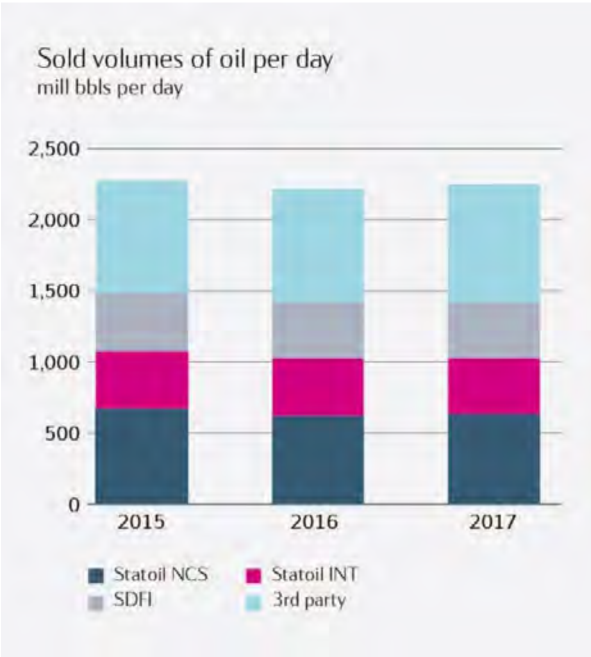


In 2017, the average invoiced natural gas sales price in Europe was USD 5.55 per mmBtu, up 7% from 2016 (USD 5.17 per mmBtu). The 2016 average invoiced natural gas price in Europe was down 27% from 2015 (USD 7.08 per mmBtu).

In 2017, the average invoiced natural gas sales price in North Americas was USD 2.73 per mmBtu, up 28% from 2016 (USD 2.12 per mmBtu). The 2016 average invoiced natural gas sales price in North Americas was down 19% from 2015 (USD 2.62 per mmBtu).

All of Statoil's gas produced on the NCS is sold by MMP, purchased from E&P Norway at the fields' lifting point at a market-based internal price with deduction for the cost of bringing gas from the field to market and a marketing fee element. Our NCS transfer price for gas was USD 4.33 per mmBtu in 2017, an increase of 27% compared to USD 3.42 per mmBtu in 2016. The 2016 NCS transfer price was down 34% from 2015 (USD 5.17 per mmBtu).

Average crude, condensate and NGL sales were 2.2 mmbbl per day in 2017 of which approximately 1.01 mmbbl were sales of our equity volumes, 0.83 mmbbl sales of third-party volumes and 0.40 mmbbl sales of volumes purchased from SDFI. Our average sales volumes were 2.2 and 2.3 mmbbl per day in 2016 and 2015. The average daily third-party volumes sold were 0.80 and 0.79 mmbbl in 2016 and 2015



MMPs refining margins were higher in 2017 than in 2016, and results were also impacted by higher production from the refineries. Statoil's refining reference margin was 6.3 USD/bbl in 2017, compared to 4.8 USD/bbl in 2016, an increase of 31%. The refining reference margin was 8.0 USD/bbl in 2015.

Income statement under IFRS (in USD million)	For the year ended 31 December 2017	2016	2015	17-16 change	16-15 change
Revenues	**59,017**	44,847	57,873	32%	(23%)
Net income/(loss) from equity accounted investments	**53**	61	55	(14%)	12%
Other income	**1**	72	178	(98%)	(60%)
Total revenues and other income	**59,071**	44,979	58,106	31%	(23%)
Purchases [net of inventory]	**(52,647)**	(39,696)	(50,547)	33%	(21%)
Operating, selling, general and administrative expenses	**(3,925)**	(4,439)	(4,664)	(12%)	(5%)
Depreciation, amortisation and net impairment losses	**(256)**	(221)	37	16%	N/A
Net operating income/(loss)	**2,243**	623	2,931	>100%	(79%)

Total revenues and other income were USD 59,071 million in 2017, compared to USD 44,979 million in 2016 and USD 58,106 million in 2015.

The increase in **revenues** from 2016 to 2017 was mainly due to increase in prices for all products. The average crude price in USD increased by approximately 25% in 2017 compared to 2016.

The decrease in revenues from 2015 to 2016 was mainly due to decrease in crude and gas prices. The average crude price in USD declined by approximately 17% in 2016 compared to 2015. Revenues in 2016 were negatively impacted by loss from derivatives, mainly due to significant increase in the forward curve in the oil and gas market.

Other income in 2017 was negligible. In 2016, other income was positively impacted by gain on sale of assets of USD 72 million, and in 2015 other income was positively impacted by gain on sale of assets of USD 178 million.

Because of the factors explained above, **total revenues and other income** increased by 31% from 2016 to 2017 and decreased by 23% from 2015 to 2016.

Purchases [net of inventory] were USD 52,647 million in 2017, compared to USD 39,696 million in 2016 and USD 50,547 million in 2015. The increase from 2016 to 2017 was mainly due to increase in price for all products. The decrease from 2015 to 2016 was mainly due to decrease in gas and crude prices.

Operating expenses and selling, general and administrative expenses were USD 3,925 million in 2017, compared to USD 4,439 million in 2016 and USD 4,664 million in 2015. The decrease from 2016 to 2017 was mainly due to a change in the internal allocation of gas transportation cost between MMP and E&P Norway, partially offset by higher maintenance cost on plants. The decrease from 2015 to 2016 was mainly due to lower transportation cost and cost reduction initiatives in 2016.

Depreciation, amortisation and net impairment losses amounted to a loss of USD 256 million in 2017, and a loss of USD 221 million in 2016 compared to an income of USD 37 million in 2015. The increase in depreciation, amortisation and net impairment losses from 2016 to 2017 was mainly caused by lower reversal of impairments in 2017 compared to 2016. Net reversal of impairments in 2017 was mainly related to refinery assets, impacted by expected lower cost base in the future cash flows. The increase in depreciation, amortisation and net impairment losses from 2015 to 2016 was mainly caused by net reversal of impairment charges of USD 421 million in 2015, related to our refineries.

Other operations

The Other reporting segment includes activities within New Energy Solutions; Global Strategy & Business Development; Technology, Projects & Drilling; and Corporate staffs and support functions.

In 2017, the Other reporting segment recorded a net operating loss of USD 239 million compared to a net operating loss of USD 423 million in 2016 and a net operating loss of USD 129 million in 2015.

2.10 LIQUIDITY AND CAPITAL RESOURCES

REVIEW OF CASH FLOWS

Statoil`s cash flow generation in 2017 was strong across the business and total cash flows increased by USD 2,234 compared to 2016.

CONDENSED CONSOLIDATED STATEMENT OF CASH FLOWS

	Full year		
(in USD million)	2017	2016	2015
Cash flows provided by operating activities	14,363	9,034	13,628
Cash flows used in investing activities	(9,678)	(10,446)	(14,501)
Cash flows provided by (used in) financing activities	(5,822)	(1,959)	(729)
Net increase (decrease) in cash and cash equivalents	(1,137)	(3,371)	(1,602)

Cash flows provided by operating activities
The most significant drivers of cash flows provided by operations were the level of production and prices for liquids and natural gas that impact revenues, purchases [net of inventory], taxes paid and changes in working capital items.

In 2017, cash flows provided by operating activities were increased by USD 5,329 million compared to 2016. The increase was mainly due to increased liquids and gas prices, combined with higher production and a reduction in working capital, partially offset by increased tax payments.

In 2016, cash flows provided by operating activities were reduced by USD 4,594 million compared to 2015. The decrease was mainly due to reduced liquids and gas prices, partially offset by lower taxes paid.

Cash flows used in investing activities
In 2017, cash flows used in investing activities were reduced by USD 768 million compared to 2016. The decrease was due to decreased capital expenditures, partially offset by reduced proceeds from sale of assets and increased financial investments.

In 2016, cash flows used in investing were reduced by USD 4,055 million compared to 2015. The decrease was due to significantly lower capital expenditures, lower financial investments and reduced proceeds from sale of assets.

Cash flows provided by (used in) financing activities
In 2017, cash flows used in financing activities were increased by USD 3,863 million compared to 2016. The cash outflow was mainly due to repayment of finance debt, partially offset by increased cash flow from collateral related to derivatives.

In 2016, cash flows used in financing activities increased by USD 1,230 million compared to 2015. The change is mainly due to reduced cash flow from finance debt, partially offset by reduced cash dividend due to the scrip dividend.

FINANCIAL ASSETS AND DEBT

Statoil's financial position is strong. The net debt to capital employed ratio before adjustments at year end decreased from 34.4% in 2016 to 27.9% in 2017. See section 5.2 for non-GAAP measures for net debt ratio. Net interest-bearing debt decreased from USD 18.4 billion to USD 15.4 billion. During 2017 Statoil's total equity increased from USD 35.1 billion to USD 39.9 billion, mainly due to a positive net income in 2017. Cash flows provided by operating activities increased in 2017 mainly due to increased prices. Cash flows used in investing activities were reduced in 2017, while cash flows used in financing activities increased. Statoil has paid out four quarterly dividends in 2017. For the fourth quarter of 2017 the board of directors will propose to the annual general meeting (AGM) to increase the dividend from USD 0.2201 to USD 0.23 per share. The two-year scrip dividend programme ended as planned with the third quarter 2017 dividend. For further information, see note 17 Shareholders equity and dividends to the Consolidated financial statements.

Statoil believes that, given its current liquidity reserves, including committed credit facilities of USD 5.0 billion and its access to various capital markets, Statoil has sufficient funds available to meet its liquidity needs, including working capital.

Funding needs arise as a result of Statoil's general business activities. Statoil generally seeks to establish financing at the corporate (top company) level. Project financing may also be used in cases involving joint ventures with other companies. Statoil aims to have access to a variety of funding sources in respect of markets and instruments at all times, as well as maintaining relationships with a core group of international banks that provide a wide range of banking services.

Moody's and Standard & Poor's (S&P) provide credit ratings on Statoil. Statoil's current long-term ratings are A+ with a positive outlook and Aa3 with a stable outlook from S&P and Moody's, respectively. The outlook from S&P was revised from "Stable" to "Positive" on 14 November 2017 based on stronger than expected cash flow generation year to date. The short-term ratings are P-1 from Moody's and A-1 from S&P. In order to maintain financial flexibility going forward, Statoil intend to keep key financial ratios at levels consistent with our objective of maintaining Statoil's long-term credit rating at least within the single A category on a stand-alone basis.

The management of financial assets and liabilities takes into consideration funding sources, the maturity profile of non-current debt, interest rate risk, currency risk and available liquid assets. Statoil's borrowings are denominated in various currencies and normally swapped into USD. In addition, interest rate derivatives, primarily interest rate swaps, are used to manage the interest rate risk of our long-term debt portfolio. Statoil's funding and liquidity activities are handled centrally.

Statoil has diversified its cash investments across a range of financial instruments and counterparties to avoid concentrating risk in any one type of investment or any single country. As of 31 December 2017, approximately 21% of Statoil's liquid assets were held in USD-denominated assets, 21% in NOK, 32% in EUR, 10% in DKK and 15% in SEK, before the effect of currency swaps and forward contracts. Approximately 49% of Statoil's liquid assets were held in treasury bills and commercial paper, 42% in time deposits, 3% in money market funds and 2% in bank deposits. As of 31 December 2017, approximately 3.8% of Statoil's liquid assets were classified as restricted cash (including collateral deposits).

Statoil's general policy is to keep a liquidity reserve in the form of cash and cash equivalents or other current financial investments in Statoil's balance sheet, as well as committed, unused credit facilities and credit lines in order to ensure that Statoil has sufficient financial resources to meet short-term requirements.

Long-term funding is raised when a need is identified for such financing based on Statoil's business activities, cash flows and required financial flexibility or when market conditions are considered to be favourable.

The Group's borrowing needs are usually covered through the issuance of short-, medium- and long-term securities, including utilisation of a US Commercial Paper Programme (programme limit USD 5.0 billion) and a Shelf Registration Statement (unlimited) filed with the Securities and Exchange Commission (SEC) in the USA as well as through issues under a Euro Medium-Term Note (EMTN) Programme listed on the London Stock Exchange. Committed credit facilities and credit lines may also be utilised. After the effect of currency swaps, the major part of Statoil's borrowings is in USD.

Effective 14 December 2017, Statoil bought back USD 2.25 billion of issued bonds. During 2017, Statoil issued no new bonds, while in 2016 new debt securities equivalent to USD 1.3 billion and in 2015 equivalent to USD 4.3 billion were issued. All the bonds are unconditionally guaranteed by Statoil Petroleum AS. For more information, see note 18 Finance debt to the Consolidated financial statements.

FINANCIAL INDICATORS

FINANCIAL INDICATORS (in USD million)	For the year ended 31 December 2017	2016	2015
Gross interest-bearing debt [1)]	**28,274**	31,673	32,291
Net interest-bearing debt before adjustments	**15,437**	18,372	13,852
Net debt to capital employed ratio [2)]	**27.9%**	34.4%	25.6%
Net debt to capital employed ratio adjusted [3)]	**29.0%**	35.6%	26.8%
Cash and cash equivalents	**4,390**	5,090	8,623
Current financial investments	**8,448**	8,211	9,817
Ratio of earnings to fixed charges [4)]	**6.8**	0.9	1.0

1) Defined as non-current and current finance debt.

2) As calculated according to IFRS. Net debt to capital employed ratio is the net debt divided by capital employed. Net debt is interest-bearing debt less cash and cash equivalents and current financial investments. Capital employed is net debt, shareholders' equity and minority interest.

3) In order to calculate the net debt to capital employed ratio adjusted, Statoil makes adjustments to capital employed as it would be reported under IFRS. Restricted funds held as financial investments in Statoil Forsikting AS and Collateral deposits has been added to the net debt whilst the SDFI part of the financial lease in the Snøhvit vessel has been taken out of the net debt. See section 5.2 Net debt to capital employed ratio for a reconciliation of capital employed and a description of why Statoil considers this measure to be useful.

4) For the purpose of these ratios, earnings consist of the income before (i) tax, (ii) minority interest, (iii) amortisation of capitalised interest and (iv) fixed charges (which have been adjusted for capitalised interest) and after adjustment for unremitted earnings from equity accounted entities. Fixed charges consist of interest (including capitalised interest) and estimated interest within operating leases.

Gross interest-bearing debt

Gross interest-bearing debt was USD 28.3 billion, USD 31.7 billion and USD 32.3 billion at 31 December 2017, 2016 and 2015, respectively. The USD 3.4 billion net decrease from 2016 to 2017 was due to a decrease in non-current finance debt of USD 3.8 billion, offset by an increase in current finance debt of USD 0.4 billion. The USD 0.6 billion net decrease from 2015 to 2016 was due to a decrease in non-current finance debt of USD 2.0 billion offset by an increase in current finance debt of USD 1.4 billion. Our weighted average annual interest rate was 3.50%, 3.41% and 3.39% at 31 December 2017, 2016 and 2015, respectively. Statoil's weighted average maturity on finance debt was nine years at 31 December 2017, nine years at 31 December 2016 and nine years at 31 December 2015.

Net interest-bearing debt
Net interest-bearing debt before adjustments were USD 15.4 billion, USD 18.4 billion and USD 13.9 billion at 31 December 2017, 2016 and 2015, respectively. The decrease of USD 2.9 billion from 2016 to 2017 was mainly related to a decrease in gross interest-bearing debt of USD 3.4 billion, an increase of current financial investments of USD 0.2 billion offset by a USD 0.7 billion decrease in cash and cash equivalents. The increase of USD 4.5 billion from 2015 to 2016 was mainly related to a decrease in cash and cash equivalents of USD 3.5 billion, a decrease of current financial investments of USD 1.6 billion offset by a USD 0.6 billion decrease in gross interest-bearing debt.

The net debt to capital employed ratio
The net debt to capital employed ratio before adjustments was 27.9%, 34.4% and 25.6% in 2017, 2016 and 2015 respectively.

The net debt to capital employed ratio adjusted (non-GAAP financial measure, see footnote three above) was 29.0%, 35.6% and 26.8% in 2017, 2016, and 2015, respectively.

The 6.5 percentage points decrease in net debt to capital employed ratio before adjustments from 2016 to 2017 was related to the decrease in net interest-bearing debt of USD 2.9 billion in combination with an increase in capital employed of USD 1.9 billion. The 8.8 percentage points increase in net debt to capital employed ratio before adjustments from 2015 to 2016 was related to the increase in net interest-bearing debt of USD 4.5 billion in combination with a decrease in capital employed of USD 0.7 billion.

The 6.6 percentage points decrease in net debt to capital employed ratio adjusted from 2016 to 2017 was related to the decrease in net interest-bearing debt adjusted of USD 3.1 billion in combination with an increase in capital employed adjusted of USD 1.7 billion. The 8.8 percentage points increase in net debt to capital employed ratio adjusted from 2015 to 2016 was related to the increase in net interest-bearing debt adjusted of USD 4.6 billion in combination with a decrease in capital employed adjusted of USD 0.6 billion.

Cash, cash equivalents and current financial investments
Cash and cash equivalents were USD 4.4 billion, USD 5.1 billion and USD 8.6 billion at 31 December 2017, 2016 and 2015 respectively. See note 16 Cash and cash equivalents to the Consolidated financial statements for information concerning restricted cash. Current financial investments, which are part of Statoil's liquidity management, amounted to USD 8.4 billion, USD 8.2 billion and USD 9.8 billion at 31 December 2017, 2016 and 2015, respectively.

INVESTMENTS

In 2017, capital expenditures, defined as additions to property, plant and equipment (including capitalised financial leases), capitalised exploration expenditures, intangible assets, long-term share investments and investments in equity accounted companies, amounted to USD 10.8 billion, of which USD 9.4 billion were organic capital expenditures.[5]

In 2016, capital expenditures were USD 14.1 billion, of which organic capital expenditures amounted to USD 10.1 billion.

In Norway, a substantial proportion of our 2018 capital expenditures will be spent on ongoing development projects such as Johan Sverdrup, Johan Castberg, Martin Linge and Aasta Hansteen, in addition to various extensions, modifications and improvements on currently producing fields like Gullfaks, Oseberg and Troll.

Internationally, we currently estimate that a substantial proportion of our 2018 capital expenditure will be spent on the following ongoing and planned development projects: Mariner in the UK, Peregrino in Brazil, and onshore activity in the US.

Within renewable energy, a substantial proportion of our 2018 capital expenditure is expected to be spent on the Arkona offshore wind project in Germany.

Statoil finances its capital expenditures both internally and externally. For more information, see Financial assets and debt earlier in this section.

As illustrated in section Principal contractual obligations later in this report, Statoil has committed to certain investments in the future. The further into the future, the more flexibility we will have to revise expenditure. This flexibility is partly dependent on the expenditure our partners in joint ventures agree to commit to. A large part of the capital expenditure for 2018 is committed.

Statoil may alter the amount, timing or segmental or project allocation of our capital expenditures in anticipation of, or as a result of a number of factors outside our control.

PRINCIPAL CONTRACTUAL OBLIGATIONS

The table summarises our principal contractual obligations, excluding derivatives and other hedging instruments, as well as, asset retirement obligations, which for the most part are expected to lead to cash disbursements more than five years in the future.

Non-current finance debt in the table represents principal payment obligations, including interest obligation. Obligations related to an ownership interest and the transport capacity cost for a pipeline and exceeding Statoil ownership in unconsolidated equity affiliates are included as part of the other long-term commitments.

[5] See section 5.2 for non-GAAP measures

Principal contractual obligations (in USD million)	As at 31 December 2017 Payment due by period [1] Less than 1 year	1-3 years	3-5 years	More than 5 years	Total
Undiscounted finance debt- principal and interest[2]	3,763	5,165	4,521	22,925	36,375
Minimum operating lease payments[3]	1,961	2,477	1,649	2,014	8,101
Nominal minimum other long-term commitments[4]	1,548	2,727	2,043	5,563	11,881
Total contractual obligations	7,273	10,370	8,213	30,502	56,357

1) "Less than 1 year" represents 2018; "1-3 years" represents 2019 and 2020, "3-5 years" represents 2021 and 2022, while "More than 5 years" includes amounts for later periods.

2) See note 18 Finance debt to the Consolidated financial statements. The main differences between the table and the note is interest.

3) See note 22 Leases to the Consolidated financial statements.

4) See note 23 Other commitments and contingencies to the Consolidated financial statements.

Statoil had contractual commitments of USD 6,012 million at 31 December 2017. The contractual commitments reflect Statoil's share and mainly comprise construction and acquisition of property, plant and equipment.

Statoil's projected pension benefit obligation was USD 8,286 million, and the fair value of plan assets amounted to USD 5,687 million as of 31 December 2017. Company contributions are mainly related to employees in Norway. See note 19 Pensions to the Consolidated financial statements for more information.

OFF BALANCE SHEET ARRANGEMENTS

Statoil is party to various agreements, such as operational leases and transportation and processing capacity contracts, that are not recognised in the balance sheet. For more information, see Principal contractual obligations in section 2.10 Liquidity and capital resources, and note 22 Leases to the Consolidated financial statements. Statoil is also party to certain guarantees, commitments and contingencies that, pursuant to IFRS, are not necessarily recognised in the balance sheet as liabilities. See note 23 Other commitments and contingencies to the Consolidated financial statements for more information.

2.11 RISK REVIEW

RISK FACTORS

Statoil is exposed to a number of risks that could affect its operational and financial performance. In this section, some of the key risk factors are addressed.

Risks related to our business

This section describes the most significant potential risks relating to Statoil's business:

Oil and natural gas prices risks

A prolonged period of low oil and/or natural gas prices would have a material adverse effect on Statoil

The prices of oil and natural gas have fluctuated greatly in response to changes in many factors. We have experienced a situation where oil and natural gas prices declined substantially compared to levels seen over the last few years. There are several reasons for this decline, but fundamental market forces beyond the control of Statoil or other similar market participants have impacted and can continue to impact oil and natural gas prices in the future. Recently, as a consequence of agreements within Opec and also between Opec and some non-Opec countries, oil prices have increased due to expectations of an earlier tightening of market balances. However, the uncertainty about future developments still prevails.

Generally, Statoil does not and will not have control over the factors that affect the prices of oil and natural gas. These factors include:

- economic and political developments in resource-producing regions
- global and regional supply and demand
- the ability of the Organisation of the Petroleum Exporting Countries (Opec) and/or other producing nations to influence global production levels and prices
- prices of alternative fuels that affect the prices realised under Statoil's long-term gas sales contracts
- government regulations and actions; including changes in energy and climate policies
- global economic conditions
- war or other international conflicts
- changes in population growth and consumer preferences
- the price and availability of new technology and
- weather conditions

It is impossible to predict future price movements for oil and/or natural gas with certainty. A prolonged period of low oil and natural gas prices will adversely affect Statoil's business, the results of operations, financial condition, liquidity and Statoil's ability to finance planned capital expenditure, including possible reductions in capital expenditures which could lead to reduced reserve replacement. In addition to the adverse effect on revenues, margins and profitability from any fall in oil and natural gas prices, a prolonged period of low prices or other indicators could, if deemed to have longer term impact, lead to further reviews for impairment of the group's oil and natural gas properties. Such reviews would reflect the management's view of long-term oil and natural gas prices and could result in a charge for impairment that could have a significant effect on the results of Statoil's operations in the period in which it occurs.

Changes in management's view on long-term oil and/or natural gas prices or further material reductions in oil, gas and/or product prices could have an adverse impact on the economic viability of projects that are planned or in development.

Proved reserves and expected reserves calculation risks

Statoil's crude oil and natural gas reserves are only estimates and Statoil's future production, revenues and expenditures with respect to its reserves may differ materially from these estimates. The reliability of proved reserve estimates depends on:

- the quality and quantity of Statoil's geological, technical and economic data
- the production performance of Statoil's reservoirs
- extensive engineering judgments and
- whether the prevailing tax rules and other government regulations, contracts and oil, gas and other prices will remain the same as on the date estimates are made

Proved reserves are calculated based on the U.S. Securities and Exchange Commission (SEC) requirements and may therefore differ substantially from Statoil's view on expected reserves.

Many of the factors, assumptions and variables involved in estimating reserves are beyond Statoil's control and may prove to be incorrect over time. The results of drilling, testing and production after the date of the estimates may require substantial upward or downward revisions in Statoil's reserve data. The prices used for proved reserves are defined by the SEC and are calculated based on a 12 month un-weighted arithmetic average of the first day of the month price for each month during the reporting year, leading to a forward price strongly linked to last year's price environment. Fluctuations in oil and gas prices will have a direct impact on Statoil's proved reserves. For fields governed by production sharing agreements (PSAs), a lower price may lead to higher entitlement to the production and increased reserves for those fields. Adversely, a lower price environment may also lead to lower activity resulting in reduced reserves. For PSAs these two effects may to some degree offset each other. In addition a low price environment may result in earlier shutdown due to uneconomic production. This will affect both PSAs and fields with concession types of agreement.

Technical, commercial and country specific risks

Statoil is engaged in global exploration activities that involve a number of technical, commercial and country specific risks.

General risks are technical risks related to Statoil's ability to conduct its seismic and drilling operations in a safe and efficient manner and to encounter commercially productive oil and gas reservoirs and commercial risks related to Statoil's ability to secure access to new acreage in an uncertain global competitive and political environment and competent personnel to perform exploration activities and mature resources along the value-chain. Country specific risks are related to security threats and compliance with and understanding of local laws or licence agreements. These risks may adversely affect Statoil's current operations and financial results, and its long-term replacement of reserves.

Decline reserves risks

If Statoil fails to acquire or discover and develop additional reserves, its reserves and production will decline materially from their current levels

Successful implementation of Statoil's group strategy for value growth is critically dependent on sustaining its long-term reserve replacement. If upstream resources are not progressed to proved reserves in a timely manner, Statoil's reserve base and thereby future production will gradually decline and future revenue will be reduced.

Statoil's future production is highly dependent on its success in acquiring or finding and developing additional reserves adding value. If unsuccessful, future total proved reserves and production will decline.

If a low price environment continues for a substantial time, this may result in undeveloped acreage not being considered economically viable and consequently discovered resources not being matured to reserves. This may also lead to exploration areas not being explored for new resources and subsequently not being matured for development resulting in less future proved reserves.

In a number of resource-rich countries, national oil companies control a significant proportion of oil and gas reserves that remain to be developed. To the extent that national oil companies choose to develop their oil and gas resources without the participation of international oil companies, or if Statoil is unable to develop partnerships with national oil companies, its ability to find and acquire or develop additional reserves will be more limited.

Statoil's US onshore portfolio contains significant amount of undeveloped resources that depend on Statoil's ability to develop these successfully. If commodity prices are low over a sustained period of time, this may result in Statoil deciding not to develop these resources or at least deferring development awaiting improved prices. Additionally, the development of these resources is subject to Statoil ability to continue to deliver on its US onshore strategy to enhance value and create robust developments.

Health, safety and environmental risks

Statoil is exposed to a wide range of health, safety and environmental risks that could result in significant losses.

Exploration, development, production, processing and transportation related to oil and natural gas, as well as development and operation of renewable energy production, can be hazardous. Technical integrity failures, operational failures, natural disasters or other occurrences can result in: loss of life, oil spills, gas leaks, loss of containment of hazardous materials, water contamination, blowouts, cratering, fires and equipment failure, among other things.

The risks associated with Statoil's activities are affected by the difficult geographies, climate zones and environmentally sensitive regions in which Statoil operates. All modes of transportation of hydrocarbons - including road, rail, sea or pipeline - are particularly susceptible to a loss of containment of hydrocarbons and other hazardous materials, and, given the high volumes involved, these could represent a significant risk to people and the environment. Offshore operations and transportation are subject to marine perils, including severe storms and other adverse weather conditions and vessel collisions. Onshore operations and transportation are subject to adverse weather conditions and incidents. Both onshore and offshore operations and transportation are subject to interruptions, restrictions or termination by government authorities based on safety, environmental or other considerations.

The transition to a lower carbon economy risks

The transition to a lower carbon economy, and the physical effects of climate change, could impact Statoil's business.

The transition to a low-carbon energy future poses fundamental strategic challenges for the oil and gas industry. The company review and monitor climate change-related business risks and opportunities, whether political, regulatory, market, physical or related to reputation impact. To assess climate-related business risk, Statoil uses tools such as internal carbon pricing, scenario planning and stress testing of the project portfolio against various oil and gas price assumptions. Statoil monitors technology developments and changes in regulation and assesses how these might impact the oil and gas price, the cost of developing new assets and the demand for oil and gas and opportunities in renewable energy and low carbon solutions.

Regulatory and climate policy risk: Statoil expects and is preparing for regulatory changes and policy measures targeted at reducing greenhouse gas emissions. Stricter climate regulations and climate policies could impact Statoil's financial outlook, whether directly through changes in taxation and regulation, or indirectly through changes in consumer behaviour. The Paris Agreement on climate change entered into force in November 2016. Norway, collectively with the European Union, intends to deliver 40% reductions in greenhouse gas emissions by 2030. The national targets are intended to be strengthened every five years. Additionally, Norway has set an ambition to achieve close to net zero emissions by 2050. The implications for the industry are not clear, however requirements to reduce emissions could result in increased costs. Statoil's operations in Norway are subject to emissions taxes as well as emissions allowances granted for Statoil's larger European operations under the EU Emissions Trading System. The agreed strengthening of the European Union's emission trading scheme may result in higher costs for installations at the NCS as the price of the EU ETS emissions allowances is expected to increase significantly towards 2030.

Globally, Statoil expects greenhouse gas emission costs to increase from current levels beyond 2020 and to have a wider geographical range than today. To be prepared for a potential increased carbon price, Statoil uses an internal carbon price of minimum USD 50 for all projects after 2020 as part of the investment analysis and as a basis for investment decisions. In countries where a higher carbon price is used and/or predicted, a higher price is used in the investment analysis. Other regulatory risks related to climate change include potential direct regulations, for example measures to improve energy efficiency such as fuel efficiency standards (e.g. in the EU) and requirements to assess the use of power from shore for new offshore developments at the Norwegian Continental Shelf. This could impact Statoil's operational costs. Climate-related policy changes may also reduce access to prospective geographical areas for exploration and production in the future, which could impact Statoil's ability to replace reserves.

Market-related risk: There is continuing uncertainty over demand for oil and gas after 2030, due to factors such as technology development, climate policies, changing consumer behaviour and demographic changes. Statoil uses scenario analysis to outline different possible energy futures. Technology development and increased cost-competitiveness of renewable energy and low-carbon technologies represent both threats and opportunities for Statoil. As an example, the development of battery technologies could allow more intermittent renewables to be used in the power sector. This could impact Statoil's gas sales, particularly if subsidies of renewable energy in Europe were to increase and/or costs of renewable energy were to significantly decrease. On the other hand, Statoil's renewable energy business could be impacted if such subsidies were reduced or withdrawn. As such, there is significant uncertainty regarding the long-term implications to costs and opportunities for Statoil in the transition to a lower-carbon economy.

Reputational impact: Increased concern over climate change could lead to increased litigation against fossil fuel producers, as well as a more negative perception of the oil and gas industry. The latter could impact talent attraction and retention.

Physical climate risk factors: Changes in physical climate parameters could impact Statoil's operations, for example through restrained water availability, rising sea level, changes in sea currents and increasing frequency of extreme weather events. Although Statoil's facilities are designed to withstand extreme weather events, there is significant uncertainty regarding the magnitude of impact and time horizon for the occurrence of physical impacts of climate change, which leads to considerable uncertainty regarding the potential impact on Statoil. As most of Statoil's physical assets are located offshore, the most relevant potential physical climate impact is expected to be rising sea level.

Portfolio sensitivity test: To assess energy transition-related risks, Statoil has analysed the sensitivity with changing the oil and gas prices and keeping other parameters constant, of its project portfolio (equity production and expected production from accessed exploration acreage) against the assumptions regarding commodity and carbon prices in the International Energy Agency's (IEA) energy scenarios, as laid out in their "World Economic Outlook 2017" report. The sensitivity analysis demonstrated a positive impact of around 20% on Statoil's net present value (NPV) when replacing Statoil's price assumptions as of 1 December 2017 with the price assumptions in the IEA's New Policies Scenario, a positive impact of 42% when using the price assumptions in the Current Policies Scenario, and a negative NPV impact of approximately 13% when using the price assumptions in the Sustainable Development Scenario. This sensitivity analysis is based on Statoil's and the IEA's energy scenario assumptions which may not be accurate and which are likely to develop over time as new information becomes available. Scenarios should not be mistaken for forecasts or predictions. Accordingly, there can be no assurance that the assessment, which is presented in more detail in Statoil ASA's 2017 Sustainability report, is a reliable indicator of the actual impact of climate change on Statoil's portfolio.

Hydraulic fracturing risk

Statoil is exposed to risks as a result of its hydraulic fracturing usage

Statoil's US operations use hydraulic fracturing which is subject to a range of applicable federal, state and local laws, including those discussed under the heading "Legal and Regulatory Risks". Fracturing is an important and common practice that is used to stimulate production of crude oil and/or natural gas from dense subsurface rock formations. Statoil's hydraulic fracturing and fluid handling operations are designed and operated to minimise the risk, if any, of subsurface migration of hydraulic fracturing fluids and spillage or mishandling of hydraulic fracturing fluids. However, a case of subsurface migration of hydraulic fracturing fluids or a case of spillage or mishandling of hydraulic fracturing fluids during these activities could potentially subject Statoil to civil and/or criminal liability and the possibility of substantial costs, including environmental remediation, depending on the circumstances of the underground migration, spillage, or mishandling, the nature and scope of the underground migration, spillage, or mishandling, and the applicable laws and regulations.

In addition, various states and local governments have implemented, or are considering, increased regulatory oversight of hydraulic fracturing through additional permit requirements, operational restrictions, disclosure requirements and temporary or permanent bans. New or further changes in laws and regulations imposing reporting obligations on, or otherwise banning or limiting, the hydraulic fracturing process could make it more difficult to complete oil and natural gas wells in shale formations, cause operational delays, increase costs of regulatory compliance or in exploration and production, which could adversely affect Statoil's US onshore business and the demand for fracturing services.

Security threats and Cyber-attacks risks

Statoil is exposed to security threats that could have a materially adverse effect on Statoil's results of operations and financial condition

Security threats such as acts of terrorism and cyber-attacks against Statoil's production and exploration facilities, offices, pipelines, means of transportation or computer systems or breaches of Statoil's security system, could result in losses. No assurances can be made that such attacks will not occur in the future and adversely impact its operations. Failure to manage the foregoing risks could result in injury or loss of life, damage to the environment, damage to or the destruction of wells and production facilities, pipelines and other property. Statoil could face, among other things, regulatory action, legal liability, damage to its reputation, a significant reduction in revenues, an increase in costs, a shutdown of operations and a loss of its investments in affected areas.

Statoil is exposed to security threats on its information systems and digital infrastructure that could harm its assets and operations.

Statoil's security barriers are intended to protect its information systems and digital infrastructure from being compromised by unauthorised parties. Failure to maintain and develop these barriers may affect the confidentiality, integrity and availability of its information systems and digital infrastructure, including those critical to Statoil's operations. Threats to Statoil's information systems could result in significant financial damage to Statoil. Threats to Statoil's industrial control systems are not limited by geography as Statoil's digital infrastructure is accessible globally, and incidents in the industry in recent years have shown that parties who are able to circumvent barriers aimed at securing industrial control systems are capable and willing to perform attacks that destroy, disrupt or otherwise compromise operations. Such attacks could result in material losses or loss of life with consequent financial implications.

Crisis management systems risks

Statoil's crisis management systems may prove inadequate

Statoil has plans and capability to deal with crisis and emergencies at every level of its operations (ie; plant fires, terror, well instability etc). If Statoil does not respond or is perceived not to have responded in an appropriate manner to either an external or internal crisis, or if its plans to carry on or recover operations following a disruption or incident are not effected quickly enough, its business, operations and reputation could be severely affected. Inability to restore or replace critical capacity to an agreed level within an agreed time frame could prolong the impact of any disruption and could severely affect Statoil's business and operations.

Increased competition risks

Statoil encounters competition from other oil and gas companies in all areas of its operations

Statoil may experience increased competition from larger players with stronger financial resources and smaller ones with increased agility and flexibility. Gaining access to commercial resources via licence acquisition, exploration, or development of existing assets is key to ensuring the long-term economic viability of the business and failure to address this could negatively impact future performance.

Technology is a key competitive advantage in Statoil's industry and our competition may be able to invest more in developing or acquiring intellectual property rights to technology that Statoil may require to remain competitive. Should Statoil's innovation and digitalisation lag behind the industry, its performance could be impeded.

Project development and production activities risks

Statoil's development projects and production activities involve many uncertainties and operating risks that can prevent Statoil from realising profits and cause substantial losses

Oil and gas projects may be curtailed, delayed or cancelled for many reasons, including equipment shortages or failures, natural hazards, unexpected drilling conditions or reservoir characteristics, irregularities in geological formations, accidents, mechanical and technical difficulties or challenges due to new technology. This is particularly relevant because of the physical environments in which some of Statoil's projects are situated. Many of Statoil's development and production projects are located in deep waters or other harsh environments or have challenging field characteristics. In US onshore, low regional prices may cause certain areas to be unprofitable and the company may curtail production until prices recover. There is therefore a risk that prolonged low oil and gas prices, combined with the relatively high levels of tax and government take in several jurisdictions, could erode the profitability of some of Statoil's projects.

Strategic objective risks

Statoil faces challenges in achieving its strategic objective of successfully exploiting profitable growth opportunities

Statoil intends to continue to nurture attractive commercial opportunities in order to sustain future growth. This may involve acquisition of new businesses or properties to expand the existing portfolio or to move into new markets. This challenge will grow as global competition for access to new opportunities rises.

Statoil's ability to increase this optionality depends on several factors; including the ability to:

- maintain and impart Statoil's zero-harm safety culture
- identify suitable opportunities
- negotiate favourable terms
- develop new market opportunities or acquire properties or businesses in an agile and efficient way
- effectively integrate acquired properties or businesses into Statoil's operations
- arrange financing, if necessary and
- comply with legal regulations

Statoil anticipates significant investments and costs as it cultivates business opportunities in new and existing markets, and this process may incur or assume unanticipated liabilities, losses or costs associated with assets or businesses acquired. Failure by Statoil to successfully pursue and exploit new business opportunities could result in financial losses and inhibit growth. New projects may have different risk profiles than Statoil's existing portfolio. These and other effects of such acquisitions could result in Statoil having to revise its forecasts either or both with respect to unit production costs and production.

In addition, the pursuit of acquisitions or new business opportunities could divert financial and management resources away from Statoil's day-to-day operations to the integration of acquired operations or properties. Statoil may require additional debt or equity financing to undertake or consummate future acquisitions or projects, and such financing may not be available on terms satisfactory to Statoil, if at all, and it may, in the case of equity, be dilutive to Statoil's earnings per share.

Limited transportation infrastructure risks

The profitability of Statoil's oil and gas production may be affected by limited transportation infrastructure when a field is in a remote location

Statoil's ability to exploit economically any discovered petroleum resources beyond its proved reserves will depend, among other factors, on the availability of the infrastructure required to transport oil and gas to potential buyers at a commercially acceptable price. Oil is transported by vessels, rail or pipelines to refineries, and natural gas is usually transported by pipeline or by vessels (for liquid natural gas) to processing plants and end users. Statoil may not be successful in its efforts to secure transportation and markets for all of its potential production.

International political, social and economic risks

Some of Statoil's international interests are located in regions where political, social and economic instability could adversely impact Statoil's business

Statoil has assets and operations located in diverse regions globally where potentially negative economic, social, and political developments could occur. These political risks and security threats require continuous monitoring. Adverse and hostile actions against Statoil's staff, its facilities, its transportation systems and its digital infrastructure (cybersecurity) may cause harm to people and disrupt Statoil's operations and further business opportunities in these or other regions, lead to a decline in production and otherwise adversely affect Statoil's business. This could have a materially adverse effect on Statoil's operations' results and its financial condition.

International governmental and regulatory framework risks

Statoil's operations are subject to dynamic political and legal factors in the countries in which it operates

Statoil has assets in a number of countries with emerging or transitioning economies that, in part or in whole, lack well-functioning and reliable legal systems, where the enforcement of contractual rights is uncertain or where the governmental and regulatory framework is subject to unexpected change. Statoil's exploration and production activities in these countries are often undertaken together with national oil companies and are subject to a significant degree of state control. In recent years, governments and national oil companies in some regions have begun to exercise greater authority and to impose more stringent conditions on companies engaged in exploration and production activities. Intervention by governments in such countries can take a wide variety of forms, including:

- restrictions on exploration, production, imports and exports
- the awarding or denial of exploration and production interests
- the imposition of specific seismic and/or drilling obligations
- price and exchange controls
- tax or royalty increases, including retroactive claims
- nationalisation or expropriation of Statoil's assets
- unilateral cancellation or modification of Statoil's licence or contractual rights
- the renegotiation of contracts
- payment delays and
- currency exchange restrictions or currency devaluation

The likelihood of these occurrences and their overall effect on Statoil vary greatly from country to country and are hard to predict. If such risks materialise, they could cause Statoil to incur material costs and/or cause Statoil's production to decrease, potentially having a materially adverse effect on Statoil's operations or financial condition.

International tax regimes risks

Statoil is exposed to potentially adverse changes in the tax regimes of each jurisdiction in which Statoil operates

Statoil has business operations in many countries around the world. Changes in the tax laws of the countries in which Statoil operates could have a material adverse effect on its liquidity and results of operations.

Foreign exchange risks

Statoil faces foreign exchange risks that could adversely affect the results of Statoil's operations

Statoil's business faces foreign exchange risks. Statoil has a large percentage of its revenues and cash receipts denominated in USD and sales of gas and refined products are mainly denominated in EUR and GBP. Further, Statoil pays a large portion of its income taxes, and a share of our operating expenses and capital expenditures, in NOK. The majority of Statoil's long term debt has USD exposure.

Trading and supply activities risks

Statoil is exposed to risks relating to trading and supply activities

Statoil is engaged in trading and commercial activities in the physical markets. Statoil also uses financial instruments such as futures, options, over-the-counter (OTC) forward contracts, market swaps and contracts for differences related to crude oil, petroleum products, natural gas and electricity in order to manage price volatility. Statoil also uses financial instruments to manage foreign exchange and interest rate risk. Trading activities involve elements of forecasting, and Statoil bears the risk of market movements, the risk of losses if prices develop contrary to expectations, and the risk of default by counterparties.

Failure to comply with anti-corruption, anti-bribery laws and Statoil Code of Conduct risks

Non-compliance with anti-bribery, anti-corruption and other applicable laws, including failure to meet Statoil's ethical requirements, exposes Statoil to legal liability and damage to its reputation, business and shareholder value

Statoil has activities in countries which present corruption risks and which may have weak legal institutions, lack of control and transparency. In addition, governments play a significant role in the oil and gas sector, through ownership of resources, participation, licensing and local content which leads to a high level of interaction with public officials. Statoil is, through its international activities, subject to anti-corruption and bribery laws in multiple jurisdictions, including the Norwegian Penal code, the US Foreign Corrupt Practices Act and the UK Bribery Act. A violation of any applicable anti-corruption and bribery laws could expose Statoil to investigations from multiple authorities, and any violations of laws may lead to criminal and/or civil liability with substantial fines. Incidents of non-compliance with applicable anti-corruption and bribery laws and regulations and the Statoil Code of Conduct could be damaging to Statoil's reputation, competitiveness and shareholder value.

Inadequate insurance coverage risk

Statoil's insurance coverage may not provide adequate protection

Statoil maintains insurance coverage that includes coverage for physical damage to its oil and gas properties, third-party liability, workers' compensation and employers' liability, general liability, sudden pollution and other coverage. Statoil's insurance coverage includes deductibles that must be met prior to recovery. Statoil's external insurance is subject to caps, exclusions and limitations, and there is no assurance that such coverage will adequately protect Statoil against liability from all potential consequences and damages.

Inefficient operations and lack of new technology risks

Statoil's future performance depends on efficient operations and the ability to develop and deploy new technologies and new products

Our ability to remain efficient, to develop and adapt to new technology, to seek profitable renewable energy and other low-carbon energy solutions, are key success factors for future business. There is a possibility of Statoil not being able to define and implement the necessary changes due to the organisation's capability, external competition or underestimated cost of implementing new technology. Any of these factors may have an adverse effect on Statoil's future business goals.

Failure to secure capable and competent workforce risk

Statoil may fail to secure the right level of workforce competence and capacity over the short and medium term

The uncertainty of the future of the oil industry in light of reduced oil and natural gas prices and climate policy changes, creates a risk in ensuring a robust workforce through industry cycles. The oil industry is a long term business and needs to take a long term perspective on workforce capacity and competence. Given the current extensive change agenda there is a risk that Statoil will fail to secure the right level of workforce competence and capacity.

International sanctions and trade restrictions risks

Statoil's activities may be affected by international sanctions and trade restrictions

Statoil, like other major international energy companies, has a diverse portfolio of projects which may expose its business and financial affairs to political and economic risks, including operations in areas subject to sanctions and international trade restrictions.

Sanctions and trade restrictions are often complex and changes in these laws and regulations can come about on short notice and be hard to predict. For example in 2017 there have been trade sanctions targeting certain activity in Venezuela where Statoil has activities.

While this remains the case, Statoil's business portfolio is evolving and will constantly be subject to review.

New or additional trade sanctions could be imposed on countries where we have business activities. Statoil could in the future decide to take part in new and additional business activity where sanctions and trade restrictions are particularly relevant.

While Statoil remains committed to do business in compliance with sanctions and trade restrictions, there can be no assurance that no Statoil entity, officer, director, employee or agent is not in violation of such laws. Any such violation of applicable laws could result in substantial civil and/or criminal penalties and could materially adversely affect Statoil's business and results of operations or financial condition.

Statoil holds an interest in several on- and offshore oil and gas projects in Russia. Most of these projects result from a strategic cooperation with Rosneft Oil Company (Rosneft) initiated in 2012. In each of these projects, Rosneft holds the majority interest. A minority of the projects are in Arctic offshore and/or deep-water areas. The Norwegian, EU and U.S. sanctions adopted on Russia target several sectors - including the financial and energy sector. Accordingly, certain Russian energy companies have been particularly targeted under the sanctions - including Rosneft. This being the case, the sanctions in place affect the way Statoil conducts its business in the country. Moreover, Statoil's ability to continue to progress its projects in Russia is in part relying on government authorizations as well as the future of sanctions and trade controls. While Statoil continues to pursue its business in Russia within existing sanctions and trade controls, possible future developments could impact Statoil's ability to continue and conclude these projects as earlier envisaged.

In Venezuela, Statoil is a 9,67% shareholder in the mixed company Petrocedeno majority owned by Venezuelan national oil company PDVSA. In addition, Statoil holds a 51% interest in a gas licence offshore Venezuela. During 2017, various sanctions and trade controls have been adopted targeting certain Venezuelan individuals as well as the Government of Venezuela and PDVSA. The sanctions and trade controls in place restrict the way in which Statoil can conduct its business in the country. The current sanctions and trade restrictions, alone or in combination with other factors, could in the future further negatively impact Statoil's position and ability to continue its business projects in Venezuela.

Disclosure Pursuant to Section 13 (r) of the Exchange Act

Statoil is providing the following disclosure pursuant to Section 13(r) of the Exchange Act.

Statoil is a party to agreements with the National Iranian Oil Company (NIOC), namely, a Development Service Contract for South Pars Gas Phases 6, 7 & 8 (offshore part), an Exploration Service Contract for the Anaran Block and an Exploration Service Contract for the Khorramabad Block, which are located in Iran. Statoil's operational obligations under these agreements have terminated and the licences have been abandoned. The cost recovery programme for these contracts was completed in 2012, except for the recovery of tax and obligations to the Social Security Organisation (SSO).

Since 2013, after closing Statoil's office in Iran, Statoil's activity was focused on a final settlement with the Iranian tax and SSO authorities relating to the above-mentioned agreements.

During 2017 Statoil paid the equivalent of USD 0.01 million in tax to Iranian authorities. Also during 2017 Statoil paid the equivalent of USD 713 in stamp duty to Iran Tax Organisation. All payments were made in local currency (Iranian Rials). The funds utilised for these purposes were held by Statoil in EN Bank (Iran). Additionally, NIOC, on behalf of Statoil, in 2017 paid a tax obligation of USD 5.13 million equivalent in Iranian Rial to the local tax authorities. The amount was settled towards historical recoverable costs from NIOC to Statoil.

Statoil has provided information about its Iran related activity to the US State Department as well as to the Norwegian Ministry of Foreign Affairs.

In a letter from the US State Department of 1 November 2010, Statoil was informed that the company was not considered to be a company of concern based on its previous Iran-related activities.

Statoil earned no net profit from the aforementioned 2017 activities. Payments of the above-mentioned nature may also be made in 2018, in relation to Statoil's continued efforts to settle all remaining obligations.

Legal and regulatory risks

Health, safety and environmental laws and regulations risks

Compliance with health, safety and environmental laws and regulations that apply to Statoil's operations could materially increase Statoil's costs. The enactment of such laws and regulations in the future is uncertain.

Statoil incurs, and expects to continue to incur, substantial capital, operating, maintenance and remediation costs relating to compliance with increasingly complex laws and regulations for the protection of the environment and human health and safety, including:

- higher price on greenhouse gas emissions
- costs of preventing, controlling, eliminating or reducing certain types of emissions to air and discharges to the sea
- remedying of environmental contamination and adverse impacts caused by Statoil's activities
- decommissioning obligations and related costs
- compensation of cost related to persons and/or entities claiming damages as a result of Statoil's activities

Statoil`s activity is increasingly subject to statutory strict liability in respect of losses or damage suffered as a result of pollution caused by spills or discharges of petroleum from petroleum facilities.

Compliance with laws, regulations and obligations relating to climate change and other environmental regulations could result in substantial capital expenditure, reduced profitability as a result of changes in operating costs, and adverse effects on revenue generation and strategic growth opportunities. However, more stringent climate change regulations could also represent business opportunities for Statoil. For more information about climate change related legal and regulatory risks, see the risks described under the heading "The transition to a lower carbon economy, and the physical effects of climate change, could impact Statoil's business" in Risks related to our business in Risk Factors in this section 2.7 Corporate.

Statoil's investments in US onshore producing assets will be subject to evolving regulations that could affect these operations and their profitability. In the United States, Federal agencies have taken steps to rescind, delay, or revise regulations seen as overly burdensome to the upstream oil and gas sector, including methane emission controls. Statoil supports Federal regulation of methane emissions and is operating in compliance with all current requirements. To the extent new or revised regulations impose additional compliance or data gathering requirements, Statoil could incur higher operating costs. Statoil has also joined voluntary emission reduction programs (One Future and API's Environmental Partnership) and implemented a climate roadmap to reduce CO2 and methane emissions.

Supervision, regulatory reviews, and financial reporting risks

Statoil conducts business in many countries and its products are marketed and traded worldwide. Statoil is exposed to risk of supervision, review and sanctions for violations of laws and regulations at the supranational, national and local level. These include, among others, laws and regulations relating to financial reporting, taxation, bribery and corruption, securities and commodities trading, fraud, competition and antitrust, safety and the environment, and labour and employment practices. Statoil is exposed to changes in those laws and regulations and to the outcome of any investigations conducted by regulatory and supervisory authorities. Violations of the applicable laws and regulations may lead to legal liability, substantial fines and other sanctions for noncompliance.

Statoil is also exposed to financial review from financial supervisory authorities such as the Norwegian Financial Supervisory Authority (FSA) and the US Securities and Exchange Commission (the SEC). Reviews performed by these authorities could result in changes to previously published financial statements and future accounting practices. In addition, failure in our external reporting to report data accurately and in compliance with applicable standards could result in regulatory action, legal liability and damage to our reputation.

Statoil is listed on both the Oslo Børs and New York Stock Exchange (NYSE), and is registered with the SEC. Statoil is required to comply with the continuing obligations of these regulatory authorities, and violation of these obligations may result in legal liability, the imposition of fines and other sanctions.

The Norwegian Petroleum Supervisor (PSA) supervises all aspects of Statoil's operations, from exploration drilling through development and operation, to cessation and removal. Its regulatory authority covers the whole NCS as well as petroleum-related plants on land in Norway. Statoil is exposed to supervision from PSA, and as its business grows internationally other regulators, and such supervision could result in audit reports, orders and investigations.

The EU-wide quantity of carbon allowances issued each year under the Emission Trading Scheme (ETS) for greenhouse gas emission allowances began to decrease in a linear manner in 2013. The ETS can have a positive or negative impact on Statoil, depending on the price of carbon, which will consequently have an impact on the development of gas-fired power generation in the EU. Until now, the carbon price has been too low to replace coal with gas fired generation capacity. This effect has been worsened by heavy subsidising of renewables which has caused gas fired power plants to shut down. Current EU climate and energy policies do not address this problem, but there is a tendency towards more market based subsidies in the new guidelines on environment and energy aid.

Failure to remediate a material weakness relating to operational effectiveness in our Internal Control over Financial Reporting could cause our internal control over financial reporting to be ineffective again in the future.

Management and external auditor have concluded that Statoil's internal control over financial reporting as of 31 December 2017 was not effective due to the existence of a material weakness in our controls and procedures for the identification, assessment and timely and appropriate communication to the Board Audit Committee of questions or concerns (including allegations of misconduct) raised by employees in connection with termination of their employment relating to issues that could potentially have a material impact on our Consolidated financial statements and internal controls over financial reporting (otherwise than through Statoil's external Ethics help line established by the Board Audit Committee). The allegations were subject to thorough investigations with external advisors, and no material misstatements were identified. There has been no effect on the 2017 Consolidated financial statements, or earlier periods, related to this matter.

Failure to remediate the material weakness could cause our internal control over financial reporting to be ineffective again in the future and could cause investors to lose confidence in our reported financial information and potentially impact our share price. See section 3.10 Controls and procedures.

Political and economic policies of the Norwegian State risks

Political and economic policies of the Norwegian State could affect Statoil's business

The Norwegian State plays an active role in the management of NCS hydrocarbon resources. In addition to its direct participation in petroleum activities through the State's direct financial interest (SDFI) and its indirect impact through legislation, such as tax and environmental laws and regulations, the Norwegian State, among other things, awards licences for exploration, production and transportation, approves exploration and development projects and applications for production rates for individual fields and may, if important public interests are at stake, also instruct Statoil and other oil companies to reduce petroleum production. Furthermore, in the production licences in which the SDFI holds an interest, the Norwegian State has the power to direct petroleum licences' actions in certain circumstances.

If the Norwegian State were to take additional action under its activities on the NCS or to change laws, regulations, policies or practices relating to the oil and gas industry, Statoil's NCS exploration, development and production activities and the results of its operations could be affected.

Risks related to state ownership

This section discusses some of the potential risks relating to Statoil's business that could derive from the Norwegian State's majority ownership and from Statoil's involvement in the SDFI.

Statoil's shareholder alignment risks

The interests of Statoil's majority shareholder, the Norwegian State, may not always be aligned with the interests of Statoil's other shareholders, and this may affect Statoil's decisions relating to the NCS

The Norwegian Parliament, known as the Storting, and the Norwegian State have resolved that the Norwegian State's shares in Statoil and the SDFI's interest in NCS licences must be managed in accordance with a coordinated ownership strategy for the Norwegian State's oil and gas interests. Under this strategy, the Norwegian State has required Statoil to continue to market the Norwegian State's oil and gas together with Statoil's own oil and gas as a single economic unit.

Pursuant to this coordinated ownership strategy, the Norwegian State requires Statoil, in its activities on the NCS, to take account of the Norwegian State's interests in all decisions that may affect the development and marketing of Statoil's own and the Norwegian State's oil and gas.

The Norwegian State directly held 67% of Statoil's ordinary shares as of 31 December 2017. Based on the Norwegian Public Limited Companies Act, the Norwegian State effectively has the power to influence the outcome of any vote of shareholders due to the percentage of Statoil's shares it owns, including amending its articles of association and electing all non-employee members of the corporate assembly. The employees are entitled to be represented by up to one-third of the members of the board of directors and one third of the corporate assembly.

The corporate assembly is responsible for electing Statoil's board of directors. It also makes recommendations to the general meeting concerning the board of directors' proposals relating to the company's annual accounts, balance sheet, allocation of profit and coverage of loss. The interests of the Norwegian State in deciding these and other matters and the factors it considers when casting its votes, especially under the coordinated ownership strategy for the SDFI and Statoil's shares held by the Norwegian State, could be different from the interests of Statoil's other shareholders.
If the Norwegian State's coordinated ownership strategy is not implemented and pursued in the future, then Statoil's mandate to continue to sell the Norwegian State's oil and gas together with its own oil and gas as a single economic unit is likely to be prejudiced. Loss of the mandate to sell the SDFI's oil and gas could have an adverse effect on Statoil's position in the markets in which it operates.

For further information about the mandate to sell the Norwegian State's oil and gas, see SDFI oil and gas marketing and sale in section 2.7 Corporate.

RISK MANAGEMENT

Statoil's overall risk management includes identifying, evaluating and managing risk in all its activities to ensure safe operations and to achieve Statoil's corporate goals.

Statoil bases its risk management on an enterprise risk management (ERM) approach in order to achieve optimal corporate solutions. This includes identifying, evaluating and managing risk in all its activities. Risk is defined as a deviation from a specified reference value and the uncertainty associated with it. A positive deviation is an upside risk, while a negative deviation is a downside risk. The reference value is most commonly a forecast, percentile or target. In Statoil's ERM approach:

- focus is on the value impact for Statoil
- risk is managed to make sure that Statoil's operations are safe and in compliance with Statoil's requirements and

Risk is managed in the business line and is an integral part of any manager's responsibility. However, to ensure optimal corporate solutions, some risks are managed at corporate level. This includes oil and natural gas price risks, interest and currency risks, risk dimension in the strategy work, prioritisation processes and capital structure discussions.

Statoil's corporate risk committee, which is headed by the chief financial officer and includes representatives from the principal business segments, is responsible for defining, developing and reviewing Statoil's risk policies and methodology. The chief financial officer, assisted by the committee, is also responsible for overseeing and developing Statoil's Enterprise Risk Management and proposing appropriate measures to adjust risk at the corporate level.

Managing operational risk

Statoil manages risk in order to ensure safe operations and to achieve its corporate goals in compliance with its requirements

- All risks related to activities in Statoil's value chain, which denotes the value that is added in each step - from access, maturing, project execution and operation to market. In addition to the economic impact these risks could have on Statoil's cash flows, Statoil has a strong focus on avoiding HSE and integrity-related incidents (such as accidents, fraud and corruption). Most of the risks are managed by the principal business area line managers. Some operational risks are insurable and insured by Statoil's captive insurance company operating in the Norwegian and international insurance markets
- Statoil's risk management process is based on ISO31000 Risk management – principles and guidelines. The process provides a standardised framework and methodology for assessing and managing risk. A standardisation of the process across Statoil ASA and its subsidiaries allows for comparable risk levels and efficiency in decisions and it enables the organisation to create sustainable value while seeking to avoid incidents. The process seeks to ensure

that risks are identified, analysed, evaluated and managed. Risk adjusting actions are subject to a cost benefit evaluation (except certain safety related risks which could be subject to specific regulations)

Managing financial risk

The following section describes how Statoil manages the market risks to which it is exposed.

Statoil's business activities expose the group to financial risk. Using a holistic approach, correlations between the most important market risks and the natural hedges inherent in Statoil's portfolio are taken into account. This approach allows Statoil to reduce the number of risk management transactions and avoid sub-optimisation.

Statoil's activities expose the company to financial risks such as market risks (including commodity price risk, interest rate risk and currency risk), liquidity risk and credit risk. For a discussion of financial risk management see note 5 Financial risk management in the Consolidated financial statements.

Statoil has developed policies aimed at managing the financial volatility inherent in some of the business exposures. In accordance with these policies, Statoil enters into various financial and commodity-based transactions (derivatives). The business areas for marketing and trading commodities are responsible for managing commodity-based price risks within mandates. Interest, liquidity, liability and credit risks are managed by the company's central finance department. All major strategic transactions are required to be coordinated at corporate level.

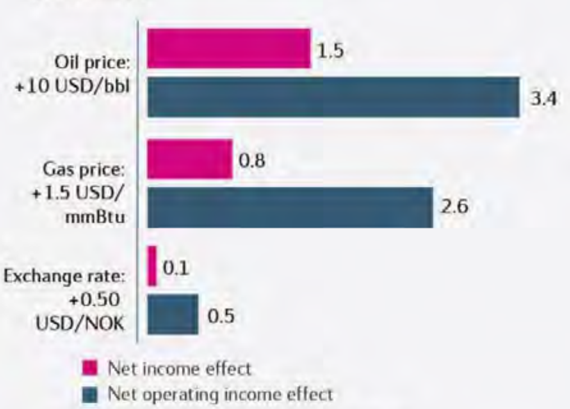
The main factors influencing Statoil's operational and financial results include: the level of crude oil and natural gas prices, trends in the exchange rates between mainly the USD, EUR, GBP and NOK; Statoil's oil and natural gas production volumes, which in turn depend on entitlement volumes under PSAs and available petroleum reserves, and Statoil's own, as well as partners' expertise and cooperation in recovering oil and natural gas from those reserves; and changes in Statoil's portfolio of assets due to acquisitions and disposals.

Statoil's operational and financial results will also be affected by trends in the international oil industry, including possible actions by governments and other regulatory authorities in the jurisdictions in which Statoil operates, or possible or continued actions by members of the Organization of Petroleum Exporting Countries (OPEC) and/or other producing nations that affect price levels and volumes, refining margins, the cost of oilfield services, supplies and equipment, competition for exploration opportunities and operatorships, and deregulation of the natural gas markets, all of which may cause substantial changes to existing market structures and to the overall level and volatility of prices and price differentials.

The following table shows the yearly averages for quoted Brent Blend crude oil prices, natural gas average sales prices, refining reference margins and the USD/NOK exchange rates for 2017, 2016 and 2015.

Yearly average	2017	2016	2015
Average Brent oil price (USD/bbl)	54.2	43.7	52.4
Average invoiced gas prices - Europe (USD/mmBtu)	5.6	5.2	7.1
Refining reference margin (USD/bbl)	6.3	4.8	8.0
USD/NOK average daily exchange rate	8.3	8.4	8.1

Indicative effects on 2018 results *
(USD billion)



* *Based on USD/NOK exchange rate of 8.25*

The sensitivity analysis shows the estimated 12-month effects on net operating income and net income from change in parameters. The sensitivities do not have the same probability.

The illustration shows the indicative full-year effect on the financial result for 2018 given certain changes in the crude oil price, natural gas contract prices and the USD/NOK exchange rate. The estimated price sensitivity of Statoil's financial results to each of the factors has been estimated based on the assumption that all other factors remain unchanged. The estimated indicative effects of the negative changes in these factors are not expected to be materially asymmetric to the effects shown in the illustration.

Significant downward adjustments of Statoil's commodity price assumptions could result in impairments on certain producing and development assets in the portfolio. See note 10 Property, plant and equipment to the Consolidated financial statements for sensitivity analysis related to impairments.

Statoil assesses oil and gas price hedging opportunities on a regular basis as a tool to increase financial robustness and strengthen flexibility.

Fluctuating foreign exchange rates can also have a significant impact on the operating results. Statoil's revenues and cash flows are mainly denominated in or driven by USD, while a large portion of the operating expenses, capital expenditures and income taxes payable accrue in NOK. Statoil seeks to manage this currency mismatch by issuing or swapping non-current financial debt in USD. This long-term funding policy is an integrated part of our total risk management programme. Statoil also engages in foreign currency management in order to cover the non-USD needs, which are primarily in NOK. In general, an increase in the value of USD in relation to NOK can be expected to increase Statoil's reported earnings.

Historically, Statoil's revenues have largely been generated by the production of oil and natural gas on the NCS. Norway imposes a 78% marginal tax rate on income from offshore oil and natural gas activities (a symmetrical tax system). For further information, see section 2.7 Corporate under Taxation of Statoil.

Statoil's earnings volatility is moderated as a result of the significant proportion of its Norwegian offshore income that is subject to a 78% tax rate in profitable periods, and the significant tax assets generated by its Norwegian offshore operations in any loss-making periods. The basis for taxation is 3% of the dividend received, which is subject to the standard income tax rate (reduced from 24% in 2017 to 23% in 2018). Dividends received from Norwegian companies and from similar companies resident in the EEA for tax purposes, in which the recipient holds more than 90% of the shares and votes, are fully exempt from tax. Dividends from companies resident in the EEA that are not similar to Norwegian companies, companies in low-tax countries and portfolio investments outside the EEA will, under certain circumstances, be subject to the standard income tax rate (reduced from 24% in 2017 to 23% in 2018) based on the full amounts received.

Disclosures about market risk

Statoil uses financial instruments to manage commodity price risks, interest rate risks, currency risks and liquidity risks. Significant amounts of assets and liabilities are accounted for as financial instruments.

See note 25 Financial instruments: fair value measurement and sensitivity analysis of market risk in the Consolidated financial statements, for details of the nature and extent of such positions, and for qualitative and quantitative disclosures of the risks associated with these instruments.

2.12 SAFETY, SECURITY AND SUSTAINABILITY

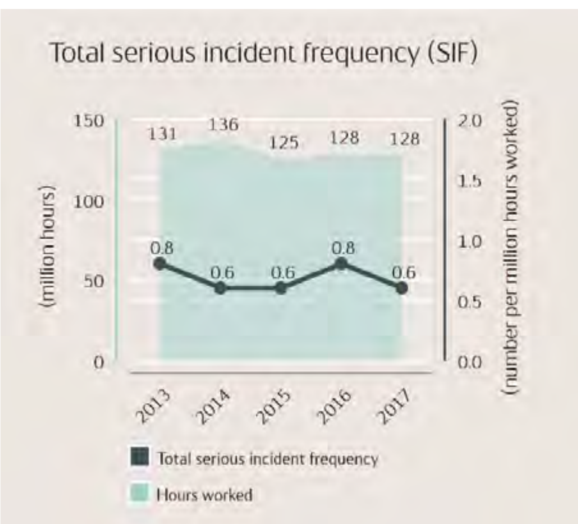
Safety and security

Safety and security risks are particularly relevant for the oil and gas industry, because our core activities involve the risk of accidents and incidents. We work with flammable hydrocarbons at high pressure, often in harsh offshore environments and at height or depths. Oil spills are a major risk we need to handle in both our offshore and onshore oil and gas operations. To this end we have established a global oil spill response system, which includes close collaboration with industry peers and national and local communities.

We focus on identifying safety and security risks and having in place procedures and work processes to control them. Our ambition is to be an industry leader in ensuring safe and secure operations that protect our people, the environment, the communities we work with and our assets.

Our total serious incident frequency (SIF), including both actual and potential incidents, was 0.6 incidents per million hours worked, a decrease compared to 0.8 in 2016. We had no serious incidents with major accident potential in 2017.

Total recordable injuries per million hours worked (TRIF) was 2.8 in 2017, compared to 2.7[6] in 2016.



In 2017, the total number of serious oil and gas leakages (with a leakage rate above 0.1 kg per second) was 16, down from 18 in 2016. None of the serious oil and gas leakages ignited. We experienced a 50% reduction (i.e. from 6 to 3) in the number oil and gas leakages in our onshore operations in Norway and Denmark compared to 2016. The number outside of Norway and Denmark remained at a similar level in 2017 as for 2016.

For the period 2012 to 2016 our performance showed a reduction in the number of oil spills per year. For 2017 the number of oil spills increased to 206 compared to 146 in 2016. The main contributor to this increase was our onshore activities in the US. Three initiatives have been mounted to reduce the number of leaks and spills: a programme to proactively identify and prevent leaks and spills; enhanced control of technical integrity before start-up/restart at facilities; and strengthening of suppliers' commitment through training and follow-up.

The total volume of oil spills decreased from 61 m³ in 2016 to 34 m³ in 2017. The largest spill was an 8 m³ leak of gasoil from a pressure relief valve at the Kalundborg refinery in Denmark of which 5 m³ were collected by secondary barriers.

Security is an important consideration for the energy industry and we assess security threats and risks on a continuous basis to achieve effective and proportionate security risk management. We had no serious security incidents in 2017.

In 2017, we launched the "I am Safety" programme to further strengthen safety and security performance. The focus is on strengthening personal commitment by increasing engagement, visibility and awareness of individually relevant safety and security factors.

Health and work environment

Statoil is committed to providing a healthy working environment for its employees. Systematic efforts are made to design and improve working conditions in order to prevent occupational injuries, work-related illness and sickness absence, due to both physical and psychosocial risk factors.

The most significant risk factors related to the work environment are noise, ergonomics, chemical risk as well as psychosocial conditions.

The sickness absence rate for Statoil ASA employees increased slightly from 4.3% in 2016 to 4.6% in 2017.

Climate change

Statoil supports the ambition set by the Paris Climate Agreement of December 2015 to limit the average global temperature rise to well below two degrees Celsius compared to pre-industrial levels by 2100.

The transition towards a lower carbon economy is underway. During 2017, Statoil embedded our response to climate change into our sharpened business strategy. Statoil aims to develop a high value, lower carbon portfolio that will be robust to future fluctuations in energy prices and potentially higher carbon costs.

Statoil's Climate roadmap, launched in March 2017, explains how Statoil expects to deliver on the strategic ambition to create a low carbon advantage and develop the business by 2030 in support of the ambitions in the Paris climate agreement and of the United Nations Sustainable Development Goals 7 (Ensure access to affordable, reliable sustainable energy for all) and 13 (Take urgent action to combat climate change and its impacts).

To implement the Climate roadmap, Statoil focuses on three broad areas:

- realising a lower carbon oil and gas portfolio
- building an industrial position in new energy
- stress testing and transparent reporting

[6] The TRIF for 2016 has been restated due to misreporting of man hours worked. It was previously reported as 2.9

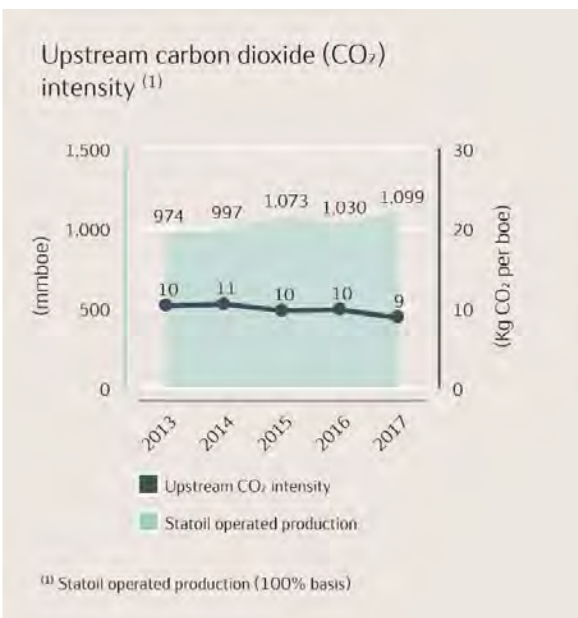
Statoil applies an internal carbon price of minimum USD 50 per tonne carbon dioxide equivalents from 2020 to all potential projects and investments. In countries where the actual carbon price is higher than USD 50 (e.g. in Norway), Statoil uses the actual price and predicted future carbon price in the investment analysis.

During 2017, climate principles were further embedded into the decision-making process by including a corporate-wide requirement for the assessment of the carbon intensity and emission reduction opportunities for all potential projects and investments.

The work to reduce CO_2 emissions and emission intensity from Statoil-operated assets continued, and a plan of action for international partner operated activities was initiated.

Statoil aims to achieve, by 2030, annual carbon dioxide (CO_2) emissions reductions of 3 million tonnes compared to emission levels at the start of 2017[7] through continued energy efficiency measures and use of low carbon energy sources.

2017 performance
Statoil's upstream CO_2 intensity improved from 10kg/boe in 2016 to 9kg/boe in 2017, mainly due to our exit from our activity in the Canadian oils sands and increased export of gas from the electrified Troll field. Total CO_2 emissions increased slightly from 14.8 million tonnes in 2016 to 14.9 million tonnes in 2017.



Direct greenhouse gas emissions (so called Scope 1 emissions) remained at the same level in 2017 as for 2016, at 15.4 million tonnes CO_2 equivalents. Greenhouse gas emissions include carbon CO_2 and methane (CH_4), where CO_2 constitutes the largest part. Methane (CH_4) emissions decreased from 24.2 thousand tonnes in 2016 to 22.2 thousand tonnes in 2017.

[7] Statoil is aiming to achieve, by 2030, annual CO2 emissions that are 3 million tonnes less than they would have been, had no reduction measures been implemented between 2017 and 2030.

Several CO_2 emission reduction initiatives were implemented in 2017, amounting to a total of around 360,000 tonnes of CO_2. The largest contributor was energy efficiency measurements at Hammerfest LNG.

Growth opportunities for Statoil within renewables and new energy solutions include both commercial investments and research and development (R&D). Statoil is engaged in offshore wind projects, carbon capture and storage, solar and hydrogen projects. Statoil's capital expenditure in new energy solutions during 2017 was in line with our ambition. In 2017 approximately 18% of Statoil's expenditure on R&D efforts addressed energy efficiency, carbon capture and renewables.

Climate-related risk and disclosure: The Task Force on Climate-related Financial Disclosures
The Climate roadmap serves to enhance our disclosure on climate-related business risks, in line with the recommendations put forward by the Financial Stability Board's Task Force on Climate-related Financial Disclosure (TCFD), which is supported by Statoil. In 2017, we joined the TCFD Preparer Forum for oil and gas companies to engage with the Task Force on efficient and feasible ways to implement the TCFD recommendation for disclosure.

Executing the company's climate ambition is a line responsibility. However, the Corporate Sustainability Unit is responsible for monitoring progress on the Climate roadmap and reporting on sustainability and climate risk issues and performance at group level, to the corporate executive committee and the board of directors.

Statoil regularly assesses climate-related business risk, whether political, regulatory, market, physical or related to reputation, as part of the enterprise risk management process. This includes assessment of both upsides and downsides. Statoil uses tools such as internal carbon pricing, scenario analysis and sensitivity analysis of the project portfolio against various oil and gas price assumptions. We monitor technology developments and changes in regulation and assess how these might impact the oil and gas price, the cost of developing new assets and the demand for oil and gas and opportunities in renewable energy and low carbon solutions.

A detailed overview of climate-related risk factors, and the results of stress testing our portfolio against the International Energy Agency (IEA) scenarios, are provided in section 2.11 Risk review under Risk Factors in this report.

On a regular basis, the corporate executive committee and board of directors review and monitor climate change-related business risks and opportunities. In 2017, the board discussed climate-related issues in four out of eight meetings (including one risk update), and the safety, sustainability and ethics committee discussed climate-related issues in all of the five committee meetings held.

Stakeholder engagement and collaboration
Climate change is complex and requires global and cross sector cooperation. We are committed to working with our suppliers, customers, governments and peers to find innovative and commercially viable ways to reduce emissions across the oil and gas value chain. We are members of the CEO-led Oil and Gas Climate Initiative. Through our participation in the government-led Climate and Clean Air Coalition's Oil and Gas Methane Partnership we continued our efforts to systematically address methane emissions and report on annual progress.

We work with governments and other organisations to support climate and energy policies that encourage fuel switching from coal to gas, growth in renewables, the deployment of carbon capture usage and storage and other low carbon solutions, and efficient production, distribution and use of energy globally. We have also teamed up with global peers through OGCI to help shape the industry's climate response.

Through the World Bank led Carbon Pricing Leadership Coalition and our membership of the International Emission Trading Association we continued our advocacy for a price on carbon during 2017. And through our membership in the OGCI and World Business Council for Sustainable Development we expressed our continued support for the ambitions of the Paris climate agreement. Statoil is an endorser of the World Bank Global Gas Flaring Reduction Partnership and we have made a commitment to contribute to stopping routine flaring by 2030 through the World Bank Zero Routine Flaring by 2030 initiative.

Environmental impact and resource efficiency
Statoil is committed to using resources efficiently and responsible management of waste, emissions to air and impacts on ecosystems. This reduces the impact on the local environment and can also save costs.

Responsible water management is important for Statoil. Total fresh water withdrawal increased from 13.5 million cubic metres in 2016 to 14.8 million cubic metres in 2017. The main contributor to this increase was the higher number of wells fracked, relative to 2016, in our US onshore shale and tight oil assets. We work actively to improve water efficiency in our onshore activities in North America, through means such as water recycling and substituting fresh water with brackish water.

Nitrogen oxide emissions were 40 thousand tonnes in 2017, up from 39 thousand tonnes in 2016. The increased drilling and well stimulation activity was the main contributor to this increase. Sulphur oxide emissions were 1.7 thousand tonnes, down from 1.8 thousand tonnes in 2016. The main contributor to this reduction was the exit, during 2017, from our Canadian oil sands projects activities. Total emissions of non-methane volatile organic compounds remained at the same level in 2017 as in 2016, at 49 thousand tonnes.

Statoil is concerned with valuing and protecting biodiversity and ecosystems and follows precautionary principles to minimise potential negative effects of the company's activities. Statoil supports research programmes to increase knowledge about ecosystems and biodiversity and collaborates with industry peers to share knowledge and develop tools for biodiversity management. In addition, Statoil works with our suppliers to minimise invasive aquatic species and reduce risks pertaining to accidental spills related to shipping transportation.

During 2017 we saw a 32% reduction in the volume of hazardous waste generated, from 438 thousand tonnes in 2016 to 296 thousand tonnes in 2017. The main contributor to this volume decrease was less drilling and well start-up activities, on the Norwegian continental shelf, at locations without treatment facilities for oil contaminated water. As such less untreated oil contaminated water was sent to shore for treatment. The hazardous waste recovery rate was slightly lower in 2017, at 83% compared to 84% in 2016.

For our US onshore operations in 2017, 105 thousand tonnes of drill cuttings and solid waste were sent to landfill, and around 4.7 million cubic meters of produced and flow back water was directed to deep well disposal. These waste types are exempt from US hazardous waste regulations.

In 2017 the volume of non-hazardous waste generated for all Statoil operated assets was 34 thousand tonnes, compared to 50 tonnes in 2016. The recovery rate was 71% in 2017 compared to 56% in 2016. The decrease in the volume generated and the increase in the recovery rate is mainly attributed to the divestment of our oil sands projects in Canada.

Regular discharges of oil to water were 1.2 thousand tonnes in 2017, compared to 1.4 in 2016. This reduction is attributed to a combination of turnaround activity during 2017, reducing production levels, and operational measures at several assets that have reduced the volume of produced water discharged to sea, and reduced the oil in water content of the discharged water.

Working with suppliers
Statoil is committed to using suppliers who operate in accordance with Statoil's values and who maintain high standards of safety, security and sustainability. These aspects are incorporated in all phases of the procurement process. Potential suppliers must meet Statoil's minimum requirements to qualify as a supplier, including those related to safety, security and sustainability.

Statoil expect our suppliers to comply with applicable laws, respect internationally recognised human rights and adhere to ethical standards which are consistent with our ethical requirements, when working for Statoil. During 2017 a new compliance annex, covering human rights and anti-corruption standards for suppliers, was introduced for use in new contracts. Potential suppliers for contracts valued at more than USD 800 thousand are, in addition, required to sign Statoil's Supplier Declaration, which establishes minimum requirements for ethics, anti-corruption, environment, health, safety, respect for human rights, and for further promoting these requirements among their own suppliers. Potential suppliers are also screened for integrity risk, in accordance with our procedures for integrity due diligence.

Human rights
Statoil seeks to conduct its business in a way that is consistent with the UN Guiding Principles on Business and Human Rights (the UN Guiding Principles), the ten UN Global Compact principles and the Voluntary Principles on Security and Human Rights. Statoil is committed to respecting internationally recognised human rights as laid out in the International Bill of Human Rights, the International Labour Organization's 1998 Declaration on Fundamental Rights and Principles at Work, and applicable standards of international humanitarian law.

Labour rights and working conditions for our workforce and suppliers, human rights of individuals in communities and human rights in security arrangements are the three broad focus areas for human rights for Statoil's activities.

Human rights aspects are integrated into relevant internal management processes, tools and training. On-going activities, business relationships and new business opportunities are assessed for potential human rights impacts and aspects, following a risk-based approach.

During 2017, Statoil continued to focus on strengthening our health and safety performance. Statoil also continued efforts to strengthen the diversity of its workforce, taking into account gender, nationality, background, ethnicity, competence, age and preferences. Work also continued on the strengthening of Statoil's centralised governance of remuneration and benefits to ensure they are both fair and attractive.

In 2017, Statoil continued the strengthening of its processes for managing human rights in our supply chain and on raising awareness through training. We conducted 41 verifications across 16 countries in 2017. Over 260 employees attended classroom training on human rights in the supply chain. A compliance appendix, covering human rights and anti-corruption standards for suppliers, was introduced for use in new contracts. Work was started on supporting guidance that will be introduced in 2018.

In 2017, Statoil's Human Rights Steering Committee (HRSC), responsible for overseeing the development and implementation of Statoil's human rights policy, closely followed the ongoing implementation efforts and provided guidance on human rights related reporting requirements.

Statoil recognises that a company-wide commitment to respect human rights requires continuous training and awareness raising in order to embed good practices throughout the organisation. Over 500 staff and consultants registered for the human rights e-learning awareness training during 2017. Other training initiatives, during 2017, included human rights focus sessions on the agenda of various management meetings, reaching a total of 42 leaders across the company. Statoil also started the development, during 2017, of a human rights training course to be used company-wide, that can be tailored for use with specific target groups.

The context of Statoil's operations requires that security services are engaged to safeguard Statoil's people and property. Particular focus is needed to ensure respect for human rights in security arrangements, in jurisdictions where security services are not well regulated or security personnel are not adequately trained. Statoil follows international standards of good practices in security and human rights. Statoil's commitment to the Voluntary Principles on Security and Human Rights is reflected in policies and procedures for risk assessment, deployment, training and follow-up of private and public security providers.

Transparency, ethics and anti-corruption

Transparency is a cornerstone of good governance. It is embodied in our corporate values. Transparency allows business to prosper in a predictable and competitive environment and enables society to hold governments and businesses accountable. Statoil supports and promotes effective, transparent and accountable management of wealth derived from the extractives industries.

Statoil supports and engages in global transparency initiatives through its membership in the Extractive Industries Transparency Initiative (EITI), the United Nations Global Compact Anti-Corruption Working Group and the World Economic Forum's Partnering Against Corruption Initiative (PACI), and supports Transparency International Norway. In 2017 Statoil actively participated in the Norwegian national EITI multi-stakeholder group and on the international EITI board through its board member. Statoil also engaged with local and national organisations in other EITI implementing countries, and provided USD 60,000 in financial support to the international EITI. Statoil also participated in a multi-stakeholder working group organised by Transparency International in preparation of the report Ten Anti-corruption principles for state-owned enterprises, published in November 2017.

Statoil believes that doing business in an ethical and transparent manner is a prerequisite for sustainable business. Statoil has a zero-tolerance policy towards all forms of corruption. This policy is embedded across the company through Statoil's values, the Code of Conduct and the Anti-corruption compliance programme. The Code of Conduct (the Code) prohibits all forms of corruption and bribery, including facilitation payments.

The Code reflects Statoil's values and its commitment to high ethical standards in business activities. It describes the company's requirements in areas such as anti-corruption, anti-money laundering, fair competition, human rights and a non-discriminatory working environment with equal opportunities. It applies to all Statoil employees, board members, hired personnel and those performing services for or on behalf of Statoil.

Statoil seeks to work with others who share the company's commitment to business integrity and who have codes of conduct consistent with the Code. Before entering into a new business relationship, or extending an existing one, the relationship has to satisfy Statoil's integrity due diligence requirements. Statoil's due diligence vetting process is risk-based, allowing us to dedicate resources where we see potential concerns. In joint ventures and business partnerships that are not controlled by Statoil, Statoil encourages the adoption of ethics and anti-corruption policies, procedures and controls that are consistent with Statoil's own standards.

All Statoil employees have to confirm annually that they understand and will comply with the Code. The purpose of such confirmation is to remind each individual employee about the duty to comply with Statoil's values and ethical requirements. Failure to comply with the Code may be met with disciplinary measures, including termination of the contractual relationship with Statoil.

Statoil's Anti-Corruption Compliance Programme summarises the standards, requirements and procedures implemented to comply with applicable laws and regulations and to uphold our high standard of doing business ethically. A global network of compliance officers is integrated into our business activities to ensure that appropriate consideration is given to ethics and anti-corruption in Statoil's business activities, regardless of where they take place.

We expect and encourage anyone who becomes aware of a possible violation of the Code, Statoil policies or applicable law, to report their concerns in a prompt and responsible manner. Indeed, concerns can be reported through internal channels or through the publicly available Ethics Helpline, which allows for anonymous reporting. The number and types of cases from the helpline is reported quarterly to the board of directors. In 2017, we received 107 cases through the Ethics Helpline, compared to 51 in 2016.

Other relevant reports

More information about Statoil's policies and approach taken to manage safety and sustainability performance is available in Statoil ASA's 2017 Sustainability report.

2.13 OUR PEOPLE

In Statoil we work together to shape the future of energy in a partnership between the organisation and the individual. We all apply our skills and personal commitment to help Statoil towards achieving our vision.

Statoil aims to offer challenging and meaningful job opportunities that attract and retain the right people. Through our engagement, creativity and collaboration, we aim to build a better Statoil for tomorrow. We are committed to creating a caring and collaborative working environment, promoting diversity, inclusion and equal opportunities for all employees.

Empowered people are a key enabler for realising Statoil's sharpened strategy. In 2017, we started to implement our new people and leadership strategy designed to ensure we have the right skills and capabilities in place going forward. The foundation for the strategy's guiding principles is our commitment to safety supported by our people processes; a consistent presence in talent markets; a company culture which embraces digitalisation; building flexibility within the workforce and growing diversity.

In 2017, we enhanced our performance management approach to further develop a performance development culture at Statoil. Our main goal is to build a stronger culture of continuous feedback, coaching and development. Instead of focusing on backward looking annual ratings, we are focused on continuous real-time feedback, strength based development and reward and talent outcomes based on multiple inputs. People@Statoil is our common process for people development, deployment, performance, and reward. It is an integrated part of performance development and applies to all employees.

Learning and development is at the core of Statoil. We encourage our employees to take responsibility for their own learning and development, continuously build new skills and share knowledge. Our focus on people development has continued throughout 2017 and the activity level has been closely monitored in our people development key performance indicator (KPI) at both corporate and business area levels. This KPI sets the ambition level for both our corporate university and internal job market.

Our corporate university is our platform for learning. It enables the company to build the capabilities needed to deliver on its strategy, continuously improve, and take the lead in developing leadership and technology. Recognising that digitalisation and automation will transform the way we work in the coming years we established a new digital academy, in our corporate university, to build digital skills across the organisation. In addition, our platform for learning and content delivery has been upgraded with the implementation of a new learning management system, supporting our ambition of making engaging and virtual learning available for all. The average training days for employees in 2017 increased to 3.9 (from 3.2 in 2016) for formal learning. Our ambition is to increase the learning activity level further to support the development of our people.

	Number of employees			Women		
Permanent employees and percentage of women in the Statoil group	2017	2016	2015	2017	2016	2015
Norway	17,632	18,034	18,977	30%	30%	30%
Rest of Europe	947	838	855	25%	28%	29%
Africa	78	78	98	37%	36%	35%
Asia	69	73	97	52%	59%	36%
North America	1,174	1,230	1,265	33%	35%	35%
South America	345	286	289	35%	37%	38%
Total	20,245	20,539	21,581	30%	31%	30%
Non-OECD	599	541	590	37%	40%	40%

Total workforce by region, employment type and new hires in the Statoil group in 2017

Geographical Region	Permanent employees	Consultants	Total Workforce[1)]	Consultants (%)	Part time (%)	New hires
Norway	17,632	493	18,125	3%	3%	213
Rest of Europe	947	84	1,031	8%	2%	168
Africa	78	2	80	3%	0%	7
Asia	69	4	73	5%	0%	7
North America	1,174	201	1,375	15%	0%	231
South America	345	4	349	1%	0%	79
Total	20,245	788	21,033	4%	3%	705
Non-OECD	599	10	609	2%	NA	106

1) Contractor personnel, defined as third-party service providers who work at our onshore and offshore operations, are not included. These were roughly estimated to be around 30,000 in 2017.

EMPLOYEES IN STATOIL

The Statoil group employs 20,245 employees. Of these, approximately 17,600 are employed in Norway and approximately 2,600 outside Norway.

Statoil works systematically to build a diverse workforce by attracting, recruiting, developing and retaining people of every gender and different nationalities and age groups across all types of positions. In 2017, 19% of employees and 23% of our managerial staff held nationalities other than Norwegian. Outside Norway, Statoil aims to increase the number of people and managers who are locally recruited and to reduce the long-term use of expats in business operations. In 2017, 71% of new hires in Statoil were non-Norwegians and 27% were women.

We believe that the global competition for talent in key development areas will grow over the coming years. We remain the employer of choice for engineering students and professionals in Norway, according to the annual Norwegian Universum Employer Attractiveness ranking.

During 2017 we continued to strengthen our entry level talent programmes. Our corporate graduate programme was revised into a two-year accelerated development programme spanning all geographies and professions, encompassing an introduction programme, networking activities, learning events and field trips, rotations and mentoring. This programme accelerates the development of young professionals and builds a strong understanding of Statoil's value chains. In 2017, we recruited 69 graduates (of which 26 were women). At the end of 2017 we had 143 graduates (including 57 women) in Statoil.

In addition, our company-wide annual intake of apprentices reflects our long-term commitment to the education and training of young technicians and operators in our industry. In 2017, we awarded 139 apprenticeships, of which 45 were to women. The total number of apprentices at year end was 291 (including 85 women). In 2017, Statoil launched a subsurface internship programme pilot. This offers 30 newly graduated candidates a one year stay with us to build experience and help the transition from studies to working life.

Our annual Global People Survey (GPS), which addresses issues relevant to employee's well-being and performance had a noticeably high response rate of 88% in 2017. Employees' responses reflected continued engagement for working with Statoil[8], with a score of 75 out of 100, compared to 72 out of 100 in 2016.[9] This score exceeded the corporate engagement KPI target. Employees reported an overall score of 71 out of 100 for competence and people development which is a good score. Our ambition is to strengthen this even further in 2018.

Our people performance data relates to permanent employees in our direct employment. Statoil defines consultants as contracted personnel that are mainly based in our offices. Temporary employees and contractor personnel, defined as third party service providers to our onshore and offshore operations, are not included in the table. These were roughly estimated to be around 30,000 in 2017. The information about people policies applies to Statoil ASA and its subsidiaries.

Equal opportunities

We are committed to building a workplace that promotes diversity and aspire for Statoil to be an inclusive workplace where all individuals can share their perspectives, be themselves and develop and thrive in a safe working environment.

During 2017, we continued to analyse the diversity of our pipeline, at all levels and in all locations, to ensure continued improvement in our representation. In 2017, the overall percentage of women in the company was 30%. The percentage of women in the board of directors is 40% (33% among the employee representatives and 43% among members elected by the shareholders). In the corporate executive committee, the female representation remained at 27%. The percentage of women in leadership positions was 28% in 2017.

[8] The overall people engagement scoring reflects employee satisfaction, enthusiasm and pride associated with working for Statoil. The scoring is based on feedback received through an annual survey sent out to all employees.

[9] During 2017 the Global People Survey (GPS) questionnaire scale was changed from 1-6 to 1-10 and the reporting index was changed to 0-100. Historical data have therefore been converted to enable trend reporting.

We continue to pay close attention to male-dominated positions and discipline areas, and in 2017 the proportion of female engineers remained stable at 27% in Statoil ASA. We will work actively to increase these numbers in 2018 through our development programmes, such as the local talent programme, as part of a broader diversity and inclusion agenda.

Unions and representatives

We believe in involving our people and their appropriate representatives in the development of the company. We respect our employees' right to freedom of association and thereby their right to negotiate and cooperate through relevant representative bodies. The specific ways in which we involve our employees and/or their appropriate representatives in business and organisational issues may vary according to local laws and practices in specific geographical locations.

In Statoil ASA, 73% of the employees in the parent company are members of a trade union. Work councils and working environment committees are established where required by law or agreement.

In Norway, the formal basis for collaboration with labour unions is established in the Basic Agreements between the Confederation of Norwegian Enterprise (NHO) and the corresponding respective national labour confederations (unions). We have local collective wage agreements with five trade unions in Statoil ASA.

The European Works Council continues to be an important forum for collaboration between the company and our European employees.

Statoil promotes good employee and industrial relations practices through various networks and forums, including IndustriALL Global Union.

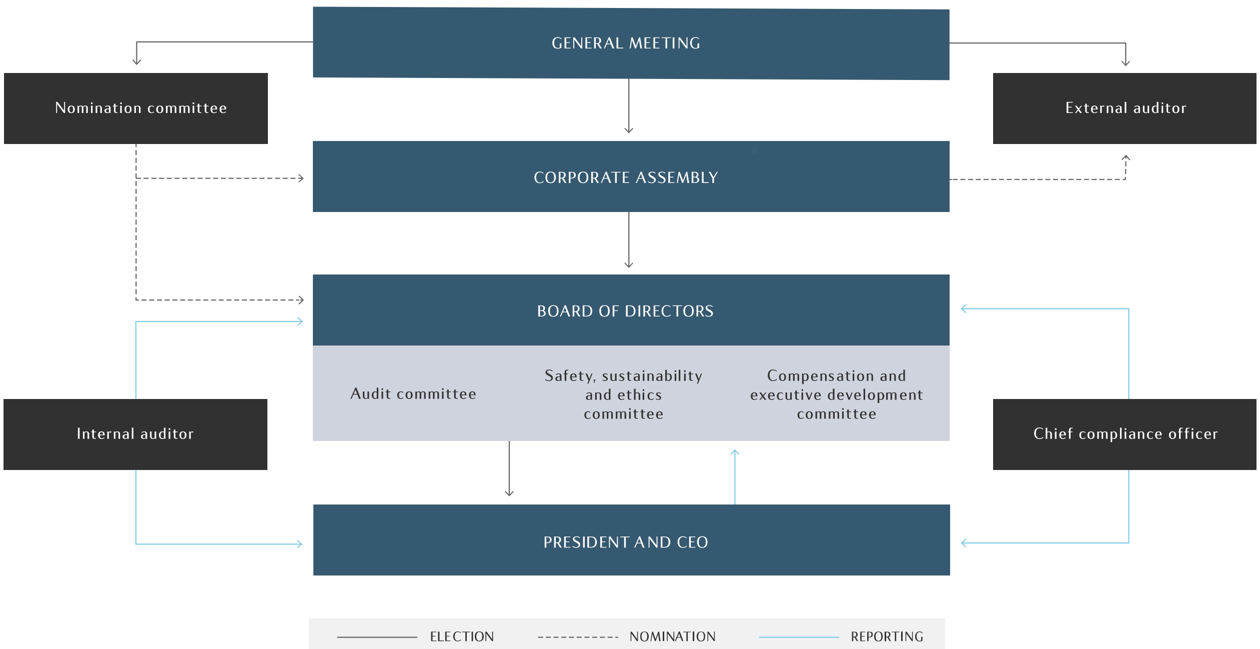
In 2017, we continued to have close cooperation with employee representatives in Norway discussing strategic matters such as changes to our people performance evaluation, organisational changes and ongoing safety improvement work. Such dialogues provide valuable perspectives and better decisions.

More information about Statoil's people is available in the 2017 Sustainability Report.

Governance

BOARD STATEMENT ON CORPORATE GOVERNANCE

Nomination and elections in Statoil ASA



Statoil's board of directors actively adheres to good corporate governance standards and will at all times ensure that Statoil either complies with the Norwegian Code of Practice for Corporate Governance (the "Code") or explains possible deviations from the Code. The topic of corporate governance is subject to regular assessment and discussion by the board, which has also considered the text of this chapter at a board meeting. The Code can be found at www.nues.no.

The Code covers 15 topics, and the board statement covers each of these topics and describes Statoil's adherence to the Code. The statement describes the foundation and principles for Statoil's corporate governance structure. More detailed factual information can be found on our website, in our Annual Report on Form 20-F and in our Sustainability Report.

The information concerning corporate governance required to be disclosed according to the Norwegian Accounting Act Section 3-3b is included in this statement as follows:

1. "An overview of the recommendations and regulations concerning corporate governance that the enterprise is subject to or otherwise chooses to comply with": Described in this introduction as well as in section 3.1 Implementation and reporting below.
2. "Information on where the recommendations and regulations mentioned in no 1 are available to the public": Described in this introduction.
3. "Reasons for any non-conformance with recommendations and regulations mentioned in no 1"; There are two deviations from the Code's recommendations, one in section 3.6 General meeting of shareholders and the other in section 3.14 Take-overs. The reasons for these deviations are described under the respective sections of this statement.
4. "A description of the main elements in the enterprise's, and for entities that prepare Consolidated financial statements, also the Group's (if relevant) internal control and risk management systems linked to the financial reporting process": Described in section 3.10 Risk management and internal control.
5. "Articles of Association which entirely or partly expand or depart from provisions of Chapter 5 of the Public Limited Liability Companies Act": Described in section 3.6 General meeting of shareholders.
6. "The composition of the board of directors, the Corporate Assembly, the Committee of Shareholders' Representatives and the Control Committee and any working committees related to these bodies, as well as a description of the main instructions and guidelines that apply to the work of the bodies and any committees": Described in section 3.8 Corporate assembly, board of directors and management and section 3.9 The work of the board of directors.
7. "Articles of Association governing the appointment and replacement of Directors": Described in section 3.8 Corporate assembly, board of directors and management under the sub-heading Board of directors.
8. "Articles of Association and authorisations empowering the board of directors to decide that the enterprise is to buy back or issue its own shares or equity certificates": Described in section 3.3 Equity and dividends.

3.1 IMPLEMENTATION AND REPORTING

Introduction

Statoil ASA is a Norwegian-registered public limited liability company with its primary listing on Oslo Børs, and the foundation for the Statoil group's governance structure is Norwegian law. Our American Depositary Receipts representing our ordinary shares are also listed on the New York Stock Exchange (NYSE), and we are subject to the listing requirements of NYSE and the requirements of the US Securities and Exchange Commission.

The board of directors focuses on maintaining a high standard of corporate governance in line with Norwegian and international standards of best practice. Good corporate governance is a prerequisite for a sound and sustainable company, and our corporate governance is based on openness and equal treatment of our shareholders. Our governing structures and controls help to ensure that we run our business in a justifiable and profitable manner for the benefit of our employees, shareholders, partners, customers and society. We continuously consider prevailing international standards of best practice when defining and implementing company policies, as we believe that there is a clear link between high-quality governance and the creation of shareholder value.

At Statoil, the way we deliver is as important as what we deliver. The Statoil Book, which addresses all Statoil employees, sets the standards for our behaviour, our delivery and our leadership.

Our values guide the behaviour of all Statoil employees. Our corporate values are "courageous", "open", "collaborative" and "caring". Both our values and ethics are treated as an integral part of our business activities. Our Code of Conduct is further described under the heading Risk management and internal control.

We also focus on managing the impacts of our activities on people, society and the environment, in line with our corporate policies for health, safety, security, human rights, ethics and sustainability, including corporate social responsibility (CSR). Areas covered by these policies include labour standards, transparency and anti-corruption, local hiring and procurement, health and safety, the working environment, security and broader environmental issues.

Our governance and management system is further elaborated on our website at www.statoil.com/cg, where shareholders and other stakeholders can explore any topic of particular interest in more detail and easily navigate to related documentation.

Statoil's objective and principles

Statoil's objective is to create long-term value for its shareholders through the exploration for and production, transportation, refining and marketing of petroleum and petroleum-derived products and other forms of energy.

In pursuing its corporate objective, Statoil is committed to the highest standard of governance and to cultivating a values-based performance culture that rewards exemplary ethical practices, respect for the environment and personal and corporate integrity. Statoil believes that there is a link between high-quality governance and the creation of shareholder value.

The work of the board of directors is based on the existence of a clearly defined division of roles and responsibilities between the shareholders, the board of directors and the company's management.

Statoil's governing structures and controls help to ensure that Statoil runs its business in a profitable manner for the benefit of shareholders, employees and other stakeholders in the societies in which Statoil operates.

The following principles underline Statoil's approach to corporate governance:

- All shareholders will be treated equally
- Statoil will ensure that all shareholders have access to up-to-date, reliable and relevant information about its activities
- Statoil will have a board of directors that is independent (as defined by Norwegian standards) of the group's management. The board focuses on preventing conflicts of interest between shareholders, the board of directors and the company's management
- The board of directors will base its work on the principles for good corporate governance applicable at all times

Corporate governance in Statoil is subject to regular review and discussion by the board of directors.

Articles of association

Statoil's current articles of association were adopted at the annual general meeting of shareholders on 14 May 2013, and last changed on 6 February 2018 following a share capital increase in connection to Statoil's scrip dividend programme.

Summary of Statoil's articles of association:

Name of the company
The registered name is Statoil ASA. Statoil is a Norwegian public limited company.

Registered office
Statoil's registered office is in Stavanger, Norway, registered with the Norwegian Register of Business Enterprises under number 923 609 016.

Objective of the company
The objective of Statoil is, either by itself or through participation in or together with other companies, to engage in the exploration, production, transportation, refining and marketing of petroleum and petroleum-derived products, and other forms of energy, as well as other business.

Share capital
Statoil's share capital is NOK 8,346,653,047.50 divided into 3,338,661,219 ordinary shares.

Nominal value of shares
The nominal value of each ordinary share is NOK 2.50.

Board of directors
Statoil's articles of association provide that the board of directors shall consist of nine to 11 directors. The board, including the chair and the deputy chair, shall be elected by the corporate assembly for a period of up to two years.

Corporate assembly
Statoil has a corporate assembly comprising 18 members who are normally elected for a term of two years. The general meeting elects 12 members with four deputy members, and six members with deputy members are elected by and among the employees.

General meetings of shareholders
Statoil's annual general meeting is held no later than 30 June each year. The meeting will consider the annual report and accounts, including the distribution of any dividend, and any other matters required by law or the articles of association.

Documents relating to matters to be dealt with at general meetings do not need to be sent to all shareholders if the documents are accessible on Statoil's website. A shareholder may nevertheless request that such documents be sent to him/her.

Shareholders may vote in writing, including through electronic communication, for a period before the general meeting. In order to practise advance voting, the board of directors must stipulate applicable guidelines. Statoil's board of directors adopted guidelines for such advance voting in March 2012, and these guidelines are described in the notices of the annual general meetings.

Marketing of petroleum on behalf of the Norwegian State
Statoil's articles of association provide that Statoil is responsible for marketing and selling petroleum produced under the SDFI's shares in production licences on the Norwegian continental shelf as well as petroleum received by the Norwegian State paid as royalty together with its own production. Statoil's general meeting adopted an instruction in respect of such marketing on 25 May 2001, as most recently amended by authorisation of the annual general meeting on 11 May 2017.

Nomination committee
The tasks of the nomination committee are to make recommendations to the general meeting for the election of shareholder-elected members and deputy members of the corporate assembly, the remuneration of members of the corporate assembly, the election and remuneration of the nomination committee, and to make recommendations to the corporate assembly for the election of shareholder-elected members of the board of directors and remuneration of the members of the board of directors and the election of the chair and deputy chair of the corporate assembly. The general meeting may adopt instructions for the nomination committee.

The articles of association are available at www.statoil.com/articlesofassociation.

Compliance with NYSE listing rules

Statoil's primary listing is on the Oslo Børs, but Statoil is also registered as a foreign private issuer with the US Securities and Exchange Commission and listed on the New York Stock Exchange.

American Depositary Receipts represent the company's ordinary shares listed on the New York Stock Exchange (NYSE). While Statoil's corporate governance practices follow the requirements of Norwegian law, Statoil is also subject to the NYSE's listing rules.

As a foreign private issuer, Statoil is exempted from most of the NYSE corporate governance standards that domestic US companies must comply with. However, Statoil is required to disclose any significant ways in which its corporate governance practices differ from those applicable to domestic US companies under the NYSE rules. A statement of differences is set out below:

Corporate governance guidelines
The NYSE rules require domestic US companies to adopt and disclose corporate governance guidelines. Statoil's corporate governance principles are developed by the management and the board of directors, in accordance with the Norwegian Code of Practice for Corporate Governance and applicable law. Oversight of the board of directors and management is exercised by the corporate assembly.

Director independence
The NYSE rules require domestic US companies to have a majority of "independent directors". The NYSE definition of an "independent director" sets out five specific tests of independence and also requires an affirmative determination by the board of directors that the director has no material relationship with the company.

Pursuant to Norwegian company law, Statoil's board of directors consists of members elected by shareholders and employees. Statoil's board of directors has determined that, in its judgment, all of the shareholder-elected directors are independent. In making its determinations of independence, the board focuses inter alia on there not being any conflicts of interest between shareholders, the board of directors and the company's management. It does not strictly make its determination based on the NYSE's five specific tests, but take into consideration all relevant circumstances which may in the board's view affect the directors' independence. The directors elected from among Statoil's employees would not be considered independent under the NYSE rules because they are employees of Statoil. None of the employee-elected directors are an executive officer of the company.

For further information about the board of directors, see 3.8 Corporate assembly, board of directors and management.

Board committees
Pursuant to Norwegian company law, managing the company is the responsibility of the board of directors. Statoil has an audit committee, a safety, sustainability and ethics committee and a compensation and executive development committee. They are responsible for preparing certain matters for the board of directors. The audit committee and the compensation and executive development committee operate pursuant to charters that are broadly comparable to the form required by the NYSE rules. They report on a regular basis to, and are subject to, continuous oversight by the board of directors. For further information about the board's sub-committees, see the section The work of the board of directors.

Statoil complies with the NYSE rule regarding the obligation to have an audit committee that meets the requirements of Rule 10A-3 of the US Securities Exchange Act of 1934.

The members of Statoil's audit committee include an employee-elected director. Statoil relies on the exemption provided for in Rule 10A-3(b)(1)(iv)(C) from the independence requirements of the US Securities Exchange Act of 1934 with respect to the employee-elected director. Statoil does not believe that its reliance on this exemption will materially adversely affect the ability of the audit committee to act independently or to satisfy the other requirements of Rule 10A-3 relating to audit committees. The other members of the audit committee meet the independence requirements under Rule 10A-3.

Among other things, the audit committee evaluates the qualifications and independence of the company's external auditor. However, in accordance with Norwegian law, the auditor is elected by the annual general meeting of the company's shareholders.

Statoil does not have a nominating/corporate governance sub-committee formed from its board of directors. Instead, the roles prescribed for a nominating/corporate governance committee under the NYSE rules are principally carried out by the corporate assembly and the nomination committee which are elected by the general meeting of shareholders. NYSE rules require the compensation committee of US companies to comprise independent directors under the NYSE rules, recommend senior management remuneration and make a determination on the independence of advisors when engaging them. Statoil, as foreign private issuer, is exempt from complying with these rules and is permitted to follow its home country regulations. Statoil considers all its compensation committee members to be independent (under Statoil's framework which, as discussed above, is not identical to that of NYSE). Statoil's compensation committee makes recommendations to the board about management remuneration, including that of the CEO. The compensation committee assesses its own performance and has the authority to hire external advisors. The nomination committee, which is elected by the general meeting of shareholders, recommends to the corporate assembly the candidates and remuneration of the board of directors. Also, the nomination committee recommends to the general meeting of shareholders the candidates and remuneration of the corporate assembly and the nomination committee.

Shareholder approval of equity compensation plans
The NYSE rules require that, with limited exemptions, all equity compensation plans must be subject to a shareholder vote. Under Norwegian company law, although the issuance of shares and authority to buy back company shares must be approved by Statoil's annual general meeting of shareholders, the approval of equity compensation plans is normally reserved for the board of directors.

Deviations from the Code: None

3.2 BUSINESS

Statoil is an international energy company headquartered in Stavanger, Norway. The company has business operations in more than 30 countries and 20,245 employees worldwide. Statoil ASA is a public limited liability company organised under the laws of Norway and subject to the provisions of the Norwegian Public Limited Liability Companies Act. The Norwegian State is the largest shareholder in Statoil ASA, with a direct ownership interest of 67%. Statoil is the leading operator on the NCS and is also expanding its international activities.

Statoil is among the world's largest net sellers of crude oil and condensate and is the second-largest supplier of natural gas to the European market. Statoil also has substantial processing and refining operations, contributes to the development of new energy resources, has on-going offshore wind activities internationally and is at the forefront of the implementation of technology for carbon capture and storage (CCS).

Statoil's objective is defined in the articles of association (www.statoil.com/articlesofassociation). We shall, either on our own or through participation in or together with other companies, engage in exploration, production, transportation, refining and marketing of petroleum and petroleum-derived products, and other forms of energy, as well as other business.

Statoil's vision is to "shape the future of energy". The board and the administration have formulated a corporate strategy to deliver on this vision. It has been translated into concrete objectives and targets to align strategy execution across the company.

To succeed going forward in turning our vision into reality, Statoil pursues a strategy around the following pillars:

- Norwegian continental shelf - Build on unique position to maximise and develop long-term value
- International Oil & Gas - Deepen core areas and develop growth options
- New Energy Solutions - Create a material new industrial position
- Midstream and Marketing - Secure premium market access and grow value creation through cycles

To enable successful execution of the strategy, safe and secure operations always comes first. Statoil will deliver through empowered people leveraging technology, digitalisation and innovation. Through stakeholder engagement, Statoil will build trust and respond actively to challenges and opportunities. In pursuing our vision and strategy, we are committed to the highest standard of governance and to cultivating a values-based performance culture that rewards exemplary ethical practices, respect for the environment and personal and corporate integrity. We believe that there is a link between high-quality governance and the creation of shareholder value.

Deviations from the Code: None

3.3 EQUITY AND DIVIDENDS

Shareholders' equity
The company's shareholders' equity at 31 December 2017 amounted to USD 39,861 million (excluding USD 24 million in non-controlling interest, minority interest), equivalent to 35.9% of the company's total assets. The board of directors considers this to be satisfactory given the company's requirement for financial robustness in relation to its expressed goals, strategy and risk profile.

Any increase of the company's share capital must be mandated by the general meeting. If a mandate was to be granted to the board of directors to increase the company's share capital, such mandate would be restricted to a defined purpose. If the general meeting is to consider mandates to the board of directors for the issue of shares for different purposes, each mandate would be considered separately by the general meeting.

Dividend policy
It is Statoil's ambition to grow the annual cash dividend, measured in USD per share, in line with long-term underlying earnings. Statoil announces dividends on a quarterly basis. The board approves first to

third quarter interim dividends based on an authorisation from the general meeting, while the annual general meeting approves the fourth quarter (and total annual) dividend based on a proposal from the board. When deciding the interim dividends and recommending the total annual dividend level, the board will take into consideration expected cash flow, capital expenditure plans, financing requirements and appropriate financial flexibility. In addition to cash dividend, Statoil might buy back shares as part of total distribution of capital to the shareholders.

The shareholders at the AGM may vote to reduce, but may not increase, the fourth quarter dividend proposed by the board of directors. Statoil announces dividend payments in connection with quarterly results. Payment of quarterly dividends is expected to take place approximately four months after the announcement of each quarterly dividend.

Statoil declares dividends in USD. Dividends in NOK per share will be calculated and communicated four business days after record date for shareholders at Oslo Børs.

The board of directors will propose to the annual general meeting a dividend of USD 0.23 per share for the fourth quarter of 2017.

Buy-back of own shares for subsequent annulment
In addition to a cash dividend, Statoil may buy back shares as part of the total distribution of capital to the shareholders. In order to be able to buy back shares the board of directors will need an authorisation from the general meeting. Such authorisation must be renewed on an annual basis. At the annual general meeting on 11 May 2017, the board of directors was authorised to acquire in the market, on behalf of the company, Statoil ASA shares with a nominal value of up to NOK 187,500,000. Within minimum and maximum prices of NOK 50 and NOK 500, respectively, the board of directors were authorised to decide at what price and at what time such acquisition should take place. Own shares acquired pursuant to this authorisation could only be used for annulment through a reduction of the company's share capital, pursuant to the Public Limited Companies Act section 12-1. It was also a precondition for the repurchase and the annulment of own shares that the Norwegian state's ownership interest in Statoil ASA was not changed. In order to achieve this, a proposal for the redemption of a proportion of the state's shares, so that the state's ownership interest in the company remains unchanged, would also be put forward at the later general meeting which was to decide the annulment of the repurchased shares. The authorisation remains valid until the next annual general meeting, but no longer than until 30 June 2018. As of 14 March 2018, the board of directors has not used this authorisation to buy back own shares for subsequent annulment.

Purchase of own shares for use in the share savings programme
Since 2004, Statoil has had a share savings plan for its employees. The purpose of this plan is to strengthen the business culture and encourage loyalty through employees becoming part-owners of the company. The annual general meeting annually authorises the board of directors to acquire Statoil shares in the market in order to continue implementation of the employees share savings plan. The authorisation remains valid until the next annual general meeting, but no longer than until 30 June the following year.

On 11 May 2017, the board was authorised on behalf of the company to acquire Statoil ASA shares for a total nominal value of up to NOK 35,000,000 for use in the share savings plan. This authorisation remains valid until the next general meeting, but not beyond 30 June 2018.

Deviations from the Code: None

3.4 EQUAL TREATMENT OF SHAREHOLDERS AND TRANSACTIONS WITH CLOSE ASSOCIATES

Equal treatment of all shareholders is a core governance principle in Statoil. Statoil has one class of shares, and each share confers one vote at the general meeting. The articles of association contain no restrictions on voting rights and all shares have equal rights. The nominal value of each share is NOK 2.50. The repurchase of own shares for use in the share savings programme for employees (or, if applicable, for subsequent cancellation) is carried out through the Oslo Børs.

The Norwegian State as majority owner
The Norwegian State is the majority shareholder of Statoil and also holds major investments in other Norwegian companies. As of 31 December 2017 the Norwegian State had an ownership interest in Statoil of 67% (excluding Folketrygdfondet's (Norwegian national insurance fund) ownership interest of 3.3%). This ownership structure means that Statoil participates in transactions with many parties that are under a common ownership structure and therefore meet the definition of a related party. All transactions are considered to be on an arm's length basis. The State's ownership interest in Statoil is managed by the Norwegian Ministry of Petroleum and Energy.

The Norwegian State's ownership policy is that the principles in the Norwegian Code of Practice for Corporate Governance will apply to state ownership and the Government has stated that it expects companies in which the State has ownership interests to adhere to the Code. The principles are presented in the State's annual ownership reports.

Contact between the State as owner and Statoil takes place in the same manner as for other institutional investors. In all matters in which the State acts in its capacity as shareholder, exchanges with the company are based on information that is available to all shareholders. We ensure that, in any interaction between the Norwegian State and Statoil, a distinction is drawn between the State's different roles.

The State has no appointed board members or members of the corporate assembly in Statoil. As majority shareholder, the State has appointed a member of Statoil's nomination committee.

Sale of the State's oil and gas
Pursuant to Statoil's articles of association, Statoil markets and sells the Norwegian State's share of oil and gas production from the Norwegian continental shelf together with its own production. The Norwegian State has a common ownership strategy aimed at maximising the total value of its ownership interests in Statoil and its own oil and gas interests. This is incorporated in the marketing instruction, which obliges Statoil, in its activities on the Norwegian continental shelf, to emphasise these overall interests in decisions

that may be of significance to the implementation of the sales arrangements.

The state-owned company Petoro AS handles commercial matters relating to the Norwegian State's direct involvement in petroleum activities on the Norwegian continental shelf and pertaining activities.

Other transactions
In relation to its ordinary business operations such as pipeline transport, gas storage and processing of petroleum products, Statoil also has regular transactions with certain entities in which Statoil has ownership interests. Such transactions are carried out on an arm's length basis.

Requirements for board members and management
It follows from our Code of Conduct, which applies to both management, employees and board members, that individuals must behave impartially in all business dealings and not give other companies, organisations or individuals improper advantages. The importance of openness is underlined, and any situations that might lead to an actual or perceived conflict of interest should be discussed with the individual's leader. All external directorships or other material assignments held or carried out by Statoil employees must be approved by Statoil.

The board's rules of procedures state that members of the board and the chief executive officer may not participate in the discussion or decision of issues which are of special personal importance to them, or to any closely-related party, so that the individual must be regarded as having a major personal or special financial interest in the matter. Each board member and the chief executive officer are individually responsible for ensuring that they are not disqualified from discussing any particular matter. Members of the board are obliged to disclose any interests they themselves or their closely-related parties may have in the outcome of a particular issue. The board must approve any agreement between the company and a member of the board or the chief executive officer. The board must also approve any agreement between the company and a third party in which a member of the board or the chief executive officer may have a special interest. Each member of the board shall also continually assess whether there are circumstances which could undermine the general confidence in the board member's independence. It is incumbent on each board member to be especially vigilant when making such assessments in connection with the board's handling of transactions, investments and strategic decisions. The board member shall immediately notify the chair of the board if such circumstances are present or arise and the chair of the board will determine how the matter will be dealt with.

Deviations from the Code: None

3.5 FREELY NEGOTIABLE SHARES

Statoil's primary listing is on the Oslo Børs. Our American Depositary Receipts (ADRs) are traded on the New York Stock Exchange. Each Statoil ADR represents one underlying ordinary share.

Statoil's articles of association contain no form of restriction on the negotiability of its shares and the shares and ADRs are freely negotiable.

Deviations from the Code: None

3.6 GENERAL MEETING OF SHAREHOLDERS

The general meeting of shareholders is Statoil's supreme corporate body. It serves as a democratic and effective forum for interaction between the company's shareholders, board of directors and management.

The next annual general meeting (AGM) is scheduled for 15 May 2018 in Stavanger, Norway, with simultaneous transmission by webcast through our website. The AGM is conducted in Norwegian, with simultaneous English translation during the webcast. At Statoil's AGM on 11 May 2017, 76.80% of the share capital was represented either by advance voting, in person or by proxy.

The main framework for convening and holding Statoil's AGM is as follows:
Pursuant to Statoil's articles of association, the AGM must be held by the end of June each year. Notice of the meeting and documents relating to the AGM are published on Statoil's website and notice is sent to all shareholders with known addresses at least 21 days prior to the meeting. All shareholders who are registered in the Norwegian Central Securities Depository (VPS) will receive an invitation to the AGM. Other documents relating to Statoil's AGMs will be made available on Statoil's website. A shareholder may nevertheless request that documents that relate to matters to be dealt with at the AGM be sent to him/her.

Shareholders are entitled to have their proposals dealt with at the AGM if the proposal has been submitted in writing to the board of directors in sufficient time to enable it to be included in the notice of meeting, i.e. no later than 28 days before the meeting. Shareholders who are unable to attend may vote by proxy.

As described in the notice of the general meeting, shareholders may vote in writing, including through electronic communication, for a period before the general meeting.

The AGM is normally opened and chaired by the chair of the corporate assembly. If there is a dispute concerning individual matters and the chair of the corporate assembly belongs to one of the disputing parties, or is for some other reason not perceived as being impartial, another person will be appointed to chair the AGM. This is in order to ensure impartiality in relation to the matters to be considered. As Statoil has a large number of shareholders with a wide geographic distribution, Statoil offers shareholders the opportunity to follow the AGM by webcast.

The following matters are decided at the AGM:

- Approval of the board of directors' report, the financial statements and any dividend proposed by the board of directors and recommended by the corporate assembly
- Election of the shareholders' representatives to the corporate assembly and approval of the corporate assembly's fees
- Election of the nomination committee and approval of the nomination committee's fees
- Election of the external auditor and approval of the auditor's fee
- Any other matters listed in the notice convening the AGM

All shares carry an equal right to vote at general meetings. Resolutions at general meetings are normally passed by simple majority. However, Norwegian company law requires a qualified majority for certain resolutions, including resolutions to waive preferential rights in connection with any share issue, approval of a merger or demerger, amendment of the articles of association or authorisation to increase or reduce the share capital. Such matters require the approval of at least two-thirds of the aggregate number of votes cast as well as two-thirds of the share capital represented at the general meeting.

If shares are registered by a nominee in the Norwegian Central Securities Depositary (VPS), cf. section 4-10 of the Norwegian Public Limited Liability Companies Act, and the beneficial shareholder wants to vote for their shares, the beneficial shareholder must re-register the shares in a separate VPS account in their own name prior to the general meeting. If the holder can prove that such steps have been taken and that the holder has a de facto shareholder interest in the company, the company will allow the shareholder to vote for the shares. Decisions regarding voting rights for shareholders and proxy holders are made by the person opening the meeting, whose decisions may be reversed by the general meeting by simple majority vote.

The minutes of the AGM are made available on Statoil's website immediately after the AGM.

As regards to extraordinary general meetings (EGM), an EGM will be held in order to consider and decide a specific matter if demanded by the corporate assembly, the chair of the corporate assembly, the auditor or shareholders representing at least 5% of the share capital. The board must ensure that an EGM is held within a month of such demand being submitted.

In the following, certain types of resolutions by the general meeting of shareholders are outlined:

New share issues

If Statoil issues any new shares, including bonus shares, the articles of association must be amended. This requires the same majority as other amendments to the articles of association. In addition, under Norwegian law, the shareholders have a preferential right to subscribe for new shares issued by Statoil. The preferential right to subscribe for an issue may be waived by a resolution of a general meeting passed by the same percentage majority as required to approve amendments to the articles of association. The general meeting may, with a majority as described above, authorise the board of directors to issue new shares, and to waive the preferential rights of shareholders in connection with such share issues. Such authorisation may be effective for a maximum of two years, and the par value of the shares to be issued may not exceed 50% of the nominal share capital when the authorisation was granted.

The issuing of shares through the exercise of preferential rights to holders who are citizens or residents of the USA may require Statoil to file a registration statement in the USA under US securities laws. If Statoil decides not to file a registration statement, these holders may not be able to exercise their preferential rights.

Right of redemption and repurchase of shares

Statoil's articles of association do not authorise the redemption of shares. In the absence of authorisation, the redemption of shares may nonetheless be decided upon by a general meeting of shareholders by a two-thirds majority on certain conditions. However, such share redemption would, for all practical purposes, depend on the consent of all shareholders whose shares are redeemed.

A Norwegian company may purchase its own shares if authorisation to do so has been granted by a general meeting with the approval of at least two-thirds of the aggregate number of votes cast as well as two-thirds of the share capital represented at the general meeting. The aggregate par value of such treasury shares held by the company must not exceed 10% of the company's share capital, and treasury shares may only be acquired if, according to the most recently adopted balance sheet, the company's distributable equity exceeds the consideration to be paid for the shares. Pursuant to Norwegian law, authorisation by the general meeting cannot be granted for a period exceeding 18 months.

Distribution of assets on liquidation

Under Norwegian law, a company may be wound up by a resolution of the company's shareholders at a general meeting passed by both a two-thirds majority of the aggregate votes cast and a two-thirds majority of the aggregate share capital represented at the general meeting. The shares are ranked equally in the event of a return on capital by the company upon winding up or otherwise.

Deviations from the Code:

The Code recommends that the board of directors, the nomination committee and the company's auditor are present at the general meetings. Statoil has not deemed it necessary to require the presence of all members of the board of directors and the nomination committee. The chair of the board, our external auditor, the chair of the nomination committee, as well as the chair of the corporate assembly, the CEO and other members of management, are, however, always present at general meetings.

3.7 NOMINATION COMMITTEE

Pursuant to Statoil's articles of association, the nomination committee shall consist of four members who are shareholders or representatives of shareholders. The duties of the nomination committee are set forth in the articles of association, and the instructions for the committee are adopted by the general meeting of shareholders.

The duties of the nomination committee are to submit recommendations to:

- The annual general meeting for the election of shareholder-elected members and deputy members of the corporate assembly, and the remuneration of members of the corporate assembly
- The annual general meeting for the election and remuneration of members of the nomination committee
- The corporate assembly for the election of shareholder-elected members of the board of directors and remuneration of the members of the board of directors and
- The corporate assembly for the election of the chair and deputy chair of the corporate assembly

The nomination committee would like to ensure that the shareholders' views are taken into consideration when candidates to the governing bodies of Statoil ASA are proposed. The nomination committee invites in writing Statoil's largest shareholders to propose shareholder-elected candidates of the corporate assembly and the board of directors, as well as members of the nomination committee. The shareholders are also invited to provide input to the nomination committee in respect of the composition and competence of Statoil's governing bodies in light of Statoil's strategies and challenges going forward. The deadline for providing input is normally set to early January in order to secure that the response is taken into account in the upcoming nominations. In addition, all shareholders have an opportunity to submit proposals through an electronic mailbox as described on Statoil's website. In the board nomination process, the board shares with the nomination committee the results from the annual, normally externally facilitated board evaluation with input from both management and the board. Separate meetings are held between the nomination committee and each board member, including employee-elected board members. The chair of the board and the chief executive officer are invited, without having the right to vote, to attend at least one meeting of the nomination committee before it makes its final recommendations. The committee regularly utilises external expertise in its work.

The members of the nomination committee are elected by the annual general meeting. The chair of the nomination committee and one other member are elected from among the shareholder-elected members of the corporate assembly. Members of the nomination committee are normally elected for a term of two years.

Personal deputy members for one or more of the nomination committee's members may be elected in accordance with the same criteria as described above. A deputy member normally only meets for the permanent member if the appointment of that member terminates before the term of office has expired.

Statoil's nomination committee consists of the following members as per 31 December 2017 and are elected for the period up to the annual general meeting in 2018:

- Tone Lunde Bakker (chair), General Manager, Swedbank Norge (also chair of Statoil's corporate assembly)
- Tom Rathke, Advisor to the CEO of DNB ASA
- Elisabeth Berge, Secretary General, Norwegian Ministry of Petroleum and Energy (personal deputy for Elisabeth Berge is Bjørn Ståle Haavik, Director, Department of Economic and Administrative Affairs, at the Norwegian Ministry of Petroleum and Energy)
- Jarle Roth, CEO of Arendals Fossekompani ASA (also a member of Statoil's corporate assembly)

The board considers all members of the nomination committee to be independent of Statoil's management and board of directors. The general meeting decides the remuneration of the nomination committee.

The nomination committee held 14 ordinary meetings and 2 telephone meetings in 2017.

The instructions for the nomination committee are available at www.statoil.com/nominationcommittee.

Deviations from the Code: None

3.8 CORPORATE ASSEMBLY, BOARD OF DIRECTORS AND MANAGEMENT

Corporate assembly

Pursuant to the Norwegian Public Limited Liability Companies Act, companies with more than 200 employees must elect a corporate assembly unless otherwise agreed between the company and a majority of its employees.

In accordance with Statoil's articles of association, the corporate assembly normally consists of 18 members, 12 of whom (with four deputy members) are nominated by the nomination committee and elected by the annual general meeting. They represent a broad cross-section of the company's shareholders and stakeholders. Six members, with deputy members, and three observers are elected by and among our employees. Such employees are non-executive personnel. The corporate assembly elects its own chair and deputy chair from and among its members.

Members of the corporate assembly are normally elected for a term of two years. Members of the board of directors and management cannot be members of the corporate assembly, but they are entitled to attend and to speak at meetings of the corporate assembly unless the corporate assembly decides otherwise in individual cases. All members of the corporate assembly live in Norway. Members of the corporate assembly do not have service contracts with the company or its subsidiaries providing for benefits upon termination of office.

An overview of the members and observers of the corporate assembly as of 31 December 2017 follows below.

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Name	Occupation	Place of residence	Year of birth	Position	Family relations to corporate executive committee, board or corporate assembly members	Share ownership for members as of 31.12.2017	Share ownership for members as of 14.03.2018	First time elected	Expiration date of current term
Tone Lunde Bakker	General Manager Swedbank Norge	Oslo	1962	Chair, Shareholder-elected	No	0	0	2014	2018
Nils Bastiansen	Executive director of equities in Folketrygdfondet	Oslo	1960	Deputy chair, Shareholder-elected	No	0	0	2016	2018
Jarle Roth	CEO, Arendals Fossekompani ASA	Bærum	1960	Shareholder-elected	No	43	43	2016	2018
Greger Mannsverk	Managing director, Kimek AS	Kirkenes	1961	Shareholder-elected	No	0	0	2002	2018
Steinar Olsen	CEO, Jemso A/S	Stavanger	1949	Shareholder-elected	No	0	0	2007	2018
Kathrine Næss	Plant manager at the aluminium smelter at Alcoa Mosjøen	Mosjøen	1979	Shareholder-elected	No	0	0	2016	2018
Ingvald Strømmen	Professor at the Faculty of Engineering at Norwegian University of Science and Technology	Ranheim	1950	Shareholder-elected	No	0	0	2006	2018
Rune Bjerke	President and CEO, DNB ASA	Oslo	1960	Shareholder-elected	No	0	0	2007	2018
Birgitte Ringstad Vartdal	CEO of Golden Ocean Management AS, managing the dry bulk shipping company Golden Ocean Group Ltd	Oslo	1977	Shareholder-elected	No	0	0	2016	2018
Siri Kalvig	Associate professor, University of Stavanger	Stavanger	1970	Shareholder-elected	No	0	0	2010	2018
Terje Venold	Independent advisor with various directorships	Bærum	1950	Shareholder-elected	No	544	544	2014	2018
Kjersti Kleven	Co-owner of John Kleven AS	Ulsteinvik	1967	Shareholder-elected	No	0	0	2014	2018
Steinar Kåre Dale	Union representative, NITO, SR Analyst. Prin Analyst IT Infrastr.	Mongstad	1961	Employee-elected	No	2072	2351	2013	2019
Anne K.S. Horneland	Union representative, Industri Energi. Employee Representative RIR.	Hafrsfjord	1956	Employee-elected	No	5722	6049	2006	2019
Hilde Møllerstad	Union representative, Tekna. Proj Leader Petech.	Oslo	1966	Employee-elected	No	3642	4091	2013	2019
Terje Enes	Union representative, SAFE. Discipl Resp Maint Mech.	Stavanger	1958	Employee-elected	No	2464	2674	2017	2019
Lars Olav Grøvik	Union representative, Tekna. Advisor Petech.	Bergen	1961	Employee-elected	No	5775	6172	2017	2019
Dag-Rune Dale	Union representative, Industri Energi, Safety officer. Employee representative O&M.	Kollsnes	1963	Employee-elected	No	3918	4179	2017	2019
Per Helge Ødegård	Union representative, Lederne. Discipl resp operation process.	Porsgrunn	1963	Employee-elected, observer	No	554	425	1994	2019
Sun Lehmann	Union representative, Tekna. Leading Engineer IT.	Trondheim	1972	Employee-elected, observer	No	4383	4756	2015	2019
Dag Unnar Mongstad	Union representative, Industri Energi. Operator Ops Labratory.	Bergen	1954	Employee-elected, observer	No	1722	1745	2017	2019
Total						30,839	33,029		

An election of the employee-elected members of the corporate assembly was held early 2017. As of 26 April 2017, Terje Enes and Lars Olav Grøvik were elected as new members. Dag-Rune Dale became a new member and Dag Unnar Mongstad became a new observer in June 2017 replacing former corporate assembly member Per Martin Labråten who was elected as a new board member. Tove Bjordal, Peter B. Sabel, Thor-Ole Vågene, Mina Helene Aase, Kine Merethe Pedersen, Katrine Knarvik-Skogstø and Jan-Eirik Feste (Feste from the former position as member) were elected as new deputy members.

The number of deputy members for the employee-elected members of the corporate assembly was also reduced from 11 to 10 as a result of Per Martin Labråten's election to the board of directors.

The duties of the corporate assembly are defined in section 6-37 of the Norwegian Public Limited Liability Companies Act. The corporate assembly elects the board of directors and the chair of the board and can vote separately on each nominated candidate. Its responsibilities also include overseeing the board and the CEO's management of the company, making decisions on investments of considerable magnitude in relation to the company's resources, and making decisions involving the rationalisation or reorganisation of operations that will entail major changes in or reallocation of the workforce.

Statoil's corporate assembly held four ordinary meetings in 2017. The chair of the board participated at all four meetings, and the CEO at three meetings (with the CFO acting on his behalf at one meeting). Other members of management were also present at the meetings.

The procedure for the work of the corporate assembly, as well as an updated overview of its members, is available at www.statoil.com/corporateassembly.

Board of directors

Pursuant to Statoil's articles of association, the board of directors consists of between nine and 11 members elected by the corporate assembly. The chair of the board and the deputy chair of the board are also elected by the corporate assembly. At present, Statoil's board of directors consists of 10 members. As required by Norwegian company law, the company's employees are represented by three board members.

The employee-elected board members, but not the shareholder-elected board members, have three deputy members who attend board meetings in the event an employee-elected member of the board is unable to attend. The management is not represented on the board of directors. Members of the board are elected for a term of up to two years, normally for one year at a time. There are no board member service contracts that provide for benefits upon termination of office.

The board considers its composition to be diverse and competent with respect to the expertise, capacity and diversity appropriate to attend to the company's goals, main challenges, and the common interest of all shareholders. The board also deems its composition to be made up of individuals who are willing and able to work as a team, resulting in the board working effectively as a collegiate body. At least one board member qualifies as "audit committee financial expert", as defined in the US Securities and Exchange Commission requirements. Statoil's board of directors has determined that, in its judgment, all the shareholder representatives on the board are considered independent. Four board members are women and three board members are non-Norwegians resident outside of Norway.

The board held eight ordinary board meetings and three extraordinary meetings in 2017. Average attendance at these board meetings was 95,41%.

Further information about the members of the board and its sub-committees, including information about expertise, experience, other directorships, independence, share ownership and loans, is available below as well as on our website at www.statoil.com/board which is regularly updated.

Members of the board of directors as of 31 December 2017:

Jon Erik Reinhardsen
Born: 1956
Position: Shareholder-elected chair of the board and chair of the board's compensation and executive development committee.
Term of office: Chair of the board of Statoil ASA since 1 September 2017. Up for election in 2018.
Independent: Yes
Other directorships: Member of the board of directors of Oceaneering International, Inc., Borregaard ASA, Telenor ASA and Awilhelmsen AS.
Number of shares in Statoil ASA as of 31 December 2017: 2,558
Loans from Statoil: None
Experience: Reinhardsen was the Chief Executive Officer of Petroleum Geo-Services (PGS) from 2008 - August 2017. PGS delivers global geophysical- and reservoir services. The company has its headquarters in Oslo and offices in 17 countries with approximately 1,800 employees. In the period 2005 - 2008 Reinhardsen was President Growth, Primary Products in the international aluminium company Alcoa Inc. with headquarters in the US, and he was in this period based in New York.
From 1983 to 2005, Reinhardsen held various positions in the Aker Kværner group, including Group Executive Vice President of Aker Kværner ASA, Deputy Chief Executive Officer and Executive Vice President of Aker Kværner Oil & Gas AS in Houston and Executive Vice President in Aker Maritime ASA.
Education: Reinhardsen has a Master's Degree in Applied Mathematics and Geophysics from the University of Bergen. He has also attended the International Executive Program at the Institute for Management Development (IMD) in Lausanne, Switzerland.
Family relations: No family relations to other members of the board, members of the corporate executive committee or the corporate assembly.
Other matters: In 2017 Reinhardsen participated in three ordinary board meetings, two extraordinary board meetings, two meetings of

the compensation and executive development committee and one meeting of the audit committee. Reinhardsen is a Norwegian citizen and resident in Norway.

Roy Franklin
Born: 1953
Position: Shareholder-elected deputy chair of the board, chair of the board's safety, sustainability and ethics committee and member of the board's audit committee.
Term of office: Board member and deputy chair of the board of Statoil ASA since 1 July 2015. Franklin was also previously a member of the board of StatoilHydro from October 2007 and Statoil from November 2009 until June 2013. Chair of the board's safety, sustainability and ethics committee and member of the board's audit committee. Up for election in 2018.
Independent: Yes
Other directorships: Non-executive chair of the boards of Premier Oil plc, Cuadrilla Resources Holdings Limited, a privately held UK company focusing on unconventional energy sources and Eregean Israel Ltd., a private company focused on gas development offshore Israel. Board member of the private equity firm Kerogen Capital Ltd and the Aberdeen-based international engineering company Wood plc.
Number of shares in Statoil ASA as of 31 December 2017: None
Loans from Statoil ASA: None
Experience: Franklin has broad oil and gas experience from management positions in several countries, including positions with BP, Paladin Resources plc and Clyde Petroleum plc.
Education: Franklin has a Bachelor of Science in Geology from the University of Southampton, UK.
Family relations: No family relations to other members of the board, members of the corporate executive committee or the corporate assembly.
Other matters: In 2017, Franklin participated in eight ordinary board meetings, two extraordinary board meetings, one meeting in the compensation and executive development committee, six meetings of the audit committee and five meetings of the safety, sustainability and ethics committee. Franklin is a UK citizen and resident in UK.

Bjørn Tore Godal
Born: 1945
Position: Shareholder-elected member of the board, the board's compensation and executive development committee and the board's safety, sustainability and ethics committee.
Term of office: Member of the board of Statoil ASA since 1 September 2010. Up for election in 2018.
Independent: Yes
Other directorships: Vice chair of the board of the Fridtjof Nansen Institute (FNI).
Number of shares in Statoil ASA as of 31 December 2017: None
Loans from Statoil ASA: None
Experience: Godal was a member of the Norwegian parliament for 15 years during the period 1986-2001. At various times, he served as minister for trade and shipping, minister for defense and minister of foreign affairs for a total of eight years between 1991 and 2001. From 2007-2010, Godal was special adviser for international energy and climate issues at the Norwegian Ministry of Foreign Affairs. From 2003-2007, Godal was Norway's ambassador to Germany and from 2002-2003 he was senior adviser at the department of political science at the University of Oslo. From 2014-2016, Godal led a government-appointed committee responsible for the evaluation of the civil and military contribution from Norway in Afghanistan in the period 2001 - 2014.
Education: Godal has a bachelor of arts degree in political science, history and sociology from the University of Oslo.
Family relations: No family relations to other members of the board, members of the corporate executive committee or the corporate assembly.
Other matters: In 2017, Godal participated in eight ordinary board meetings, three extraordinary board meetings, six meetings of the compensation and executive development committee and five meetings of the safety, sustainability and ethics committee. Godal is a Norwegian citizen and resident in Norway.

Maria Johanna Oudeman
Born: 1958
Position: Shareholder-elected member of the board and member of the board's compensation and executive development committee.
Term of office: Member of the board of Statoil ASA since 15 September 2012. Up for election in 2018.
Independent: Yes
Other directorships: Oudeman is a member of the boards of Het Concertgebouw, Rijksmuseum, Solvay SA, SHV Holdings NV and Aalberts Industries NV.
Number of shares in Statoil ASA as of 31 December 2017: None
Loans from Statoil: None
Experience: Oudeman was the President of Utrecht University in the Netherlands, one of Europe's leading universities, until June 2017. From 2010 to 2013, Oudeman was a member of the Executive Committee of Akzo Nobel, responsible for HR and Organisational Development. Akzo Nobel is the world's largest paint and coatings company and major producer of specialty chemicals, with operations in more than 80 countries. Before joining Akzo Nobel, she was Executive Director Strip Products Division at Corus Group, now Tata Steel Europe. Oudeman has extensive experience as a line manager in the steel industry and considerable international business experience.
Education: Oudeman has a law degree from Rijksuniversiteit Groningen in the Netherlands and an MBA in business administration from the University of Rochester, New York, USA and Erasmus University, Rotterdam, the Netherlands.
Family relations: No family relations to other members of the board, members of the corporate executive committee or the corporate assembly.
Other matters: In 2017, Oudeman participated in eight ordinary board meetings, three extraordinary board meetings and six meetings of the compensation and executive development committee. Oudeman is a Dutch citizen and resident in the Netherlands.

Rebekka Glasser Herlofsen
Born: 1970
Position: Shareholder-elected member of the board and the board's audit committee.
Term of office: Member of the board of Statoil ASA since 19 March 2015. Up for election in 2018.
Independent: Yes
Other directorships: None
Number of shares in Statoil ASA as of 31 December 2017: None
Loans from Statoil: None
Experience: In April 2017 Herlofsen took on a new position as Chief Financial Officer in Wallenius Willhelmsen Logistics ASA, an international shipping company. Before joining WWL ASA she was the Chief Financial Officer in the shipping company Torvald Klaveness since 2012. She has broad financial and strategic experience from several corporations and board directorships. Herlofsen's professional career began in the Nordic Investment Bank, Enskilda Securities, where she worked with corporate finance from 1995 to 1999 in Oslo and London. During the next ten years Herlofsen worked in the Norwegian shipping company Bergesen d.y. ASA (later BW Group). During her period with Bergesen d.y. ASA/BW Group Herlofsen held leading positions within M&A, strategy and corporate planning and was part of the group management team.
Education: MSc in Economics and Business Administration (Siviløkonom) and Certified Financial Analyst Programme (AFA), the Norwegian School of Economics (NHH). Breakthrough Programme for Top Executives at IMD business school, Switzerland.
Family relations: No family relations to other members of the board, members of the corporate executive committee or the corporate assembly.
Other matters: In 2017, Herlofsen participated in eight ordinary board meetings, three extraordinary board meeting and six meetings of the audit committee. Herlofsen is a Norwegian citizen and resident in Norway.

Wenche Agerup
Born: 1964
Position: Shareholder-elected member of the board, the board's compensation and executive development committee and the board's safety, sustainability and ethics committee.
Term of office: Member of the board of Statoil ASA since 21 August 2015. Up for election in 2018.
Independent: Yes
Other directorships: Agerup is a member of the board of the seismic company TGS ASA and a member of Det Norske Veritas Council and its nomination committee.
Number of shares in Statoil ASA as of 31 December 2017: 2,650
Loans from Statoil: None
Experience: Agerup is an Executive Vice President (Corporate Affairs) and General Counsel in Telenor ASA. Agerup was the Executive Vice President for Corporate Staffs and the General Counsel of Norsk Hydro ASA from 2010 to 31 December 2014. She has held various executive roles in Hydro since 1997, including within the company's M&A-activities, the business area Alumina, Bauxite and Energy, as a plant manager at Hydro's metal plant in Årdal and as a project director for a Joint Venture in Australia where Hydro cooperated with the Australian listed company UMC.
Education: MA in Law from the University of Oslo, Norway (1989) and a Master of Business Administration from Babson College, USA (1991).
Family relations: No family relations to other members of the board, members of the corporate executive committee or the corporate assembly.
Other matters: In 2017, Agerup participated in eight ordinary board meetings, three extraordinary board meetings, six meetings of the compensation and executive development committee and four meetings of the safety, sustainability and ethics committee. Agerup is a Norwegian citizen and resident in Norway.

Jeroen van der Veer
Born: 1947
Position: Shareholder-elected member of the board and chair of the board's audit committee.
Term of office: Member of the board of Statoil ASA since 18 March 2016. Up for election in 2018.
Independent: Yes
Other directorships: van der Veer is the chair of the supervisory boards of ING Bank NV and Royal Philips Electronics, chair of the supervisory council of Technical University of Delft and Platform Beta Techniek, chair of the advisory board of the Rotterdam Climate Initiative as well as a board member in Boskalis Westminster Groep NV and Het Concertgebouw.
Number of shares in Statoil ASA as of 31 December 2017: None
Loans from Statoil: None
Experience: van der Veer was the Chief Executive Officer in the international oil and gas company Royal Dutch Shell Plc (Shell) in the period 2004 to 2009 when he retired. van der Veer thereafter continued as a non-executive director on the board of Shell until 2013. He started to work for Shell in 1971 and has experience within all sectors of the business and has significant competence within corporate governance.
Education: van der Veer has a degree in Mechanical Engineering (MSc) from Delft University of Technology, Netherlands and a degree in Economics (MSc) from Erasmus University, Rotterdam, Netherlands. Since 2005 he holds an honorary doctorate from the University of Port Harcourt, Nigeria.
Family relations: No family relations to other members of the board, members of the corporate executive committee or the corporate assembly.
Other matters: In 2017, van der Veer participated in seven ordinary board meetings, two extraordinary board meetings and six meetings of the audit committee. van der Veer is a Dutch citizen and resident in the Netherlands

Per Martin Labråten
Born: 1961
Position: Employee-elected member of the board and member of the board's safety, sustainability and ethics committee.
Term of office: Member of the board of Statoil ASA since 8 June 2017. Up for election in 2019.
Independent: No
Other directorships: Labråten is a member of the executive committee of the Industry Energy (IE) trade union and holds a number of offices as a result of this.
Number of shares in Statoil ASA as of 31 December 2017: 1,343
Loans from Statoil: None
Experience: Labråten has worked as a process technician at the petrochemical plant on Oseberg field in the North Sea. Labråten is now a full-time employee representative as the leader of IE Statoil branch.
Education: Labråten has a craft certificate as a process/chemistry worker.
Family relations: No family relations to other members of the board, members of the corporate executive committee or the corporate assembly.

Other matters: In 2017, Labråten participated in four ordinary board meetings, one extraordinary board meeting and one meeting of the safety, sustainability and ethics committee. Labråten is a Norwegian citizen and resident in Norway.

Ingrid Elisabeth di Valerio
Born: 1964
Position: Employee-elected member of the board and member of the board's audit committee.
Term of office: Member of the board of Statoil ASA since 1 July 2013. Up for election in 2019.
Independent: No
Other directorships: Board member of Tekna's central nomination committee.
Number of shares held in Statoil ASA as of 31 December 2017: 4,471
Loans from Statoil: None
Experience: di Valerio has been employed by Statoil since 2005, and works within materials discipline for Technology, Projects & Drilling. di Valerio was the union Tekna's main representative in Statoil from 2008 to 2013. She also sat on Tekna's central committee from 2005 to 2013.
Education: Chartered engineer (mathematics and physics) from the Norwegian University of Science and Technology in Trondheim (NTNU).
Familiy relations: No family relationships to other board members, members of the corporate executive committee or the corporate assembly.
Other matters: In 2017, di Valerio participated in eight ordinary board meetings, three extraordinary board meetings and six meetings of the audit committee. di Valerio is a Norwegian citizen and resident in Norway.

Stig Lægreid
Born: 1963
Position: Employee-elected member of the board and member of the board's safety, sustainability and ethics committee.
Term of office: Member of the board of Statoil ASA since 1 July 2013. Up for election in 2019.
Independent: No
Other directorships: Member of The Norwegian society for Engineers and Technologists' (NITO) negotiation committee for private sector.
Number of shares held in Statoil ASA as of 31 December 2017: 1,975
Loans from Statoil: None
Experience: Employed in ÅSV and Norsk Hydro since 1985. Mainly occupied as project engineer and constructor for production of primary metals until 2005 and from 2005 as weight estimator for platform design. He is now a full-time employee representative as the leader of the union NITO, Statoil.
Education: Bachelor degree, mechanical construction from OIH.
Family relations: No family relationships to other board members, members of the corporate executive committee or the corporate assembly.
Other matters: In 2017, Lægreid participated in eight ordinary board meetings, three extraordinary board meetings and five meetings of the safety, sustainability and ethics committee. Lægreid is a Norwegian citizen and resident in Norway.

The most recent changes to the composition of the board of directors was the election of Jon Erik Reinhardsen as the new shareholder-elected chair effective as of 1 September 2017 after the former shareholder-elected chair Øystein Løseth resigned effective as of 30 June 2017. Deputy chair Roy Franklin acted as chair of the board between 1 July and 31 August 2017. Employee-elected member Per Martin Labråten was elected as of 8 June 2017, replacing Lill Heidi Bakkerud. Reinhardsen replaced Løseth as chair of the board's compensation and executive development committee as per 5 September 2017.

Management

The president and CEO has overall responsibility for day-to-day operations in Statoil and appoints the corporate executive committee (CEC). The president and CEO is responsible for developing Statoil's business strategy and presenting it to the board of directors for decision, for the execution of the business strategy and for cultivating a performance-driven, values-based culture.

Members of the CEC have a collective duty to safeguard and promote Statoil's corporate interests and to provide the president and CEO with the best possible basis for deciding the company's direction, making decisions and executing and following up business activities. In addition, each of the CEC members is head of a separate business area or staff function.

Members of Statoil's corporate executive committee as of 31 December 2017:

Eldar Sætre,
President and CEO

Eldar Sætre
Born: 1956
Position: President and chief executive officer (CEO) of Statoil ASA since 15 October 2014.
External offices: Member of the board of Strømberg Gruppen AS and Trucknor AS.
Number of shares in Statoil ASA as of 31 December 2017: 56,896
Loans from Statoil: None
Experience: Sætre joined Statoil in 1980. Executive vice president and CFO from October 2003 until December 2010. Executive vice president for Marketing, Midstream and Processing (MMP) from 2011 until 2014.
Education: MA in business economics from the Norwegian School of Economics and Business Administration (NHH).
Family relations: No family relations to other members of the corporate executive committee, members of the board or the corporate assembly.
Other matters: Sætre is a Norwegian citizen and resident in Norway.

Hans Jakob Hegge,
Chief financial
officer (CFO)

Hans Jakob Hegge
Born: 1969
Position: Executive vice president and chief financial officer (CFO) of Statoil ASA since 1 August 2015.
External offices: None
Number of shares in Statoil ASA as of 31 December 2017: 32,104
Loans from Statoil: None
Experience: Hegge has held several managerial positions in Statoil, including senior vice president (SVP) for Operations North in Development & Production Norway (DPN) (2013-2015), SVP for Operations East (2011-2013) in DPN, SVP for Operational Development in DPN (2009-2011) and SVP for Global Business Services in Chief Financial Officer area (CFO) (2005-2009). From 1995 to 2004 he held various positions in DPN, Natural Gas business area and corporate functions in Statoil.
Education: Master of Science degree from the Norwegian School of Economics and Business Administration (NHH).
Family relations: No family relations to other members of the corporate executive committee, members of the board or the corporate assembly.
Other matters: Hegge is a Norwegian citizen and resident in Norway.

Jannicke Nilsson
Chief operating officer (COO)

Jannicke Nilsson
Born: 1965
Position: Executive vice president and chief operating officer (COO) of Statoil ASA since 1 December 2016.
External offices: Member of the board of Odfjell SE
Number of shares in Statoil ASA as of 31 December 2017: 38,491
Loans from Statoil: None
Experience: Jannicke Nilsson joined Statoil in 1999 and has held a number of central management positions within upstream operations Norway, including senior vice president for Technical Excellence in Technology, Projects & Drilling, senior vice president for Operations North Sea, vice president for modifications and project portfolio Bergen and platform manager at Oseberg South. In August 2013,

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she was appointed programme leader for Statoil technical efficiency programme (STEP), responsible for a project portfolio delivering yearly efficiency gains of 3.2 billion USD from 2016.
Education: MSc in cybernetics and process automation and a BSc in automation from the Rogaland Regional College/University of Stavanger.
Family relations: No family relations to other members of the corporate executive committee, members of the board or the corporate assembly.
Other matters: Nilsson is a Norwegian citizen and resident in Norway.

Lars Christian Bacher,
Executive vice president Development & Production International (DPI)

Lars Christian Bacher
Born: 1964
Position: Executive vice president Development & Production International (DPI) of Statoil ASA since 1 September 2012.
External offices: None
Number of shares in Statoil ASA as of 31 December 2017: 23,309
Loans from Statoil ASA: None
Experience: Bacher joined Statoil in 1991 and has held a number of leading positions in Statoil, including that of platform manager on the Norne and Statfjord fields on the Norwegian continental shelf. He was in charge of the merger process involving the offshore installations of Norsk Hydro and Statoil. Bacher has also been senior vice president for Gullfaks operations and subsequently for the Tampen area. His most recent position, which he held from September 2009, was as senior vice president for Statoil's Canadian operations within DPI.
Education: Master of science in chemical engineering from the Norwegian Institute of Technology (NTH). He also holds a business degree in Finance from the Norwegian School of Economics and Business Administration (NHH).
Family relations: No family relations to other members of the corporate executive committee, the board of directors or the corporate assembly.
Other matters: Bacher is a Norwegian citizen and resident in Norway.

Torgrim Reitan,
Executive vice president Development & Production USA (DPUSA)

Torgrim Reitan
Born: 1969
Position: Executive vice president Development & Production USA (DPUSA) of Statoil ASA since 1 August 2015.
External offices: None
Number of shares in Statoil ASA as of 31 December 2017: 36,235
Loans from Statoil: None
Experience: From 1 January 2011 to 1 August 2015 Reitan held the position as executive vice president and chief financial officer of Statoil (CFO). He has held several managerial positions in Statoil, including senior vice president (SVP) in trading and operations in the Natural Gas business area (2009 - 2010), SVP in performance management and analysis (2007 - 2009) and SVP in performance management, tax and M&A (2005 - 2007). From 1995 to 2004, Reitan held various positions in the Natural Gas business area and corporate functions in Statoil.
Education: Master of science degree from the Norwegian School of Economics and Business Administration (Siviløkonom) (NHH).
Family relations: No family relations to other members of the corporate executive committee, members of the board or the corporate assembly.
Other matters: Reitan is a Norwegian citizen and resident in the United States.

John Knight,
Executive vice president
Global Strategy & Business
Development (GSB)

John Knight
Born: 1958
Position: Executive vice president Global Strategy & Business Development (GSB) of Statoil ASA since 1 January 2011.
External offices: Member on the advisory board of the Columbia University Center on Global Energy Policy in New York and member of the advisory board of Lloyd's Register. Chair of ONS 18 Conference Committee in Stavanger, Norway.
Numbers of shares in Statoil ASA as of 31 December 2017: 109,901
Loans from Statoil ASA: None
Experience: Knight held several central managerial positions in International Operations in Statoil since 2002, mainly in business development. Between 1987 and 2002, Knight held various

positions in energy investment banking. From 1977 to 1987, he qualified and worked as a barrister/lawyer, and was employed by Shell Petroleum in London during the period 1980-1987.
Education: Knight has first and post-graduate degrees in law from Cambridge University and the Inns of Court School of Law in London.
Family relations: No family relations to other members of the corporate executive committee, members of the board or the corporate assembly.
Other matters: Knight is a British citizen and resident in England.

Tim Dodson.
Executive vice president, Exploration (EXP)

Tim Dodson
Born: 1959
Position: Executive vice president Exploration (EXP) of Statoil ASA since 1 January 2011.
External offices: None
Number of shares in Statoil ASA as of 31 December 2017: 34,425
Loans from Statoil ASA: None
Experience: Dodson has worked in Statoil since 1985 and held central management positions in the company, including the positions of senior vice president for Global Exploration, Exploration & Production Norway and the Technology arena.
Education: Bachelor's degree of science in geology and geography from the University of Keele.
Family relations: No family relations to other members of the corporate executive committee, members of the board or the corporate assembly.
Other matters: Dodson is a British citizen and resident in Norway.

Margareth Øvrum.
Executive vice president Technology, Projects & Drilling (TPD)

Margareth Øvrum
Born: 1958
Position: Executive vice president Technology, Projects & Drilling (TPD) of Statoil ASA since September 2004.
External offices: Member of the board of Alfa Laval (Sweden) and FMC Corporation (US).
Number of shares in Statoil ASA as of 31 December 2017: 56,125
Loans from Statoil: None
Experience: Øvrum has worked for Statoil since 1982 and has held central management positions in the company, including the position of executive vice president for Health, Safety and the Environment and executive vice president for Technology & Projects. Øvrum was the company's first female platform manager, on the Gullfaks field. She was senior vice president for operations for Veslefrikk and vice president of Operations Support for the Norwegian continental shelf.
Education: Master's degree in engineering (sivilingeniør) from the Norwegian Institute of Technology (NTH), specialising in technical physics.
Family relations: No family relations to other members of the corporate executive committee, members of the board or the corporate assembly.
Other matters: Øvrum is a Norwegian citizen and resident in Norway.

Arne Sigve Nylund,
Executive vice president Development & Production Norway (DPN)

Arne Sigve Nylund
Born: 1960
Position: Executive vice president Development & Production Norway (DPN) of Statoil ASA since 1 January 2014.
External offices: Member of the board of directors of The Norwegian Oil & Gas Association (Norsk Olje & Gass).
Number of shares in Statoil ASA as of 31 December 2017: 13,354
Loans from Statoil: None
Experience: Nylund was employed by Mobil Exploration Inc. from 1983-1987. Since 1987, he has held several central management positions in Statoil.
Education: Mechanical engineer from Stavanger College of Engineering with further qualifications in operational technology

from Rogaland Regional College/University of Stavanger (UiS). Business graduate of the Norwegian School of Business and Management (NHH).
Family relations: No family relations to other members of the corporate executive committee, members of the board or the corporate assembly.
Other matters: Nylund is a Norwegian citizen and resident in Norway.

Jens Økland,
Executive vice president Marketing, Midstream & Processing (MMP)

Jens Økland
Born: 1969
Position: Executive vice president Marketing, Midstream & Processing (MMP) of Statoil ASA since 1 June 2015.
External offices: None
Number of shares in Statoil ASA as of 31 December 2017: 17,207
Loans from Statoil ASA: None
Experience: Økland joined Statoil in 1994 and has mainly worked in the mid and downstream areas. Before becoming executive vice president of MMP, Økland worked as vice president of operations for the Åsgard area in Development & Production Norway. Previously Økland was senior vice president of Statoil's natural gas portfolio and supply business in North America, marketing and developing infrastructure solutions for equity and non-equity production. Before heading up Statoil's downstream gas division in North America, he had senior marketing and business development positions within natural gas in Europe mainly focusing on Germany, Statoil's largest gas market.
Education: MSc in business from BI Norwegian Business School.
Family relations: No family relations to other members of the corporate executive committee, members of the board or the corporate assembly.
Other matters: Økland is a Norwegian citizen and resident in Norway.

Irene Rummelhoff,
Executive vice president New Energy Solutions (NES)

Irene Rummelhoff
Born: 1967
Position: Executive vice president New Energy Solutions (NES)of Statoil ASA since 1 June 2015.
External offices: Deputy chair of the board of directors of Norsk Hydro ASA.
Number of shares in Statoil ASA as of 31 December 2017: 25,081
Loans from Statoil ASA: None
Experience: Rummelhoff joined Statoil in 1991. She has held a number of management positions within international business development, exploration and the downstream business in Statoil.
Education: Master's degree in petroleum geosciences from the Norwegian Institute of Technology (NTH).
Family relations: No family relations to other members of the corporate executive committee, members of the board or the corporate assembly.
Other matters: Rummehoff is a Norwegian citizen and resident in Norway.

Statoil has granted loans to the Statoil-employed spouse of certain of the executive vice presidents as part of its general loan arrangement for Statoil employees. Employees in salary grade 12 or higher may take out a car loan from Statoil in accordance with standardised provisions set by the company. The standard maximum car loan is limited to the cost of the car, including registration fees, but not exceeding NOK 300,000. Employees outside the collective labour area are entitled to a car loan up to NOK 575,000 (vice presidents and senior vice presidents) or NOK 475,000 (other positions). The car loan is interest-free, but the tax value, "interest advantage", must be reported as salary. Permanent employees in Statoil ASA may also apply for a consumer loan up to NOK 350.000. The interest rate on consumer loans is corresponding to the standard rate in effect at any time for "reasonable loans" from employer as decided by the Norwegian Ministry of Finance, i.e. the lowest rate an employer may offer without triggering taxation of the advantage for the employee.

Deviations from the Code: None

3.9 THE WORK OF THE BOARD OF DIRECTORS

The board is responsible for managing the Statoil group and for monitoring day-to-day management and the group's business activities. This means that the board is responsible for establishing control systems and for ensuring that Statoil operates in compliance with laws and regulations, with our values as stated in The Statoil Book, the Code of Conduct, as well as in accordance with the owners' expectations of good corporate governance. The board emphasises the safeguarding of the interests of all shareholders, but also the interests of Statoil's other stakeholders.

The board handles matters of major importance, or of an extraordinary nature, and may in addition require the management to refer any matter to it. An important task for the board is to appoint the chief executive officer (CEO) and stipulate his/her job instructions and terms and conditions of employment.

The board has adopted a generic annual plan for its work which is revised with regular intervals. Recurrent items on the board's annual plan are: security, safety, sustainability and climate, corporate strategy, business plans, quarterly and annual results, annual reporting, ethics, management's monthly performance reporting, management compensation issues, CEO and top management leadership assessment and succession planning, project status review, people and organisation strategy and priorities, an annual enterprise risk management review, two yearly discussions of main risks and risk issues and an annual review of the board's governing documentation. In the beginning of each board meeting, the CEO meets separately with the board to discuss key matters in the company. At the end of all board meetings, the board has a closed session with only board members attending the discussions and evaluating the meeting.

The work of the board is based on rules of procedure that describe the board's responsibilities, duties and administrative procedures, and determines which cases are to be handled by the board. The rules of procedure also determine the handling of matters in which individual board members or a closely related party have a major personal or financial interest. The rules of procedure further describe the duties of the CEO and his/her duties vis-à-vis the board of directors. The board's rules of procedure are available on our website at www.statoil.com/board. In addition to the board of directors, the CEO, the CFO, the COO, the senior vice president for communication, the general counsel and the company secretary attend all board meetings. Other members of the executive committee and senior management attend board meetings by invitation in connection with specific matters.

New members of the board are offered an induction programme where meetings with key members of the management are arranged, an introduction to Statoil's business is given and relevant information about the company and the board's work is made available through the company's web based board portal.

The board carries out an annual board evaluation, with input from various sources and as a main rule with external facilitation. The evaluation report is discussed in a board meeting and is made available to the nomination committee as input to the committee's work.

The entire board, or part of it, regularly visits several Statoil locations in Norway and globally, and a longer board trip for all board members to an international location is made at least on a biannual basis. When visiting Statoil locations globally, the board emphasises the importance of improving its insight into, and knowledge about, safety and security in Statoil's operations, Statoil's technical and commercial activities as well as the company's local organisations. In 2017, whole or parts of the board visited Statoil's operations in London, Brazil and USA as well as, in Norway, the Oseberg Field and yards in Stord and Haugesund.

Statoil's board has established three sub-committees: the audit committee; the compensation and executive development committee; and the safety, sustainability and ethics committee. The committees prepare items for consideration by the board and their authority is limited to making such recommendations. The committees consist entirely of board members and are answerable to the board alone for the performance of their duties. Minutes of the committee meetings are sent to the whole board, and the chair of each committee regularly informs the board at board meetings about the committee's work. The composition and work of the committees are further described below.

Audit committee

The board of directors elects at least three of its members to serve on the board of directors' audit committee and appoints one of them to act as chair. The employee-elected members of the board of directors may nominate one audit committee member.

At year-end 2017, the audit committee members were Jeroen van der Veer (chair), Roy Franklin, Rebekka Glasser Herlofsen and Ingrid di Valerio (employee-elected board member).

The audit committee is a sub-committee of the board of directors, and its objective is to act as a preparatory body in connection with the board's supervisory roles with respect to financial reporting and the effectiveness of the company's internal control system. It also attends to other tasks assigned to it in accordance with the instructions for the audit committee adopted by the board of directors. The audit committee is instructed to assist the board of directors in its supervising of matters such as:

- Approving the internal audit plan on behalf of the board of directors
- Monitoring the financial reporting process, including oil and gas reserves, fraudulent issues and reviewing the implementation of accounting principles and policies
- Monitoring the effectiveness of the company's internal control, internal audit and risk management systems
- Maintaining continuous contact with the external auditor regarding the annual and consolidated accounts
- Reviewing and monitoring the independence of the company's internal auditor and the independence of the external auditor, reference is made to the Norwegian Auditors Act chapter 4, and, in particular, whether services other than audits provided by the external auditor or the audit firm are a threat to the external auditor's independence

The audit committee supervises implementation of and compliance with the group's Code of Conduct in relation to financial reporting.

Corporate Audit reports administratively to the president and CEO of Statoil and functionally to the chair of the board of directors' audit committee.

Under Norwegian law, the external auditor is appointed by the shareholders at the annual general meeting based on a proposal from the corporate assembly. The audit committee issues a statement to the annual general meeting relating to the proposal.

The audit committee meets at least five times a year and both the board and the board's audit committee hold meetings with the internal auditor and the external auditor on a regular basis without the company's management being present.

The audit committee is also charged with reviewing the scope of the audit and the nature of any non-audit services provided by external auditors.

The audit committee is tasked with ensuring that the company has procedures in place for receiving and dealing with complaints received by the company regarding accounting, internal control or auditing matters, and procedures for the confidential and anonymous submission, via the group's ethics helpline, by company employees of concerns regarding accounting or auditing matters, as well as other matters regarded as being in breach of the group's Code of Conduct, a material violation of an applicable US federal or state securities law, a material breach of fiduciary duties or a similar material violation of any other US or Norwegian statutory provision. The audit committee is designated as the company's qualified legal compliance committee for the purposes of Part 205 in Title 17 of the U.S. Code of Federal Regulations.

In the execution of its tasks, the audit committee may examine all activities and circumstances relating to the operations of the company. In this regard, the audit committee may request the chief executive officer or any other employee to grant it access to information, facilities and personnel and such assistance as it requests. The audit committee is authorised to carry out or instigate such investigations as it deems necessary in order to carry out its tasks and it may use the company's internal audit or investigation unit, the external auditor or other external advice and assistance. The costs of such work will be covered by the company.

The audit committee is only responsible to the board of directors for the execution of its tasks. The work of the audit committee in no way alters the responsibility of the board of directors and its individual members, and the board of directors retains full responsibility for the audit committee's tasks.

The audit committee held six meetings in 2017. There was 100% attendance at the committee's meetings.

The board of directors has decided that a member of the audit committee, Jeroen van der Veer, qualifies as an "audit committee financial expert", as defined in Item 16A of Form 20-F. The board of directors has also concluded that Jeroen van der Veer, Roy Franklin and Rebekka Glasser Herlofsen are independent within the meaning of Rule 10A-3 under the Securities Exchange Act.

The committee's mandate is available at www.statoil.com/auditcommittee.

Compensation and executive development committee

The compensation and executive development committee is a sub-committee of the board of directors that assists the board in matters relating to management compensation and leadership development. The main responsibilities of the compensation and executive development committee are:

(1) as a preparatory body for the board, to make recommendations to the board in all matters relating to principles and the framework for executive rewards, remuneration strategies and concepts, the CEO's contract and terms of employment, and leadership development, assessments and succession planning;

(2) to be informed about and advise the company's management in its work on Statoil's remuneration strategy for senior executive and in drawing up appropriate remuneration policies for senior executives; and

(3) to review Statoil's remuneration policies in order to safeguard the owners' long-term interests.

The committee consists of up to four board members. At year-end 2017, the committee members were Jon Erik Reinhardsen (chair), Bjørn Tore Godal, Maria Johanna Oudeman and Wenche Agerup. All the committee members are non-executive directors. All members are deemed independent.

The committee held six meetings in 2017 and attendance was 100%.

For a more detailed description of the objective and duties of the compensation and executive development committee, please see the instructions for the committee available at www.statoil.com/compensationcommittee.

Safety, sustainability and ethics committee

The safety, sustainability and ethics committee is a sub-committee of the board of directors that assists the board in matters relating to safety, sustainability and ethics.

At year-end 2017, the safety, sustainability and ethics committee was chaired by Roy Franklin and the other members are Bjørn Tore Godal, Wenche Agerup, Stig Lægreid (employee-elected board member) and Per Martin Labråten (employee-elected board member).

In its business activities, Statoil is committed to comply with applicable laws and regulations and to act in an ethical, environmental, safe and socially responsible manner. The committee has been established to support our commitment in this regard, and it assists the board of directors in its supervision of the company's safety, sustainability and ethics policies, systems and principles with the exception of aspects related to "financial matters".

Establishing and maintaining a committee dedicated to safety, sustainability and ethics is intended to ensure that the board of directors has a strong focus on and knowledge of these complex, important and constantly evolving areas. The committee acts as a preparatory body for the board of directors and, among other things, monitors and assesses the effectiveness, development and implementation of policies, systems and principles in the areas of safety, sustainability and ethics, with the exception of aspects related to "financial matters". The committee also reviews the annual Sustainability Report.

The committee held five meetings in 2017, and attendance was 96%.

For a more detailed description of the objective, duties and composition of the committee, please see the instructions for the committee available at www.statoil.com/ssecommittee.

Deviations from the Code: None

3.10 RISK MANAGEMENT AND INTERNAL CONTROL

Risk management

The board focuses on ensuring adequate control of the company's internal control and overall risk management. The board conducts an annual enterprise risk management review and two times pr. year the board is presented with and discusses the main risks and risk issues Statoil is facing. The board's audit committee assists the board and act as a preparatory body in connection with monitoring of the company's internal control, internal audit and risk management systems. The board's safety, sustainability and ethics committee monitors and assesses safety, sustainability and climate risks which are relevant for Statoil's operations and both committees report regularly to the full board.

Statoil manages risk to make sure that our operations are safe and in compliance with our requirements. Our overall risk management approach includes continuously assessing and managing risks related to our value chain in order to support the achievement of our principal objectives, i.e. value creation and avoiding incidents.

The company has a separate corporate risk committee chaired by the chief financial officer. The committee meets at least five times a year to give advice and make recommendations on Statoil's enterprise risk management. Further information about the company's risk management is presented in section 2.11 of the form 20-F Risk review.

All risks are related to Statoil's value chain - from access, maturing, project execution and operations to market. In addition to the financial impact these risks could have on Statoil's cash flows, we have also implemented procedures and systems to reduce safety, security and integrity incidents (such as fraud and corruption), as well as any reputation impact resulting from human rights, labour standards and transparency issues. Most of the risks are managed by our principal business area line managers. Some operational risks are insured by our captive insurance company, which operates in the Norwegian and international insurance markets.

Controls and procedures

This section describes controls and procedures relating to our financial reporting.

Evaluation of disclosure controls and procedures

The management, with the participation of our chief executive officer and chief financial officer, has evaluated the effectiveness of the design and operation of our disclosure controls and procedures pursuant to Exchange Act Rule 13a-15(b) as of the end of the period covered by the Form 20-F. Based on that evaluation, the chief executive officer and chief financial officer have concluded that as a result of a material weakness in internal controls over financial reporting described below, these disclosure controls and procedures were not effective at a reasonable level of assurance as of 31 December 2017.

In order to facilitate the evaluation, the disclosure committee reviews material disclosures made by Statoil for any errors, misstatements and omissions. The disclosure committee is chaired by the chief financial officer. It consists of the heads of investor relations, accounting and financial compliance, performance management and controlling, tax and the general counsel and it may be supplemented by other internal and external personnel. The head of the internal audit is an observer at the committee's meetings.

In designing and evaluating our disclosure controls and procedures, our management, with the participation of the chief executive officer and chief financial officer, recognised that any controls and procedures, no matter how well designed and operated, can only provide reasonable assurance that the desired control objectives will be achieved, and that the management must necessarily exercise judgment when evaluating the cost-benefit aspects of possible controls and procedures. Because of the limitations inherent in all control systems, no evaluation of controls can provide absolute assurance that all control issues and any instances of fraud in the company have been detected.

The management's report on internal control over financial reporting

The management of Statoil ASA is responsible for establishing and maintaining adequate internal control over financial reporting. Our internal control over financial reporting is a process designed, under the supervision of the chief executive officer and chief financial officer, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of Statoil's financial statements for external reporting purposes in accordance with International Financial Reporting Standards (IFRS) as adopted by the European Union (EU). The accounting policies applied by the group also comply with IFRS as issued by the International Accounting Standards Board (IASB).

Material weakness

The management of Statoil has assessed the effectiveness of internal control over financial reporting based on the Internal Control - Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Based on this assessment, management has concluded that Statoil's internal control over financial reporting as of 31 December 2017 was not effective due to the existence of a material weakness in our controls and procedures for the identification, assessment and timely and appropriate communication to the Board Audit Committee of questions or concerns (including allegations of misconduct) raised by employees in connection with termination of their employment relating to issues that could potentially have a material impact on our Consolidated financial statements and internal controls over financial reporting (otherwise than through Statoil's external Ethics help line established by the Board Audit Committee). The allegations were subject to thorough investigations with external advisors, and no material misstatements were identified. There has been no effect on the 2017 Consolidated financial statements, or earlier periods, related to this matter.

Specifically, management identified that the established controls, policies and procedures did not operate as intended because our written procedures did not contain a sufficient level of precision for the identification, assessment and timely and appropriate communication of such matters to the appropriate relevant internal bodies including, where appropriate the Board Audit Committee. Other controls that should have compensated for this weakness did not operate as intended with respect to the reporting of such matters by some employees and so were ineffective.

Management has analysed the material weakness and performed additional analysis and procedures in preparing our Consolidated financial statements. We have concluded that our Consolidated financial statements fairly present, in all material respects, our financial condition, results of operations and cash flow at and for the periods presented. Apart from the material weakness described above, Statoil's management has not identified any other deficiencies that would have led management to conclude that Statoil's internal control over financial reporting was not effective. However, the material weakness identified created a possibility that a material misstatement to the Consolidated financial statements would not be prevented or detected on a timely basis and accordingly a remediation plan has been undertaken.

Statoil's internal control over financial reporting includes policies and procedures that pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect transactions and dispositions of assets, provide reasonable assurance that transactions are recorded in the manner necessary to permit the preparation of financial statements in accordance with IFRS, and that receipts and expenditures are only carried out in accordance with the authorisation of the management and directors of Statoil; and provide reasonable assurance regarding the prevention or timely detection of any unauthorised acquisition, use or disposition of Statoil's assets that could have a material effect on our financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect all misstatements. Moreover, projections of any evaluation of the effectiveness of internal control to future periods are subject to a risk that controls may become inadequate because of changes in conditions and that the degree of compliance with the policies or procedures may deteriorate.

Attestation report of the registered public accounting firm
The effectiveness of internal control over financial reporting as of 31 December 2017 has been audited by KPMG AS, an independent registered accounting firm that also audits the Consolidated financial statements in this report. Their report on internal control over financial reporting expresses an adverse opinion on the effectiveness of our internal control over financial reporting as of 31 December 2017.

Remediation plan
Our management is actively undertaking remediation efforts to address the material weakness identified above as follows:

- Enhancement of the precision level of written controls, policies and procedures regarding identification, assessment and timely communication to the Board Audit Committee
- Enhanced training of Statoil employees, with respect to these policies and relevant procedures

Management believes the foregoing plan effectively remediate the material weakness. As the remediation is implemented, management may take additional measures or modify the plan described above.

Changes in internal control over financial reporting
Other than the remediation plan described above, no changes occurred in our internal control over financial reporting during the period that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

We will continue to monitor and evaluate the effectiveness of our internal control over financial reporting and are committed to taking further action by implementing additional enhancements or improvements as may be deemed necessary.

Code of Conduct

Ethics - Statoil's approach
Statoil believes that responsible and ethical behaviour is a necessary condition for a sustainable business. Statoil's Code of Conduct is based on its values and reflects Statoil's commitment to high ethical standards in all its activities.

Our Code of Conduct
The Code of Conduct describes Statoil's code of business practice and the requirements to expected behaviour in areas such as anti-corruption, fair competition, human rights and non-discrimination working environments with equal opportunities. The Code of Conduct applies to Statoil's board members, employees and hired personnel.

Statoil seeks to work with others who share its commitment to ethics and compliance, and Statoil manages its risks through in-depth knowledge of suppliers, business partners and markets. Statoil expects its suppliers and business partners to comply with applicable laws, respect internationally recognised human rights and adhere to ethical standards which are consistent with Statoil's ethical requirements when working for or together with Statoil. In joint ventures and entities where Statoil does not have control, Statoil makes good faith efforts to encourage the adoption of ethics and anti-corruption policies and procedures that are consistent with its standards. Anyone working for Statoil who does not comply with the Code of Conduct faces disciplinary action, up to and including summery dismissal or termination of their contract.

Training and Certifying the Code of Conduct
The Code of Conduct training and comprehensive trainings on specific issues, including anti-corruption, anti-trust and reporting, is carried out to explain how the Code of Conduct applies and to describe the tools that Statoil has made available to address risk.

All Statoil employees have to annually confirm electronically that they understand and will comply with the Code of Conduct (Code certification). The Code certification reminds the individuals of their duty to comply with Statoil's values and ethical requirements, and creates an environment with open dialog on ethical issues, both internally and externally.

Anti-corruption compliance programme
Statoil is against all forms of corruption including bribery, facilitation payments and trading in influence and has a company-wide anti-corruption compliance programme which implements its zero-tolerance policy. The programme includes mandatory procedures designed to comply with applicable laws and regulations and training on relevant issues such as gifts, hospitality and conflicts of interest. Compliance officers, who are responsible for ensuring that ethics and anti-corruption considerations are integrated into Statoil's business activities, constitute an important part of the programme.

In 2017, Statoil Anti-Corruption Compliance Manual was updated to reflect the ongoing improvements and best practice in our anti-corruption program. Statoil continues to maintain is global network of compliance officers responsible for supporting the business to ensure that ethical and anti-corruption considerations are integrated into Statoil's activities no matter where they take place. In 2017, we worked towards strengthening support across the organisation through the deployment of senior corporate compliance resources to support regional activities. Statoil continue to work with our partners and suppliers on ethics and anti-corruption, and have initiated dialogs with several of our partners on the risks that we jointly face and actions that can be taken to address them.

Speak Up
Statoil is committed to maintain an open dialog on ethical issues. The Code of Conduct requires those who have a question or suspect misconduct to raise their concern either through internal channels or through Statoil's external Ethics Helpline. Employees are encouraged to discuss their concerns with their supervisor. Statoil recognises that raising a concern is not always easy so there are several internal channels for taking concerns forward, including through human resources or the ethics and compliance function in the legal department. Concerns can also be expressed through the externally operated Ethics Helpline which is available 24/7, and allows for anonymous reporting and two-way communication through the use of a pin-code. Statoil has a non-retaliation policy for anyone who reports in good faith.

More information about Statoil's policies and requirements related to the Code of Conduct is available on www.statoil.com/ethics.

Deviations from the Code: None

3.11 REMUNERATION TO THE BOARD OF DIRECTORS AND CORPORATE ASSEMBLY

Remuneration to the board of directors

The remuneration of the board and its sub-committees is decided by the corporate assembly, based on a recommendation from the nomination committee. The members have an annual, fixed remuneration, except for deputy members (only elected for employee-elected board members) who receive remuneration per meeting attended. Separate rates are set for the board's chair, deputy chair and other members, respectively. Separate rates are also adopted for the board's sub-committees, with similar differentiation between the chair and the other members of each committee. The employee-elected members of the board receive the same remuneration as the shareholder-elected members.

The board receives its remuneration by cash payment. Board members from outside Scandinavia and outside Europe, respectively, receive separate travel allowances for each meeting attended. The remuneration is not linked to the board members' performance, option programmes or similar. None of the shareholder-elected board members have a pension scheme or agreement concerning pay after termination of their office with the company. If shareholder-elected members of the board and/or companies they are associated with should take on specific assignments for Statoil in addition to their board membership, this will be disclosed to the full board.

In 2017, the total remuneration to the board, including fees for the board's three sub-committees, was NOK 6,278,638 (USD 759,846).

Detailed information about the individual remuneration to the members of the board of directors in 2017 is provided in the table below.

Members of the board (figures in USD thousand except number of shares)	Total remuneration	Share ownership as of 31 December 2017
Jon Erik Reinhardsen (chair of the board)1)	37	2,558
Øystein Løseth (chair of the board)2)	52	n.a.
Roy Franklin (deputy chair of the board)3)	118	-
Wenche Agerup	67	2,650
Bjørn Tore Godal	67	-
Rebekka Glasser Herlofsen	63	-
Maria Johanna Oudeman	89	-
Jeroen van der Veer	88	-
Per Martin Labråthen4)	33	1,343
Lill-Heidi Bakkerud5)	25	n.a.
Stig Lægreid	57	1,975
Ingrid Elisabeth di Valerio	63	4,471
Total	760	12,997

1) Chair from September 1, 2017

2) Chair until June 30, 2017 (resigned)

3) Chair between July 1 and August 31, 2017

4) Member from June 8, 2017

5) Member until June 7, 2017 (resigned)

Remuneration to the corporate assembly

The remuneration of the corporate assembly is decided by the general meeting, based on a recommendation from the nomination committee. The members have an annual, fixed remuneration, except for deputy members who receive remuneration per meeting attended. Separate rates are set for the corporate assembly's chair, deputy chair and other members, respectively. The employee-elected members of the corporate assembly receive the same remuneration as the shareholder-elected members. The corporate assembly receives its remuneration by cash payment.

In 2017, the total remuneration to the corporate assembly was NOK 1,070,497 (USD 129,552).
Deviations from the Code: None

3.12 REMUNERATION TO THE CORPORATE EXECUTIVE COMMITTEE

In 2017, the aggregate remuneration to the corporate executive committee was NOK 85,556, 482 (USD 10,354,122). The board of directors' complete declaration on remuneration of executive personnel follows below.

Only the following portions of this Section 3.12 Remuneration to the corporate executive committee form part of Statoil's annual report on Form 20-F as filed with the SEC: the table summarising the main elements of Statoil executive remuneration; the description regarding pension and insurance schemes, severance pay arrangements and other benefits; the deescription regarding performance management and results essential for variable pay and the table summarising the main objectives and KPIs for each perspective; the table summarising remuneration paid to each member of the corporate executive committee; the description of the company performance modifier; and the description regarding share ownership, including the summary table.

DECLARATION FROM CHAIR OF THE BOARD

Declaration on remuneration and other employment terms for Statoil's corporate executive committee

Statoil's remuneration policy and terms are aligned with the company's overall values, people policy and performance-oriented framework. Our rewards and recognition for executives are designed to attract and retain the right people; people who are committed to deliver on our business strategy and able to adapt to changing business environment. A key role for the board is to ensure that executive compensation is competitive, but not market leading, in the markets in which we operate. Executive compensation should also be seen as fair and aligned with overall compensation levels in the company, and with shareholders' interests. The board is responsible for finding this balance.

The board has reviewed the remuneration systems and concluded that practices are efficient, transparent and in accordance with prevailing guidelines and good corporate governance.

Oslo 14 March 2018
Jon Erik Reinhardsen

Pursuant to the Norwegian Public Limited Liability Companies Act, section 6-16 a, the board will present the following declaration regarding remuneration of Statoil's corporate executive committee to the 2018 annual general meeting.

Remuneration policy and concept for the accounting year 2018

Policy and principles
The company's established remuneration principles and concept as described in previous year's declaration on remuneration and other employment terms for Statoil's corporate executive committee will, with exception of the revised threshold for variable pay, be continued in the accounting year 2018.

The remuneration concept is an integrated part of our values based performance framework. It has been designed to:

- Be competitive and aligned with local markets
- Equally reward and recognise "What" we deliver and "How" we deliver
- Differentiate on the basis of responsibilities and performance
- Be acknowledged as fair, transparent, consistent and non-discriminatory
- Promote collaboration and teamwork
- Reflect the company's overall performance and financial result
- Strengthen the common interests of employees in the Statoil group and its shareholders
- Fully aligned with our values and HSE
- Promote continuous improvement and a sustainable cost level

The remuneration concept for the corporate executive committee
Statoil's remuneration policy and guidelines for the corporate executive committee are translated into the following main elements;

- Fixed remuneration: base salary and as applicable cash compensation
- Variable pay: annual variable pay (AVP) and long-term incentive (LTI)
- Benefits: primarily pension, insurance and share savings plan
- Company performance modifier and threshold for variable pay

The table below illustrate how our reward policy and framework is translated into key remuneration elements.

Main elements - Statoil executive remuneration

Remuneration element	Objective	Award level	Performance criteria
Base salary	Attract and retain the right individuals providing competitive but not market-leading terms.	We offer base salary levels which are aligned with and differentiated according to the individual's responsibility and performance. The level is competitive in the markets in which we operate.	The base salary is normally subject to annual review based on an evaluation of the individual's performance; see "Annual Variable Pay" below.
Cash compensation	The cash compensation is applied as a supplementing fixed remuneration element to be competitive in the market.	Reference is made to the remuneration table. Four of the executive vice presidents receive a cash compensation in lieu of pension accrual with reference to the section on pension and insurance scheme.	No performance criteria are linked to the cash compensation. The cash compensation is not included in the pensionable income.
Annual variable pay	Encourage a strong performance culture. Reward individuals for annual achievement of business objectives and goals relating to 'How' results are delivered.	Members of the corporate executive committee are entitled to annual variable pay ranging from 0 - 50% of their fixed remuneration. Target[10] value is 25%. The threshold principles and the company performance modifier are applied. The Company reserves the right to reclaim variable components of the remuneration awarded for performance if performance data is subsequently proven to be misstated.	Achievement of annual performance goals ("How" and "What" to deliver), in order to create long-term and sustainable shareholder value. Assessment of goals defined on the individual's performance contract including objectives related to selected KPI's on the balanced scorecard constitute the basis for annual variable pay.
Long-term incentive (LTI)	Strengthen the alignment of top management and shareholders' long-term interests. Retention of key executives.	The LTI system is a monetary compensation calculated as a portion of the participant's base salary. On behalf of the participant, the company acquires shares equivalent to the net annual grant amount. The shares are subject to a three-year lock-in period and then released for the participant's disposal. If the lock-in obligations are not fulfilled, the executive has to pay back the gross value of the locked-in shares limited to the gross value of the grant amount. The level of the annual LTI reward is in the range of 25-30%. The threshold principles are applied for the annual grant. The company performance modifier is not applied for the LTI in Statoil ASA.	In Statoil ASA, LTI participation and grant level are reflective of the level and impact of the position and not directly linked to the incumbent's performance.
Threshold	Financial threshold for payment of variable remuneration and award of LTI grant.	The threshold has the following guiding parameters; 1) Cash flows provided by operating activities after tax and before working capital items 2) Net debt ratio and development 3) Company's overall operational and financial performance. Cash flows provided by operating activities after tax and before working capital items higher than USD 12 billion and a net debt ratio below 30% will normally guide for no reduction of bonus.	Application of the threshold is subject to a discretionary assessment of the company's overall performance by the board of directors. These measures and targets are indicative and will form part of a broader assessment of bonus award.
Company performance modifier	Strengthen the alignment between variable remuneration and the company's performance.	The company performance modifier determines the proportion of the bonus that will be paid, ranging from 50% to 150% The company performance modifier is subject to approval by the annual general meeting.	Company performance is assessed against two equally weighted measures: relative total shareholder return (TSR) and relative return on average capital employed (ROACE). Application of the modifier is subject to discretionary assessment based on the company's overall performance.
Pension & insurance schemes	Provide competitive postemployment and other benefits.	The company offers a general occupational pension plan and insurance scheme aligned with local markets. Reference is made to the section on pension and insurance scheme.	N/A
Employee share savings plan	Align and strengthen employee and shareholders' interests and remunerate for long term commitment and value creation.	The share savings plan is offered to all employees in the group, provided no restrictions due to local legislation or business requirements. Participants are offered to purchase Statoil shares in the market limited to 5% of annual base salary.	If shares are kept for two calendar years of continued employment, the participants will be allocated bonus shares proportionate to their purchase.

[1] Target value reflects satisfactory deliveries according to agreed goals

Pension and insurance schemes
Members of the corporate executive committee in Statoil ASA are covered by the company's general occupational pension scheme which is a defined contribution scheme with a contribution level of 7% below 7,1 G and 22% above 7,1 G[2]. A defined benefit scheme is retained by a grandfathered group of employees. For new members of the corporate executive committee appointed after 13 February 2015, a cap on pension contribution at 12 G is applied. In lieu of pension accrual above 12 G a cash compensation is provided. Four of the executive vice presidents receive a cash compensation in lieu of pension accrual.

Members of the corporate executive committee appointed before 13 February 2015, will maintain their pension contribution above 12 G based on obligations in previously established agreements.

The chief executive officer and three executive vice presidents have individual early retirement pension agreement with the company.

The chief executive officer and one of the executive vice presidents have individual pension terms according to a previous standard arrangement implemented in October 2006. Subject to specific terms those executives are entitled to a pension amounting to 66% of pensionable salary and a retirement age of 62. Reference is made to the section on CEO terms and conditions below. When calculating the number of years of membership in Statoil's general pension plan, these agreements grant the right to an extra contribution time corresponding to half a year of extra membership for each year the individual has served as executive vice president.

In addition, two members of the corporate executive committee have individually agreed retirement age of 65 and an early retirement pension level amounting to 66% of pensionable salary.

The pension terms for executive vice presidents outlined above are results of previously established individual agreements.

Statoil has implemented a general cap on pensionable income at 12 G for all new hires into the company employed as of 1 September 2017.

In addition to the pension benefits outlined above, the executive vice presidents in the parent company are offered disability and dependents' benefits in accordance with Statoil's general pension plan/defined benefit plan. Members of the corporate executive committee are covered by the general insurance schemes applicable within Statoil.

Severance pay arrangements
The chief executive officer and the executive vice presidents are entitled to a severance payment equivalent to six months' salary, commencing at the time of expiry of a six months' notice period, when the resignation is at the request from the company. The same amount of severance payment is also payable if the parties agree that the employment should be discontinued and the executive vice president gives notice pursuant to a written agreement with the company. Any other payment earned by the executive vice president during the period of severance payment will be fully deducted. This relates to earnings from any employment or business activity where the executive vice president has active ownership.

The entitlement to severance payment is conditional on the chief executive officer or the executive vice president not being guilty of gross misconduct, gross negligence, disloyalty or other material breach of his/her duties.

As a general rule, the chief executive officer's/executive vice president's own notice will not instigate any severance payment.

Other benefits
The members of the corporate executive committee have benefits in kind such as company car and electronic communication. They are also eligible for participation in the share saving scheme as described above.

Performance management, assessment and results essential for variable pay

Individual salary and annual variable pay reviews are based on the performance evaluation in our performance development process.

Performance is evaluated in two dimensions; "What" we deliver and "How" we deliver. "What" we deliver (business delivery) is defined through the company's performance framework "Ambition to Action", which addresses strategic objectives, key performance Indicators (KPIs) and actions across the five perspectives; Safety, Security and Sustainability, People and Leadership, Operations, Market and Finance. Generally, Statoil believes in setting ambitious targets to inspire and drive strong performance.

Goals on "How" we deliver are based on our core values and leadership principles and address the behaviour required and expected in order to achieve our delivery goals.

Performance evaluation is holistic, involving both measurement and assessment. Since KPIs are indicators only, sound judgement are applied. Significant changes in assumptions are taken into account, as well as target ambition levels, sustainability of delivered results and strategic contribution.

This balanced approach, which involves a broad set of goals defined in relation to both "What" and "How" dimensions and an overall performance evaluation, is viewed to significantly reduce the likelihood that remuneration policies may stimulate excessive risk-taking or have other material adverse effects.

In the performance contracts of the chief executive officer and chief financial officer, one of several targets is related to the company's relative total shareholder return (TSR). The amount of the annual variable pay is decided based on an overall assessment of the performance of various targets including but not limited to the company's relative TSR.

[2] G = The basic amount of the Norwegian social security system

In 2017, the main objectives and KPIs for each perspective were as outlined below. Each perspective was in addition supported by comprehensive plans and actions.

Strategic objectives		2017 assessment
Safety, security and sustainability	The strategic objectives and actions address safety, security and sustainability	Total Serious Incident Frequency of 0.6 was on target, improving from the 2016 level. The target on Total Recordable Injury Frequency was narrowly missed. The number of oil and gas leakages improved from 2016 but exceeded the target. CO_2 intensity for the upstream portfolio improved from the 2016 level, and Statoil reached its target of being in the top quartile in the IOGP company report on this parameter.
People and organisation	The strategic objectives and actions address a value based and high performing organisation	The score on Employee engagement exceeded the target, also increasing from the 2016 level, which confirmed the employees' continued engagement and commitment to Statoil despite a challenging business context The results on People development were above target, showing positive trends both in learning activities and in internal deployment.
Operations	The strategic objectives and actions address reliable and cost-efficient operations, and being a driver in oil and gas industry transformation	Production was highest in Statoil's history and exceeded the target. On relative unit production cost, Statoil reached the target of being in the first quartile of the peer group. The company maintained its position at the top of the peer group for the third year running. Production efficiency was above target.
Market	The strategic objectives and actions address a flexible and resilient energy portfolio	Reserve replacement ratio exceeded the target of 1, driven by project sanctions and upward revisions on a number of existing assets, both offshore and onshore. Organic capex was better than the original guiding and target, mainly due to strict prioritisation and continuous focus on capital efficiency. Value creation from exploration did not reach the target, mainly due to lower-than-expected discovered volumes. However, Statoil has secured access to new acreage, such as the Carcara North block in Brazil and the Bajo del Toro block in Argentina.
Finance	The strategic objectives and actions address cash generation, profitability and competitiveness	On Relative Shareholder Return, Statoil ranked 4th in an industry peer group of 12, thus meeting the target of securing a position above average. On Relative ROACE, Statoil ranked 2nd in the peer group, thus meeting the target of securing a position above average. The cash flow improvement programme delivered above target.

Board assessment of the chief executive officer's performance

In its assessment of the chief executive officer's performance, and consequently his annual pay for 2017, the board has put emphasis on a strong delivery on production, continued efficiency improvements, and a positive trend within Safety, Security and Sustainability (SSU). The negative trend from 2016 has been turned and the Serious Incidents Frequency (SIF) is on target. CO2 intensity per boe has been reduced with more than 10% compared to 2016 results.

Statoil has increased production guiding and at the same time reduced the capex, enabled by further efficiency improvements and strict prioritization. Statoil has secured access to new acreage and strengthened the portfolio. The TSR and ROACE results are solid. Employee engagement is strong and improving, supported by a dedicated focus on people development.

Key performance indicators for the chief executive officer for 2018

The delivery dimension for the CEO's variable remuneration (performance year 2018) and base salary merit in 2019 will be based on assessment of results on the following KPIs:

Safety, Security and Sustainability
- Serious Incident Frequency
- CO_2 intensity for the upstream portfolio

Market
- Fixed operating and SG&A expenses (per boe)

Results
- Relative Total Shareholder Return
- Relative ROACE

Execution of the remuneration policy and principles in 2017

Introduction

- The remuneration policy and principles executed in 2017 were in accordance with the declaration given to the AGM 11 May 2017
- Subject to application of the threshold described in the remuneration concept, the LTI grant in 2017 was reduced by 50% of the maximum level.
- Based on a holistic evaluation, with focus on opportunity for further performance improvement, the annual variable pay for members of the corporate executive committee has been reduced by 12%. 12

Performance management system

Statoil's performance management system was changed in 2017, to strengthen continuous feedback and development focus. The aim is to enable performance through a more dynamic approach, strength-based development and forward focus. Some of the principled changes to the performance management system includes discontinuation of the five-grade rating system, while increasing performance and development dialogues throughout the year.

Performance is still assessed, and "How" we deliver will continue to be as important as "What" we deliver.

Revised threshold for variable pay

In 2015 Statoil introduced a threshold for variable pay to strengthen the link between the company's performance and variable pay. Based on experience and market information, the threshold concept has been reviewed and adjusted. The annual threshold decision will be founded on a broad-based assessment comprising several criteria including the company's overall operational and financial performance.

The revised threshold has the following guiding parameters;

- Cash flow provided by operating activities after tax and before working capital items
- Net debt ratio and development
- Company's overall operational and financial performance

Cash flow provided by operating activities after tax and before working capital items higher than USD 12 billion and a net debt ratio below 30% will normally guide for no reduction of bonus. These measures and targets are indicative and will form part of a broader assessment of bonus award. The holistic assessment of the company's overall operational and financial performance, will focus on (but not be limited to); HSE, production, operational efficiency, progress of improvements, project execution, adjusted earnings and adjusted ROACE. The revised threshold will apply for the performance year 2017.

Company modifier for variable pay relating to performance year 2017

The company modifier depends on the outcome of two metrics ROACE and TSR, both parameters measured relatively to a peer group of 11 other companies. The results for Statoil in 2017 were; relative ROACE number 2 and relative TSR number 4 in the peer group. This gives first quartile result for ROACE and second quartile result for TSR, which gives a company modifier of 1,33 for 2017.

12 This reduction is compared to pay-out levels when applying individual performance assessment and the company modifier for 2017

CEO Terms and conditions

Eldar Sætre was appointed chief executive on 4 February 2015, after acting CEO since October 2014. Under his individual pension agreement Eldar Sætre had the right to retire at the age of 62, after three years as chief executive. Due to this, an element of his fixed pay was excluded from his pensionable income. Statoil's board of directors and chief executive Eldar Sætre agreed in 2017 that Sætre will continue as CEO after he turns 62 in February 2018. Hence, it was agreed that the CEO would not use his contractual right to retire at the age of 62. As the CEO did not exercise his right to retire at 62, the board decided to revert to the original provision of pension being calculated on total fixed pay. The fixed pay element amounting to NOK 2,408,505 has thus been included in the pensionable income. Eldar Sætre will at the latest retire when he turns 67, but retains the right to retire at an earlier stage.

The Statoil board has reviewed the CEO's remuneration package compared to the market. Subsequently, the board has increased the CEO's fixed annual pay to NOK 8,767,682, effective from 1 September 2017.

The chief executive officer will continue to participate in an annual variable pay scheme with a target level of 25% (max 50%), and participation in the company's 2018 LTI scheme with a value of 30% (gross) of base salary. Except for the inclusion of the fixed pay element in the CEO's base salary as pensionable income, pension terms remain unchanged, as described in section on pension and insurance scheme.

The decision-making process

The decision-making process for implementing or changing remuneration policies and concepts, and the determination of salaries and other remuneration for corporate executive committee, are in accordance with the provisions of the Norwegian public limited liability companies act sections 5-6 and 6-16 a and the board's rules of procedure. The board's rules of procedure are available at www.statoil.com/board.

The board of directors has appointed a designated compensation and executive development committee. The compensation and executive development committee is a preparatory body for the board. The committee's main objective is to assist the board of directors in its work relating to the terms of employment for Statoil's chief executive officer and the main principles and strategy for the remuneration and leadership development of our senior executives. The board of directors determines the chief executive officer's salary and other terms of employment.

The compensation and executive development committee answers to the board of Statoil ASA for the performance of its duties. The work of the committee in no way alters the responsibilities of the board of directors or the individual board members.

For further details about the roles and responsibilities of the compensation and executive development committee, please refer to the committee's instructions available at www.statoil.com/compensationcommittee.

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Compensation to and share ownership of the corporate executive committee (CEC)

	Fixed remuneration										
Members of the corporate executive committee (figures in USD thousand, except no. of shares)[1), 2)]	Fixed pay[3)]	Cash allowance[4)]	LTI [5)]	Annual variable pay[6)]	Taxable benefits	2017 Taxable compensation	Non-taxable benefits in kind	Estimated pension cost[7)]	Estimated present value of pension obligation [8)]	2016 Taxable compensation[9)]	Share ownership at 31 December 2017
Eldar Sætre[10)]	1,045	0	149	570	48	1,812	0	0	14,489	1,356	56,896
Margareth Øvrum	494	0	54	253	36	837	24	0	6,912	631	56,125
Timothy Dodson	466	0	52	140	31	689	46	152	4,977	573	34,425
Irene Rummelhoff	381	62	38	154	22	657	0	29	1,404	511	25,081
Jens Økland	396	65	41	145	20	667	0	24	1,067	509	17,207
Arne Sigve Nylund	429	0	50	218	23	720	0	120	4,314	546	13,354
Lars Christian Bacher	447	0	46	193	24	710	58	128	2,733	567	23,309
Hans Jakob Hegge	398	66	44	170	25	703	0	25	1,493	561	32,104
Jannicke Nilsson	401	63	42	147	25	678	24	36	1,315	40	38,491
Torgrim Reitan[11)]	696	0	50	169	143	1,058	0	121	2,712	884	36,235
John Knight[12)]	1,643	0	0	0	181	1,824	0	0	0	1,810	109,901

1) All figures in the table are presented in USD based on average currency rates (2017: USD/NOK = 8.2630, USD/GBP = 1.2882. 2016: USD/NOK = 8.3987, USD/GBP = 1.3538). The figures are presented on accrual basis.
2) All CEC members receive their remuneration in NOK except John Knight who receives the remuneration in GBP.
3) Fixed pay consists of base salary, fixed remuneration element, holiday allowance and other administrative benefits.
4) Cash allowance in lieu of pension accrual above 12 G (G is the base amount in the national insurance scheme).
5) The long-term incentive (LTI) element implies an obligation to invest the net amount in Statoil shares, including a lock-in period. The LTI element is presented the year it is granted for the members of the corporate executive committee employed by Statoil ASA.
6) Annual variable pay includes holiday allowance for corporate executive committee (CEC) members resident in Norway.
7) Estimated pension cost is calculated based on actuarial assumptions and pensionable salary (mainly base salary) at 31 December 2016 and is recognised as pension cost in the statement of income for 2017.
8) Eldar Sætre, Arne Sigve Nylund, Margareth Øvrum and Timothy Dodson are maintained in the closed Defined Benefit Scheme, whereas the remaining members of corporate executive committee employed by Statoil ASA, is covered by the Defined Contribution Pension Scheme.
9) Includes 2016 CEC members who are also CEC members in 2017.
10) Estimated present value of pension obligation for Eldar Sætre is based on retirement at the age of 67. Eldar Sætre has the right to retire at an earlier stage.
11) Terms and conditions for Torgrim Reitan also include compensation according to Statoil's international assignment terms.
12) John Knight's fixed pay includes a fixed remuneration element of USD 143,000 that replaces his defined contribution pension plan and a fixed remuneration element of USD 689,000 replacing his variable pay arrangements.

There are no loans from the company to members of the corporate executive committee.

Company performance modifier

Introduction
Based on initial approval by the annual general meeting in 2016 a company performance modifier was introduced to be applied in calculation of variable pay. The intention is to continue with the performance modifier in 2018. The relative total shareholder return is recommended as one of the criteria in the modifier. Thus, the proposal is submitted to the annual general meeting for approval, pursuant to the provisions in the Public Limited Companies Act § 5-6 third paragraph last sentence ref. § 6-16 a, first paragraph third sentence number 3.

Background
Statoil has implemented annual variable pay schemes (AVP) for members of the corporate executive committee. The schemes are described in section on remuneration concept for the corporate executive committee of this declaration. Other executives, managers and employees in defined professional positions are also eligible for individual variable pay according to the company's guidelines.

The company performance modifier is implemented to strengthen the link between the company's overall financial results and the individual variable pay. The governmental guidelines on executive remuneration also underline that "there shall be a clear connection between the variable salary and the performance of the company."

Proposal
Based on this, the performance modifier will be continued in 2018. The company performance will be assessed against two equally weighted measures: relative total shareholder return (TSR) and relative return on average capital employed (ROACE). TSR and ROACE are currently also applied as performance indicators in the corporate performance management system.

The results of these two performance measures are compared to our peers and our relative position determined. A position of Quartile 1 means that Statoil is amongst the top scoring quartile of peer companies. A position of Quartile 4 means Statoil is in the bottom performing quartile. In years with strong deliveries on relative TSR and ROACE, the matrix will result in the variable pay being modified with a factor higher than one and, correspondingly, lower than one in weak years. The combination of ratings for both measures, will act as a 'multiplier' according to the guideline in the matrix displayed below.

Relative RoACE	Q4	Q3	Q2	Q1
Q1	100 %	117 %	133 %	150 %
Q2	83 %	100 %	117 %	133 %
Q3	67 %	83 %	100 %	117 %
Q4	50 %	67 %	83 %	100 %

Relative TSR

By applying relative numbers, the effect of fluctuating oil price will be reduced. Within the framework of 50 - 150%, the matrix is a guideline and the multiplier (percentages) may be adjusted if oil or gas price effects or other occurrences outside the control of the company are deemed to cause disproportionate results in a given year.

Subject to approval by the 2018 annual general meeting, the company performance modifier will be continued in calculations of annual variable pay for members of the corporate executive committee in the earning year 2018 with subsequent impact on annual variable pay in 2019. The modifier will also be applied in other variable pay schemes below the corporate executive level. Further application of the company performance modifier will also be assessed and decided if deemed appropriate.

The annual variable pay for members of the corporate executive committee will be within a framework of 50% of the fixed remuneration irrespective of the result of the modifier. Any deviations from this framework for members of the corporate executive committee will be explained in the board's annual declaration on remuneration and other employment terms for Statoil's corporate executive committee.

Share ownership

The number of Statoil shares owned by the members of the board of directors and the executive committee and/or owned by their close associates is shown below. Individually, each member of the board of directors and the corporate executive committee owned less than 1% of the outstanding Statoil shares.

Ownership of Statoil shares (including share ownership of «close associates»)	As of 31 December 2017	As of 14 March 2018
Members of the corporate executive committee		
Eldar Sætre	56,896	57,783
Hans Jakob Hegge	32,104	33,305
Jannicke Nilsson	38,491	39,638
Lars Christian Bacher	23,309	24,400
Torgrim Reitan	36,235	37,358
John Knight	109,901	112,543
Tim Dodson	34,425	35,506
Margareth Øvrum	56,125	57,655
Arne Sigve Nylund	13,354	13,354
Jens Økland	17,207	17,657
Irene Rummelhoff	25,081	25,795
Members of the board of directors		
Jon Erik Reinhardsen	2,558	2,558
Roy Franklin	0	0
Bjørn Tore Godal	0	0
Jeroen van der Veer	0	0
Maria Johanna Oudeman	0	0
Rebekka Glasser Herlofsen	0	0
Wenche Agerup	2,650	2,650
Per Martin Labråten	1,343	1,516
Ingrid Elisabeth di Valerio	4,471	4,821
Stig Lægreid	1,975	1,975

Individually, each member of the corporate assembly owned less than 1% of the outstanding Statoil shares as of 31 December 2017 and as of 14 March 2018. In aggregate, members of the corporate assembly owned a total of 30,839 shares as of 31 December 2017 and a total of 33,029 shares as of 14 March 2018. Information about the individual share ownership of the members of the corporate assembly is presented in the section 3.8 Corporate assembly, board of directors and management.

The voting rights of members of the board of directors, the corporate executive committee and the corporate assembly do not differ from those of ordinary shareholders.

Deviations from the Code: None

3.13 INFORMATION AND COMMUNICATIONS

The reporting is based on openness and it takes into account the requirement for equal treatment of all participants in the securities market. Statoil has established guidelines for the company's reporting of financial and other information and the purpose of these guidelines is to ensure that timely and correct information about the company is made available to our shareholders and society in general.

A financial calendar and shareholder information is published at www.statoil.com/calendar.

The investor relations corporate staff function is responsible for coordinating the company's communication with capital markets and for relations between Statoil and existing and potential investors. Investor relations is responsible for distributing and registering information in accordance with the legislation and regulations that apply where Statoil securities are listed. Investor relations reports directly to the chief financial officer.

The company's management holds regular presentations for investors and analysts. The company's quarterly presentations are broadcast live on our website. Investor relations communicate with present and potential shareholders through presentations, one-to-one meetings, conferences, web-site, financial media, telephone, mail and e-mail contact. The pertaining reports from these communication channels are made available together with other relevant information at www.statoil.com/investor.

All information distributed to the company's shareholders is published on the company's website at the same time as it is sent to the shareholders.

Deviations from the Code: None

3.14 TAKE-OVERS

The board of directors endorses the principles concerning equal treatment of all shareholders and Statoil's articles of association do not set limits on share acquisitions. Statoil has no defence mechanisms against take-over bids in its articles of association, nor has it implemented other measures that limit the opportunity to acquire shares in the company. The Norwegian State owns 67% of the shares, and the marketability of these shares is subject to parliamentary decree.

The board is obliged to act professionally and in accordance with the applicable principles for good corporate governance if a situation should arise in which this principle in the Code were put to the test.

Deviations from the Code:
The Code recommends that the board establish guiding principles for how it will act in the event of a take-over bid. The board has not established such guidelines, due to Statoil's ownership structure and for the reasons stated above. In the event of a bid as discussed in section 14 of the Code, the board of directors will, in addition to complying with relevant legislation and regulations, seek to comply with the recommendations in the Code. The board has no other explicit basic principles or written guidelines for procedures to be followed in the event of a take-over bid. The board of directors otherwise concurs with what is stated in the Code regarding this issue.

3.15 EXTERNAL AUDITOR

Our independent registered public accounting firm (external auditor) is independent in relation to Statoil and is elected by the general meeting of shareholders. The external auditor's fee must be approved by the general meeting of shareholders.

Pursuant to the instructions for the board's audit committee approved by the board of directors, the audit committee is responsible for ensuring that the company is subject to an independent and effective external and internal audit. Every year, the external auditor presents a plan to the audit committee for the execution of the external auditor's work. The external auditor attends the meeting of the board of directors that deals with the preparation of the annual accounts.

The external auditor also participates in meetings of the audit committee. The audit committee considers all reports from the external auditor before they are considered by the board of directors. The audit committee meets at least five times a year and both the board and the board's audit committee hold meetings with the internal auditor and the external auditor on a regular basis without the company's management being present.

When evaluating the external auditor, emphasis is placed on the firm's qualifications, capacity, local and international availability and the size of the fee.

The audit committee evaluates and makes a recommendation to the board of directors, the corporate assembly and the general meeting of shareholders regarding the choice of external auditor. The committee is responsible for ensuring that the external auditor meets the requirements in Norway and in the countries where Statoil is listed. The external auditor is subject to the provisions of US securities legislation, which stipulates that a responsible partner may not lead the engagement for more than five consecutive years.

The audit committee's policies and procedures for pre-approval
In its instructions for the audit committee, the board of directors has delegated authority to the audit committee to pre-approve assignments to be performed by the external auditor. Within this pre-approval, the audit committee has issued further guidelines. The audit committee has issued guidelines for the management's pre-approval of assignments to be performed by the external auditor.

All audit-related and other services provided by the external auditor must be pre-approved by the audit committee. Provided that the types of services proposed are permissible under SEC guidelines, pre-approval is usually granted at a regular audit committee meeting. The chair of the audit committee has been authorised to pre-approve services that are in accordance with policies established by the audit committee that specify in detail the types of services that qualify. It is a condition that any services pre-approved in this manner are presented to the full audit committee at its next meeting. Some pre-approvals can therefore be granted by the chair of the audit committee if an urgent reply is deemed necessary.

Remuneration of the external auditor in 2015 - 2017
In the annual Consolidated financial statements and in the parent company's financial statements, the independent auditor's remuneration is split between the audit fee and the fee for audit-related and other services. The chair presents the breakdown between the audit fee and the fee for audit-related and other services to the annual general meeting of shareholders.

The following table sets out the aggregate fees related to professional services rendered by Statoil's external auditor KPMG AS, for the fiscal year 2017, 2016 and 2015.

Auditor's remuneration

(in USD million, excluding VAT)	Full year 2017	2016	2015
Audit fee	6.1	6.5	6.1
Audit related fee	0.9	1.0	1.7
Tax fee	0.0	0.1	0.0
Other service fee	0.0	0.0	0.0
Total	7.0	7.5	7.9

All fees included in the table have been approved by the board's audit committee.

Audit fee is defined as the fee for standard audit work that must be performed every year in order to issue an opinion on Statoil's Consolidated financial statements, on Statoil's internal control over annual reporting and to issue reports on the statutory financial statements. It also includes other audit services, which are services that only the independent auditor can reasonably provide, such as the auditing of non-recurring transactions and the application of new accounting policies, audits of significant and newly implemented system controls and limited reviews of quarterly financial results.

Audit-related fees include other assurance and related services provided by auditors, but not limited to those that can only reasonably be provided by the external auditor who signs the audit report, that are reasonably related to the performance of the audit or review of the company's financial statements, such as acquisition due diligence, audits of pension and benefit plans, consultations concerning financial accounting and reporting standards.

Other services fees include services, if any, provided by the auditors within the framework of the Sarbanes-Oxley Act, i.e. certain agreed procedures.

In addition to the figures in the table above, the audit fees and audit-related fees relating to Statoil operated licences paid to KPMG for the years 2017, 2016 and 2015 amounted to USD 0.8 million, USD 0.8 million and USD 0.9 million, respectively.

Deviations from the Code: None

Financial statements and supplements

Bakken.
Photo: Jan Arne Wold/Woldcam

4.1 Consolidated financial statements of the Statoil group

The report set out below is provided in accordance with law, regulations, and auditing standards and practices generally accepted in Norway, including International Standards on Auditing (ISAs). KPMG AS has also issued reports in accordance with standards of the Public Company Accounting Oversight Board in the US, which include opinions on the Consolidated financial statements of Statoil ASA and on the effectiveness of internal control over financial reporting as at 31 December 2017. Those reports are set out on pages 131 and 132.

Independent auditor's report

To the annual shareholders' meeting of Statoil ASA

Report on the audit of the financial statements

Opinion

We have audited the financial statements of Statoil ASA for the year ended 31 December 2017.

The financial statements comprise:

- the Consolidated financial statements of Statoil ASA and its subsidiaries (the Group), which comprise the Consolidated balance sheet as at 31 December 2017, the Consolidated statements of income, comprehensive income, changes in equity and cash flows for the year then ended, and notes to the financial statements, including a summary of significant accounting policies.
- the parent company financial statements of Statoil ASA (the Company) on page, which comprise the company balance sheet as at 31 December 2017, and the company's statements of income, comprehensive income and cash flows for the year then ended, and notes to the financial statements, including a summary of significant accounting policies.

In our opinion:

- the financial statements are prepared in accordance with relevant Norwegian law and regulations.
- the Consolidated financial statements give a true and fair view of the financial position of Statoil ASA and its subsidiaries as at 31 December 2017, of its financial performance and its cash flows for the year then ended in accordance with International Financial Reporting Standards as adopted by the EU.
- the parent company financial statements give a true and fair view of the financial position of Statoil ASA as at 31 December 2017, of its financial performance and its cash flows for the year then ended in accordance with simplified application of international accounting standards according to section 3-9 of the Norwegian Accounting Act.

Basis for opinion

We conducted our audit in accordance with laws, regulations, and auditing standards and practices generally accepted in Norway, including International Standards on Auditing (ISAs). Our responsibilities under those standards are further described in the *Auditor's Responsibilities for the Audit of the Financial Statements* section of our report. We are independent of the Company and the Group as required by laws and regulations, and we have fulfilled our other ethical responsibilities in accordance with these requirements. We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our opinion.

Key audit matters

Key audit matters are those matters that, in our professional judgment, were of most significance in our audit of the financial statements for the year ended 31 December 2017. These matters were addressed in the context of our audit of the financial statements as a whole, and in forming our opinion thereon, and we do not provide any discrete opinion on these matters.

Key audit matter	*How the matter was addressed in our audit*
Valuation of upstream assets including assets under development, capitalised exploration expenses and acquisition costs for oil and gas prospects The Group owns significant upstream assets including assets under development, capitalised exploration expenses and acquisition costs for oil and gas prospects. The recoverability of these assets is dependent on management's estimates of the future cash flows that these assets are expected to produce. The carrying value of these assets are therefore particularly sensitive to changes in management's long term commodity price forecasts. Changes in short term commodity price forecasts, which management derives from observed forward oil and gas price curves over a one year period, can also have a significant impact for shorter-lived assets. Additionally, the carrying value of these assets can be impacted by changes in expected reserves and revised cost estimates due to operational developments. In 2017, management recognised various impairment charges and reversals of impairment following asset specific impairment (reversal) triggers, most notably: • a reversal of impairment related to an unconventional onshore asset in North America, triggered by changes in US tax legislation, including a change in the corporate tax from 35 % to 21 % combined with operational improvements and increased recovery rates; • a reversal of impairment related to a conventional offshore asset in the development phase in Norway, triggered by increased expected reserves, cost reductions and increased short term price assumptions; and • an impairment charge for an unconventional onshore asset in North America triggered by changes in the operational plan following lower than expected production and a significant reduction in expected reserves. Capitalised exploration expenses and the capitalised acquisition cost of oil and gas prospects are assessed for impairment when facts and circumstances suggest that the carrying amount of the asset may exceed its recoverable amount. Refer to note 10 *Property, plant and equipment* and note 11 *Intangible assets* to the consolidated financial statements.	We evaluated and tested management's controls over the process it uses to identify triggers that would require impairment (reversal) testing of specific assets. We also assessed the appropriateness of management's identification of cash generating units in light of our knowledge of the business. In addition, we undertook our own analysis to assess whether all material assets requiring impairment testing had been identified by management. We did not identify any assets where impairment testing was required that had not been identified by management. For those assets where management identified an impairment (reversal) trigger, we evaluated and tested management's controls over the impairment calculations performed, including the assumptions applied. We assessed management's macroeconomic assumptions including short and long term commodity price, foreign currency rate and inflation rate forecasts and discount rates. We compared the short term price forecasts to observable market forward curves that we sourced independently. We compared management's long term assumptions to views published by brokers, economists, consultancies and respected industry bodies that we sourced independently, which provided a range of relevant third-party data points, and to our own views. We also assessed by reference to market data the inputs to and calculation of the discount rate used by management. The key inputs included the risk-free rate, market risk premium and industry financing structures (gearing and cost of debt and equity). In testing these assumptions we made use of KPMG valuation experts. For those assets where management identified an impairment (reversal) trigger, we assessed the valuation method, estimates of future cash flows and challenged whether these were appropriate in light of: • management's commodity price, foreign currency rate and inflation rate forecasts; • production and reserve estimates; • capital and operating budgets and historical performance; and • previous estimates. When management relies on valuations prepared by external valuation experts, we have assessed the appropriateness of such valuations making use of KPMG valuation experts. We assessed the mathematical accuracy of the valuation models and the accuracy of the impairment (reversal) recognised in the financial statements. Based on our procedures we consider the impairment charges/reversals to be appropriate. We considered whether the sensitivity analysis included in note 10 *Property, plant and equipment* appropriately described the Group's exposure to further impairments should future commodity prices deviate from management's forecasts. We evaluated and tested management's controls over the process it uses to evaluate whether the carrying value of capitalised exploration expenses and acquisition cost for oil and gas prospects is no longer sustainable.

Key audit matter	*How the matter was addressed in our audit*
Income tax estimates The Group has operations in multiple countries, each with its own taxation regime. Management makes judgements and estimates in relation to uncertain tax positions and valuation of deferred tax assets. The Group has significant deferred tax assets related to historic tax losses. The period over which such assets are expected to be recovered can be extensive and management applies significant judgement in assessing whether those deferred tax assets should be recognised and to determine the recoverability of those balances. In addition, management applies significant judgement in estimating the provision relating to uncertain tax positions and/or related disclosure. These usually arise in countries where the fiscal contribution of the oil and gas industry to the country's budget is very significant and where the tax regime and administration are immature and/or developing. The most notable significant uncertain tax position is a dispute with the Norwegian tax authorities that issued a deviation notice in 2016 regarding transactions between Statoil Coordination Centre (SSC) in Belgium and Norwegian entities within the Group. The issue relates to SCC's capital structure and compliance with the arm's length principle. In addition, in 2016, the Brazilian tax authorities have issued a tax assessment for 2011 disputing the allocation of sale proceeds between entities and assets involved, with regard to a divestment of 40 % interest in the Peregrino field to Sinochem at the time. A dispute with the Angolan Ministry of Finance regarding the Group's participation in Block 4, Block 15, Block 17 and Block 31 offshore Angola with regards to profit oil and taxes on activities between 2002 and 2016 has been settled in 2017. Refer to note 9 *Income taxes* and note 23 *Other commitments, contingent liabilities and contingent assets* to the consolidated financial statements.	We evaluated and tested management's controls over the process it uses to measure deferred tax assets related to historic tax losses and to determine provisions for uncertain tax positions and/or related disclosure. In determining the extent to which deferred tax assets should be recognised, we assessed whether the applied long term commodity price forecasts and foreign currency assumptions were consistent with those described in the key audit matter relating to valuation of upstream assets including assets under development, capitalised exploration expenses and acquisition costs for oil and gas prospects. We challenged the key assumptions made by management and confirmed that these were consistent with the long term business plans used by management to manage and monitor the development of the business. We performed detailed testing over the tax position in each significant jurisdiction in which the Group operates using our global and local tax experts as appropriate. We examined and assessed correspondence with tax authorities and the Group's tax advisers and papers relating to tax investigations/cases as appropriate. The calculations used by management to determine the provisions for uncertain tax positions were assessed based on our understanding of the position of the Group and the position of the tax authorities. We consider that the provisions for uncertain tax positions and related disclosure are appropriate. We highlighted the high level of inherent uncertainty in some of the positions.

Key audit matter	*How the matter was addressed in our audit*
Estimate of asset retirement obligation Given the nature of its operations, the Group incurs obligations to dismantle and remove facilities and to restore the site on which it is located. Management applies significant judgement to estimate the asset retirement obligation due to the inherent complexity in estimating future costs and the limited historical experience against which to benchmark estimates of future costs. Key assumptions are future abandonment costs, foreign currency assumptions and inflation rates. Refer to note 20 *Provisions* to the consolidated financial statements.	We challenged the key assumptions in management's annual process for determining the asset retirement obligation. Our testing was focused on those assumptions having the most significant impact on the asset retirement obligation selected based on our sensitivity analysis. To validate the appropriateness of the expected future abandonment costs we tested whether technical inputs including the number of wells, weight of the structure and length of pipelines applied in the calculation are consistent with technical assessments of the relevant fields. Further, we assessed the reasonableness of rig rates using external market data and historic rig contracts. Our procedures over foreign currency assumptions and inflation rates were an integral part of our assessment of assumptions as applied in impairment testing. We refer to our response as described in the key audit matter over the valuation of upstream including assets under development, capitalised exploration expenses and acquisition costs for oil and gas prospects. Based on our procedures, we consider management's estimate of the asset retirement obligation as at 31 December 2017 to be appropriate.

Key audit matter	*How the matter was addressed in our audit*
Potential illegal acts including alleged accounting misconduct raised by former employees Similar to most large multinational companies, from time to time, the Group receives allegations regarding potentially illegal acts that could potentially have a material impact on the financial statements. The Group has developed certain policies and procedures and designed a control environment to respond to any such allegations and to establish whether or not there are misstatements in its financial statements. It has also developed certain controls designed to reduce the risk that, where any such allegations are in fact correct, intentional misstatement or other material misstatements would not be detected and corrected in a timely manner. In connection with the audit of the financial statements, there were identified such an allegation made by a former employee which had not been communicated to relevant internal bodies, including the Board Audit Committee. The risk is that (1) there could be material misstatement arising from known allegations and (2) the Group's control environment, policies, procedures and controls regarding allegations or indications of accounting impropriety or override of internal controls are not effective to identify and assess whether they have material impact on the financial statements. Refer to section 3.10 *Risk management and internal control*.	We sought to understand why the controls that should have operated in this case had failed to result in the matter being appropriately communicated. We examined whether there were other instances of employee allegations of accounting impropriety during the year. Where it was considered necessary, additional investigative work was carried out which did not identify any misstatements or illegal acts. We assessed the qualifications and independence of the investigations teams and assessed the appropriateness of the investigation activities and their results including utilising our forensic specialists. We requested management to undertake a retrospective review of historical allegations of accounting impropriety or override of internal financial control to establish whether there were any instances that had not been notified to us. We assessed the appropriateness of the review performed by management and no further instances were identified. We independently assessed the related internal control deficiencies described in section 3.10 of the 2017 Annual Report and Form 20-F, which we consider to be balanced disclosure. We concluded that there was a material weakness. We assessed the impact of these deficiencies and the results of our work relating to the additional investigations on our planned audit work and carried out additional audit procedures as we considered necessary. Finally we assessed the control environment, policies and procedures and tested the controls that should operate where such allegations are identified through the Group's Ethics Helpline. We found these to operate effectively and no material weaknesses in this regard.

Other information

Management is responsible for the other information. The other information comprises the chapters introduction, strategic report, governance, section 4.2 *Supplementary oil and gas information* and additional information included in the annual report, but does not include the financial statements and our auditor's report thereon.

Our opinion on the financial statements does not cover the other information and we do not express any form of assurance conclusion thereon.

In connection with our audit of the financial statements, our responsibility is to read the other information and, in doing so, consider whether the other information is materially inconsistent with the financial statements or our knowledge obtained in the audit or otherwise appears to be materially misstated.

If, based on the work we have performed, we conclude that there is a material misstatement of this other information, we are required to report that fact. We have nothing to report in this regard.

Responsibilities of the board of directors and chief executive officer for the financial statements

The board of directors and chief executive officer ('management') are responsible for the preparation and fair presentation of the financial statements of the parent company in accordance with simplified application of international accounting standards according to the Norwegian Accounting Act section 3-9, and for the preparation and fair presentation of the Consolidated financial statements of the Group in accordance with International Financial Reporting Standards as adopted by the EU, and for such internal control as management determines is necessary to enable the preparation of financial statements that are free from material misstatement, whether due to fraud or error.

In preparing the financial statements, management is responsible for assessing the Company's and the Group's ability to continue as a going concern, disclosing, as applicable, matters related to going concern and using the going concern basis of accounting unless management either intends to liquidate the Group or to cease operations, or has no realistic alternative but to do so.

Auditor's responsibilities for the audit of the financial statements

Our objectives are to obtain reasonable assurance about whether the financial statements as a whole are free from material misstatement, whether due to fraud or error, and to issue an auditor's report that includes our opinion. Reasonable assurance is a high level of assurance, but is not a guarantee that an audit conducted in accordance with laws, regulations, and auditing standards and practices generally accepted in Norway, including ISAs will always detect a material misstatement when it exists. Misstatements can arise from fraud or error and are considered material if, individually or in aggregate, they could reasonably be expected to influence the economic decisions of users taken on the basis of these financial statements (see further explanation below).

As part of an audit in accordance with laws, regulations, and auditing standards and practices generally accepted in Norway, including ISAs, we exercise professional judgment and maintain professional scepticism throughout the audit. We also:

- identify and assess the risks of material misstatement of the financial statements, whether due to fraud or error. We design and perform audit procedures responsive to those risks, and obtain audit evidence that is sufficient and appropriate to provide a basis for our opinion. The risk of not detecting a material misstatement resulting from fraud is higher than for one resulting from error, as fraud may involve collusion, forgery, intentional omissions, misrepresentations, or the override of internal control.
- obtain an understanding of internal control relevant to the audit in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's or the Group's internal control.
- evaluate the appropriateness of accounting policies used and the reasonableness of accounting estimates and related disclosures made by management.
- conclude on the appropriateness of management's use of the going concern basis of accounting and, based on the audit evidence obtained, whether a material uncertainty exists related to events or conditions that may cast significant doubt on the Company's and the Group's ability to continue as a going concern. If we conclude that a material uncertainty exists, we are required to draw attention in our auditor's report to the related disclosures in the financial statements or, if such disclosures are inadequate, to modify our opinion. Our conclusions are based on the audit evidence obtained up to the date of our auditor's report. However, future events or conditions may cause the Company and the Group to cease to continue as a going concern.
- evaluate the overall presentation, structure and content of the financial statements, including the disclosures, and whether the financial statements represent the underlying transactions and events in a manner that achieves fair presentation.
- obtain sufficient appropriate audit evidence regarding the financial information of the entities or business activities within the Group to express an opinion on the Consolidated financial statements. We are responsible for the direction, supervision and performance of the audit of the Group. We remain solely responsible for our audit opinion.

We communicate with the board of directors regarding, among other matters, the planned scope and timing of the audit and significant audit findings, including any significant deficiencies in internal control that we identify during our audit.

We also provide the board of directors with a statement that we have complied with relevant ethical requirements regarding independence, and to communicate with them all relationships and other matters that may reasonably be thought to bear on our independence, and where applicable, related safeguards.

From the matters communicated with the board of directors, we determine those matters that were of most significance in the audit of the financial statements of the current period and are therefore the key audit matters. We describe these matters in our auditor's report unless law or regulation precludes public disclosure about the matter or when, in extremely rare circumstances, we determine that a matter should not be communicated in our report because the adverse consequences of doing so would reasonably be expected to outweigh the public interest benefits of such communication.

Report on other legal and regulatory requirements

Opinion on the board of directors' report and the statements on corporate governance and corporate social responsibility

Based on our audit of the financial statements as described above, it is our opinion that the information presented in the board of directors' report and in the statements on Corporate Governance and Corporate Social Responsibility concerning the financial statements and the going concern assumption, and the proposal for the allocation of the profit is consistent with the financial statements and complies with relevant law and regulations.

Opinion on registration and documentation

Based on our audit of the financial statements as described above, and procedures we considered necessary in accordance with the International Standard on Assurance Engagements (ISAE) 3000, «Assurance Engagements Other than Audits or Reviews of Historical Financial Information», it is our opinion that management has fulfilled its duty to produce a proper and clearly set out registration and documentation of the Company's accounting information in accordance with relevant law and bookkeeping standards and practices generally accepted in Norway.

Stavanger, 15 March 2018
KPMG AS

Ståle Christensen[13]
State Authorised Public Accountant

Jimmy Daboo

Note: This translation from Norwegian has been prepared for information purposes only.

[13] Appointed as the responsible auditor by KPMG AS according to the Auditing and Auditors Act section 2-2

The reports set out below are provided in accordance with standards of the Public Company Accounting Oversight Board (United States). KPMG AS has also issued a report in accordance with law, regulations, and auditing standards and practices generally accepted in Norway, including International Standards on Auditing (ISAs), which includes opinions on the Consolidated financial statements and the parent company financial statements of Statoil ASA, and on other required matters. That report is set out on pages 125 to 130.

Report of Independent Registered Public Accounting Firm

The board of directors and shareholders of Statoil ASA

Opinion on the Consolidated Financial Statements

We have audited the accompanying consolidated balance sheets of Statoil ASA and subsidiaries (the Company) as of 31 December 2017 and 2016, the related consolidated statements of income, comprehensive income, changes in equity, and cash flows for each of the years in the three-year period ended 31 December 2017, and the related notes (collectively, the consolidated financial statements). In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of the Company as of 31 December 2017 and 2016, and the results of its operations and its cash flows for each of the years in the three-year period ended 31 December 2017, in conformity with International Financial Reporting Standards as issued by the International Accounting Standards Board and International Financial Reporting Standards as adopted by the European Union.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the Company's internal control over financial reporting as of 31 December 2017, based on criteria established in *Internal Control - Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission, and our report dated 15 March 2018 expressed an adverse opinion on the effectiveness of the Company's internal control over financial reporting.

Changes in Accounting Principle

As discussed in Note 2 to the consolidated financial statements, the Company has elected to present net interest costs related to its defined benefit pension plans within net financial items in 2017. These expenses were previously included in the consolidated statement of income as part of pension cost within net operating income in prior periods.

Basis for Opinion

These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement, whether due to error or fraud. Our audits included performing procedures to assess the risks of material misstatement of the consolidated financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the consolidated financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements. We believe that our audits provide a reasonable basis for our opinion.

We have served as the Company's auditor since 2012.

/s/ KPMG AS

Stavanger, Norway
15 March 2018

Report of KPMG on Statoil's internal control over financial reporting

The board of directors and shareholders of Statoil ASA

Opinion on Internal Control Over Financial Reporting

We have audited Statoil ASA*'s* and subsidiaries (the Company) internal control over financial reporting as of 31 December 2017, based on criteria established in *Internal Control – Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. In our opinion, because of the effect of the material weakness, described below, on the achievement of the objectives of the control criteria, the Company has not maintained effective internal control over financial reporting as of 31 December 2017, based on criteria established in *Internal Control – Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the consolidated balance sheets of the Company as of 31 December 2017 and 2016, the related consolidated statements of income, comprehensive income, changes in equity, and cash flows for each of the years in the three-year period ended 31 December 2017, and the related notes (collectively, the consolidated financial statements), and our report dated 15 March 2018 expressed an unqualified opinion on those consolidated financial statements.

A material weakness is a deficiency, or a combination of deficiencies, in internal control over financial reporting, such that there is a reasonable possibility that a material misstatement of the company's annual or interim financial statements will not be prevented or detected on a timely basis.

A material weakness related to controls and procedures for the identification, assessment and timely and appropriate communication to the Board Audit Committee of questions or concerns (including allegation of misconduct) raised by employees in connection with termination of their employment (otherwise than through the Company's external Ethics help line) has been identified as described in management's assessment.

No misstatements in the consolidated financial statements were identified as a result of this matter. The material weakness was considered in determining the nature, timing, and extent of audit tests applied in our audit of the 2017 consolidated financial statements, and this report does not affect our report on those consolidated financial statements.

Basis for Opinion

The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying management's report on internal control over financial reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audit in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audit also included performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

Definition and Limitations of Internal Control Over Financial Reporting

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

/s/ KPMG AS

Stavanger, Norway
15 March 2018

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CONSOLIDATED STATEMENT OF INCOME

		Full year		
(in USD million)	Note	2017	2016	2015
Revenues	26	60,971	45,688	57,900
Net income/(loss) from equity accounted investments	12	188	(119)	(29)
Other income	4	27	304	1,770
Total revenues and other income	3	61,187	45,873	59,642
Purchases [net of inventory variation]		(28,212)	(21,505)	(26,254)
Operating expenses		(8,763)	(9,025)	(10,512)
Selling, general and administrative expenses		(738)	(762)	(921)
Depreciation, amortisation and net impairment losses	10, 11	(8,644)	(11,550)	(16,715)
Exploration expenses	11	(1,059)	(2,952)	(3,872)
Net operating income/(loss)	3	13,771	80	1,366
Net financial items	8	(351)	(258)	(1,311)
Income/(loss) before tax		13,420	(178)	55
Income tax	9	(8,822)	(2,724)	(5,225)
Net income/(loss)		4,598	(2,902)	(5,169)
Attributable to equity holders of the company		4,590	(2,922)	(5,192)
Attributable to non-controlling interests		8	20	22
Basic earnings per share (in USD)		1.40	(0.91)	(1.63)
Diluted earnings per share (in USD)		1.40	(0.91)	(1.63)
Weighted average number of ordinary shares outstanding (in millions)		3,268	3,195	3,179
Weighted average number of ordinary shares outstanding, diluted (in millions)		3,288	3,207	3,189

CONSOLIDATED STATEMENT OF COMPREHENSIVE INCOME

(in USD million)	Note	Full year 2017	2016	2015
Net income/(loss)		4,598	(2,902)	(5,169)
Actuarial gains/(losses) on defined benefit pension plans	19	172	(503)	1,599
Income tax effect on income and expenses recognised in OCI[1]		(38)	129	(461)
Items that will not be reclassified to the Consolidated statement of income		134	(374)	1,138
Currency translation adjustments		1,710	17	(3,976)
Net gains/(losses) from available for sale financial assets		(64)	0	0
Share of OCI from equity accounted investments		(40)	0	0
Items that may subsequently be reclassified to the Consolidated statement of income		1,607	17	(3,976)
Other comprehensive income/(loss)		1,741	(357)	(2,838)
Total comprehensive income/(loss)		6,339	(3,259)	(8,007)
Attributable to the equity holders of the company		6,331	(3,279)	(8,030)
Attributable to non-controlling interests		8	20	22

1) OCI = Other Comprehensive Income

CONSOLIDATED BALANCE SHEET

(in USD million)	Note	At 31 December 2017	2016
ASSETS			
Property, plant and equipment	10	63,637	59,556
Intangible assets	11	8,621	9,243
Equity accounted investments	12	2,551	2,245
Deferred tax assets	9	2,441	2,195
Pension assets	19	1,306	839
Derivative financial instruments	25	1,603	1,819
Financial investments	13	2,841	2,344
Prepayments and financial receivables	13	912	893
Total non-current assets		83,911	79,133
Inventories	14	3,398	3,227
Trade and other receivables	15	9,425	7,839
Derivative financial instruments	25	159	492
Financial investments	13	8,448	8,211
Cash and cash equivalents	16	4,390	5,090
Total current assets		25,820	24,859
Assets classified as held for sale	4	1,369	537
Total assets		111,100	104,530
EQUITY AND LIABILITIES			
Shareholders' equity		39,861	35,072
Non-controlling interests		24	27
Total equity	17	39,885	35,099
Finance debt	18, 22	24,183	27,999
Deferred tax liabilities	9	7,654	6,427
Pension liabilities	19	3,904	3,380
Provisions	20	15,557	13,406
Derivative financial instruments	25	900	1,420
Total non-current liabilities		52,198	52,633
Trade, other payables and provisions	21	9,737	9,666
Current tax payable		4,057	2,184
Finance debt	18	4,091	3,674
Dividends payable	17	729	712
Derivative financial instruments	25	403	508
Total current liabilities		19,017	16,744
Liabilities directly associated with the assets classified as held for sale	4	0	54
Total liabilities		71,214	69,431
Total equity and liabilities		111,100	104,530

CONSOLIDATED STATEMENT OF CHANGES IN EQUITY

(in USD million)	Share capital	Additional paid-in capital	Retained earnings	Currency translation adjustments	Available for sale financial assets	OCI from equity accounted investments	Shareholders' equity	Non-controlling interests	Total equity
At 31 December 2014	1,139	5,714	45,677	(1,305)	0	0	51,225	57	51,282
Net income/(loss)			(5,192)				(5,192)	22	(5,169)
Other comprehensive income/(loss)			1,138	(3,976)	0	0	(2,838)		(2,838)
Total comprehensive income/(loss)									(8,007)
Dividends			(2,930)				(2,930)		(2,930)
Other equity transactions		6	(0)				6	(43)	(38)
At 31 December 2015	1,139	5,720	38,693	(5,281)	0	0	40,271	36	40,307
Net income/(loss)			(2,922)				(2,922)	20	(2,902)
Other comprehensive income/(loss)			(374)	17	0	0	(357)		(357)
Total comprehensive income/(loss)									(3,259)
Dividends	17	887	(2,824)				(1,920)		(1,920)
Other equity transactions		1	0				2	(30)	(28)
At 31 December 2016	1,156	6,607	32,573	(5,264)	0	0	35,072	27	35,099
Net income/(loss)			4,590				4,590	8	4,598
Other comprehensive income/(loss)			134	1,710 [1)]	(64)	(40)	1,741		1,741
Total comprehensive income/(loss)									6,339
Dividends	24	1,333	(2,891)				(1,534)		(1,534)
Other equity transactions		(8)	0				(8)	(10)	(18)
At 31 December 2017	1,180	7,933	34,406	(3,554)	(64)	(40)	39,861	24	39,885

1) Currency translation adjustments year to date includes a loss of USD 294 million directly associated with the sale of interest in Kai Kos Dehseh oil sands project. See note 4 Acquisitions and divestments for information on transaction.

Refer to note 17 Shareholders' equity and dividends.

CONSOLIDATED STATEMENT OF CASH FLOWS

(in USD million)	Note	2017	Full year 2016	2015
Income/(loss) before tax		13,420	(178)	55
Depreciation, amortisation and net impairment losses	10, 11	8,644	11,550	16,715
Exploration expenditures written off	11	(8)	1,800	2,164
(Gains) losses on foreign currency transactions and balances		(453)	(137)	1,166
(Gains) losses on sales of assets and businesses	4	395	(110)	(1,716)
(Increase) decrease in other items related to operating activities		(391)	1,076	558
(Increase) decrease in net derivative financial instruments	25	(596)	1,307	1,551
Interest received		282	280	363
Interest paid		(622)	(548)	(443)
Cash flows provided by operating activities before taxes paid and working capital items		20,671	15,040	20,414
Taxes paid		(5,766)	(4,386)	(8,078)
(Increase) decrease in working capital		(542)	(1,620)	1,292
Cash flows provided by operating activities		14,363	9,034	13,628
Additions through business combinations	4	0	0	(398)
Capital expenditures and investments		(10,755)	(12,191)	(15,518)
(Increase) decrease in financial investments		592	877	(2,813)
(Increase) decrease in other items interest bearing		79	107	(22)
Proceeds from sale of assets and businesses	4	406	761	4,249
Cash flows used in investing activities		(9,678)	(10,446)	(14,501)
New finance debt	18	0	1,322	4,272
Repayment of finance debt		(4,775)	(1,072)	(1,464)
Dividend paid	17	(1,491)	(1,876)	(2,836)
Net current finance debt and other		444	(333)	(701)
Cash flows provided by (used in) financing activities	18	(5,822)	(1,959)	(729)
Net increase (decrease) in cash and cash equivalents		(1,137)	(3,371)	(1,602)
Effect of exchange rate changes on cash and cash equivalents		436	(152)	(871)
Cash and cash equivalents at the beginning of the period (net of overdraft)	16	5,090	8,613	11,085
Cash and cash equivalents at the end of the period (net of overdraft)	16	4,390	5,090	8,613

Cash and cash equivalents include bank overdrafts of zero at 31 December 2017, zero at 31 December 2016 and USD 10 million at 31 December 2015.

Interest paid in cash flows provided by operating activities is excluding capitalised interest of USD 454 million at 31 December 2017, USD 355 million at 31 December 2016 and USD 392 million at 31 December 2015. Capitalised interest is included in Capital expenditures and investments in cash flows used in investing activities.

Notes to the Consolidated financial statements

1 Organisation

Statoil ASA, originally Den Norske Stats Oljeselskap AS, was founded in 1972 and is incorporated and domiciled in Norway. The address of its registered office is Forusbeen 50, N-4035 Stavanger, Norway.

Statoil ASA's shares are listed on the Oslo Børs (OSL, Norway) and the New York Stock Exchange (NYSE, USA).

The Statoil group's business consists principally of the exploration, production, transportation, refining and marketing of petroleum and petroleum-derived products and other forms of energy.

All the Statoil group's oil and gas activities and net assets on the Norwegian continental shelf are owned by Statoil Petroleum AS, a 100% owned operating subsidiary. Statoil Petroleum AS is co-obligor or guarantor of certain debt obligations of Statoil ASA.

The Consolidated financial statements of Statoil for the full year 2017 were authorised for issue in accordance with a resolution of the board of directors on 14 March 2018.

2 Significant accounting policies

Statement of compliance
The Consolidated financial statements of Statoil ASA and its subsidiaries (Statoil) have been prepared in accordance with International Financial Reporting Standards (IFRSs) as adopted by the European Union (EU) and also comply with IFRSs as issued by the International Accounting Standards Board (IASB), effective at 31 December 2017.

Basis of preparation
The financial statements are prepared on the historical cost basis with some exceptions, as detailed in the accounting policies set out below. The policies described in the main part of this note are the ones in effect at the balance sheet date, and these policies have been applied consistently to all periods presented in these Consolidated financial statements. Certain amounts in the comparable years have been restated to conform to current year presentation. The subtotals and totals in some of the tables may not equal the sum of the amounts shown due to rounding.

Operating related expenses in the Consolidated statement of income are presented as a combination of function and nature in conformity with industry practice. Purchases [net of inventory variation] and Depreciation, amortisation and net impairment losses are presented in separate lines based on their nature, while Operating expenses and Selling, general and administrative expenses as well as Exploration expenses are presented on a functional basis. Significant expenses such as salaries, pensions, etc. are presented by their nature in the notes to the Consolidated financial statements.

Standards, amendments to standards, and interpretations of standards, issued but not yet adopted
At the date of these Consolidated financial statements, the following standards, amendments to standards and interpretations of standards applicable to Statoil have been issued, but were not yet effective:

IFRS 9 Financial Instruments
IFRS 9 will be implemented by Statoil on the effective date 1 January 2018. The standard replaces IAS 39 Financial instruments: Recognition and Measurement. Statoil will implement IFRS 9 retrospectively with the cumulative effect of initially applying the standard recognised at the date of initial application. The impact of the IFRS 9 implementation on Statoil's equity is immaterial.

Portions of Statoil's cash equivalents and current financial investments tied to liquidity management, which under IAS 39 are classified as held for trading and reflected at fair value through profit and loss, will under IFRS 9 be measured at amortised cost, based on an evaluation of the contractual terms and the business model applied. For certain financial assets currently classified as Available for sale (AFS), changes in fair value which are currently reflected in OCI, will be reflected in profit and loss under IFRS 9. No major changes are currently deemed necessary for Statoil's expected loss recognition process to satisfy IFRS 9's financial asset impairment requirements.

IFRS 15 Revenue from Contracts with Customers
IFRS 15, which will be implemented by Statoil on the effective date 1 January 2018, covers the recognition of revenue in the financial statements and related disclosure. IFRS 15 replaces existing revenue recognition guidance, including IAS 18 Revenue. IFRS 15 requires identification of the performance obligations for the transfer of goods and services in each contract with customers. Revenue will be recognised upon satisfaction of the performance obligations for the amounts that reflect the consideration to which Statoil expects to be entitled in exchange for those goods and services.

IFRS 15 will principally impact the Marketing, Midstream & Processing segment (MMP), which accounts for the majority of Statoil's sales to customers, and which is responsible for the marketing and sale of the Norwegian State's direct financial interest's (SDFI's) petroleum volumes. To a lesser extent, the segments Exploration & Production International (E&P International) and Exploration & Production Norway (E&P Norway) are however also affected.

The impact on Statoil's equity of the implementation of IFRS 15 is immaterial. Mainly on the basis of the limited implementation impact, Statoil will implement IFRS 15 retrospectively with the cumulative effect recognised at the date of initial application. IFRS 15 will require updated disclosures, in particular related to the distinction between revenue from contracts with customers and other revenue, and disaggregation of revenue streams. Such disclosures will be provided based on consideration of the level of detail necessary. The most significant accounting evaluations and conclusions related to the implementation of IFRS 15 in Statoil are summarised below.

Sale and transportation of goods;
Under IFRS 15, revenue from the sale and transportation of crude oil, natural gas, petroleum products and other merchandise will be recognised when a customer obtains control of the goods, which normally will be when title passes at point of delivery of the goods, based on the contractual terms of the agreements. Each such sale normally represents one performance obligation, which in the case of natural gas sales are completed over time in line with the delivery of the actual physical quantities. A number of bi-lateral long-term contracts, mainly for the sale of natural gas, as well as certain spot and term contracts, represent the sale of non-financial items that may be settled net in cash, but which have been entered into for the purpose of delivery of non-financial commodity items in accordance with Statoil's expected purchase, sale or usage requirements. Statoil consequently will apply IFRS 9's "own use" exemption for such contracts, and these physical sales will be accounted for as revenue from contracts with customers.

In some sales of goods, such as certain sales of crude oil, Statoil may provide transport services after control of the goods has been transferred to the customer. Following implementation of IFRS 15, such transport, which previously was considered part of a single sale of goods transaction, will be considered to be a distinct service that is completed over time and is distinct from the good sold. These transport services will consequently be recognised separately and be combined with other transport revenues. The impact from the resulting immaterial timing differences constitutes the only identified IFRS 15 implementation impact with a net effect on equity and net operating profit in Statoil.

Marketing and sale of the Norwegian State's (the State's) share of crude oil and natural gas production from the Norwegian continental shelf (NCS);
Statoil has considered whether it acts as the principal in these transactions under IFRS 15, i.e. whether it controls the State's volumes prior to onwards sales to third party customers. Statoil's sales of the State's natural gas volumes are performed for the State's account and risk, and although Statoil has been granted the ability to direct the use of the volumes, all the benefits from the sales of these volumes flow to the State. On that basis, Statoil is not considered the principal in the sale of the SDFI's natural gas volumes. In the sales of the State-originated crude oil, Statoil also directs the use of the volumes. However, although certain benefits from these sales subsequently flow to the State, Statoil purchases the crude oil volumes from the State and obtains substantially all the remaining benefits. Statoil therefore is considered the principal in the crude oil sales. The accounting for Statoil's sale of the SDFI's natural gas and crude oil under IFRS 15 will consequently not lead to changes compared to the practice under IAS 18.

Other identified differences;
Certain items, which have previously been classified as Revenues in the Consolidated statement of income, will not qualify as revenue from contracts with customers under IFRS 15. These include taxes paid in kind under certain production sharing agreements (PSAs), and the reflection of commodity-based derivatives connected with sales contracts or revenue-related risk management. Adjustments for imbalances between oil and gas production and sales, following Statoil's transition from the sales method to imbalances accounting on 1 January 2018 (see the item "Voluntary change in significant accounting policies decided upon, but not yet adopted" below), will also not qualify as revenue from contracts with customers under IFRS 15. These items however still either represent a form of revenue or are closely connected to revenue transactions, and they will be reflected as Other revenue following the IFRS 15 implementation. Statoil will combine 'Revenue from contracts with customers' and 'Other revenue' into a single line item, Revenues, in the Consolidated statement of income, and will disclose the relevant disaggregation in the notes to the Consolidated financial statements. In addition, Statoil will reclassify the impact of certain commodity-based earn-out agreements and contingent consideration elements, which previously have been reflected under Revenues, to Other income. Total revenues and other income in the Statement of income will consequently not be impacted by this reclassification.

IFRS 16 Leases
IFRS 16, effective from 1 January 2019, covers the recognition of leases and related disclosure in the financial statements, and will replace IAS 17 Leases. The new standard defines a lease as a contract that conveys the right to control the use of an identified asset for a period of time in exchange for consideration. In the financial statement of lessees, IFRS 16 requires recognition in the balance sheet for each contract that meets its definition of a lease as right-of-use asset and lease liability, while lease payments are to be reflected as interest expense and a reduction of lease liabilities. The right-of-use assets are to be depreciated in accordance with IAS 16 Property, Plant and Equipment over the shorter of each contract's term and the assets' useful life. IFRS 16 will also lead to changes in the classification of lease-related payments in the statement of cash flows, and the portion of lease payments representing payments of lease liabilities will be classified as cash flows used in financing activities. The standard consequently implies a significant change in lessees' accounting for leases currently defined as operating leases under IAS 17 and for other contracts that do not meet this definition but are considered to be leases under IFRS 16, impacting both the balance sheet, the statement of income and the statement of cash flows.

As a practical expedient, IFRS 16 allows for contracts already classified either as leases under IAS 17 or as non-lease service arrangements, to maintain their respective classifications upon the implementation of IFRS 16. Statoil expects to apply this "grandfathering" transition option.

IFRS 16 requires adoption either on a full retrospective basis, or retrospectively with the cumulative effect of initially recognising the standard as an adjustment to retained earnings at the date of initial application ("the modified retrospective method"), and in the latter case allows a number of practical expedients in transitioning existing leases at the time of initial application. Statoil anticipates applying the modified retrospective method in the implementation of IFRS 16.

Implementation of IFRS 16 will affect all Statoil's segments. Statoil will adopt IFRS 16 on 1 January 2019, and is in the process of evaluating the impact of the standard. The actual impact on the Consolidated financial statements of applying IFRS 16 will depend on future economic conditions, including Statoil's borrowing rate and the composition of Statoil's lease portfolio at implementation. IFRS 16 involves several implementation choices and interpretations which may also significantly impact Statoil's Consolidated financial statements. The accounting issues which at this stage are expected to most significantly affect the implementation of IFRS 16 in Statoil, as well as their expected impact where this can currently be determined, are summarised below. In addition to these issues, Statoil has identified several other leasing related interpretations and policy decisions which are under evaluation. Work is continuing in order to determine the impact and the proper accounting for all identified issues, but the assessments have not yet been concluded. Statoil is consequently not yet in a position to determine the expected impact of IFRS 16 on its Consolidated financial statements.

Distinguishing operators and joint operations as lessees, including sublease considerations;
IFRS 16 establishes that when a lease contract is entered into by a joint arrangement, or on behalf of a joint arrangement, the joint arrangement is considered to be the customer, and hence the lessee, in the contract. In the oil and gas industry, where activity frequently is carried out through joint arrangements or similar arrangements, the application of this IFRS 16 requirement depends on evaluations of whether the joint arrangement or its operator is the lessee in each lease agreement. In many cases where an operator is the sole signatory to a contract to lease an asset to be used in the activities of a specific joint operation, the operator does so implicitly or explicitly on behalf of the joint arrangement. In certain jurisdictions, and importantly for Statoil this includes the NCS, the concessions granted by the authorities establish both a right and an obligation for the operator to enter into necessary agreements in the name of the joint operations (licences). As is the customary norm in upstream activities operated through joint arrangements, the operator will manage the lease, pay the lessor, and subsequently re-bill the partners for their share of the lease costs. In each such instance, it is necessary to determine whether the operator is the sole lessee in the arrangement, and if so, whether the billings to partners may represent sub-leases, or whether it is in fact the joint arrangement which is the lessee, with each participant accounting for its proportionate share of the lease. Depending on facts and circumstances in each case, the conclusions reached may vary between contracts and legal jurisdictions. This issue may materially impact the financial statements of Statoil both as an operator and joint operation participant in the oil and gas industry.

Separation of lease and non-lease components;
IFRS 16 allows for additional services and non-lease components included in lease contracts to be accounted for either separately, or as part of the lease. The standard's presumption is that non-lease components should be accounted for separately, while accounting for such components as part of a lease is an exemption that must be taken consistently by class of underlying asset. In the case of significant non-lease components in contracts containing leases, the choice of accounting policy may impact the financial statements significantly, as it entails choosing between expensing service elements as a form of operating cost as incurred, or reflecting them as part of right of use assets (with a corresponding increase in the lease liabilities), with related amortisation and financial expenses. Many of Statoil's lease contracts, such as rig and vessel leases, involve a number of additional services and components, including personnel cost, maintenance, drilling related activities, and other items. For a number of contracts, the additional services may represent a not inconsiderable portion of the total contract value, and such additional services are not always identified and separately priced. The full extent of non-lease components in Statoil's contracts has yet to be established, and Statoil has not yet determined whether it will account for additional services as parts of the lease, and if so, for which underlying classes of assets.

Leases applied in activities that are capitalised;
In exploration activities, direct costs are capitalised until the result of the exploration has been evaluated. In the development phase of projects, direct costs are likewise capitalised and normally become part of Property, plant and equipment (PP&E). During upstream production activities, asset enhancements such as the drilling of production wells are also capitalised. In all these activities, Statoil will frequently employ leased drilling rigs and other leased assets. Statoil is in the process of evaluating how leases under IFRS 16 will be reflected when leased assets are used in an activity for which the costs are capitalised.

Evaluating the impact of option periods for the lease terms;
The term of a lease determines the period of time for which cash flow will be discounted and reflected in the balance sheet. Under IFRS 16 the lease term therefore impacts the recognised amounts of right of use assets and lease liabilities. Many of Statoil's major leases, such as leases of vessels, rigs and buildings, include term options. In applying IFRS 16 it is of increasing importance for Statoil to determine whether each lease contract's term options should be considered to be reasonably certain to be exercised. Such evaluations will be made at commencement of the leases and subsequently when facts and circumstances require it. In Statoil's view, the term 'reasonably certain' implies a probability level significantly higher than 'probable', and this will be reflected in Statoil's ongoing evaluations.

Distinguishing fixed and variable lease payment elements;
Under IFRS 16, fixed and in-substance fixed lease payments are to be included in the commencement date computation of a lease liability, while variable payments dependent on use of the asset are not. Particularly as regards drilling rig leases, Statoil's lease contracts may include fixed rates for when the asset in question is in operation, and alternative, lower rates ("stand-by rates") for periods where the asset is idle, but still under contract. Statoil is currently evaluating the appropriate rates to be reflected in the lease liability.

Use of the standard's short-term lease exemption;
As a practical expedient, IFRS 16 allows an entity not to capitalise short term leases on its balance sheet. The choice must be made by class of underlying asset. The practical expedient provides a simplification, but will also result in less comparability in the Statement of income, as the short-term lease

expenses will be presented as a form of operating expenses, while the cost for long-term leases will be presented as interest expenses and depreciation. Statoil has not yet determined whether the exemption will be applied, and if so, for which classes of underlying assets.

Other standards, amendments to standards and interpretations of standards
The amendments to IFRS 10 Consolidated Financial Statements and IAS 28 Investments in Associates and Joint Ventures, effective from a future date to be determined by the IASB, establish requirements for the accounting for sales or contributions of assets between an investor and its associate or joint venture. Whether or not the assets are housed in a subsidiary, a full gain or loss will be recognised in the statement of income when the transaction involves assets that constitute a business, whereas a partial gain or loss will be recognised when the transaction involves assets that do not constitute a business. The amendments are to be applied prospectively. Statoil has not determined an adoption date for the amendments.

Other standards, amendments to standards, and interpretations of standards, issued but not yet effective, are either not expected to impact Statoil's Consolidated financial statements materially, or are not expected to be relevant to Statoil's Consolidated financial statements upon adoption.

Voluntary change in significant accounting policies decided upon, but not yet adopted
With effect from 1 January 2018, Statoil will change its policy for recognition of revenue from the production of oil and gas properties in which Statoil shares an interest with other companies. Currently Statoil recognises revenue on the basis of volumes lifted and sold to customers during the period (the sales method). Under the new method, Statoil will recognise revenues according to Statoil's ownership in producing fields, where the accounting for the imbalances will be presented as other revenue. This voluntary change in policy is made because it better reflects Statoil's operational performance, and also increases comparability with the financial reporting of Statoil's peers. The change in policy affects the timing of revenue recognition from oil and gas production, however the impact on Statoil's equity upon implementation is immaterial.

Changes in significant accounting policies in the current period
With effect from 1 January 2017, Statoil presents net interest costs related to its defined benefit pension plans within Net financial items. These expenses were previously included in the Consolidated statement of income as part of pension cost within net operating income/(loss). The policy change better aligns the classification of the interest costs with their nature, as the benefit plan is closed to new members and now increasingly represents a financial exposure to Statoil. The change in presentation also impacts the gain or loss from changes in the fair value of Statoil's notional contribution pension plans. The impact on the net operating income at implementation and for comparative periods presented in these financial statements is immaterial.

Basis of consolidation
The Consolidated financial statements include the accounts of Statoil ASA and its subsidiaries and include Statoil's interest in jointly controlled and equity accounted investments.

Subsidiaries
Entities are determined to be controlled by Statoil, and consolidated in Statoil's financial statements, when Statoil has power over the entity, ability to use that power to affect the entity's returns, and exposure to, or rights to, variable returns from its involvement with the entity.

All intercompany balances and transactions, including unrealised profits and losses arising from Statoil's internal transactions, have been eliminated in full.

Non-controlling interests are presented separately within equity in the balance sheet.

Joint operations and similar arrangements, joint ventures and associates
A joint arrangement is present where Statoil holds a long-term interest which is jointly controlled by Statoil and one or more other venturers under a contractual arrangement in which decisions about the relevant activities require the unanimous consent of the parties sharing control. Such joint arrangements are classified as either joint operations or joint ventures.

The parties to a joint operation have rights to the assets and obligations for the liabilities, relating to their respective share of the joint arrangement. In determining whether the terms of contractual arrangements and other facts and circumstances lead to a classification as joint operations, Statoil considers the nature of products and markets of the arrangement and whether the substance of their agreements is that the parties involved have rights to substantially all the arrangement's assets. Statoil accounts for the assets, liabilities, revenues and expenses relating to its interests in joint operations in accordance with the principles applicable to those particular assets, liabilities, revenues and expenses. Normally this leads to accounting for the joint operation in a manner similar to the previous proportionate consolidation method.

Those of Statoil's exploration and production licence activities that are within the scope of IFRS 11 Joint Arrangements have been classified as joint operations. A considerable number of Statoil's unincorporated joint exploration and production activities are conducted through arrangements that are not jointly controlled, either because unanimous consent is not required among all parties involved, or no single group of parties has joint control over the activity. Licence activities where control can be achieved through agreement between more than one combination of involved parties are considered to be outside the scope of IFRS 11, and these activities are accounted for on a pro-rata basis using Statoil's ownership share. Currently there are no significant differences in Statoil's accounting for unincorporated licence arrangements whether in scope of IFRS 11 or not.

Joint ventures, in which Statoil has rights to the net assets, are accounted for using the equity method.

Investments in companies in which Statoil has neither control nor joint control, but has the ability to exercise significant influence over operating and financial policies, are classified as Equity accounted investments.

Under the equity method, the investment is carried on the balance sheet at cost plus post-acquisition changes in Statoil's share of net assets of the entity, less distributions received and less any impairment in value of the investment. Goodwill may arise as the surplus of the cost of investment over Statoil's share of the net fair value of the identifiable assets and liabilities of the joint venture or associate. Such goodwill is recorded within the corresponding investment. The Consolidated statement of income reflects Statoil's share of the results after tax of an equity-accounted entity, adjusted to account for depreciation, amortisation and any impairment of the equity-accounted entity's assets based on their fair values at the date of acquisition. Where material differences in accounting policies arise, adjustments are made to the financial statements of equity-accounted entities in order to bring the accounting policies used into line with Statoil's. Material unrealised gains on transactions between Statoil and its equity-accounted entities are eliminated to the extent of Statoil's interest in each equity-accounted entity. Unrealised losses are also eliminated unless the transaction provides evidence of an impairment of the asset transferred. Statoil assesses investments in equity-accounted entities for impairment whenever events or changes in circumstances indicate that the carrying value may not be recoverable.

Statoil as operator of joint operations and similar arrangements

Indirect operating expenses such as personnel expenses are accumulated in cost pools. These costs are allocated on an hours' incurred basis to business areas and Statoil operated joint operations under IFRS 11 and to similar arrangements (licences) outside the scope of IFRS 11. Costs allocated to the other partners' share of operated joint operations and similar arrangements reduce the costs in the Consolidated statement of income. Only Statoil's share of the statement of income and balance sheet items related to Statoil operated joint operations and similar arrangements are reflected in the Consolidated statement of income and the Consolidated balance sheet.

Reportable segments

Statoil identifies its business areas on the basis of those components of Statoil that are regularly reviewed by the chief operating decision maker, Statoil's corporate executive committee (CEC). Statoil combines business areas when these satisfy relevant aggregation criteria.

Statoil's accounting policies as described in this note also apply to the specific financial information included in reportable segments-related disclosure in these Consolidated financial statements.

Foreign currency translation

In preparing the financial statements of the individual entities, transactions in foreign currencies (those other than functional currency) are translated at the foreign exchange rate at the dates of the transactions. Monetary assets and liabilities denominated in foreign currencies are translated to the functional currency at the foreign exchange rate at the balance sheet date. Foreign exchange differences arising on translation are recognised in the Consolidated statement of income as foreign exchange gains or losses within net financial items. Foreign exchange differences arising from the translation of estimate-based provisions, however, generally are accounted for as part of the change in the underlying estimate and as such may be included within the relevant operating expense or income tax sections of the Consolidated statement of income depending on the nature of the provision. Non-monetary assets that are measured at historical cost in a foreign currency are translated using the exchange rate at the date of the transactions.

Presentation currency

For the purpose of the Consolidated financial statements, the statement of income, the balance sheet and the cash flows of each entity are translated from the functional currency into the presentation currency, USD. The assets and liabilities of entities whose functional currencies are other than USD, are translated into USD at the foreign exchange rate at the balance sheet date. The revenues and expenses of such entities are translated using the foreign exchange rates on the dates of the transactions. Foreign exchange differences arising on translation from functional currency to presentation currency are recognised separately in Other comprehensive income (OCI). The cumulative amount of such translation differences relating to an entity and previously recognised in OCI, is reclassified to the Consolidated statement of income and reflected as a part of the gain or loss on disposal of that entity.

Business combinations

Determining whether an acquisition meets the definition of a business combination requires judgement to be applied on a case by case basis. Acquisitions are assessed under the relevant IFRS criteria to establish whether the transaction represents a business combination or an asset purchase. Depending on the specific facts, acquisitions of exploration and evaluation licences for which a development decision has not yet been made, have largely been concluded to represent asset purchases.

Business combinations, except for transactions between entities under common control, are accounted for using the acquisition method of accounting. The acquired identifiable tangible and intangible assets, liabilities and contingent liabilities are measured at their fair values at the date of the acquisition. Acquisition costs incurred are expensed under Selling, general and administrative expenses.

Revenue recognition

Revenues associated with sale and transportation of crude oil, natural gas, petroleum products and other merchandise are recognised when risk passes to the customer, which is normally when title passes at the point of delivery of the goods, based on the contractual terms of the agreements.

Revenues from the production of oil and gas properties in which Statoil shares an interest with other companies are recognised on the basis of volumes lifted and sold to customers during the period (the sales method). Where Statoil has lifted and sold more than the ownership interest, an accrual is recognised for the cost of the overlift. Where Statoil has lifted and sold less than the ownership interest, costs are deferred for the underlift.

Revenue is presented net of customs, excise taxes and royalties paid in-kind on petroleum products. Revenue is presented gross of in-kind payments of amounts representing income tax.

Sales and purchases of physical commodities, which are not settled net, are presented on a gross basis as revenues and purchases [net of inventory variation] in the statement of income. Activities related to trading and commodity-based derivative instruments are reported on a net basis, with the margin included in revenues.

Transactions with the Norwegian State

Statoil markets and sells the Norwegian State's share of oil and gas production from the Norwegian continental shelf (NCS). The Norwegian State's participation in petroleum activities is organised through the SDFI. All purchases and sales of the SDFI's oil production are classified as purchases [net of inventory variation] and revenues, respectively. Statoil sells, in its own name, but for the Norwegian State's account and risk, the State's production of natural gas. These sales and related expenditures refunded by the Norwegian State are presented net in the Consolidated financial statements.

Employee benefits

Wages, salaries, bonuses, social security contributions, paid annual leave and sick leave are accrued in the period in which the associated services are rendered by employees of Statoil.

Research and development

Statoil undertakes research and development both on a funded basis for licence holders and on an unfunded basis for projects at its own risk. Statoil's own share of the licence holders' funding and the total costs of the unfunded projects are considered for capitalisation under the applicable IFRS requirements. Subsequent to initial recognition, any capitalised development costs are reported at cost less accumulated amortisation and accumulated impairment losses.

Income tax

Income tax in the Consolidated statement of income comprises current and deferred tax expense. Income tax is recognised in the Consolidated statement of income except when it relates to items recognised in OCI.

Current tax consists of the expected tax payable on the taxable income for the year and any adjustment to tax payable for previous years. Uncertain tax positions and potential tax exposures are analysed individually, and the best estimate of the probable amount for liabilities to be paid (unpaid potential tax exposure amounts, including penalties) and for assets to be received (disputed tax positions for which payment has already been made) in each case is recognised within current tax or deferred tax as appropriate. Interest income and interest expenses relating to tax issues are estimated and recognised in the period in which they are earned or incurred, and are presented within net financial items in the Consolidated statement of income. Uplift benefit on the NCS is recognised when the deduction is included in the current year tax return and impacts taxes payable.

Deferred tax assets and liabilities are recognised for the future tax consequences attributable to differences between the carrying amounts of existing assets and liabilities and their respective tax bases, subject to the initial recognition exemption. The amount of deferred tax is based on the expected manner of realisation or settlement of the carrying amount of assets and liabilities, using tax rates enacted or substantively enacted at the balance sheet date. A deferred tax asset is recognised only to the extent that it is probable that future taxable income will be available against which the asset can be utilised. In order for a deferred tax asset to be recognised based on future taxable income, convincing evidence is required, taking into account the existence of contracts, production of oil or gas in the near future based on volumes of proved reserves, observable prices in active markets, expected volatility of trading profits, expected currency rate movements and similar facts and circumstances.

Oil and gas exploration, evaluation and development expenditures

Statoil uses the successful efforts method of accounting for oil and gas exploration costs. Expenditures to acquire mineral interests in oil and gas properties and to drill and equip exploratory wells are capitalised as exploration and evaluation expenditures within intangible assets until the well is complete and the results have been evaluated, or there is any other indicator of a potential impairment. Exploration wells that discover potentially economic quantities of oil and natural gas remain capitalised as intangible assets during the evaluation phase of the find. This evaluation is normally finalised within one year after well completion. If, following the evaluation, the exploratory well has not found potentially commercial quantities of hydrocarbons, the previously capitalised costs are evaluated for derecognition or tested for impairment. Geological and geophysical costs and other exploration and evaluation expenditures are expensed as incurred.

Capitalised exploration and evaluation expenditures, including expenditures to acquire mineral interests in oil and gas properties, related to offshore wells that find proved reserves are transferred from exploration expenditures and acquisition costs - oil and gas prospects (intangible assets) to property, plant and equipment at the time of sanctioning of the development project. For onshore wells where no sanction is required, the transfer of acquisition cost - oil and gas prospects (intangible assets) to property, plant and equipment occurs at the time when a well is ready for production.

For exploration and evaluation asset acquisitions (farm-in arrangements) in which Statoil has made arrangements to fund a portion of the selling partner's (farmor's) exploration and/or future development expenditures (carried interests), these expenditures are reflected in the Consolidated financial statements as and when the exploration and development work progresses. Statoil reflects exploration and evaluation asset dispositions (farm-out arrangements) on a historical cost basis with no gain or loss recognition.

A gain related to a post-tax based disposition of assets on the NCS includes the release of tax liabilities previously computed and recognised related to the assets in question. The resulting gross gain is recognised in full in other income in the Consolidated statement of income.

Consideration from the sale of an undeveloped part of an onshore asset reduces the carrying amount of the asset. The part of the consideration that exceeds the carrying amount of the asset, if any, is reflected in the Consolidated statement of income under other income.

Exchanges (swaps) of exploration and evaluation assets are accounted for at the carrying amounts of the assets given up with no gain or loss recognition.

Property, plant and equipment
Property, plant and equipment is reflected at cost, less accumulated depreciation and accumulated impairment losses. The initial cost of an asset comprises its purchase price or construction cost, any costs directly attributable to bringing the asset into operation, the initial estimate of an asset retirement obligation, if any, exploration costs transferred from intangible assets and, for qualifying assets, borrowing costs. Property, plant and equipment include costs relating to expenditures incurred under the terms of PSAs in certain countries, and which qualify for recognition as assets of Statoil. State-owned entities in the respective countries, however, normally hold the legal title to such PSA-based property, plant and equipment.

Exchanges of assets are measured at the fair value of the asset given up, unless the fair value of neither the asset received nor the asset given up is measurable with sufficient reliability.

Expenditure on major maintenance refits or repairs comprises the cost of replacement assets or parts of assets, inspection costs and overhaul costs. Where an asset or part of an asset is replaced and it is probable that future economic benefits associated with the item will flow to Statoil, the expenditure is capitalised. Inspection and overhaul costs, associated with regularly scheduled major maintenance programmes planned and carried out at recurring intervals exceeding one year, are capitalised and amortised over the period to the next scheduled inspection and overhaul. All other maintenance costs are expensed as incurred.

Capitalised exploration and evaluation expenditures, development expenditure on the construction, installation or completion of infrastructure facilities such as platforms, pipelines and the drilling of production wells, and field-dedicated transport systems for oil and gas are capitalised as producing oil and gas properties within property, plant and equipment. Such capitalised costs, when designed for significantly larger volumes than the reserves from already developed and producing wells, are depreciated using the unit of production method based on proved reserves expected to be recovered from the area during the concession or contract period. Depreciation of production wells uses the unit of production method based on proved developed reserves, and capitalised acquisition costs of proved properties are depreciated using the unit of production method based on total proved reserves. In the rare circumstances where the use of proved reserves fails to provide an appropriate basis reflecting the pattern in which the asset's future economic benefits are expected to be consumed, a more appropriate reserve estimate is used. Depreciation of other assets and transport systems used by several fields is calculated on the basis of their estimated useful lives, normally using the straight-line method. Each part of an item of property, plant and equipment with a cost that is significant in relation to the total cost of the item is depreciated separately. For exploration and production assets, Statoil has established separate depreciation categories which as a minimum distinguish between platforms, pipelines and wells.

The estimated useful lives of property, plant and equipment are reviewed on an annual basis, and changes in useful lives are accounted for prospectively. An item of property, plant and equipment is de-recognised upon disposal or when no future economic benefits are expected to arise from the continued use of the asset. Any gain or loss arising on derecognition of the asset (calculated as the difference between the net disposal proceeds and the carrying amount of the item) is included in other income or operating expenses, respectively, in the period the item is de-recognised.

Assets classified as held for sale
Non-current assets are classified separately as held for sale in the balance sheet when their carrying amount will be recovered through a sale transaction rather than through continuing use. This condition is met only when the sale is highly probable, the asset is available for immediate sale in its present condition, and management is committed to the sale, which should be expected to qualify for recognition as a completed sale within one year from the date of classification. Liabilities directly associated with the assets classified as held for sale, and expected to be included as part of the sale transaction, are correspondingly also classified separately. Once classified as held for sale, property, plant and equipment and intangible assets are not subject to depreciation or amortisation. The net assets and liabilities of a disposal group classified as held for sale are measured at the lower of their carrying amount and fair value less costs to sell.

Leases
Leases for which Statoil assumes substantially all the risks and rewards of ownership are reflected as finance leases. When an asset leased by a joint operation or similar arrangement to which Statoil is a party qualifies as a finance lease, or when such an asset is leased by Statoil as operator directly on behalf of a joint operation or similar arrangement, Statoil reflects its proportionate share of the leased asset and related obligations. Finance leases are classified in the Consolidated balance sheet within property, plant and equipment and finance debt. All other leases are classified as operating leases, and the costs are charged to the relevant operating expense related caption on a straight-line basis over the lease term, unless another basis is more representative of the benefits of the lease to Statoil.

Statoil distinguishes between lease and capacity contracts. Lease contracts provide the right to use a specific asset for a period of time, while capacity contracts confer on Statoil the right to and the obligation to pay for certain volume capacity availability related to transport, terminal use, storage, etc. Such capacity contracts that do not involve specified assets or that do not involve substantially all the capacity of an undivided interest in a specific asset are not considered by Statoil to qualify as leases for accounting purposes. Capacity payments are reflected as operating expenses in the Consolidated statement of income in the period for which the capacity contractually is available to Statoil.

Intangible assets including goodwill
Intangible assets are stated at cost, less accumulated amortisation and accumulated impairment losses. Intangible assets include acquisition cost for oil and gas prospects, expenditures on the exploration for and evaluation of oil and natural gas resources, goodwill and other intangible assets.

Intangible assets relating to expenditures on the exploration for and evaluation of oil and natural gas resources are not amortised. When the decision to develop a particular area is made, its intangible exploration and evaluation assets are reclassified to property, plant and equipment.

Goodwill is initially measured at the excess of the aggregate of the consideration transferred and the amount recognised for any non-controlling interest over the fair value of the identifiable assets acquired and liabilities assumed in a business combination at the acquisition date. Goodwill acquired is allocated to each cash generating unit, or group of units, expected to benefit from the combination's synergies. Following initial recognition, goodwill is measured at cost less any accumulated impairment losses.

Financial assets
Financial assets are initially recognised at fair value when Statoil becomes a party to the contractual provisions of the asset. For additional information on fair value methods, refer to the Measurement of fair values section below. The subsequent measurement of the financial assets depends on which category they have been classified into at inception.

At initial recognition, Statoil classifies its financial assets into the following three main categories: Financial investments at fair value through profit or loss, loans and receivables, and available-for-sale (AFS) financial assets. The first main category, financial investments at fair value through profit or loss, further consists of two sub-categories: Financial assets held for trading and financial assets that on initial recognition are designated as fair value through profit and loss. The latter approach may also be referred to as the fair value option.

Cash and cash equivalents include cash in hand, current balances with banks and similar institutions, and short-term highly liquid investments that are readily convertible to known amounts of cash, are subject to an insignificant risk of changes in fair value and have a maturity of three months or less from the acquisition date.

Trade receivables are carried at the original invoice amount less a provision for doubtful receivables which is made when there is objective evidence that Statoil will be unable to recover the balances in full.

AFS financial assets are carried at fair value in the balance sheet, with changes in fair value initially recognised directly in Other comprehensive income/(loss). If the investment is de-recognised or determined to be impaired, the cumulative change in fair value previously reflected in Other comprehensive income/(loss) is recognised in the statement of income.

A significant part of Statoil's investments in treasury bills, commercial papers, bonds and listed equity securities is managed together as an investment portfolio of Statoil's captive insurance company and is held in order to comply with specific regulations for capital retention. The investment portfolio is managed and evaluated on a fair value basis in accordance with an investment strategy and is accounted for using the fair value option with changes in fair value recognised through profit or loss.

Financial assets are presented as current if they contractually will expire or otherwise are expected to be recovered within 12 months after the balance sheet date, or if they are held for the purpose of being traded. Financial assets and financial liabilities are shown separately in the Consolidated balance sheet, unless Statoil has both a legal right and a demonstrable intention to net settle certain balances payable to and receivable from the same counterparty, in which case they are shown net in the balance sheet.

Inventories
Commodity inventories are stated at the lower of cost and net realisable value. Cost is determined by the first-in first-out method and comprises direct purchase costs, cost of production, transportation and manufacturing expenses. Inventories of drilling and spare parts are reflected according to the weighted average method.

Impairment
Impairment of property, plant and equipment and intangible assets other than goodwill
Statoil assesses individual assets or groups of assets for impairment whenever events or changes in circumstances indicate that the carrying value of an asset may not be recoverable. Assets are grouped into cash generating units (CGUs) which are the smallest identifiable groups of assets that generate cash inflows that are largely independent of the cash inflows from other groups of assets. Normally, separate CGUs are individual oil and gas fields or plants. Each unconventional asset play is considered a single CGU when no cash inflows from parts of the play can be reliably identified as being largely independent of the cash inflows from other parts of the play. In impairment evaluations, the carrying amounts of CGUs are determined on a basis consistent with that of the recoverable amount. In Statoil's line of business, judgement is involved in determining what constitutes a CGU. Development in production, infrastructure solutions, markets, product pricing, management actions and other factors may over time lead to changes in CGUs such as the division of one original CGU into several.

In assessing whether a write-down of the carrying amount of a potentially impaired asset is required, the asset's carrying amount is compared to the recoverable amount. The recoverable amount of an asset is the higher of its fair value less cost of disposal and its value in use. Fair value less cost of disposal is determined based on comparable recent arm's length market transactions, or based on Statoil's estimate of the price that would be received for the asset in an orderly transaction between market participants. Such fair value estimates are mainly based on discounted cash flow models, using assumed market participants' assumptions, but may also reflect market multiples observed from comparable market transactions or independent third-party valuations. Value in use is determined using a discounted cash flow model. The estimated future cash flows applied in establishing value in use are based on reasonable and supportable assumptions and represent management's best estimates of the range of economic conditions that will exist over the remaining useful life of the assets, as set down in Statoil's most recently approved long-term forecasts. Updates of assumptions and economic conditions in establishing the long-term forecasts are reviewed by corporate management on regular basis and updated at least annually. For assets and CGUs with an expected useful life or timeline for production of expected reserves extending beyond 5 years, the forecasts reflect expected production volumes for oil and natural gas, and the related cash flows include project or asset specific estimates reflecting the relevant period. Such estimates are established based on Statoil's principles and assumptions and are consistently applied.

In performing a value-in-use-based impairment test, the estimated future cash flows are adjusted for risks specific to the asset and discounted using a real post-tax discount rate which is based on Statoil's post-tax weighted average cost of capital (WACC). The use of post-tax discount rates in determining value in use does not result in a materially different determination of the need for, or the amount of, impairment that would be required if pre-tax discount rates had been used.

Unproved oil and gas properties are assessed for impairment when facts and circumstances suggest that the carrying amount of the asset or CGU to which the unproved properties belong may exceed its recoverable amount, and at least once a year. Exploratory wells that have found reserves, but where classification of those reserves as proved depends on whether major capital expenditure can be justified or where the economic viability of that major capital expenditure depends on the successful completion of further exploration work, will remain capitalised during the evaluation phase for the exploratory finds. Thereafter it will be considered a trigger for impairment evaluation of the well if no development decision is planned for the near future and there are no firm plans for future drilling in the licence.

An assessment is made at each reporting date as to whether there is any indication that previously recognised impairment losses may no longer be relevant or may have decreased. If such an indication exists, the recoverable amount is estimated. A previously recognised impairment loss is reversed only if there has been a change in the estimates used to determine the asset's recoverable amount since the last impairment loss was recognised. If that is the case, the carrying amount of the asset is increased to its recoverable amount. That increased amount cannot exceed the carrying amount that would have been determined, net of depreciation, had no impairment loss been recognised for the asset in prior years.

Impairment losses and reversals of impairment losses are presented in the Consolidated statement of income as Exploration expenses or Depreciation, amortisation and net impairment losses, on the basis of their nature as either exploration assets (intangible exploration assets) or development and producing assets (property, plant and equipment and other intangible assets), respectively.

Impairment of goodwill

Goodwill is reviewed for impairment annually or more frequently if events or changes in circumstances indicate that the carrying value may be impaired. Impairment is determined by assessing the recoverable amount of the CGU, or group of units, to which the goodwill relates. Where the recoverable amount of the CGU, or group of units, is less than the carrying amount, an impairment loss is recognised. Once recognised, impairments of goodwill are not reversed in future periods.

Financial liabilities

Financial liabilities are initially recognised at fair value when Statoil becomes a party to the contractual provisions of the liability. The subsequent measurement of financial liabilities depends on which category they have been classified into. The categories applicable for Statoil are either financial liabilities at fair value through profit or loss or financial liabilities measured at amortised cost using the effective interest method. The latter applies to Statoil's non-current bank loans and bonds.

Financial liabilities are presented as current if the liability is due to be settled within 12 months after the balance sheet date, or if they are held for the purpose of being traded. Financial liabilities are de-recognised when the contractual obligations expire, are discharged or cancelled. Gains and losses arising on the repurchase, settlement or cancellation of liabilities are recognised either in interest income and other financial items or in interest and other finance expenses within net financial items.

Derivative financial instruments

Statoil uses derivative financial instruments to manage certain exposures to fluctuations in foreign currency exchange rates, interest rates and commodity prices. Such derivative financial instruments are initially recognised at fair value on the date on which a derivative contract is entered into and are subsequently re-measured at fair value through profit and loss. The impact of commodity-based derivative financial instruments is recognised in the Consolidated statement of income under revenues, as such derivative instruments are related to sales contracts or revenue-related risk management for all significant purposes. The impact of other financial instruments is reflected under net financial items.

Derivatives are carried as assets when the fair value is positive and as liabilities when the fair value is negative. Derivative assets or liabilities expected to be recovered, or with the legal right to be settled more than 12 months after the balance sheet date are classified as non-current, with the exception of derivative financial instruments held for the purpose of being traded.

Contracts to buy or sell a non-financial item that can be settled net in cash or another financial instrument, or by exchanging financial instruments, as if the contracts were financial instruments, are accounted for as financial instruments. However, contracts that are entered into and continue to be held for the purpose of the receipt or delivery of a non-financial item in accordance with Statoil's expected purchase, sale or usage requirements, also referred to as own-use, are not accounted for as financial instruments. This is applicable to a significant number of contracts for the purchase or sale of crude oil and natural gas, which are recognised upon delivery.

Derivatives embedded in other financial instruments or in non-financial host contracts are recognised as separate derivatives and are reflected at fair value with subsequent changes through profit and loss, when their risks and economic characteristics are not closely related to those of the host contracts, and the host contracts are not carried at fair value. Where there is an active market for a commodity or other non-financial item referenced in a purchase or sale contract, a pricing formula will, for instance, be considered to be closely related to the host purchase or sales contract if the price formula is based on the active market in question. A price formula with indexation to other markets or products will however result in the recognition of a separate derivative. Where there is no active market for the commodity or other non-financial item in question, Statoil assesses the characteristics of such a price related embedded derivative to be closely related to the host contract if the price formula is based on relevant indexations commonly used by other market participants. This applies to certain long-term natural gas sales agreements.

Pension liabilities
Statoil has pension plans for employees that either provide a defined pension benefit upon retirement or a pension dependent on defined contributions and related returns. A portion of the contributions are provided for as notional contributions, for which the liability increases with a promised notional return, set equal to the actual return of assets invested through the ordinary defined contribution plan. For defined benefit plans, the benefit to be received by employees generally depends on many factors including length of service, retirement date and future salary levels.

Statoil's proportionate share of multi-employer defined benefit plans are recognised as liabilities in the balance sheet to the extent that sufficient information is available and a reliable estimate of the obligation can be made.

Statoil's net obligation in respect of defined benefit pension plans is calculated separately for each plan by estimating the amount of future benefit that employees have earned in return for their services in the current and prior periods. That benefit is discounted to determine its present value, and the fair value of any plan assets is deducted. The discount rate is the yield at the balance sheet date, reflecting the maturity dates approximating the terms of Statoil's obligations. The discount rate for the main part of the pension obligations has been established on the basis of Norwegian mortgage covered bonds, which are considered high quality corporate bonds. The cost of pension benefit plans is expensed over the period that the employees render services and become eligible to receive benefits. The calculation is performed by an external actuary.

The net interest related to defined benefit plans is calculated by applying the discount rate to the opening present value of the benefit obligation and opening present value of the plan assets, adjusted for material changes during the year. The resulting net interest element is presented in the statement of income within Net financial items. The difference between estimated interest income and actual return is recognised in the Consolidated statement of comprehensive income.

Past service cost is recognised when a plan amendment (the introduction or withdrawal of, or changes to, a defined benefit plan) or curtailment (a significant reduction by the entity in the number of employees covered by a plan) occurs, or when recognising related restructuring costs or termination benefits. The obligation and related plan assets are re-measured using current actuarial assumptions, and the gain or loss is recognised in the statement of income.

Actuarial gains and losses are recognised in full in the Consolidated statement of comprehensive income in the period in which they occur, while actuarial gains and losses related to provision for termination benefits are recognised in the Consolidated statement of income in the period in which they occur. Due to the parent company Statoil ASA's functional currency being USD, the significant part of Statoil's pension obligations will be payable in a foreign currency (i.e. NOK). As a consequence, actuarial gains and losses related to the parent company's pension obligation include the impact of exchange rate fluctuations.

Contributions to defined contribution schemes are recognised in the statement of income in the period in which the contribution amounts are earned by the employees.

Notional contribution plans, reported in the parent company Statoil ASA, are recognised as pension liabilities with the actual value of the notional contributions and promised return at reporting date. Notional contributions are recognised in the statement of income as periodic pension cost, while changes in fair value of notional assets are reflected in the statement of income under Net financial items.

Periodic pension cost is accumulated in cost pools and allocated to business areas and Statoil operated joint operations (licences) on an hours' incurred basis and recognised in the statement of income based on the function of the cost.

Onerous contracts
Statoil recognises as provisions the net obligation under contracts defined as onerous. Contracts are deemed to be onerous if the unavoidable cost of meeting the obligations under the contract exceeds the economic benefits expected to be received in relation to the contract. A contract which forms an integral part of the operations of a CGU whose assets are dedicated to that contract, and for which the economic benefits cannot be reliably separated from those of the CGU, is included in impairment considerations for the applicable CGU.

Asset retirement obligations (ARO)
Provisions for ARO costs are recognised when Statoil has an obligation (legal or constructive) to dismantle and remove a facility or an item of property, plant and equipment and to restore the site on which it is located, and when a reliable estimate of that liability can be made. The amount recognised is the present value of the estimated future expenditures determined in accordance with local conditions and requirements. Cost is estimated based on current regulations and technology, considering relevant risks and uncertainties. The discount rate used in the calculation of the ARO is a risk-free rate based on the applicable currency and time horizon of the underlying cash flows, adjusted for a credit premium which reflects Statoil's own credit risk. Normally an obligation arises for a new facility, such as an oil and natural gas production or transportation facility, upon construction or installation. An obligation may also arise during the period of operation of a facility through a change in legislation or through a decision to terminate operations, or be based on

commitments associated with Statoil's ongoing use of pipeline transport systems where removal obligations rest with the volume shippers. The provisions are classified under provisions in the Consolidated balance sheet.

When a provision for ARO cost is recognised, a corresponding amount is recognised to increase the related property, plant and equipment and is subsequently depreciated as part of the costs of the facility or item of property, plant and equipment. Any change in the present value of the estimated expenditure is reflected as an adjustment to the provision and the corresponding property, plant and equipment. When a decrease in the ARO provision related to a producing asset exceeds the carrying amount of the asset, the excess is recognised as a reduction of depreciation, amortisation and net impairment losses in the Consolidated statement of income. When an asset has reached the end of its useful life, all subsequent changes to the ARO provision are recognised as they occur in operating expenses in the Consolidated statement of income. Removal provisions associated with Statoil's role as shipper of volumes through third party transport systems are expensed as incurred.

Measurement of fair values
Quoted prices in active markets represent the best evidence of fair value and are used by Statoil in determining the fair values of assets and liabilities to the extent possible. Financial instruments quoted in active markets will typically include commercial papers, bonds and equity instruments with quoted market prices obtained from the relevant exchanges or clearing houses. The fair values of quoted financial assets, financial liabilities and derivative instruments are determined by reference to mid-market prices, at the close of business on the balance sheet date.

Where there is no active market, fair value is determined using valuation techniques. These include using recent arm's-length market transactions, reference to other instruments that are substantially the same, discounted cash flow analysis, and pricing models and related internal assumptions. In the valuation techniques, Statoil also takes into consideration the counterparty and its own credit risk. This is either reflected in the discount rate used or through direct adjustments to the calculated cash flows. Consequently, where Statoil reflects elements of long-term physical delivery commodity contracts at fair value, such fair value estimates to the extent possible are based on quoted forward prices in the market and underlying indexes in the contracts, as well as assumptions of forward prices and margins where observable market prices are not available. Similarly, the fair values of interest and currency swaps are estimated based on relevant quotes from active markets, quotes of comparable instruments, and other appropriate valuation techniques.

Critical accounting judgements and key sources of estimation uncertainty

Critical judgements in applying accounting policies
The following are the critical judgements, apart from those involving estimations (see below), that Statoil has made in the process of applying the accounting policies and that have the most significant effect on the amounts recognised in the financial statements:

Revenue recognition - gross versus net presentation of traded SDFI volumes of oil and gas production
As described under Transactions with the Norwegian State above, Statoil markets and sells the Norwegian State's share of oil and gas production from the NCS. Statoil includes the costs of purchase and proceeds from the sale of the SDFI oil production in purchases [net of inventory variation] and revenues, respectively. In making the judgement, Statoil considered the detailed criteria for the recognition of revenue from the sale of goods and, in particular, concluded that the risk and reward of the ownership of the oil had been transferred from the SDFI to Statoil.

Statoil sells, in its own name, but for the Norwegian State's account and risk, the State's production of natural gas. These gas sales, and related expenditures refunded by the State, are shown net in Statoil's Consolidated financial statements. In making the judgement, Statoil considered the same criteria as for the oil production and concluded that the risk and reward of the ownership of the gas had not been transferred from the SDFI to Statoil.

Key sources of estimation uncertainty
The preparation of the Consolidated financial statements requires that management make estimates and assumptions that affect reported amounts of assets, liabilities, income and expenses. The estimates and associated assumptions are based on historical experience and various other factors that are believed to be reasonable under the circumstances, the result of which form the basis of making the judgements about carrying values of assets and liabilities that are not readily apparent from other sources. Actual results may differ from these estimates. The estimates and underlying assumptions are reviewed on an on-going basis considering the current and expected future market conditions.

Statoil is exposed to a number of underlying economic factors which affect the overall results, such as liquids prices, natural gas prices, refining margins, foreign exchange rates and interest rates as well as financial instruments with fair values derived from changes in these factors. In addition, Statoil's results are influenced by the level of production, which in the short term may be influenced by, for instance, maintenance programmes. In the long term, the results are impacted by the success of exploration and field development activities.

The matters described below are considered to be the most important in understanding the key sources of estimation uncertainty that are involved in preparing these Consolidated financial statements and the uncertainties that could most significantly impact the amounts reported on the results of operations, financial position and cash flows.

Proved oil and gas reserves
Proved oil and gas reserves may materially impact the Consolidated financial statements, as changes in the proved reserves, for instance as a result of changes in prices, will impact the unit of production rates used for depreciation and amortisation. Proved oil and gas reserves are those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward, from known reservoirs, and under existing economic conditions, operating methods and government regulations. Unless evidence indicates that renewal is reasonably certain, estimates of economically producible reserves only reflect the period before the contracts providing the right to operate

expire. The project to extract the hydrocarbons must have commenced, or the operator must be reasonably certain that it will commence within a reasonable time.

Proved oil and gas reserves have been estimated by internal qualified professionals on the basis of industry standards and are governed by the oil and gas rules and disclosure requirements in the U.S. Securities Exchange Commission (SEC) regulations S-K and S-X, and the Financial Accounting Standards Board (FASB) requirements for supplemental oil and gas disclosures. The estimates have been based on a 12-month average product price and on existing economic conditions and operating methods as required, and recovery of the estimated quantities have a high degree of certainty (at least a 90% probability).

Reserves estimates are based on subjective judgements involving geological and engineering assessments of in-place hydrocarbon volumes, the production, historical recovery and processing yield factors and installed plant operating capacity. For future development projects, proved reserves estimates are included only where there is a significant commitment to project funding and execution and when relevant governmental and regulatory approvals have been secured or are reasonably certain to be secured. The reliability of these estimates at any point in time depends on both the quality and availability of the technical and economic data and the efficiency of extracting and processing the hydrocarbons. An independent third party has evaluated Statoil's proved reserves estimates, and the results of this evaluation do not differ materially from Statoil's estimates.

Expected oil and gas reserves
Expected oil and gas reserves may materially impact the Consolidated financial statements, as changes in the expected reserves, for instance as a result of changes in prices, will impact asset retirement obligations and impairment testing of upstream assets, which in turn may lead to changes in impairment charges affecting operating income. Expected oil and gas reserves are the estimated remaining, commercially recoverable quantities, based on Statoil's judgement of future economic conditions, from projects in operation or justified for development. Recoverable oil and gas quantities are always uncertain, and the expected value is the weighted average, or statistical mean, of the possible outcomes. Expected reserves are therefore typically larger than proved reserves as defined by the SEC rules. Expected oil and gas reserves have been estimated by internal qualified professionals on the basis of industry standards and are used for impairment testing purposes and for calculation of asset retirement obligations. Reserves estimates are based on subjective judgements involving geological and engineering assessments of in-place hydrocarbon volumes, the production, historical recovery and processing yield factors, installed plant operating capacity and operating approval limits. The reliability of these estimates at any point in time depends on both the quality and quantity of the technical and economic data and the efficiency of extracting and processing the hydrocarbons. Such estimates are inherently less reliable in early field life or where the available data is limited following a recently implemented change in the method of production.

Exploration and leasehold acquisition costs
Statoil capitalises the costs of drilling exploratory wells pending determination of whether the wells have found proved oil and gas reserves. Statoil also capitalises leasehold acquisition costs and signature bonuses paid to obtain access to undeveloped oil and gas acreage. Judgements as to whether these expenditures should remain capitalised, be de-recognised or written down in the period may materially affect the operating income for the period.

Impairment/reversal of impairment
Statoil has significant investments in property, plant and equipment and intangible assets. Changes in the circumstances or expectations of future performance of an individual asset may be an indicator that the asset is impaired, requiring the carrying amount to be written down to its recoverable amount. Impairments are reversed if conditions for impairment are no longer present. Evaluating whether an asset is impaired or if an impairment should be reversed requires a high degree of judgement and may to a large extent depend upon the selection of key assumptions about the future.

The key assumptions used will bear the risk of change based on the inherent volatile nature of macro-economic factors such as future commodity prices or discount rate and uncertainty in asset specific factors such as reserve estimates and operational decisions impacting the production profile or activity levels for our oil and natural gas properties. When estimating the recoverable amount, the single most likely future cash flows, the point estimate, is the primary method applied to reflect uncertainties in timing and amount inherent in the assumptions used in the estimated future cash flows. For assumptions in which the expected probability distributions or outcome are expected to be significantly skewed the use of decision trees or simulation is applied.

Unproved oil and gas properties are assessed for impairment when facts and circumstances suggest that the carrying amount of the relevant asset or CGU may exceed its recoverable amount, and at least annually. If, following evaluation, an exploratory well has not found proved reserves, the previously capitalised costs are tested for impairment. Subsequent to the initial evaluation phase for a well, it will be considered a trigger for impairment testing of a well if no development decision is planned for the near future and there is no firm plan for future drilling in the licence. Impairment of unsuccessful wells is reversed, as applicable, to the extent that conditions for impairment are no longer present.

Where recoverable amounts are based on estimated future cash flows, reflecting Statoil's or market participants' assumptions about the future and discounted to their present value, the estimates involve complexity. Impairment testing requires long-term assumptions to be made concerning a number of economic factors such as future market prices, refinery margins, currency exchange rates and future output, discount rates and political and country risk among others, in order to establish relevant future cash flows. Long-term assumptions for major economic factors are made at a group level, and there is a high degree of reasoned judgement involved in establishing these assumptions, in determining other relevant factors such as forward price curves, in estimating production outputs and in determining the ultimate terminal value of an asset.

Employee retirement plans
When estimating the present value of defined benefit pension obligations that represent a long-term liability in the Consolidated balance sheet, and indirectly, the period's net pension expense in the Consolidated statement of income, management make a number of critical assumptions affecting these estimates. Most notably, assumptions made about the discount rate to be applied to future benefit payments and plan assets, the expected rate of pension

increase and the annual rate of compensation increase, have a direct and potentially material impact on the amounts presented. Significant changes in these assumptions between periods can have a material effect on the Consolidated financial statements.

Asset retirement obligations
Statoil has significant obligations to decommission and remove offshore installations at the end of the production period. The costs of these decommissioning and removal activities require revisions due to changes in current regulations and technology while considering relevant risks and uncertainties. Most of the removal activities are many years into the future, and the removal technology and costs are constantly changing. The estimates include assumptions of the time required and the day rates for rigs, marine operations and heavy lift vessels that can vary considerably depending on the assumed removal complexity. As a result, the initial recognition of the liability and the capitalised cost associated with decommissioning and removal obligations, and the subsequent adjustment of these balance sheet items, involve the application of significant judgement.

Derivative financial instruments
When not directly observable in active markets, the fair value of derivative contracts must be computed internally based on internal assumptions as well as directly observable market information, including forward and yield curves for commodities, currencies and interest rates. Changes in internal assumptions, forward and yield curves could materially impact the internally computed fair value of derivative contracts, particularly long-term contracts, resulting in a corresponding impact on income or loss in the Consolidated statement of income.

Income tax
Every year Statoil incurs significant amounts of income taxes payable to various jurisdictions around the world and recognises significant changes to deferred tax assets and deferred tax liabilities, all of which are based on management's interpretations of applicable laws, regulations and relevant court decisions. The quality of these estimates is highly dependent upon proper application of at times very complex sets of rules, the recognition of changes in applicable rules and, in the case of deferred tax assets, management's ability to project future earnings from activities that may apply loss carry forward positions against future income taxes.

3 Segments

Statoil's operations are managed through the following business areas: Development & Production Norway (DPN), Development & Production USA (DPUSA), Development & Production International (DPI), Marketing, Midstream & Processing (MMP), New Energy Solutions (NES), Technology, Projects & Drilling (TPD), Exploration (EXP) and Global Strategy & Business Development (GSB).

The development and production business areas are responsible for the commercial development of the oil and gas portfolios within their respective geographical areas: DPN on the Norwegian continental shelf, DPUSA including offshore and onshore activities in the USA and Mexico, and DPI worldwide outside of DPN and DPUSA.

Exploration activities are managed by a separate business area, which has the global responsibility across the group for discovery and appraisal of new resources. Exploration activities are allocated to and presented in the respective development and production business areas.

The MMP business area is responsible for marketing and trading of oil and gas commodities (crude, condensate, gas liquids, products, natural gas and liquefied natural gas), electricity and emission rights, as well as transportation, processing and manufacturing of the above-mentioned commodities, operations of refineries, terminals, processing and power plants.

The NES business area is responsible for wind parks, carbon capture and storage as well as other renewable energy and low-carbon energy solutions.

The business areas DPI and DPUSA are aggregated into the reporting segment Exploration & Production International (E&P International), previously named Development and Production International. The aggregation has its basis in similar economic characteristics, such as the assets' long term and capital-intensive nature and exposure to volatile oil and gas commodity prices, the nature of products, service and production processes, the type and class of customers, the methods of distribution and regulatory environment. The reporting segments Exploration & Production Norway (E&P Norway), previously named Development and Production Norway, and MMP consists of the business areas DPN and MMP respectively. The business areas NES, GSB, TPD, EXP and corporate staffs and support functions are aggregated into the reporting segment "Other" due to the immateriality of these areas. The majority of costs within the business areas GSB, TPD and EXP are allocated to the E&P International, E&P Norway and MMP reporting segments.

The eliminations section includes the elimination of inter-segment sales and related unrealised profits, mainly from the sale of crude oil and products. Inter-segment revenues are based upon estimated market prices.

Segment data for the years ended 31 December 2017, 2016 and 2015 are presented below. The measurement basis of segment profit is Net operating income/(loss). In the tables below, deferred tax assets, pension assets and non-current financial assets are not allocated to the segments. Also, the line additions to PP&E, intangibles and equity accounted investments are excluding movements due to changes in asset retirement obligations.

(in USD million)	E&P Norway	E&P International	MMP	Other	Eliminations	Total
Full year 2017						
Revenues third party and other income	(23)	1,984	58,935	102	0	60,999
Revenues inter-segment[1)]	17,586	7,249	83	1	(24,919)	0
Net income/(loss) from equity accounted investments	129	22	53	(16)	0	188
Total revenues and other income	17,692	9,256	59,071	87	(24,919)	61,187
Purchases [net of inventory variation][1)]	0	(7)	(52,647)	(0)	24,442	(28,212)
Operating, selling, general and administrative expenses[1)]	(2,954)	(2,804)	(3,925)	(235)	418	(9,501)
Depreciation, amortisation and net impairment losses	(3,874)	(4,423)	(256)	(91)	(0)	(8,644)
Exploration expenses	(379)	(681)	0	0	0	(1,059)
Net operating income/(loss)	10,485	1,341	2,243	(239)	(59)	13,771
Additions to PP&E, intangibles and equity accounted investments	4,869	5,063	320	543	0	10,795
Balance sheet information						
Equity accounted investments	1,133	234	134	1,050	0	2,551
Non-current segment assets	30,278	36,453	5,137	390	0	72,258
Non-current assets, not allocated to segments						9,102
Total non-current assets						83,911

1) Parts of the gas transportation costs that previously were allocated to MMP and therefore deducted from the inter segment transfer price, are from 1 January 2017 allocated to E&P Norway.

(in USD million)	E&P Norway	E&P International	MMP	Other	Eliminations	Total
Full year 2016						
Revenues third party and other income	184	884	44,883	41	0	45,993
Revenues inter-segment	12,971	5,873	35	1	(18,880)	(0)
Net income/(loss) from equity accounted investments	(78)	(100)	61	(3)	0	(119)
Total revenues and other income	13,077	6,657	44,979	39	(18,880)	45,873
Purchases [net of inventory variation]	1	(7)	(39,696)	(0)	18,198	(21,505)
Operating, selling, general and administative expenses	(2,547)	(2,923)	(4,439)	(340)	463	(9,787)
Depreciation, amortisation and net impairment losses	(5,698)	(5,510)	(221)	(121)	0	(11,550)
Exploration expenses	(383)	(2,569)	0	0	0	(2,952)
Net operating income/(loss)	4,451	(4,352)	623	(423)	(219)	80
Additions to PP&E, intangibles and equity accounted investments	6,786	6,397	492	451	0	14,125
Balance sheet information						
Equity accounted investments	1,133	365	129	617	0	2,245
Non-current segment assets	27,816	36,181	4,450	352	0	68,799
Non-current assets, not allocated to segments						8,090
Total non-current assets						79,133

(in USD million)	E&P Norway	E&P International	MMP	Other	Eliminations	Total
Full year 2015						
Revenues third party and other income	(123)	1,576	57,868	349	0	59,671
Revenues inter-segment	17,459	6,715	183	1	(24,357)	(0)
Net income/(loss) from equity accounted investments	3	(91)	55	4	0	(29)
Total revenues and other income	17,339	8,200	58,106	354	(24,357)	59,642
Purchases [net of inventory variation]	(0)	(10)	(50,547)	(0)	24,303	(26,254)
Operating, selling, general and administative expenses	(3,223)	(3,391)	(4,664)	(342)	187	(11,433)
Depreciation, amortisation and net impairment losses	(6,379)	(10,231)	37	(142)	(0)	(16,715)
Exploration expenses	(576)	(3,296)	(0)	0	0	(3,872)
Net operating income /(loss)	7,161	(8,729)	2,931	(129)	133	1,366
Additions to PP&E, intangibles and equity accounted investments	6,293	8,119	900	273	0	15,584
Balance sheet information						
Equity accounted investments	5	333	214	272	0	824
Non-current segment assets	27,706	37,475	5,588	690	0	71,458
Non-current assets, not allocated to segments						9,305
Total non-current assets						81,588

See note 4 Acquisitions and divestments for information on transactions that affect the different segments.

See note 10 Property, plant and equipment for further information on impairment losses that affected the different segments.

See note 11 Intangible assets for information on impairment losses that affected the different segments.

See note 23 Other commitments, contingent liabilities and contingent assets for information on contingencies that have influenced the segments.

Revenues by geographical areas
Statoil has business operations in more than 30 countries. When attributing revenues third party and other income to the country of the legal entity executing the sale, Norway constitutes 74% and the USA constitutes 17%.

Non-current assets by country

(in USD million)	At 31 December 2017	2016	2015
Norway	34,588	31,484	31,487
USA	19,267	18,223	20,531
Brazil	4,584	5,308	3,474
UK	4,222	3,108	2,882
Angola	2,888	3,884	5,350
Canada	1,715	1,494	2,270
Azerbaijan	1,472	1,326	1,416
Algeria	1,114	1,344	1,435
Other countries	4,958	4,873	3,436
Total non-current assets[1)]	74,809	71,043	72,282

1) Excluding deferred tax assets, pension assets and non-current financial assets.

Revenues by product type

(in USD million)	2017	2016	2015
Crude oil	29,519	24,307	27,806
Natural gas	11,420	9,202	12,390
Refined products	11,423	8,142	10,761
Natural gas liquids	5,647	4,036	5,482
Other	2,963	1	1,461
Total revenues	60,971	45,688	57,900

4 Acquisitions and divestments

2017

Sale of interest in Kai Kos Dehseh

In January 2017 Statoil closed an agreement, entered in December 2016, with Athabasca Oil Corporation to divest its 100% interest in Kai Kos Dehseh (KKD) oil sands. The total consideration consisted of cash consideration of CAD 431 million (USD 328 million), 100 million common shares in Athabasca Oil Corporation (which is accounted for as an available for sale financial investment) and a series of contingent payments. The shares and the contingent consideration were measured at a combined fair value of CAD 185 million (USD 142 million) on the closing date. A loss on the transaction of USD 351 million has been recognised as operating expense and includes a reclassification of accumulated foreign exchange losses, previously recognised in other comprehensive income/(loss). The transaction is reflected in the Exploration & Production International (E&P International) segment.

Acquisition and divestment of operated interest in Brazil

In November 2016 Statoil acquired a 66% operated interest in the Brazilian offshore licence BM-S-8 in the Santos basin from Petróleo Brasileiro S.A. ("Petrobras"). A cash consideration of USD 1,250 million was paid on the closing date and USD 300 million is expected to be paid late March 2018. The payment of the remaining consideration of USD 950 million is subject to certain conditions being met, and is reflected at fair value at the reporting date. The value of the acquired exploration assets resulted in an increase in intangible assets of USD 2,271 million at the transaction date.

In August 2017 Statoil entered into an agreement with Queiroz Galvão Exploração e Produção ("QGEP") to acquire QGEP's 10% interest in the same licence in Brazil's Santos basin increasing the operated interest to 76%. A cash consideration of USD 194 million was paid on the closing date, presented as a capital expenditure in the Statement of cash flows. The remaining consideration consists of two cash payments. The payment of USD 45 million is expected to be paid late March 2018. The payment of USD 144 million is subject to certain conditions being met, and is reflected at fair value at the reporting date. The value of the acquired exploration assets resulted in an increase in intangible assets of USD 362 million at the transaction date. The agreement was closed in December 2017.

In October 2017, the consortium comprising Statoil (operator, 40%), ExxonMobil (40%) and Galp (20%) presented the winning bid (67.12% of profit oil) for the Carcará North block in the Santos basin. Statoil's share of the pre-determined signature bonus paid by the consortium in December 2017 was USD 350 million and is recognised as an intangible asset.

At the same time in October 2017 Statoil has agreed to divest 33% out of its 76% interest in BM-S-8 licence to ExxonMobil for a total potential consideration of around USD 1.3 billion, comprising an upfront cash payment of around USD 800 million and a contingent cash payment of around USD 500 million; a further 3.5% to ExxonMobil and 3% to Galp for a total consideration of around USD 250 million, comprising an upfront cash payment of around USD 155 million and a contingent cash payment of around USD 95 million. As of 31 December 2017, intangible assets related to and liabilities associated with the 39.5% of current interest in BM-S-8 were presented as held for sale in the Consolidated balance sheet. No impact on the Consolidated statement of income is expected upon the closing of the divestment.

After closing these transactions, Statoil will have an ownership share of 36.5% in the licences, which are expected to be unitised. The transactions are accounted for in the E&P International segment.

Extension of the Azeri-Chirag-Deepwater Gunashli (ACG) production sharing agreement
In the third quarter of 2017 the Azeri-Chirag-Deepwater Gunashli (ACG) production sharing agreement was extended by 25 years and will be effective until the end of 2049. The transaction was recognised in the E&P International segment in the fourth quarter of 2017, following ratification by the Parliament (Milli Majlis) of the Republic of Azerbaijan. As part of the new agreement, Statoil's participating interest will be adjusted to 7.27% down from 8.56%. The international partners will make a total payment of USD 3.6 billion to the State Oil Fund of the Republic of Azerbaijan, Statoil's share will be approximately USD 349 million, which will be paid over a period of 8 years.

Acquisition of interests in Roncador field
In December 2017 Statoil entered into agreement with Petrobras to acquire a 25% interest in Roncador, an oil field in the Campos Basin in Brazil. A cash consideration of USD 2.35 billion will be paid on the closing date. The liability for payment of the remaining consideration of up to USD 550 million is subject to certain conditions being met, and will be reflected at fair value at the acquisition date. Petrobras retains operatorship and a 75% interest. Closing is expected in 2018 and is subject to certain conditions, including government approval. The acquired interest will be reflected in accordance with the principles of IFRS 3 Business Combinations, and Statoil's ownership in the field will thereafter be accounted for as a joint operation. The transaction will be accounted for in the E&P International segment.

Acquisition of interests in Martin Linge field and Garantiana discovery
In December 2017 Statoil and Total have agreed on a transaction whereby Statoil will acquire Total's equity stakes and take over as operator in the Martin Linge field (51%) and the Garantiana discovery (40%) on the Norwegian continental shelf (NCS). The transaction is subject to certain conditions, including government approval. Statoil will pay Total consideration which, based on a 1 January 2017 valuation, amounts to USD 1.45 billion. At the completion of the transaction, which is expected late March 2018, the consideration will be subject to adjustment reflecting post-tax cash flows in the period from valuation until the date of closing. The assets and liabilities related to the acquired portion of Martin Linge will be reflected in accordance with the principles of IFRS 3 Business Combinations. The transaction will be accounted for in the Exploration & Production Norway (E&P Norway) segment.

2016

Acquisition of shares in Lundin Petroleum AB (Lundin) and sale of interests in the Edvard Grieg field
In January 2016 Statoil acquired 11.93% of the issued share capital and votes in Lundin Petroleum AB for a total purchase price of SEK 4.6 billion (USD 541 million). In June 2016 Statoil closed an agreement with Lundin to divest its entire 15% interest in the Edvard Grieg field, a 9% interest in the Edvard Grieg Oil pipeline and a 6% interest in the Utsira High Gas pipeline for an increased ownership share in Lundin. In addition to the divested interests, a cash consideration of SEK 544 million (USD 64 million) was paid to Lundin. Following the completion of the transaction Statoil owned 68.4 million shares of Lundin, corresponding to 20.1% of the outstanding shares and votes. Statoil recognised a total net gain of USD 120 million related to the divestment presented in the line item other income in the Consolidated statement of income. In the segment reporting, the gain was recognised in the E&P Norway segment (USD 114 million) and in the Marketing, Midstream & Processing (MMP) segment (USD 5 million). The transaction was tax exempt under the Norwegian petroleum tax legislation.

Following the increase in ownership interest on 30 June 2016, Statoil obtained significant influence over Lundin, and accounted for the investment as an associate under the equity method. Excess values were allocated mainly to Lundin`s exploration and production licences on the Norwegian continental shelf. The investment in Lundin was included in the Consolidated balance sheet within line item equity accounted investments with a book value of USD 1,199 million as per 30 June 2016. The Lundin investment is reported as part of the E&P Norway segment. For summarised financial information relating investment in Lundin Petroleum AB, see note 12 Equity accounted investments. Following the change in accounting classification, Statoil recognised a gain of USD 127 million representing the cumulative gain on its initial 11.93% shareholding being reclassified from the line item net gains (losses) from available for sale financial assets in the Consolidated statement of comprehensive income, to the net financial items line item in the Consolidated statement of income.

Sale of interest in Marcellus operated onshore play
In July 2016 Statoil divested its operated properties in the US state of West Virginia to EQT Corporation for USD 407 million in cash. The transaction was reported as part of E&P International segment with an immaterial effect on the Consolidated statement of income recognised in the third quarter of 2016.

2015

Sale of interests in the Marcellus onshore play
In January 2015 Statoil reduced its average working interest in the non-operated southern Marcellus onshore play from 29% to 23% through a divestment to Southwestern Energy. Proceeds from the sale were USD 365 million, recognised in the E&P International segment with no gain.

Sale of interests in the Shah Deniz project and the South Caucasus Pipeline
In April 2015 Statoil sold its remaining 15.5% interest in the Shah Deniz project and the South Caucasus Pipeline to Petronas with a total gain of USD 1,182 million, recognised in the E&P International and the MMP segments. Total proceeds from the sale were USD 2,688 million.

Sale of buildings
In 2015 Statoil sold the shares in Forusbeen 50 AS, Strandveien 4 AS and Arkitekt Ebbelsvei 10 AS with a gain of USD 211 million, recognised in the Other segment. Proceeds from the sale were USD 486 million. At the same time Statoil entered into 15 year operating lease agreements for the buildings.

Sale of interests in the Trans Adriatic Pipeline AG
In December 2015 Statoil sold its 20% interest in Trans Adriatic Pipeline AG to Snam SpA, with a gain of USD 139 million, recognised in the MMP segment. Total proceeds from the sale were USD 227 million.

Sale of interests in the Gudrun field and acquisition of interests in Eagle Ford
In December 2015 Statoil sold a 15% interest in the Gudrun field on the Norwegian continental shelf (NCS) to Repsol, recognizing a total gain of USD 142 million in the E&P Norway segment. Proceeds from the sale were USD 216 million. Simultaneously Statoil acquired an additional 13% interest in the Eagle Ford formation with the same party. The acquisition was accounted for as a business combination using the acquisition method in the E&P International and MMP segments with the fair value of net identifiable assets of USD 277 million and USD 121 million, respectively as of 30 December 2015. No goodwill was recognised.

5 Financial risk management

General information relevant to financial risks
Statoil's business activities naturally expose Statoil to financial risk. Statoil's approach to risk management includes assessing and managing risk in all activities using a holistic risk approach. Statoil takes into account correlations between the most important market risks and the natural hedges inherent in Statoil's portfolio. This approach allows Statoil to reduce the number of risk management transactions and avoid sub-optimisation.

An important element in risk management is the use of centralised trading mandates. Mandates in the trading organisations within crude oil, refined products, natural gas and electricity are relatively small compared to the total market risk of Statoil. All major strategic transactions are required to be coordinated through Statoil's corporate risk committee.

The corporate risk committee, which is headed by the chief financial officer and includes representatives from the principal business segments, is responsible for defining, developing and reviewing Statoil's risk policies. The chief financial officer, assisted by the committee, is also responsible for overseeing and developing Statoil's Enterprise Risk Management and proposing appropriate measures to adjust risk at the corporate level.

Financial risks
Statoil's activities expose Statoil to the following financial risks:
- Market risk (including commodity price risk, currency risk and interest rate risk)
- Liquidity risk
- Credit risk

Market risk
Statoil operates in the worldwide crude oil, refined products, natural gas, and electricity markets and is exposed to market risks including fluctuations in hydrocarbon prices, foreign currency rates, interest rates, and electricity prices that can affect the revenues and costs of operating, investing and financing. These risks are managed primarily on a short-term basis with a focus on achieving the highest risk-adjusted returns for Statoil within the given mandate. Long-term exposures are managed at the corporate level, while short-term exposures are managed according to trading strategies and mandates.

For more information on sensitivity analysis of market risk see note 25 Financial instruments: fair value measurement and sensitivity analysis of market risk.

Commodity price risk
Statoil's most important long-term commodity risk (oil and natural gas) is related to future market prices as Statoil's risk policy is to be exposed to both upside and downside price movements. To manage short-term commodity risk, Statoil enters into commodity- based derivative contracts, including futures, options, over-the-counter (OTC) forward contracts, market swaps and contracts for differences related to crude oil, petroleum products, natural gas and electricity. Statoil's bilateral gas sales portfolio is exposed to various price indices and uses derivatives to manage the net gas sales exposure towards a diversified combination of long and short dated gas price markers.

The term of crude oil and refined oil products derivatives are usually less than one year, and they are traded mainly on the Inter Continental Exchange (ICE) in London, the New York Mercantile Exchange (NYMEX), the OTC Brent market, and crude and refined products swap markets. The term of natural gas and electricity derivatives is usually three years or less, and they are mainly OTC physical forwards and options, NASDAQ OMX Oslo forwards and futures traded on the NYMEX and ICE.

Currency risk
Statoil's cash flows from operating activities deriving from oil and gas sales, operating expenses and capital expenditures are mainly in USD, but taxes,

dividends to shareholders on the Oslo Børs and a share of our operating expenses and capital expenditures are in NOK. Accordingly, Statoil's currency management is primarily linked to mitigate currency risk related to payments in NOK. This means that Statoil regularly purchases NOK, primarily spot, but also on a forward basis using conventional derivative instruments.

Interest rate risk

Bonds are normally issued at fixed rates in a variety of local currencies (among others USD, EUR and GBP). Bonds are normally converted to floating USD bonds by using interest rate and currency swaps. Statoil manages its interest rates exposure on its bond debt based on risk and reward considerations from an enterprise risk management perspective. This means that the fixed/floating mix on interest rate exposure may vary from time to time. For more detailed information about Statoil's long-term debt portfolio see note 18 Finance debt.

Liquidity risk

Liquidity risk is the risk that Statoil will not be able to meet obligations of financial liabilities when they become due. The purpose of liquidity management is to ensure that Statoil has sufficient funds available at all times to cover its financial obligations.

The main cash outflows are the quarterly dividend payments and Norwegian petroleum tax payments paid six times per year. If the cash flow forecasts indicate that the liquid assets will fall below target levels, new long-term funding will be considered.

Short-term funding needs will normally be covered by the USD 5.0 billion US Commercial papers programme (CP) which is backed by a revolving credit facility of USD 5.0 billion, supported by 21 core banks, maturing in 2022. The facility supports secure access to funding, supported by the best available short-term rating. As at 31 December 2017 it has not been drawn.

Statoil raises debt in all major capital markets (USA, Europe and Asia) for long-term funding purposes. The policy is to have a smooth maturity profile with repayments not exceeding 5% of capital employed in any year for the nearest five years. Statoil's non-current financial liabilities have a weighted average maturity of approximately nine years.

For more information about Statoil's non-current financial liabilities see note 18 Finance debt.

The table below shows a maturity profile, based on undiscounted contractual cash flows, for Statoil's financial liabilities.

(in USD million)	At 31 December 2017	2016
Due within 1 year	14,668	12,756
Due between 1 and 2 years	5,331	8,506
Due between 3 and 4 years	4,810	6,023
Due between 5 and 10 years	11,913	11,045
Due after 10 years	11,498	12,905
Total specified	48,221	51,234

Credit risk

Credit risk is the risk that Statoil's customers or counterparties will cause Statoil financial loss by failing to honor their obligations. Credit risk arises from credit exposures with customer accounts receivables as well as from financial investments, derivative financial instruments and deposits with financial institutions.

Prior to entering into transactions with new counterparties, Statoil's credit policy requires all counterparties to be formally identified and assigned internal credit ratings as well as exposure limits. The internal credit ratings reflect Statoil's assessment of the counterparties' credit risk and are based on a quantitative and qualitative analysis of recent financial statements and other relevant business information including general market and industry information. All counterparties are re-assessed regularly.

Statoil uses risk mitigation tools to reduce or control credit risk both on a counterparty and portfolio level. The main tools include bank and parental guarantees, prepayments and cash collateral.

Statoil has pre-defined limits for the absolute credit risk level allowed at any given time on Statoil's portfolio as well as maximum credit exposures for individual counterparties. Statoil monitors the portfolio on a regular basis and individual exposures against limits on a daily basis. The total credit exposure portfolio of Statoil is geographically diversified among a number of counterparties within the oil and energy sector, as well as larger oil and gas consumers and financial counterparties. The majority of Statoil's credit exposure is with investment grade counterparties.

The following table contains the carrying amount of Statoil's financial receivables and derivative financial instruments split by Statoil's assessment of the counterparty's credit risk. Trade and other receivables include 2% overdue receivables for 30 days and more. The overdue receivables are mainly joint venture receivables pending the settlement of disputed working interest items payable from Statoil's working interest partners within its US unconventional activities. Provisions have been made for expected losses. Only non-exchange traded instruments are included in derivative financial instruments.

(in USD million)	Non-current financial receivables	Trade and other receivables	Non-current derivative financial instruments	Current derivative financial instruments
At 31 December 2017				
Investment grade, rated A or above	262	2,148	1,079	84
Other investment grade	214	6,135	525	71
Non-investment grade or not rated	247	278	0	5
Total financial asset	723	8,560	1,603	159
At 31 December 2016				
Investment grade, rated A or above	234	1,682	754	412
Other investment grade	264	4,090	1,064	75
Non-investment grade or not rated	210	1,302	0	4
Total financial asset	707	7,074	1,819	491

For more information about Trade and other receivables, see note 15 Trade and other receivables.

At 31 December 2017, USD 704 million of cash was held as collateral to mitigate a portion of Statoil's credit exposure. At 31 December 2016, USD 571 million was held as collateral. The collateral cash is received as a security to mitigate credit exposure related to positive fair values on interest rate swaps, cross currency swaps and foreign exchange swaps. Cash is called as collateral in accordance with the master agreements with the different counterparties when the positive fair values for the different swap agreements are above an agreed threshold.

Under the terms of various master netting agreements for derivative financial instruments as of 31 December 2017, USD 706 million presented as liabilities do not meet the criteria for offsetting. At 31 December 2016, USD 817 million was not offset. The collateral received and the amounts not offset from derivative financial instrument liabilities, reduce the credit exposure in the derivative financial instruments presented in the table above as they will offset each other in a potential default situation for the counterparty. Trade and other receivables subject to similar master netting agreements USD 502 million have been offset as of 31 December 2017, and respectively USD 364 million as of 31 December 2016.

6 Remuneration

(in USD million, except average number of employees)	Full year 2017	2016	2015
Salaries[1)]	2,671	2,576	2,791
Pension costs	469	650	846
Payroll tax	387	394	419
Other compensations and social costs	290	276	312
Total payroll costs	3,818	3,895	4,369
Average number of employees[2)]	20,700	21,300	22,300

1) Salaries include bonuses, severance packages and expatriate costs in addition to base pay.
2) Part time employees amount to 3% for each of the years 2017, 2016 and 2015 respectively.

Total payroll expenses are accumulated in cost-pools and partly charged to partners of Statoil operated licences on an hours incurred basis.

Compensation to the board of directors (BoD) and the corporate executive committee (CEC)

(in USD thousand)[1]	Full year 2017	2016	2015
Current employee benefits	11,067	9,270	11,436
Post-employment benefits	636	574	799
Other non-current benefits	25	19	15
Share-based payment benefits	175	102	167
Total	11,902	9,966	12,418

1) All figures in the table are presented on accrual basis.

At 31 December 2017, 2016 and 2015 there are no loans to the members of the BoD or the CEC.

Share-based compensation
Statoil's share saving plan provides employees with the opportunity to purchase Statoil shares through monthly salary deductions and a contribution by Statoil. If the shares are kept for two full calendar years of continued employment following the year of purchase, the employees will be allocated one bonus share for each one they have purchased.

Estimated compensation expense including the contribution by Statoil for purchased shares, amounts vested for bonus shares granted and related social security tax was USD 62 million, USD 61 million and USD 77 million related to the 2017, 2016 and 2015 programmes, respectively. For the 2018 programme (granted in 2017) the estimated compensation expense is USD 72 million. At 31 December 2017 the amount of compensation cost yet to be expensed throughout the vesting period is USD 143 million.

7 Other expenses

Auditor's remuneration

(in USD million, excluding VAT)	Full year 2017	2016	2015
Audit fee	6.1	6.5	6.1
Audit related fee	0.9	1.0	1.7
Tax fee	0.0	0.1	0.0
Other service fee	0.0	0.0	0.0
Total	7.0	7.5	7.9

In addition to the figures in the table above, the audit fees and audit related fees related to Statoil operated licences amount to USD 0.8 million, USD 0.8 million and USD 0.9 million for 2017, 2016 and 2015, respectively.

Research and development expenditures
Research and development (R&D) expenditures were USD 307 million, USD 298 million and USD 344 million in 2017, 2016 and 2015, respectively. R&D expenditures are partly financed by partners of Statoil operated licences. Statoil's share of the expenditures has been recognised as expense in the Consolidated statement of income.

8 Financial items

(in USD million)	Full year 2017	2016	2015
Foreign exchange gains (losses) derivative financial instruments	(920)	353	548
Other foreign exchange gains (losses)	1,046	(473)	(793)
Net foreign exchange gains (losses)	126	(120)	(245)
Dividends received	63	46	42
Gains (losses) financial investments	108	(0)	47
Interest income financial investments	64	63	76
Interest income non-current financial receivables	24	22	23
Interest income current financial assets and other financial items	228	305	208
Interest income and other financial items	487	436	396
Gains (losses) derivative financial instruments	(61)	470	(491)
Interest expense bonds and bank loans and net interest on related derivatives	(1,004)	(830)	(707)
Interest expense finance lease liabilities	(26)	(26)	(27)
Capitalised borrowing costs	454	355	392
Accretion expense asset retirement obligations	(413)	(420)	(481)
Interest expense current financial liabilities and other finance expense	86	(122)	(147)
Interest and other finance expenses	(903)	(1,043)	(971)
Net financial items	(351)	(258)	(1,311)

Statoil's main financial items relate to assets and liabilities categorised in the held for trading category and the amortised cost category. For more information about financial instruments by category see note 25 Financial instruments: fair value measurement and sensitivity analysis of market risk.

The line item interest expense bonds and bank loans and net interest on related derivatives primarily includes interest expenses of USD 1,084 million, USD 1,018 million and USD 1,041 million from the financial liabilities at amortised cost category. This was partially offset by net interest income on related derivatives from the held for trading category, USD 80 million, USD 188 million and USD 334 million for 2017, 2016 and 2015, respectively.

The line item gains (losses) derivative financial instruments primarily includes fair value loss from the held for trading category of USD 77 million, a gain of USD 454 million and a loss of USD 492 million for 2017, 2016 and 2015, respectively.

The line item interest expense current financial liabilities and other finance expense includes an income of USD 319 million in 2017 related to release of a provision. See note 23 Other commitments and contingencies.

Foreign exchange gains (losses) derivative financial instruments include fair value changes of currency derivatives related to liquidity and currency risk.
The line item foreign exchange gains (losses) includes a net foreign exchange gain of USD 427 million, a loss of USD 205 million and a loss of USD 1,208 million from the held for trading category for 2017, 2016 and 2015, respectively.

9 Income taxes

Significant components of income tax expense

(in USD million)	Full year 2017	2016	2015
Current income tax expense in respect of current year	(7,680)	(3,869)	(6,488)
Prior period adjustments	(124)	(158)	(91)
Current income tax expense	(7,805)	(4,027)	(6,579)
Origination and reversal of temporary differences	(904)	1,372	1,519
Change in tax regulations	(14)	(50)	(90)
Prior period adjustments	(100)	(20)	(74)
Deferred tax expense	(1,017)	1,302	1,355
Income tax expense	(8,822)	(2,724)	(5,225)

During the normal course of its business, Statoil files tax returns in many different tax regimes. There may be differing interpretation of applicable tax laws and regulations regarding some of the matters in the tax returns. In certain cases it may take several years to complete the discussions with the relevant tax authorities or to reach a resolution of the tax positions through litigations. Statoil has provided for probable income tax related assets and liabilities based on best estimates reflecting consistent interpretations of the applicable laws and regulations.

Reconciliation of statutory tax rate to effective tax rate

(in USD million)	Full year 2017	2016	2015
Income/(loss) before tax	13,420	(178)	55
Calculated income tax at statutory rate[1)]	(3,827)	676	1,078
Calculated Norwegian Petroleum tax[2)]	(5,945)	(2,250)	(4,145)
Tax effect uplift[2)]	784	812	847
Tax effect of permanent differences regarding divestments	(85)	153	468
Tax effect of permanent differences caused by functional currency different from tax currency	(229)	(356)	719
Tax effect of other permanent differences	291	(48)	(2)
Tax effect of dispute with Angolan Ministry of Finance[3)]	496	0	0
Change in unrecognised deferred tax assets	(169)	(1,625)	(3,557)
Change in tax regulations	(14)	(50)	(90)
Prior period adjustments	(224)	(177)	(165)
Other items including currency effects	100	141	(376)
Income tax expense	(8,822)	(2,724)	(5,225)
Effective tax rate	65.7%	>(100%)	>100%

1) The weighted average of statutory tax rates was positive 28.5% in 2017, positive 379.8% in 2016 and negative 1,950.2% in 2015. The tax rate in 2017, the high rate in 2016 and the change in average statutory tax rates from 2016 to 2017 is mainly caused by earnings composition between tax regimes with lower statutory tax rates and tax regimes with higher statutory tax rates. The high tax rate in 2016, the negative rate in 2015 and the change in average statutory tax rates from 2015 to 2016 was mainly caused by earnings composition between tax regimes with lower statutory tax rates and tax regimes with higher statutory tax rates. In both years there are positive income in tax regimes with relatively lower tax rates and losses, including impairments and provisions, in tax regimes with relatively higher tax rates.

2) When computing the petroleum tax of 54% (55% from 2018) on income from the Norwegian continental shelf, an additional tax-free allowance, or uplift, is granted on the basis of the original capitalised cost of offshore production installations. The uplift may be deducted from taxable income for a period of four years starting in the year in which the capital expenditure is incurred. For investments made in 2017 the uplift is calculated at a rate of 5.4% per year, while the rate is 5.5% per year for investments made in 2014-2016. The rate is 5.3% per year from 2018 for new investments. Transitional rules apply to investments from 5 May 2013 covered by among others Plans for development and operation (PDOs) or Plans for installation and operation (PIOs) submitted to the Ministry of Oil and Energy prior to 5 May 2013. For these investments the rate is 7.5% per year. Unused uplift may be carried forward indefinitely. At year end 2017 and 2016, unrecognised uplift credits amounted to USD 2,003 million and USD 2,121 million, respectively.

3) Tax effect of dispute with Angolan Ministry of Finance as described in note 23 Other commitments, contingent liabilities and contingent assets.

Deferred tax assets and liabilities comprise

(in USD million)	Tax losses carried forward	Property, plant and equipment and Intangible assets	Asset removal obligation	Pensions	Derivatives	Other	Total
Deferred tax at 31 December 2017							
Deferred tax assets	4,459	259	8,049	738	34	763	14,302
Deferred tax liabilities	(0)	(19,027)	0	(11)	(27)	(451)	(19,515)
Net asset (liability) at 31 December 2017	4,459	(18,768)	8,049	728	7	312	(5,213)
Deferred tax at 31 December 2016							
Deferred tax assets	4,283	233	7,078	743	138	849	13,323
Deferred tax liabilities	0	(16,797)	0	0	(270)	(488)	(17,555)
Net asset (liability) at 31 December 2016	4,283	(16,564)	7,078	743	(132)	361	(4,231)

Changes in net deferred tax liability during the year were as follows:

(in USD million)	2017	2016	2015
Net deferred tax liability at 1 January	4,231	5,399	7,881
Charged (credited) to the Consolidated statement of income	1,017	(1,302)	(1,355)
Other comprehensive income	38	(129)	461
Translation differences and other	(73)	264	(1,588)
Net deferred tax liability at 31 December	5,213	4,231	5,399

Deferred tax assets and liabilities are offset to the extent that the deferred taxes relate to the same fiscal authority, and there is a legally enforceable right to offset current tax assets against current tax liabilities. After netting deferred tax assets and liabilities by fiscal entity, deferred taxes are presented on the balance sheet as follows:

(in USD million)	At 31 December 2017	2016
Deferred tax assets	2,441	2,195
Deferred tax liabilities	7,654	6,427

Deferred tax assets are recognised based on the expectation that sufficient taxable income will be available through reversal of taxable temporary differences or future taxable income supported by business forecast. At year end 2017 and 2016 the deferred tax assets of USD 2,441 million and USD 2,195 million, respectively, were primarily recognised in Norway, Angola, Brasil and the UK. Of these amounts USD 924 million and USD 1,258 million, respectively, is recognised in entities which have suffered a loss in either the current or preceding period.

Unrecognised deferred tax assets

	At 31 December			
	2017		2016	
(in USD million)	Basis	Tax	Basis	Tax
Deductible temporary differences	3,415	1,409	3,431	1,360
Tax losses carried forward	17,412	4,661	17,440	6,557
Total	20,827	6,070	20,871	7,917

Approximately 16% of the unrecognised carry forward tax losses can be carried forward indefinitely. The majority of the remaining part of the unrecognised tax losses expire after 2028. The unrecognised deductible temporary differences do not expire under the current tax legislation. Deferred tax assets have not been recognised in respect of these items because currently there is insufficient evidence to support that future taxable profits will be available to secure utilisation of the benefits.

At year end 2017 unrecognised deferred tax assets in the US and Angola represents USD 3,559 million and USD 879 million of the total unrecognised deferred tax assets of USD 6,070 million. Similar amounts for 2016 were USD 5,655 million in the US and USD 800 million in Angola of a total of USD 7,917 million. The reduction in unrecognised deferred tax assets in the US of USD 2,096 million is mainly caused by the change in the corporate tax rate from 35% to 21%.

10 Property, plant and equipment

(in USD million)	Machinery, equipment and transportation equipment, including vessels	Production plants and oil and gas assets	Refining and manufacturing plants	Buildings and land	Assets under development	Total
Cost at 31 December 2016	3,394	142,750	8,262	859	17,315	172,579
Additions and transfers	56	10,181	331	47	111	10,727
Disposals at cost	(7)	0	(288)	(50)	(30)	(374)
Effect of changes in foreign exchange	27	4,602	342	10	743	5,724
Cost at 31 December 2017	3,470	157,533	8,646	866	18,140	188,656
Accumulated depreciation and impairment losses at 31 December 2016	(2,767)	(100,971)	(5,772)	(446)	(3,068)	(113,023)
Depreciation	(122)	(9,051)	(485)	(29)	0	(9,688)
Impairment losses	0	(917)	(0)	0	0	(917)
Reversal of impairment losses	48	935	0	0	989	1,972
Transfers	0	(422)	(1)	(0)	370	(53)
Accumulated depreciation and impairment disposed assets	5	(24)	285	39	18	323
Effect of changes in foreign exchange	(17)	(3,331)	(227)	(4)	(55)	(3,634)
Accumulated depreciation and impairment losses at 31 December 2017	(2,853)	(113,781)	(6,200)	(439)	(1,746)	(125,019)
Carrying amount at 31 December 2017	617	43,753	2,446	427	16,394	63,637
Estimated useful lives (years)	3-20	UoP[1)]	15 - 20	20 - 33[2)]		

(in USD million)	Machinery, equipment and transportation equipment, including vessels	Production plants and oil and gas assets	Refining and manufacturing plants	Buildings and land	Assets under development	Total
Cost at 31 December 2015	3,466	133,269	7,459	928	20,284	165,406
Additions and transfers	62	11,960	776	70	(2,148)	10,720
Disposals at cost	(98)	(1,857)	(48)	(130)	(445)	(2,577)
Assets reclassified to held for sale (HFS)	(7)	(2,169)	0	(12)	(51)	(2,239)
Effect of changes in foreign exchange	(30)	1,546	75	2	(325)	1,268
Cost at 31 December 2016	3,394	142,750	8,262	859	17,315	172,579
Accumulated depreciation and impairment losses at 31 December 2015	(2,826)	(90,762)	(5,386)	(468)	(3,958)	(103,400)
Depreciation	(137)	(9,657)	(411)	(31)	0	(10,235)
Impairment losses	(0)	(1,672)	(240)	(12)	(969)	(2,893)
Reversal of impairment losses	0	1,186	371	0	35	1,592
Transfers	71	(2,013)	(79)	(0)	1,789	(232)
Accumulated depreciation and impairment disposed assets	91	1,231	44	57	14	1,437
Accumulated depreciation and impairment assets classified as HFS	6	1,757	0	8	22	1,794
Effect of changes in foreign exchange	28	(1,042)	(71)	1	(1)	(1,086)
Accumulated depreciation and impairment losses at 31 December 2016	(2,767)	(100,971)	(5,772)	(446)	(3,068)	(113,023)
Carrying amount at 31 December 2016	626	41,779	2,490	413	14,247	59,556
Estimated useful lives (years)	3-20	UoP 1)	15 - 20	20 - 33 2)		

1) Depreciation according to unit of production method (UoP), see note 2 Significant accounting policies.
2) Land is not depreciated.

The carrying amount of assets transferred to Property, plant and equipment from Intangible assets in 2017 and 2016 amounted to USD 401 million and USD 692 million, respectively.

Impairments

(in USD million)	Property, plant and equipment	Intangible assets 3)	Total
At 31 December 2017			
Producing and development assets 1)	(1,056)	(326)	(1,381)
Acquisition costs related to oil and gas prospects 2)	-	245	245
Total net impairment loss/(reversal) recognised	(1,056)	(81)	(1,137)
At 31 December 2016			
Producing and development assets 1)	1,301	590	1,890
Acquisition costs related to oil and gas prospects 2)	-	403	403
Total net impairment loss/(reversal) recognised	1,301	992	2,293

1) Producing and development assets and goodwill are subject to impairment assessment under IAS 36. The total net impairment reversal recognised under IAS 36 in 2017 amount to USD 1,381 million, compared to 2016 when the net impairment loss amounted to USD 1,890 million, including impairment reversals and impairments of acquisition costs - oil and gas prospects (intangible assets).
2) Acquisition costs related to exploration activities, subject to impairment assessment under the successful efforts method (IFRS 6).
3) See note 11 Intangible assets.

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For impairment purposes, the asset's carrying amount is compared to its recoverable amount. The recoverable amount is the higher of fair value less cost of disposal (FVLCOD) and estimated value in use (VIU).

The base discount rate for VIU calculations is 6.0% real after tax. The discount rate is derived from Statoil's weighted average cost of capital. A derived pre-tax discount rate would generally be in the range of 7-12%, depending on asset specific characteristics, such as specific tax treatments, cash flow profiles and economic life. For certain assets a pre-tax discount rate could be outside this range, mainly due to special tax elements (for example permanent differences) affecting the pre-tax equivalent. See note 2 Significant accounting policies for further information regarding impairment on property, plant and equipment.

(in USD million)	Impairment method	2017 Carrying amount after impairment [1]	2017 Net impairment loss (reversal)	2016 Carrying amount after impairment [1]	2016 Net impairment loss (reversal)
At 31 December					
Exploration & Production Norway	VIU	2,169	(826)	3,115	760
	FVLCOD	1,507	(80)	1,401	69
North America - unconventional	VIU	5,017	(1,266)	6,183	945
	FVLCOD	1,422	856	484 [2]	412
North America Conventional offshore US Gulf of Mexico	VIU	1,200	(17)	4,459	141
	FVLCOD	0	0	0	0
North Africa	VIU	0	0	0	104
	FVLCOD	0	0	0	0
Sub-Saharan Africa	VIU	0	0	772	(137)
	FVLCOD	0	0	0	0
Europe and Asia	VIU	0	0	1,124	(330)
	FVLCOD	0	0	0	0
Marketing, Midstream & Processing	VIU	263	(48)	1,088	(74)
	FVLCOD	0	0	0	0
Total		11,578	(1,381)	18,625	1,890

1) Carrying amount relates to assets impaired/reversed.
2) Asset sold in 2017

During 2017 net impairment reversal USD 1,381 million was recognised on producing and development assets. For 2016 the net impairment loss recognised was USD 1,890 million primarily due to declining commodity prices.

Exploration & Production Norway
In Exploration & Production Norway net impairment reversal of USD 906 million was recognised in 2017, mainly related to conventional offshore assets in the development phase. The net impairment reversal was mainly triggered by increased reserves, cost reductions and increased short term price assumptions. In 2016 impairment loss of USD 829 million was recognised.

North America - unconventional
In the North America – unconventional area net impairment reversal of USD 410 million was recognised in 2017.

An impairment reversal of USD 1,266 of which USD 517 million is classified as exploration expenses, was triggered by changes in US tax legislation, including a change in the corporate tax from 35% to 21%. Operational improvements and increased recovery rate also influenced the impairment reversal.

An impairment loss of USD 856 million of which USD 191 million is classified as exploration expenses, was triggered by changes in the operational plan following lower than expected production and a significant reduction in expected reserves. To establish the recoverable amount assessed to be fair value less cost of disposal for the impaired asset, Statoil made use of an independent third – party valuation expert as part of the determination. Statoil considered both discounted cash flow calculation and comparable market multiples when determining the fair value less cost of disposal. The primary basis for arriving at the recoverable amount estimate was the use of discounted cash flow calculations which is a level 3 valuation as defined in IFRS 13. The key assumptions used in the discounted cash flow calculations were future commodity prices, the expected operational plan and ultimate recovery rate as well as the discount rates used. The price assumptions used were based on 3 years observable forward prices and maintaining flat real price assumptions thereafter. The discount rate used was 7-9% for proved properties and 12-14% for unproved properties in nominal terms after tax with an additional risking for certain elements. In addition to the change in operational plan, the recoverable amount reflects, among other factors, worsening market sentiment around the shale play associated with the impaired asset and somewhat reduced commodity price outlook.

In 2016 net impairment loss of USD 1,357 million was recognised in the North America – unconventional area.

North America Conventional offshore Gulf of Mexico
In 2017 the North America Conventional offshore Gulf of Mexico area recognised net impairment reversal of USD 17 million. In 2016 the net impairment loss was USD 141 million.

Marketing, Midstream & Processing
Marketing, Midstream & Processing recognised an impairment reversal of USD 48 million in 2017. In 2016 net reversal was USD 74 million.

In the North Africa, Sub - Saharan and Europe and Asia areas no impairments or reversals were recognised in 2017. In 2016 total net reversal in these areas were USD 363 million.

Value in Use (VIU) estimates and discounted cash flows used to determine the recoverable amount of assets tested for impairment are based on internal forecasts on costs, production profiles and commodity prices. Short term commodity prices (2018/2019/2020) are forecasted by using observable forward prices for 2018 and a linear projection towards the 2021 internal forecast.

The price assumptions used for impairment calculations were generally as follows (prices used in 2016 impairment calculations for the respective years are indicated in brackets):

Year Prices in real terms1)	2018		2020		2025		2030	
Brent Blend - USD/bbl	60	(62)	67	(75)	77	(78)	80	(80)
NBP - USD/mmBtu	6.6	(6.0)	6.5	(6.0)	8.0	(8.0)	8.0	(8.0)
Henry Hub - USD/mmBtu	2.9	(3.6)	3.5	(4.0)	4.0	(4.0)	4.0	(4.0)

1) Basis year 2016

Sensitivities
Commodity prices have historically been volatile. Significant downward adjustments of Statoil's commodity price assumptions would result in impairment losses on certain producing and development assets in Statoil's portfolio. If a decline in commodity price forecasts over the lifetime of the assets were 20%, considered to represent a reasonably likely change, the impairment amount to be recognised could illustratively be in the region of USD 11 billion before tax effects. This illustrative impairment sensitivity assumes no changes to input factors other than prices; however, a price reduction of 20% is likely to result in changes in business plans as well as other factors used when estimating an asset's recoverable amount. Changes in such input factors would likely significantly reduce the actual impairment amount compared to the illustrative sensitivity above. Changes that could be expected would include a reduction in the cost level in the oil and gas industry as well as offsetting currency effects, both of which have historically occurred following significant changes in commodity prices. The illustrative sensitivity is therefore not considered to represent a best estimate of an expected impairment impact, nor an estimated impact on revenues or operating income in such a scenario. A significant and prolonged reduction in oil and gas prices would also result in mitigating actions by Statoil and its licence partners, as a reduction of oil and gas prices would impact drilling plans and production profiles for new and existing assets. Quantifying such impacts is considered impracticable, as it requires detailed technical, geological and economical evaluations based on hypothetical scenarios and not based on existing business or development plans.

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11 Intangible assets

(in USD million)	Exploration expenses	Acquisition costs - oil and gas prospects	Goodwill	Other	Total
Cost at 31 December 2016	2,856	5,907	1,570	346	10,679
Additions	154	861	0	94	1,109
Disposals at cost	(0)	(0)	0	(26)	(26)
Transfers	(276)	(124)	0	(0)	(401)
Assets reclassified to held for sale	0	(1,369)	0	0	(1,369)
Expensed exploration expenditures previously capitalised	(73)	81	0	0	8
Effect of changes in foreign exchange	56	6	11	4	77
Cost at 31 December 2017	2,715	5,363	1,581	419	10,077
Accumulated depreciation and impairment losses at 31 December 2016			(1,242)	(195)	(1,437)
Amortisation and impairments for the year			0	(12)	(12)
Amortisation and impairment losses disposed intangible assets			0	(6)	(6)
Effect of changes in foreign exchange			0	(2)	(2)
Accumulated depreciation and impairment losses at 31 December 2017			(1,242)	(215)	(1,457)
Carrying amount at 31 December 2017	2,715	5,363	339	204	8,621

(in USD million)	Exploration expenses	Acquisition costs - oil and gas prospects	Goodwill	Other	Total
Cost at 31 December 2015	3,701	5,207	1,565	402	10,875
Additions	246	2,477	0	(8)	2,715
Disposals at cost	(0)	(311)	0	(42)	(353)
Transfers	(298)	(392)	0	(2)	(692)
Assets reclassified to held for sale	(19)	(78)	0	0	(97)
Expensed exploration expenditures previously capitalised	(808)	(992)	0	0	(1,800)
Effect of changes in foreign exchange	33	(3)	5	(4)	31
Cost at 31 December 2016	2,856	5,907	1,570	346	10,679
Accumulated depreciation and impairment losses at 31 December 2015			(1,242)	(182)	(1,423)
Amortisation and impairments for the year			0	(13)	(13)
Amortisation and impairment losses disposed intangible assets			0	(2)	(2)
Effect of changes in foreign exchange			0	2	2
Accumulated depreciation and impairment losses at 31 December 2016			(1,242)	(195)	(1,437)
Carrying amount at 31 December 2016	2,856	5,907	328	151	9,243

The useful lives of intangible assets are assessed to be either finite or indefinite. Intangible assets with finite useful lives are amortised systematically over their estimated economic lives, ranging between 10-20 years.

During 2017, intangible assets were impacted by net impairment reversal of signature bonuses and acquisition costs totalling USD 326 million related to North America – unconventional assets and net impairment of acquisition costs related to exploration activities of USD 245 million primarily as a result from dry wells and uncommercial discoveries in US Gulf of Mexico and South America.

Impairment losses and reversals of impairment losses are presented as Exploration expenses and Depreciation, amortisation and net impairment losses on the basis of their nature as exploration assets (intangible assets) and other intangible assets, respectively. The impairment losses and reversal of impairment losses are based on recoverable amount estimates triggered by changes in reserve estimates, cost estimates and market conditions. See note 10 Property, plant and equipment for more information on the basis for impairment assessments.

The table below shows the aging of capitalised exploration expenditures.

(in USD million)	2017	2016
Less than one year	218	311
Between one and five years	1,799	2,216
More than five years	698	329
Total	2,715	2,856

The table below shows the components of the exploration expenses.

	Full year		
(in USD million)	2017	2016	2015
Exploration expenditures	1,234	1,437	2,860
Expensed exploration expenditures previously capitalised	(8)	1,800	2,164
Capitalised exploration	(167)	(285)	(1,151)
Exploration expenses	1,059	2,952	3,872

12 Equity accounted investments

(in USD million)	Lundin Petroleum AB	Other equity accounted investments	Total
Investment at 31 December 2016	1,121	1,124	2,245
Net income/(loss) from equity accounted investments	126	62	188
Acquisitions and increase in paid in capital	0	399	399
Dividend and other distributions	(78)	(112)	(190)
Other comprehensive income/(loss)	(44)	82	38
Divestments, derecognition and decrease in paid in capital	0	(129)	(129)
Investment at 31 December 2017	1,125	1,426	2,551

Voting rights corresponds to ownership.

Summary financial information of equity accounted investments

The following table provides summarised financial information relating to Lundin Petroleum AB. This information is presented on a Statoil's ownership basis (20.1%) and also reflects adjustments made by Statoil to Lundin Petroleum AB's own results in applying the equity method of accounting. Statoil adjusts Lundin Petroleum AB's results for depreciation of excess values determined in the purchase price allocation at the date of acquisition. Where there are significant differences in accounting policies, adjustments are made to bring the accounting policies applied in line with Statoil's. These adjustments have increased the reported net income for 2017, as shown in the table below, compared with the equivalent amount reported by Lundin Petroleum AB.

	Lundin Petroleum AB	
(in USD million)	2017	2016
At 31 December		
Current assets	101	69
Non-Current assets	2,920	3,069
Current liabilities	(62)	(70)
Non-Current liabilities	(1,834)	(1,947)
Net assets	1,125	1,121
Year ended 31 December		
Gross revenues	376	135
Income/(loss) before tax	226	(83)
Net income/(loss)	126	(78)
Capital expenditures	250	589

In April 2017 Lundin Petroleum completed a spin-off of its assets in Malaysia, France and the Netherlands into International Petroleum Corporation (IPC) by distributing the IPC share, on a pro-rata basis, to Lundin Petroleum shareholders. IPC prepared a repurchasing programme whereas they would repurchase own shares up to a certain amount, Statoil used the opportunity to sell its issued shares in the spin-off to IPC's wholly-owned subsidiary, Lundin Petroleum BV. The sale did not result in material gain or loss.

Statoil's share of Lundin Petroleum AB's quoted market value as per 31.12.2017 was USD 1,565 million.

13 Financial investments and non-current prepayments

Non-current financial investments

(in USD million)	At 31 December 2017	2016
Bonds	1,611	1,362
Listed equity securities	619	731
Non-listed equity securities	611	251
Financial investments	2,841	2,344

Bonds and listed equity securities relate to investment portfolios held by Statoil's captive insurance company which mainly are accounted for using the fair value option.

Non-current prepayments and financial receivables

(in USD million)	At 31 December 2017	2016
Financial receivables interest bearing	716	698
Prepayments and other non-interest bearing receivables	196	195
Prepayments and financial receivables	912	893

Financial receivables interest bearing primarily relate to project financing of equity accounted companies and loans to employees.

Current financial investments

(in USD million)	At 31 December 2017	2016
Time deposits	4,111	3,242
Interest bearing securities	4,337	4,970
Financial investments	8,448	8,211

At 31 December 2017, current financial investments include USD 714 million investment portfolios held by Statoil's captive insurance company which mainly are accounted for using the fair value option. The corresponding balance at 31 December 2016 was USD 818 million.

For information about financial instruments by category, see note 25 Financial instruments: fair value measurement and sensitivity analysis of market risk.

14 Inventories

(in USD million)	At 31 December 2017	2016
Crude oil	2,323	1,966
Petroleum products	596	744
Natural gas	149	160
Other	330	358
Inventories	3,398	3,227

Other inventory consists of spare parts and operational materials, including drilling and well equipment.

The write-down of inventories from cost to net realisable value amounted to an expense of USD 32 million and USD 74 million in 2017 and 2016, respectively.

15 Trade and other receivables

(in USD million)	At 31 December 2017	2016
Trade receivables	7,649	5,504
Current financial receivables	427	862
Joint venture receivables	478	592
Equity accounted associated companies and other related party receivables	6	116
Total financial trade and other receivables	8,560	7,074
Non-financial trade and other receivables	865	765
Trade and other receivables	9,425	7,839

For more information about the credit quality of Statoil's counterparties, see note 5 Financial risk management. For currency sensitivities, see note 25 Financial instruments: fair value measurement and sensitivity analysis of market risk.

16 Cash and cash equivalents

(in USD million)	At 31 December 2017	2016
Cash at bank available	591	596
Time deposits	1,889	1,660
Money market funds	381	65
Interest bearing securities	1,092	2,234
Restricted cash, including margin deposits	437	535
Cash and cash equivalents	4,390	5,090

Restricted cash at 31 December 2017 and 2016 includes collateral deposits related to trading activities of USD 300 million and USD 398 million, respectively. Collateral deposits are related to certain requirements set out by exchanges where Statoil is participating. The terms and conditions related to these requirements are determined by the respective exchanges.

17 Shareholders' equity and dividends

At 31 December 2017, Statoil's share capital of NOK 8,307,919,632.50 (USD 1,179,542,543) comprised 3,323,167,853 shares at a nominal value of NOK 2.50. Share capital at 31 December 2016 was NOK 8,112,623,527.50 (USD 1,155,993,270) comprised 3,245,049,411 shares at a nominal value of NOK 2.50.

Statoil ASA has only one class of shares and all shares have voting rights. The holders of shares are entitled to receive dividends as and when declared and are entitled to one vote per share at general meetings of the company.

A temporary scrip dividend programme was proposed by the board of directors in February 2016, approved by Statoil's general assembly in May 2016 and reconfirmed by the general assembly in May 2017. The scrip dividend programme was implemented for the quarterly dividends from fourth quarter 2015 to third quarter 2017. Issuance of new shares related to the third quarter 2017 dividend was completed 22 March 2018. As part of the scrip dividend programme, eligible shareholders could elect to receive their dividend in the form of new ordinary Statoil shares or in cash. For ADR (American Depository Receipts) holders, dividend could be received in the form of ADSs (American Depository Shares) or in cash. The subscription price for the dividend shares had a discount compared to the volume-weighted average price on OSE of the last two trading days of the subscription period for each quarter. For all quarters, the discount has been set at 5%. As part of the scrip dividend programme, the Norwegian State entered into an agreement where it committed for each quarterly dividend where a scrip option was offered, to receive newly issued shares for a fraction of its shareholdings equal to the average participation among the other shareholders. This to ensure that the State's ownership share was not impacted by the scrip dividend programme.

During 2017 dividend for the third and for the fourth quarter of 2016 and dividend for the first and second quarter of 2017 were settled. Dividend declared but not yet settled, is presented as dividends payable in the Consolidated balance sheet, regardless of whether the dividend is expected to be paid in cash or by issuance of new shares. The Consolidated statement of changes in equity shows declared dividend in the period (retained earnings), offset by scrip dividend settled during the period (share capital and additional paid-in-capital). Dividend declared in 2017 relate to the fourth quarter of 2016 and to the first three quarters of 2017.

(in USD million)	At 31 December 2017	2016
Dividends declared	2,891	2,824
USD per share or ADS	0.8804	0.8804
Dividends paid in cash	1,491	1,876
USD per share or ADS	0.8804	0.8804
NOK per share	7.2615	7.3364
Scrip dividends	1,357	904
Number of shares issued (millions)	78.1	56.4
Sum dividends settled	2,848	2,780

During 2017 a total of 3,323,671 treasury shares were purchased for USD 63 million and 3,219,327 treasury shares were allocated to employees participating in the share saving plan. During 2016 a total of 4,011,860 treasury shares were purchased for USD 62 million and 3,882,153 treasury shares were allocated to employees participating in the share saving plan. At 31 December 2017 Statoil had 11,243,234 treasury shares and at 31 December 2016 11,138,890 treasury shares, all of which are related to Statoil's share saving plan. For further information, see note 6 Remuneration.

18 Finance debt

Capital management

The main objectives of Statoil's capital management policy are to maintain a strong financial position and to ensure sufficient financial flexibility. One of the key ratios in the assessment of Statoil's financial robustness is net interest-bearing debt adjusted (ND) to capital employed adjusted (CE).

(in USD million)	At 31 December 2017	2016
Net interest-bearing debt adjusted (ND)	16,287	19,389
Capital employed adjusted (CE)	56,172	54,490
Net debt to capital employed adjusted (ND/CE)	29.0%	35.6%

ND is defined as Statoil's interest bearing financial liabilities less cash and cash equivalents and current financial investments, adjusted for collateral deposits and balances held by Statoil's captive insurance company (amounting to USD 1,014 million and USD 1,216 million for 2017 and 2016, respectively) and balances related to the SDFI (amounting to USD 164 million and USD 199 million for 2017 and 2016, respectively). CE is defined as Statoil's total equity (including non-controlling interests) and ND.

Non-current finance debt

Finance debt measured at amortised cost

	Weighted average interest rates in %[1]		Carrying amount in USD millions at 31 December		Fair value in USD millions at 31 December[2]	
	2017	2016	2017	2016	2017	2016
Unsecured bonds						
United States Dollar (USD)	3.73	3.54	14,953	19,712	16,106	20,681
Euro (EUR)	2.10	2.10	9,347	8,211	10,057	8,884
Great Britain Pound (GBP)	6.08	6.08	1,859	1,693	2,734	2,475
Norwegian kroner (NOK)	4.18	4.18	366	348	427	386
Total			26,524	29,964	29,325	32,427
Unsecured loans						
Japanese yen (JPY)	4.30	4.30	89	85	118	119
Finance lease liabilities			478	507	496	526
Total			567	592	614	645
Total finance debt			27,090	30,556	29,938	33,072
Less current portion			2,908	2,557	2,924	2,584
Non-current finance debt			24,183	27,999	27,014	30,488

1) Weighted average interest rates are calculated based on the contractual rates on the loans per currency at 31 December and do not include the effect of swap agreements.
2) Where available, the fair value of the non-current financial liabilities is determined from quoted market prices, classified at level 1 in the fair value hierarchy. If quoted market prices are not available, fair values are determined from external calculation models based on market observations from various sources, classified at level 2 in the fair value hierarchy.

Unsecured bonds amounting to USD 14,953 million are denominated in USD and unsecured bonds amounting to USD 8,347 million are swapped into USD. Four bonds denominated in EUR amounting to USD 3,224 million are not swapped. The table does not include the effects of agreements entered into to swap the various currencies into USD. For further information see note 25 Financial instruments: fair value measurement and sensitivity analysis of market risk.

Substantially all unsecured bond and unsecured bank loan agreements contain provisions restricting future pledging of assets to secure borrowings without granting a similar secured status to the existing bondholders and lenders.

Out of Statoil's total outstanding unsecured bond portfolio, 42 bond agreements contain provisions allowing Statoil to call the debt prior to its final redemption at par or at certain specified premiums if there are changes to the Norwegian tax laws. The carrying amount of these agreements is USD 26,158 million at the 31 December 2017 closing exchange rate.

In addition to the planned repayment of three bonds at maturity date, Statoil did a buy-back of two outstanding bonds of USD 2,25 billion in 2017. These notes were originally due 8 November 2018 and 15 April 2019.

For more information about the revolving credit facility, maturity profile for undiscounted cash flows and interest rate risk management, see note 5 Financial risk management.

Non-current finance debt maturity profile

(in USD million)	At 31 December 2017	2016
Year 2 and 3	3,521	6,478
Year 4 and 5	3,041	3,798
After 5 years	17,620	17,723
Total repayment of non-current finance debt	24,183	27,999
Weighted average maturity (years)	9	9
Weighted average annual interest rate (%)	3.50	3.41

More information regarding finance lease liabilities is provided in note 22 Leases.

Current finance debt

(in USD million)	At 31 December 2017	2016
Collateral liabilities	704	571
Non-current finance debt due within one year	2,908	2,557
Other including bank overdraft	479	545
Total current finance debt	4,091	3,674
Weighted average interest rate (%)	1.65	1.61

Collateral liabilities and other current liabilities relate mainly to cash received as security for a portion of Statoil's credit exposure and outstanding amounts on US Commercial paper (CP) program. Issuance on the CP program amounted to USD 449 million as of 31 December 2017 and USD 500 million as of 31 December 2016.

(in USD million)	Non current finance debt	Current finance debt	Financial receivable Collaterals 1)	Additional paid in capital Share based payment/Treasury shares	Non controlling interest	Dividend payable	Total
At 31 December 2016	27,999	3,674	(735)	(212)	27	712	31,465
Transfer to current portion	(351)	351	-	-	-	-	-
Effect of exchange rate changes	1,302	(13)	-	-	-	(11)	1,278
Dividend decleared	-	-	-	-	-	2,891	2,891
Scrip dividend	-	-	-	-	-	(1,357)	(1,357)
Cash flows provided by (used in) financing activities	(4,775)	53	464	(62)	(12)	(1,491)	(5,823)
Other changes	8	26	(1)	83	9	(15)	110
At 31 December 2017	24,183	4,091	(272)	(191)	24	729	28,564

1) Financial receivables collaterals are in included in trade and other receivables in the balance sheet. See note 15 Trade and other receivables.

19 Pensions

The main pension plans for Statoil ASA and its most significant subsidiaries are defined contribution plans, in which the pension costs are recognised in the Consolidated statement of income in line with payments of annual pension premiums. The pension contribution plans in Statoil ASA also includes certain unfunded elements (notional contribution plans), for which the annual notional contributions are recognised as pension liabilities. These notional pension liabilities are regulated equal to the return on asset within the main contribution plan. See note 2 Significant accounting policies for more information about the accounting treatment of the notional contribution plans reported in Statoil ASA.

In addition, Statoil ASA has a closed defined benefit plan for employees which in 2015 had less than 15 years of future service before their regular retirement age, and for employees in certain subsidiaries. Statoil's defined benefit plans are generally based on a minimum of 30 years of service and 66% of the final salary level, including an assumed benefit from the Norwegian National Insurance Scheme. The Norwegian companies in the group are subject to, and complies with, the requirements of the Norwegian Mandatory Company Pensions Act.

The defined benefit plans in Norway are managed and financed through Statoil Pensjon (Statoil's pension fund - hereafter "Statoil Pension"). Statoil Pension is an independent pension fund that covers the employees in Statoil's Norwegian companies. The pension fund's assets are kept separate from the company's and group companies' assets. Statoil Pension is supervised by the Financial Supervisory Authority of Norway ("Finanstilsynet") and is licensed to operate as a pension fund.

Statoil is a member of a Norwegian national agreement-based early retirement plan ("AFP"), and the premium is calculated on the basis of the employees' income between 1 and 7.1 G. The premium is payable for all employees until age 62. Pension from the AFP scheme will be paid from the AFP plan administrator to employees for their full lifetime. Statoil has determined that its obligations under this multi-employer defined benefit plan can be estimated with sufficient reliability for recognition purposes. Accordingly, the estimated proportionate share of the AFP plan is recognised as a defined benefit obligation.

The present values of the defined benefit obligation, except for the notional contribution plan, and the related current service cost and past service cost are measured using the projected unit credit method. The assumptions for salary increases, increases in pension payments and social security base amount are based on agreed regulation in the plans, historical observations, future expectations of the assumptions and the relationship between these assumptions. At 31 December 2017 the discount rate for the defined benefit plans in Norway was established on the basis of seven years' mortgage covered bonds interest rate extrapolated on a yield curve which matches the duration of Statoil's payment portfolio for earned benefits, which was calculated to be 17.2 years at the end of 2017. Social security tax is calculated based on a pension plan's net funded status and is included in the defined benefit obligation.

Statoil has more than one defined benefit plan, but the disclosure is made in total since the plans are not subject to materially different risks. Pension plans outside Norway are not material and as such not disclosed separately. The pension costs in Statoil ASA are partly re-charged to licence partners.

Net pension cost

(in USD million)	2017	2016	2015
Current service cost	242	238	378
Interest cost	-	192	191
Interest (income) on plan asset	-	(148)	(145)
Past service cost	(0)	2	-
Losses (gains) from curtailment, settlement or plan amendment	15	109	250
Actuarial (gains) losses related to termination benefits	(1)	59	(1)
Notional contribution plans	51	50	36
Defined benefit plans	308	503	709
Defined contribution plans	162	148	135
Total net pension cost	469	650	844

In addition to the pension cost presented in the table above, financial items related to defined benefit plans are included in the statement of income within Net financial items. Interest cost and changes in fair value of notional assets of USD 201 million, and interest income of USD 138 million has been recognised in 2017.

New entrants for the early retirement plans have been included as a settlement cost. The total impact in 2017 was USD 2 million, USD 123 million in 2016 and USD 173 million in 2015.

(in USD million)	2017	2016
Defined benefit obligations (DBO)		
Defined benefit obligations at 1 January	7,791	6,822
Current service cost	243	239
Interest cost	219	192
Actuarial (gains) losses - Financial assumptions	(26)	879
Actuarial (gains) losses - Experience	(21)	(282)
Benefits paid	(311)	(235)
Losses (gains) from curtailment, settlement or plan amendment	13	171
Paid-up policies	(84)	(131)
Foreign currency translation	411	87
Changes in notional contribution liability	52	50
Defined benefit obligations at 31 December	8,286	7,791
Fair value of plan assets		
Fair value of plan assets at 1 January	5,250	5,127
Interest income	148	148
Return on plan assets (excluding interest income)	283	76
Company contributions	39	22
Benefits paid	(196)	(80)
Paid-up policies and personal insurance	(121)	(92)
Foreign currency translation	283	50
Fair value of plan assets at 31 December	5,687	5,250
Net pension liability at 31 December	(2,599)	(2,541)
Represented by:		
Asset recognised as non-current pension assets (funded plan)	1,306	839
Liability recognised as non-current pension liabilities (unfunded plans)	(3,905)	(3,380)
DBO specified by funded and unfunded pension plans	8,286	7,791
Funded	4,392	4,423
Unfunded	3,894	3,368
Actual return on assets	431	131

The actuarial gain in 2017 is related to changes in financial and demographic assumptions. Statoil recognised an actuarial loss from changes in financial assumptions in 2016 mainly relate to increased pension liabilities due to reduced interest rates and a higher expected rate of pension increase.

Actuarial losses and gains recognised directly in Other comprehensive income (OCI)

(in USD million)	2017	2016	2015
Net actuarial (losses) gains recognised in OCI during the year	331	(482)	1,139
Actuarial (losses) gains related to currency effects on net obligation and foreign exchange translation	(158)	(21)	460
Tax effects of actuarial (losses) gains recognised in OCI	(38)	129	(461)
Recognised directly in OCI during the year net of tax	135	(374)	1,138
Cumulative actuarial (losses) gains recognised directly in OCI net of tax	(1,053)	(1,188)	(814)

Actuarial assumptions

	Assumptions used to determine benefit costs in %		Assumptions used to determine benefit obligations in %	
	2017	2016	2017	2016
Discount rate	2.50	2.75	2.50	2.50
Rate of compensation increase	2.25	2.25	2.25	2.25
Expected rate of pension increase	1.75	1.00	1.75	1.75
Expected increase of social security base amount (G-amount)	2.25	2.25	2.25	2.25
Weighted-average duration of the defined benefit obligation			17.2	17.4

The assumptions presented are for the Norwegian companies in Statoil which are members of Statoil's pension fund. The defined benefit plans of other subsidiaries are immaterial to the consolidated pension assets and liabilities.

Expected attrition at 31 December 2017 was 0.2% and 2.2% for employees between 50-59 years and 60-67 years, and 0.4% and 0.1% in 2016.

For population in Norway, the mortality table K2013, issued by The Financial Supervisory Authority of Norway, is used as the best mortality estimate.

Disability tables for plans in Norway developed by the actuary were implemented in 2013 and represent the best estimate to use for plans in Norway.

Sensitivity analysis

The table below presents an estimate of the potential effects of changes in the key assumptions for the defined benefit plans. The following estimates are based on facts and circumstances as of 31 December 2017.

	Discount rate		Expected rate of compensation increase		Expected rate of pension increase		Mortality assumption	
(in USD million)	0.50%	-0.50%	0.50%	-0.50%	0.50%	-0.50%	+ 1 year	- 1 year
Changes in:								
Defined benefit obligation at 31 December 2017	(607)	689	88	(92)	527	(583)	295	(323)
Service cost 2018	(22)	25	8	(8)	21	(19)	8	(11)

The sensitivity of the financial results to each of the key assumptions has been estimated based on the assumption that all other factors would remain unchanged. The estimated effects on the financial result would differ from those that would actually appear in the Consolidated financial statements because the Consolidated financial statements would also reflect the relationship between these assumptions.

Pension assets

The plan assets related to the defined benefit plans were measured at fair value. Statoil Pension invests in both financial assets and real estate.

Real estate properties owned by Statoil Pension amounted to USD 447 million and USD 402 million of total pension assets at 31 December 2017 and 2016, respectively, and are rented to Statoil companies.

The table below presents the portfolio weighting as approved by the board of Statoil Pension for 2017. The portfolio weight during a year will depend on the risk capacity.

(in %)	Pension assets on investments classes 2017	2016	Target portfolio weight
Equity securities	37.5	39.0	31 - 43
Bonds	41.7	41.1	36 - 48
Money market instruments	14.3	13.9	0 - 29
Real estate	6.1	5.4	5 - 10
Other assets	0.4	0.6	
Total	100.0	100.0	

In 2017 92% of the equity securities, 32% of bonds and 67% of money market instruments had quoted market prices in an active market (level 1). 8% of the equity securities, 68% of bonds and 32% of money market instruments had market prices based on inputs other than quoted prices. If quoted market prices are not available, fair values are determined from external calculation models based on market observations from various sources, classified at level 2 in the fair value hierarchy.

In 2016 98% of the equity securities, 30% of bonds and 71% of money market instruments had quoted market prices in an active market. 0% of the equity securities, 70% of bonds and 28% of money market instruments had market prices based on inputs other than quoted prices (level 2).

For definition of the various levels, see note 25 Financial instruments: fair value measurement and sensitivity analysis of market risk.

Company contributions expected to be made to Statoil Pension in 2018 are not considered significant.

20 Provisions

(in USD million)	Asset retirement obligations	Claims and litigations	Other provisions	Total
Non-current portion at 31 December 2016	10,711	1,209	1,487	13,406
Current portion at 31 December 2016 reported as trade and other payables	188	1,147	922	2,258
Provisions at 31 December 2016	10,899	2,356	2,409	15,664
New or increased provisions	768	128	833	1,729
Decrease in the estimates	(388)	(1,120)	(272)	(1,780)
Amounts charged against provisions	(222)	(22)	(579)	(824)
Effects of change in the discount rate	543	-	(6)	538
Reduction due to divestments	(2)	-	-	(2)
Accretion expenses	413	-	-	413
Reclassification and transfer	-	-	16	16
Currency translation	441	(2)	49	487
Provisions at 31 December 2017	12,451	1,339	2,451	16,241
Current portion at 31 December 2017 reported as trade and other payables	69	68	547	684
Non-current portion at 31 December 2017	12,383	1,271	1,904	15,557

Expected timing of cash outflows

(in USD million)	Asset retirement obligations	Other provisions, including claims and litigations	Total
2018 - 2022	993	3,082	4,076
2023 - 2027	2,413	342	2,755
2028 - 2032	986	25	1,011
2033 - 2037	4,368	16	4,384
Thereafter	3,691	324	4,015
At 31 December 2017	12,451	3,790	16,241

The claims and litigations category mainly relates to expected payments on unresolved claims. The timing and amounts of potential settlements in respect of these are uncertain and dependent on various factors that are outside management's control.

The main change in the caption claims and litigations concerns a settlement of a dispute with the Angolan Ministry of Finance. For further information on this dispute and other contingent liabilities, see note 23 Other commitments, contingent liabilities and contingent assets.

The other provisions category relates to expected payments on onerous contracts, cancellation fees and other. In 2016, Statoil recognised a provision amounting to USD 1 billion for a contingent consideration related to the BM-S-8 acquisition in Brazil. In 2017, provisions related to the BM-S-8 acquisition increased to USD 1.2 billion of which USD 0.3 billion is current portion. For further information, see note 4 Acquisitions and divestments.

For further information of methods applied and estimates required, see note 2 Significant accounting policies.

21 Trade, other payables and provisions

(in USD million)	At 31 December 2017	2016
Trade payables	3,181	2,358
Non-trade payables and accrued expenses	2,345	1,623
Joint venture payables	2,464	2,632
Equity accounted associated companies and other related party payables	858	620
Total financial trade and other payables	8,849	7,233
Current portion of provisions and other non-financial payables	888	2,433
Trade, other payables and provisions	9,737	9,666

Included in current portion of provisions and other non-financial payables are certain provisions that are further described in note 20 Provisions and in note 23 Other commitments, contingent liabilities and contingent assets. For information regarding currency sensitivities, see note 25 Financial instruments: fair value measurement and sensitivity analysis of market risk. For further information on payables to equity accounted associated companies and other related parties, see note 24 Related parties.

22 Leases

Statoil leases certain assets, notably drilling rigs, vessels and office buildings. Lease contracts committed by a licence are presented net, based on Statoil's participation interest in the respective licences. Lease contracts for helicopters, supply vessels and other assets used to serve a group of licences are presented net based on Statoil's average participation interests in these licences.

In 2017, net rental expenditures were USD 2,075 million (USD 2,569 million in 2016 and USD 3,439 million in 2015) consisting of minimum lease payments of USD 2,333 million (USD 3,113 million in 2016 and USD 4046 million in 2015) reduced with sublease payments received of USD 272 million (USD 558 million in 2016 and USD 608 million in 2015). There are no significant rig cancellation fees expensed in 2017 (USD 115 million in 2016). No material contingent rent payments have been expensed in 2017, 2016 or 2015.

The information in the table below shows future minimum lease payments due and receivable under non-cancellable operating leases at 31 December 2017:

	Operating leases						
(in USD million)	Rigs	Vessels	Land and buildings	Other	Total	Sublease	Net total
2018	1,039	615	155	152	1,961	(125)	1,837
2019	712	393	140	113	1,359	(105)	1,253
2020	509	382	136	92	1,119	(104)	1,015
2021	374	304	133	60	872	(68)	804
2022	352	233	134	57	777	(22)	755
2023-2027	287	498	621	47	1,453	(61)	1,392
2028-2032	-	93	369	23	485	(0)	485
Thereafter	-	13	50	13	76	-	76
Total future minimum lease payments	3,274	2,532	1,737	558	8,101	(484)	7,617

Statoil had certain operating lease contracts for drilling rigs at 31 December 2017. The remaining significant contracts' terms range from one month to six years. Rig lease agreements are for the most part based on fixed day rates. Certain rigs have been subleased in whole or for part of the lease term mainly to Statoil operated licences on the Norwegian continental shelf. These leases are shown gross as operating leases in the table above.

Statoil has a long-term time charter agreement with Teekay for offshore loading and transportation in the North Sea. The contract covers the lifetime of applicable producing fields and at year end 2017 includes three crude tankers. The contract's estimated nominal amount was approximately USD 585 million at year end 2017, and it is included in the category vessels in the table above.

The category land and buildings includes future minimum lease payments to related parties of USD 511 million regarding the lease of one office building located in Bergen and one in Harstad, both owned by Statoil`s pension fund ("Statoil Pension"). These operating lease commitments extend to the year 2034. USD 387 million of the total is payable after 2021.

Statoil had finance lease liabilities of USD 478 million at 31 December 2017. The nominal minimum lease payments related to these finance leases amount to USD 630 million. Property, plant and equipment includes USD 439 million for finance leases that have been capitalised at year end (USD 484 million in 2016), mainly presented in the category machinery, equipment and transportation equipment, including vessels in note 10 Property, plant and equipment.

Certain contracts contain renewal options. The execution of such options will depend on future market development and business needs at the time when such options are to be exercised.

23 Other commitments, contingent liabilities and contingent assets

Contractual commitments

Statoil had contractual commitments of USD 6,012 million at 31 December 2017. The contractual commitments reflect Statoil's share and mainly comprise construction and acquisition of property, plant and equipment as well as committed investments in equity accounted entities.

As a condition for being awarded oil and gas exploration and production licences, participants may be committed to drill a certain number of wells. At the end of 2017, Statoil was committed to participate in 29 wells, with an average ownership interest of approximately 49%. Statoil's share of estimated expenditures to drill these wells amounts to USD 456 million. Additional wells that Statoil may become committed to participating in depending on future discoveries in certain licences are not included in these numbers.

Other long-term commitments

Statoil has entered into various long-term agreements for pipeline transportation as well as terminal use, processing, storage and entry/exit capacity commitments and commitments related to specific purchase agreements. The agreements ensure the rights to the capacity or volumes in question, but also impose on Statoil the obligation to pay for the agreed-upon service or commodity, irrespective of actual use. The contracts' terms vary, with durations of up to 2045.

Take-or-pay contracts for the purchase of commodity quantities are only included in the table below if their contractually agreed pricing is of a nature that will or may deviate from the obtainable market prices for the commodity at the time of delivery.

Obligations payable by Statoil to entities accounted for using the equity method are included gross in the table below. For assets (for example pipelines) that Statoil accounts for by recognising its share of assets, liabilities, income and expenses (capacity costs) on a line-by-line basis in the Consolidated financial statements, the amounts in the table include the net commitment payable by Statoil (i.e. gross commitment less Statoil's ownership share).

Nominal minimum other long-term commitments at 31 December 2017:

(in USD million)	
2018	1,548
2019	1,415
2020	1,312
2021	1,101
2022	942
Thereafter	5,563
Total	11,881

Guarantees

Statoil has guaranteed for its proportionate portion of an associate's long-term bank debt, amounting to USD 305 million. The book value of the guarantee is immaterial.

Contingent liabilities and contingent assets

Resolution of the dispute with the Angolan Ministry of Finance

In June 2017 Statoil signed an agreement with the Angolan Ministry of Finance which resolved the dispute over previously assessed additional profit oil and taxes due, and established how to allocate profit oil and assess petroleum income tax (PIT) related to Statoil's participation in Block 4, Block 15, Block 17 and Block 31 offshore Angola for the years 2002 to 2016. In accordance with the agreement, Statoil in July 2017 paid in full and final settlement an additional PIT amount to Angola related to the prior reporting periods. The agreement also led to a certain increase in Norwegian taxes payable. In addition to taxes previously provided for in the Consolidated financial statements related to the dispute, the current income tax expense at the time reflected USD 117 million payable in Angola and Norway. Based on the agreement, profit oil and interest expense amounts previously provided for in the current portion of provisions related to claims and litigation were reversed. USD 754 million has been reflected as revenue in the E&P International segment, while USD 319 million has been reflected as interest expense reduction under Net financial items in the Consolidated statement of income. The net effect of the dispute resolution recognised in the Consolidated statement of income consequently was USD 956 million.

Redetermination process for Agbami field

Through its ownership in OML 128 in Nigeria, Statoil is party to an ownership interest redetermination process for the Agbami field. In October 2015, Statoil received the Expert's final ruling which implies a reduction of 5.17 percentage points in Statoil's equity interest in the field. Statoil had previously initiated arbitration proceedings to set aside interim decisions made by the Expert, but this was declined by the arbitration tribunal in its November 2015 judgment. Statoil has proceeded to court of Appeal to have the arbitration award set aside. In October 2016 Statoil also initiated a new arbitration to set aside the Expert's final ruling. Currently Statoil has two distinct, but connected, legal processes ongoing related to the Agbami redetermination. As of 31 December 2017, Statoil has recognised a provision of USD 1,165 million net of tax, which reflects a reduction of 5.17 percentage points in Statoil's equity interest in the Agbami field. The provision is reflected within Provisions in the Consolidated balance sheet.

Price review arbitration

Some long-term gas sales agreements contain price review clauses, which in certain cases lead to claims subject to arbitration. The exposure for Statoil related to arbitration has been estimated to an amount equivalent to approximately USD 343 million for gas delivered prior to year end 2017. Statoil has provided for its best estimate related to contractual gas price disputes in the Consolidated financial statements, with the impact to the Consolidated statement of income reflected as revenue adjustments.

Dispute concerning interpretation of the terms of the OML 128 Production Sharing Contract (PSC)

There is a dispute between the Nigerian National Petroleum Corporation (NNPC) and the partners (Contractor) in Oil Mining Lease (OML) 128 of the unitised Agbami field concerning interpretation of the terms of the OML 128 Production Sharing Contract (PSC). The dispute relates to the allocation between NNPC and Contractor of cost oil, tax oil and profit oil volumes. Following an arbitration process on the matter concluded in 2015, various disputes related to the legality and enforcement of the arbitration verdict in Contractor's favour are currently in process in the Nigerian court system. Statoil's stake in the dispute at year end 2017 mainly relates to claims for return of certain oil volumes lifted by NNPC during the arbitration process and in subsequent years contrary to the PSC terms.

Dispute with Brazilian tax authorities
Brazilian tax authorities have issued an updated tax assessment for 2011 for Statoil's Brazilian subsidiary which was party to Statoil's divestment of 40% of the Peregrino field to Sinochem at that time. The assessment disputes Statoil's allocation of the sale proceeds between entities and assets involved, resulting in a significantly higher assessed taxable gain and related taxes payable in Brazil. Statoil disagrees with the assessment, and has provided responses to this effect. The ongoing process of formal communication with the Brazilian tax authorities, as well as any subsequent litigation that may become necessary, may take several years. No taxes will become payable until the matter has been finally settled. Statoil is of the view that all applicable tax regulations have been applied in the case and that the group has a strong position. No amounts have consequently been provided for in the accounts.

Suit for an annulment of Petrobras' sale of the interest in BM-S-8 to Statoil
In April 2017, a federal judge granted an injunction request to suspend the assignment to Statoil of Petróleo Brasileiro S.A.'s ("Petrobras") 66% operated interest in the Brazilian offshore licence BM-S-8, in a class action suit filed by the Union of Workers of Oil Tankers of Sergipe (Sindipetro) against Petrobras, Statoil, and ANP - the Brazilian Regulatory Agency ("the defendants"). The suit seeks the annulment of Petrobras' sale of the interest in BM-S-8 to Statoil, which was closed in November 2016. The injunction was subsequently lifted by the Federal Regional Court. This decision is appealable. At the end of 2017 the acquired interest remains in Statoil's balance sheet as intangible assets of the Exploration & Production International (E&P International) segment. For further information about Statoil's acquisitions and divestments in BM-S-8, reference is made to the 2017 Consolidated annual financial statements note 4 Acquisitions and divestments.

A deviation notice from Norwegian tax authorities
On 6 July 2016, the Norwegian tax authorities issued a deviation notice for the years 2012 to 2014 related to the internal pricing on certain transactions between Statoil Coordination Centre (SCC) in Belgium and Norwegian entities in the Statoil group. The main issue in this matter relates to SCC`s capital structure and its compliance with the arm's length principle. Statoil is of the view that arm's length pricing has been applied and that the group has a strong position, and no amounts have consequently been provided for this issue in the accounts.

Other claims
During the normal course of its business, Statoil is involved in legal proceedings, and several other unresolved claims are currently outstanding. The ultimate liability or asset, in respect of such litigation and claims cannot be determined at this time. Statoil has provided in its Consolidated financial statements for probable liabilities related to litigation and claims based on its best estimate. Statoil does not expect that its financial position, results of operations or cash flows will be materially affected by the resolution of these legal proceedings. Statoil is actively pursuing the above disputes through the contractual and legal means available in each case, but the timing of the ultimate resolutions and related cash flows, if any, cannot at present be determined with sufficient reliability.

Provisions related to claims are reflected within note 20 Provisions.

24 Related parties

Transactions with the Norwegian State
The Norwegian State is the majority shareholder of Statoil and also holds major investments in other Norwegian companies. As of 31 December 2017, the Norwegian State had an ownership interest in Statoil of 67.0% (excluding Folketrygdfondet, the Norwegian national insurance fund, of 3.3%). This ownership structure means that Statoil participates in transactions with many parties that are under a common ownership structure and therefore meet the definition of a related party. All transactions are considered to be on an arm's length basis.

Total purchases of oil and natural gas liquids from the Norwegian State amounted to USD 7,352 million, USD 5,848 million and USD 7,431 million in 2017, 2016 and 2015, respectively. Total purchases of natural gas regarding the Tjeldbergodden methanol plant from the Norwegian State amounted to USD 39 million, USD 44 million and USD 68 million in 2017, 2016 and 2015, respectively. These purchases of oil and natural gas are recorded in Statoil ASA. In addition, Statoil ASA sells in its own name, but for the Norwegian State's account and risk, the Norwegian State's gas production. These transactions are presented net. For further information please see note 2 Significant accounting policies. The most significant items included in the line item equity accounted investments and other related party payables in note 21 Trade and other payables, are amounts payable to the Norwegian State for these purchases.

Other transactions
In relation to its ordinary business operations Statoil enters into contracts such as pipeline transport, gas storage and processing of petroleum products, with companies in which Statoil has ownership interests. Such transactions are carried out on an arm's length basis and are included within the applicable captions in the Consolidated statement of income. Gassled and certain other infrastructure assets are operated by Gassco AS, which is an entity under common control by the Norwegian Ministry of Petroleum and Energy. Gassco's activities are performed on behalf of and for the risk and reward of pipeline and terminal owners, and capacity payments flow through Gassco to the respective owners. Statoil payments that flowed through Gassco in this respect amounted to USD 1,155 million, USD 1,167 million and USD 1,105 million in 2017, 2016 and 2015, respectively. These payments are recorded in Statoil ASA. In addition, Statoil ASA process in its own name, but for the Norwegian State's account and risk, the Norwegian State's share of the Gassco costs. These transactions are presented net.

As of 31 December 2017, Statoil had an ownership interest in Lundin Petroleum AB (Lundin) of 20.1% of the outstanding shares and votes. Total purchase of oil and related products from Lundin amounted to USD 176 million and USD 155 million in 2017 and 2016, respectively. The purchase of oil and related products is recorded in Statoil ASA.

For information concerning certain lease arrangements with Statoil Pension, see note 22 Leases.

Related party transactions with management are presented in note 6 Remuneration. Management remuneration for 2017 is presented in note 4 Remuneration in the financial statements of the parent company, Statoil ASA.

25 Financial instruments: fair value measurement and sensitivity analysis of market risk

Financial instruments by category
The following tables present Statoil's classes of financial instruments and their carrying amounts by the categories as they are defined in IAS 39 Financial Instruments: Recognition and Measurement. All financial instruments' carrying amounts are measured at fair value or their carrying amounts reasonably approximate fair value except non-current financial liabilities. See note 18 Finance debt for fair value information of non-current bonds, bank loans and finance lease liabilities.

See note 2 Significant accounting policies for further information regarding measurement of fair values.

				Fair value through profit or loss			
(in USD million)	Note	Loans and receivables	Available for sale	Held for trading	Fair value option	Non-financial assets	Total carrying amount
At 31 December 2017							
Assets							
Non-current derivative financial instruments		-	-	1,603	-	-	1,603
Non-current financial investments	13	47	397	-	2,397	-	2,841
Prepayments and financial receivables	13	723	-	-	-	188	912
Trade and other receivables	15	8,560	-	-	-	865	9,425
Current derivative financial instruments		-	-	159	-	-	159
Current financial investments	13	4,085	-	3,649	714	-	8,448
Cash and cash equivalents	16	2,917	-	1,473	-	-	4,390
Total		16,332	397	6,884	3,112	1,053	27,778

				Fair value through profit or loss			
(in USD million)	Note	Loans and receivables	Available for sale	Held for trading	Fair value option	Non-financial assets	Total carrying amount
At 31 December 2016							
Assets							
Non-current derivative financial instruments		-	-	1,819	-	-	1,819
Non-current financial investments	13	-	207	-	2,137	-	2,344
Prepayments and financial receivables	13	707	-	-	-	185	893
Trade and other receivables	15	7,074	-	-	-	765	7,839
Current derivative financial instruments		-	-	492	-	-	492
Current financial investments	13	3,217	-	4,176	818	-	8,211
Cash and cash equivalents	16	2,791	-	2,299	-	-	5,090
Total		13,789	207	8,785	2,955	950	26,687

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(in USD million)	Note	Amortised cost	Fair value through profit or loss	Non-financial liabilities	Total carrying amount
At 31 December 2017					
Liabilities					
Non-current finance debt	18	24,183	-	-	24,183
Non-current derivative financial instruments		-	900	-	900
Trade and other payables	21	8,849	-	888	9,737
Current finance debt	18	4,091	-	-	4,091
Dividend payable		729	-	-	729
Current derivative financial instruments		-	403	-	403
Total		37,851	1,302	888	40,042

(in USD million)	Note	Amortised cost	Fair value through profit or loss	Non-financial liabilities	Total carrying amount
At 31 December 2016					
Liabilities					
Non-current finance debt	18	27,999	-	-	27,999
Non-current derivative financial instruments		-	1,420	-	1,420
Trade and other payables	21	7,233	-	2,433	9,666
Current finance debt	18	3,674	-	-	3,674
Dividend payable		712	-	-	712
Current derivative financial instruments		-	508	-	508
Total		39,618	1,928	2,433	43,979

Fair value hierarchy

The following table summarises each class of financial instruments which are recognised in the Consolidated balance sheet at fair value, split by Statoil's basis for fair value measurement.

(in USD million)	Non-current financial investments	Non-current derivative financial instruments - assets	Current financial investments	Current derivative financial instruments - assets	Cash equivalents	Non-current derivative financial instruments - liabilities	Current derivative financial instruments - liabilities	Net fair value
At 31 December 2017								
Level 1	1,126	-	355	-	-	-	-	1,481
Level 2	1,271	1,320	4,008	122	1,473	(900)	(399)	6,896
Level 3	397	283	-	37	-	-	(4)	713
Total fair value	2,794	1,603	4,363	159	1,473	(900)	(403)	9,090
At 31 December 2016								
Level 1	1,095	-	516	-	-	-	-	1,611
Level 2	1,042	970	4,479	426	2,299	(1,414)	(503)	7,299
Level 3	207	848	(0)	66	-	(6)	(4)	1,110
Total fair value	2,344	1,819	4,994	492	2,299	(1,420)	(508)	10,019

Level 1, fair value based on prices quoted in an active market for identical assets or liabilities, includes financial instruments actively traded and for which the values recognised in the Consolidated balance sheet are determined based on observable prices on identical instruments. For Statoil this category will, in most cases, only be relevant for investments in listed equity securities and government bonds.

Level 2, fair value based on inputs other than quoted prices included within level 1, which are derived from observable market transactions, includes Statoil's non-standardised contracts for which fair values are determined on the basis of price inputs from observable market transactions. This will typically be when Statoil uses forward prices on crude oil, natural gas, interest rates and foreign exchange rates as inputs to the valuation models to determining the fair value of its derivative financial instruments.

Level 3, fair value based on unobservable inputs, includes financial instruments for which fair values are determined on the basis of input and assumptions that are not from observable market transactions. The fair values presented in this category are mainly based on internal assumptions. The internal assumptions are only used in the absence of quoted prices from an active market or other observable price inputs for the financial instruments subject to the valuation.

The fair value of certain earn-out agreements and embedded derivative contracts are determined by the use of valuation techniques with price inputs from observable market transactions as well as internally generated price assumptions and volume profiles. The discount rate used in the valuation is a risk-free rate based on the applicable currency and time horizon of the underlying cash flows adjusted for a credit premium to reflect either Statoil's credit premium, if the value is a liability, or an estimated counterparty credit premium if the value is an asset. In addition a risk premium for risk elements not adjusted for in the cash flow may be included when applicable. The fair values of these derivative financial instruments have been classified in their entirety in the third category within current derivative financial instruments and non-current derivative financial instruments. Another reasonable assumption, that could have been applied when determining the fair value of these contracts, would be to extrapolate the last observed forward prices with inflation. Applying this assumption would have an insignificant impact on the fair value for these contracts.

The reconciliation of the changes in fair value during 2017 and 2016 for financial instruments classified in the third level in the hierarchy are presented in the following table.

(in USD million)	Non-current financial investments	Non-current derivative financial instruments - assets	Current derivative financial instruments - assets	Non-current derivative financial instruments liabilities	Current derivative financial instruments - liabilities	Total amount
Full year 2017						
Opening balance	207	848	66	(6)	(4)	1,110
Total gains and losses recognised in statement of income	-	(69)	36	6	-	(27)
Purchases	90	-	-	-	-	90
Settlement	-	(533)	(67)	-	-	(600)
Transfer into level 3	94	-	-	-	-	94
Foreign currency translation differences	5	37	3	-	-	45
Closing balance	397	283	37	-	(4)	713
Full year 2016						
Opening balance	209	941	50	(59)	-	1,141
Total gains and losses recognised in statement of income	-	(98)	66	49	-	17
Purchases	2	-	-	-	-	2
Settlement	(5)	(17)	(53)	-	-	(75)
Transfer to current portion	-	(1)	1	4	(4)	-
Foreign currency translation differences	1	23	1	-	-	25
Closing balance	207	848	66	(6)	(4)	1,110

During 2017 the financial instruments within level 3 have had a net decrease in the fair value of USD 397 million. The USD 27 million recognised in the Consolidated statement of income during 2017 are impacted by a reduction of USD 78 million related to changes in fair value of certain earn-out agreements. Related to the same earn-out agreements, USD 528 million included in the opening balance for 2017 has been agreed settled, while USD 72 million has been fully realised as the underlying volumes have been delivered during 2017.

Sensitivity analysis of market risk

Commodity price risk

The table below contains the commodity price risk sensitivities of Statoil's commodity based derivatives contracts. For further information related to the type of commodity risks and how Statoil manages these risks, see note 5 Financial risk management.

Statoil's assets and liabilities resulting from commodity based derivatives contracts consist of both exchange traded and non-exchange traded instruments, including embedded derivatives that have been bifurcated and recognised at fair value in the Consolidated balance sheet.

Price risk sensitivities at the end of 2017 at 20%, and at the end of 2016 at 30%, are assumed to represent a reasonably likely change based on the duration of the derivatives.

Since none of the derivative financial instruments included in the table below are part of hedging relationships, any changes in the fair value would be recognised in the Consolidated statement of income.

Commodity price sensitivity	2017		2016	
(in USD million)	- 20%	+ 20%	- 30%	+ 30%
At 31 December				
Crude oil and refined products net gains (losses)	687	(606)	395	(390)
Natural gas and electricity net gains (losses)	613	(613)	810	(809)

Currency risk

The following currency risk sensitivity has been calculated, by assuming an 8% reasonable change in the main exchange rates that impact Statoil's financial accounts, based on balances at 31 December 2017. At 31 December 2016 a change of 12% in the main exchange rates were viewed as a reasonable change. With reference to table below, an increase in the exchange rates means that the disclosed currency has strengthened in value against all other currencies. The estimated gains and the estimated losses following from a change in the exchange rates would impact the Consolidated statement of income. For further information related to the currency risk and how Statoil manages these risks, see note 5 Financial risk management.

Currency risk sensitivity	2017		2016	
(in USD million)	- 8%	+ 8%	- 12%	+ 12%
At 31 December				
USD net gains (losses)	119	(119)	79	(79)
NOK net gains (losses)	(94)	94	31	(31)

Interest rate risk

The following interest rate risk sensitivity has been calculated by assuming a change of 0.6 percentage points as reasonably possible changes in the interest rates at the end of 2017. At the end of 2016 a change of 0.8 percentage points in the interest rates was viewed as reasonably possible changes. The estimated gains following from a decrease in the interest rates and the estimated losses following from an interest rate increase would impact the Consolidated statement of income. For further information related to the interest risks and how Statoil manages these risks, see note 5 Financial risk management.

Interest risk sensitivity	2017		2016	
(in USD million)	- 0.6 percentage points	+ 0.6 percentage points	- 0.8 percentage points	+ 0.8 percentage points
At 31 December				
Interest rate net gains (losses)	664	(664)	897	(897)

26 Subsequent events

On 28 February 2018, Statoil received a notice of deviation from Norwegian tax authorities related to an ongoing dispute regarding the level of Research & Development cost to be allocated to the offshore tax regime, increasing the maximum exposure in this matter to USD 470 million. Statoil has provided for its best estimate in the matter, and is currently evaluating the notice of deviation.

27 Condensed consolidated financial information related to guaranteed debt securities

Statoil Petroleum AS, a 100% owned subsidiary of Statoil ASA, is the co-obligor of certain existing debt securities of Statoil ASA that are registered under the US Securities Act of 1933 ("US registered debt securities"). As co-obligor, Statoil Petroleum AS fully, unconditionally and irrevocably assumes and agrees to perform, jointly and severally with Statoil ASA, the payment and covenant obligations for these US registered debt securities. In addition, Statoil ASA is also the co-obligor of a US registered debt security of Statoil Petroleum AS. As co-obligor, Statoil ASA fully, unconditionally and irrevocably assumes and agrees to perform, jointly and severally with Statoil Petroleum AS, the payment and covenant obligations of that security. In the future, Statoil ASA may from time to time issue future US registered debt securities for which Statoil Petroleum AS will be the co-obligor or guarantor.

The following financial information on a condensed consolidated basis provides financial information about Statoil ASA, as issuer and co-obligor, Statoil Petroleum AS, as co-obligor and guarantor, and all other subsidiaries as required by SEC Rule 3-10 of Regulation S-X. The condensed consolidated information is prepared in accordance with Statoil's IFRS accounting policies as described in note 2 Significant accounting policies, except that investments in subsidiaries and jointly controlled entities are accounted for using the equity method as required by Rule 3-10.

The following is condensed consolidated financial information for the full year 2017, 2016 and 2015, and as of 31 December 2017 and 2016.

CONDENSED CONSOLIDATED STATEMENT OF INCOME AND OTHER COMPREHENSIVE INCOME

Full year 2017 (in USD million)	Statoil ASA	Statoil Petroleum AS	Non-guarantor subsidiaries	Consolidation adjustments	The Statoil group
Revenues and other income	39,750	20,579	22,204	(21,535)	60,999
Net income/(loss) from equity accounted companies	5,051	(401)	33	(4,495)	188
Total revenues and other income	44,801	20,178	22,237	(26,029)	61,187
Total operating expenses	(39,570)	(9,217)	(20,022)	21,392	(47,416)
Net operating income/(loss)	5,232	10,961	2,216	(4,637)	13,771
Net financial items	311	(378)	439	(724)	(351)
Income/(loss) before tax	5,543	10,583	2,655	(5,361)	13,420
Income tax	(230)	(8,094)	(539)	40	(8,822)
Net income/(loss)	5,314	2,489	2,116	(5,321)	4,598
Other comprehensive income/(loss)	1,017	355	878	(509)	1,741
Total comprehensive income/(loss)	6,330	2,843	2,995	(5,830)	6,339

CONDENSED CONSOLIDATED STATEMENT OF INCOME AND OTHER COMPREHENSIVE INCOME

Full year 2016 (in USD million)	Statoil ASA	Statoil Petroleum AS	Non-guarantor subsidiaries	Consolidation adjustments	The Statoil group
Revenues and other income	31,580	15,405	15,472	(16,464)	45,993
Net income/(loss) from equity accounted companies	(2,726)	(3,987)	26	6,567	(119)
Total revenues and other income	28,854	11,418	15,498	(9,898)	45,873
Total operating expenses	(31,784)	(10,989)	(19,364)	16,344	(45,793)
Net operating income/(loss)	(2,930)	429	(3,865)	6,446	80
Net financial items	728	(560)	(115)	(311)	(258)
Income/(loss) before tax	(2,202)	(131)	(3,980)	6,135	(178)
Income tax	(407)	(2,392)	97	(23)	(2,724)
Net income/(loss)	(2,608)	(2,523)	(3,884)	6,113	(2,902)
Other comprehensive income/(loss)	(671)	153	(280)	441	(357)
Total comprehensive income/(loss)	(3,279)	(2,370)	(4,163)	6,553	(3,259)

CONDENSED CONSOLIDATED STATEMENT OF INCOME AND OTHER COMPREHENSIVE INCOME

Full year 2015 (in USD million)	Statoil ASA	Statoil Petroleum AS	Non-guarantor subsidiaries	Consolidation adjustments	The Statoil group
Revenues and other income	39,289	20,583	20,248	(20,448)	59,671
Net income/(loss) from equity accounted companies	(4,686)	(8,350)	(42)	13,050	(29)
Total revenues and other income	34,603	12,232	20,205	(7,399)	59,642
Total operating expenses	(39,372)	(12,561)	(26,907)	20,566	(58,276)
Net operating income/(loss)	(4,769)	(329)	(6,702)	13,167	1,366
Net financial items	(2,771)	(106)	139	1,427	(1,311)
Income/(loss) before tax	(7,541)	(435)	(6,563)	14,594	55
Income tax	925	(5,301)	(840)	(9)	(5,225)
Net income/(loss)	(6,616)	(5,736)	(7,402)	14,585	(5,169)
Other comprehensive income/(loss)	(1,414)	(1,771)	(1,405)	1,751	(2,838)
Total comprehensive income/(loss)	(8,030)	(7,507)	(8,807)	16,336	(8,007)

CONDENSED CONSOLIDATED BALANCE SHEET

At 31 December 2017 (in USD million)	Statoil ASA	Statoil Petroleum AS	Non-guarantor subsidiaries	Consolidation adjustments	The Statoil group
ASSETS					
Property, plant, equipment and intangible assets	541	32,956	38,786	(25)	72,258
Equity accounted companies	42,625	21,593	1,311	(62,978)	2,551
Other non-current assets	3,851	346	4,989	(84)	9,102
Non-current receivables from subsidiaries	25,896	(0)	22	(25,918)	0
Total non-current assets	72,914	54,895	45,107	(89,005)	83,911
Current receivables from subsidiaries	2,448	2,615	14,215	(19,278)	0
Other current assets	16,165	923	5,582	(1,240)	21,430
Cash and cash equivalents	3,759	27	603	0	4,390
Total current assets	22,372	3,566	20,400	(20,517)	25,820
Assets classified as held for sale	0	0	1,369	0	1,369
Total assets	95,286	58,460	66,876	(109,523)	111,100
EQUITY AND LIABILITIES					
Total equity	39,861	20,813	42,634	(63,422)	39,885
Non-current liabilities to subsidiaries	19	14,682	11,263	(25,964)	0
Other non-current liabilities	29,070	16,145	7,104	(122)	52,197
Total non-current liabilities	29,090	30,827	18,367	(26,086)	52,198
Other current liabilities	9,242	5,879	4,632	(736)	19,017
Current liabilities to subsidiaries	17,094	941	1,243	(19,278)	0
Total current liabilities	26,335	6,821	5,874	(20,014)	19,017
Total liabilities	55,425	37,648	24,242	(46,100)	71,214
Total equity and liabilities	95,286	58,460	66,876	(109,523)	111,100

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CONDENSED CONSOLIDATED BALANCE SHEET

At 31 December 2016 (in USD million)	Statoil ASA	Statoil Petroleum AS	Non-guarantor subsidiaries	Consolidation adjustments	The Statoil group
ASSETS					
Property, plant, equipment and intangible assets	576	29,944	38,310	(31)	68,799
Equity accounted companies	40,294	18,089	1,013	(57,151)	2,245
Other non-current assets	3,212	945	3,933	0	8,090
Non-current receivables from subsidiaries	23,644	(0)	26	(23,670)	0
Total non-current assets	67,725	48,979	43,281	(80,852)	79,133
Current receivables from subsidiaries	4,305	2,141	12,879	(19,325)	0
Other current assets	14,716	924	4,769	(639)	19,769
Cash and cash equivalents	4,274	46	770	0	5,090
Total current assets	23,295	3,111	18,418	(19,964)	24,859
Assets classified as held for sale	0	0	537	0	537
Total assets	91,021	52,089	62,236	(100,816)	104,530
EQUITY AND LIABILITIES					
Total equity	35,072	17,974	39,510	(57,457)	35,099
Non-current liabilities to subsidiaries	17	12,848	10,806	(23,670)	0
Other non-current liabilities	33,065	13,812	5,953	(198)	52,633
Total non-current liabilities	33,082	26,660	16,759	(23,868)	52,633
Other current liabilities	7,757	4,419	4,735	(166)	16,744
Current liabilities to subsidiaries	15,109	3,037	1,179	(19,325)	0
Total current liabilities	22,866	7,456	5,913	(19,492)	16,744
Liabilities directly associated with the assets classified as held for sale	0	0	(54)	0	(54)
Total liabilities	55,948	34,116	22,727	(43,359)	69,431
Total equity and liabilities	91,021	52,089	62,236	(100,816)	104,530

CONDENSED CONSOLIDATED CASH FLOW STATEMENT

Full year 2017 (in USD million)	Statoil ASA	Statoil Petroleum AS	Non-guarantor subsidiaries	Consolidation adjustments	The Statoil group
Cash flows provided by (used in) operating activities	(92)	9,506	5,235	(286)	14,363
Cash flows provided by (used in) investing activities	3,658	(9,070)	(4,711)	444	(9,678)
Cash flows provided by (used in) financing activities	(4,459)	(478)	(727)	(158)	(5,822)
Net increase (decrease) in cash and cash equivalents	(892)	(42)	(203)	0	(1,137)
Effect of exchange rate changes on cash and cash equivalents	377	23	36	0	436
Cash and cash equivalents at the beginning of the period (net of overdraft)	4,274	46	770	0	5,090
Cash and cash equivalents at the end of the period (net of overdraft)	3,759	27	603	0	4,390

Full year 2016 (in USD million)	Statoil ASA	Statoil Petroleum AS	Non-guarantor subsidiaries	Consolidation adjustments	The Statoil group
Cash flows provided by (used in) operating activities	3,330	7,262	1,561	(3,119)	9,034
Cash flows provided by (used in) investing activities	(3,138)	(6,785)	(5,393)	4,869	(10,446)
Cash flows provided by (used in) financing activities	(3,308)	(516)	3,616	(1,750)	(1,959)
Net increase (decrease) in cash and cash equivalents	(3,116)	(39)	(216)	0	(3,371)
Effect of exchange rate changes on cash and cash equivalents	(81)	(2)	(69)	0	(152)
Cash and cash equivalents at the beginning of the period (net of overdraft)	7,471	87	1,056	0	8,613
Cash and cash equivalents at the end of the period (net of overdraft)	4,274	46	770	0	5,090

Full year 2015 (in USD million)	Statoil ASA	Statoil Petroleum AS	Non-guarantor subsidiaries	Consolidation adjustments	The Statoil group
Cash flows provided by (used in) operating activities	2,883	8,348	4,567	(2,170)	13,628
Cash flows provided by (used in) investing activities	(5,694)	(17,219)	(5,630)	14,042	(14,501)
Cash flows provided by (used in) financing activities	1,333	8,986	824	(11,872)	(729)
Net increase (decrease) in cash and cash equivalents	(1,478)	115	(239)	0	(1,602)
Effect of exchange rate changes on cash and cash equivalents	(677)	(106)	(88)	0	(871)
Cash and cash equivalents at the beginning of the period (net of overdraft)	9,625	78	1,382	0	11,085
Cash and cash equivalents at the end of the period (net of overdraft)	7,470	87	1,055	0	8,613

4.2 Supplementary oil and gas information (unaudited)

In accordance with the US Financial Accounting Standards Board Accounting Standards Codification "Extractive Activities - Oil and Gas" (Topic 932), Statoil is reporting certain supplemental disclosures about oil and gas exploration and production operations. While this information is developed with reasonable care and disclosed in good faith, it is emphasised that some of the data is necessarily imprecise and represents only approximate amounts because of the subjective judgement involved in developing such information. Accordingly, this information may not necessarily represent the present financial condition of Statoil or its expected future results.

For further information regarding the reserves estimation requirement, see note 2 Significant accounting policies - Critical accounting judgements and key sources of estimation uncertainty - Proved oil and gas reserves within the Consolidated financial statements.

No new events have occurred since 31 December 2017 that would result in a significant change in the estimated proved reserves or other figures reported as of that date.

The Agbami equity redetermination in Nigeria implies a reduction of 5.17 percentage points in Statoil's equity interest in the field. Statoil has proceeded to the court of appeal to have the arbitration award set aside. Final approval in the licence was pending at year end 2017, hence the negative effect on the proved reserves, which is estimated to be less than 10 million boe, is not yet included.

In Algeria, an agreement has been signed which will amend the In Amenas Production Sharing Contract by five years, from 2022 to 2027. The effect on the proved reserves will be included once the agreement is approved by the authorities and the effect is known. The effect of the farm out of the Leismer oil sands projects was implemented in 2017 resulting in a reduction of the proved reserves in Canada.

Oil and gas reserve quantities

Statoil's oil and gas reserves have been estimated by its qualified professionals in accordance with industry standards under the requirements of the U.S. Securities and Exchange Commission (SEC), Rule 4-10 of Regulation S-X. Statements of reserves are forward-looking statements.

The determination of these reserves is part of an ongoing process subject to continual revision as additional information becomes available. Estimates of proved reserve quantities are imprecise and change over time as new information becomes available. Moreover, identified reserves and contingent resources that may become proved in the future are excluded from the calculations.

Statoil's proved reserves are recognised under various forms of contractual agreements, including production sharing agreements (PSAs) where Statoil's share of reserves can vary due to commodity prices or other factors. Reserves from agreements such as PSAs and buy back agreements are based on the volumes to which Statoil has access (cost oil and profit oil), limited to available market access. At 31 December 2017, 6% of total proved reserves were related to such agreements (11% of total oil, condensate and natural gas liquids (NGL) reserves and 2% of total gas reserves). This compares with 7% and 9% of total proved reserves for 2016 and 2015, respectively. Net entitlement oil and gas production from fields with such agreements was 94 million boe during 2017 (96 million boe for 2016 and 104 million boe for 2015). Statoil participates in such agreements in Algeria, Angola, Azerbaijan, Libya, Nigeria and Russia.

Statoil is recording, as proved reserves, volumes equivalent to our tax liabilities under negotiated fiscal arrangements (PSAs) where the tax is paid on behalf of Statoil. Reserves are net of royalty oil paid in kind and quantities consumed during production.

Rule 4-10 of Regulation S-X requires that the estimation of reserves is based on existing economic conditions, including a 12-month average price determined as an unweighted arithmetic average of the first-of-the month price for each month within the reporting period, unless prices are defined by contractual arrangements. The proved reserves at year end 2017 have been determined based on a Brent blend price equivalent of USD 54.32/bbl, compared to USD 42.82/bbl and USD 54.17/bbl for 2016 and 2015 respectively. The volume weighted average gas price for proved reserves at year end 2017 was USD 4.65 mmBtu. The comparable gas price used to determine gas reserves at year end 2016 and 2015 was USD 4.50 mmBtu and USD 5.76 mmBtu. The volume weighted average NGL price for proved reserves at year end 2017 was USD 32.02/boe. The corresponding NGL price used to determine NGL reserves at year end 2016 and 2015 was USD 24.85/boe and USD 30.56/boe. The increase in commodity prices affects the profitable reserves to be recovered from accumulations, resulting in increased reserves. The positive revisions due to price are in general a result of extended economic cut-off. For fields with a production-sharing type of agreement this is to some degree offset by lower entitlement to the reserves. These changes are all included in the revision category in the tables below, giving a net increase of Statoil's proved reserves at year end.

From the Norwegian continental shelf (NCS), Statoil is responsible for managing, transporting and selling the Norwegian State's oil and gas on behalf of the Norwegian State's direct financial interest (SDFI). These reserves are sold in conjunction with the Statoil reserves. As part of this arrangement, Statoil delivers and sells gas to customers in accordance with various types of sales contracts on behalf of the SDFI. In order to fulfil the commitments, Statoil utilises a field supply schedule which provides the highest possible total value for the joint portfolio of oil and gas between Statoil and the SDFI.

Statoil and the SDFI receive income from the joint natural gas sales portfolio based upon their respective share in the supplied volumes. For sales of the SDFI natural gas, to Statoil and to third parties, the payment to the Norwegian State is based on achieved prices, a net back formula calculated price or market value. All of the Norwegian State's oil and NGL is acquired by Statoil. The price Statoil pays to the SDFI for the crude oil is based on market reflective prices. The prices for NGL are either based on achieved prices, market value or market reflective prices.

The regulations of the owner's instruction, as described above, may be changed or withdrawn by the Statoil ASA's general meeting. Due to this uncertainty and the Norwegian State's estimate of proved reserves not being available to Statoil, it is not possible to determine the total quantities to be purchased by Statoil under the owner's instruction.

Topic 932 requires the presentation of reserves and certain other supplemental oil and gas disclosures by geographic area, defined as country or continent containing 15% or more of total proved reserves. At 31 December 2017 Norway contains 73% and US 16% of the total proved reserves. Accordingly, management has determined that the most meaningful presentation of geographic areas would be Norway, US, and the continents of Eurasia (excluding Norway), Africa, and Americas (excluding US).

The following tables reflect the estimated proved reserves of oil and gas at 31 December 2014 through 2017, and the changes therein.

The reason for the most significant changes to our proved reserves at year end 2017 were:

- Revisions of previously booked reserves, including the effect of improved recovery, increased the proved reserves by 605 million boe in 2017. Many producing fields have significant positive revisions due to better performance, maturing of new wells and improved recovery projects, as well as reduced uncertainty due to further drilling and production experience. The effect of the increased commodity prices, increasing the proved reserves by approximately 200 million boe through extended economic life time on several fields, is also included in this. The largest revisions are seen in Norway, where many of the larger offshore fields continue to decline less than assumed for the proved reserves, and in the US where continued drilling and production from the onshore plays in the Appalachian basin (Marcellus and Utica), Bakken and Eagle Ford have increased the proved reserves
- A total of 441 million boe of new proved reserves are added through extensions and new discoveries booking proved reserves for the first time. New field developments in Norway, such as Johan Castberg, Ærfugl and Bauge, and Peregrino Phase 2 in Brazil, all contribute to this with a total of 260 million boe. Extensions of the proved areas in the US onshore plays contribute with167 million boe. The remaining 14 million boe come from other minor extensions on producing fields where new wells have been drilled in previously unproven areas
- New discoveries with proved reserves booked in 2017 are all expected to start production within a period of five years
- A total of 50 million boe of new proved reserves were purchased in 2017 (the Azeri-Chirag-Gunashli PSA extension and transfer of certain ownership shares in the Appalachian basin from Northwood Energy)
- Sale of 38 million boe of proved reserves from the Leismer oil sands development in Canada which was finalised in 2017
- The 2017 entitlement production was 705 million boe, an increase of 4.7% compared to 2016

Changes to the proved reserves in 2017 are also described in some detail by each geographic area in section 2.8 Operational performance, Proved oil and gas reserves. Development of the proved reserves are described in section 2.8 Operational performance, Development of reserves.

	Consolidated companies						Equity accounted				Total
	Norway	Eurasia excluding Norway	Africa	US	Americas excluding US	Subtotal	Norway	Eurasia excluding Norway	Americas excluding US	Subtotal	Total
Net proved oil and condensate reserves in million barrels oil equivalent											
At 31 December 2014	886	196	296	279	230	1,887			55	55	1,942
Revisions and improved recovery	71	(68)	57	(6)	(48)	5	-	-	(5)	(5)	0
Extensions and discoveries	437			39	34	511					511
Purchase of reserves-in-place				4		4					4
Sales of reserves-in-place	(4)	(38)		(1)		(43)					(43)
Production	(174)	(13)	(75)	(31)	(27)	(319)			(4)	(4)	(324)
At 31 December 2015	1,216	76	278	285	189	2,045			46	46	2,091
Revisions and improved recovery	111	6	16	7	10	149	-	-	(12)	(12)	137
Extensions and discoveries	29			45	4	78					78
Purchase of reserves-in-place							60	0		60	60
Sales of reserves-in-place	(14)					(14)					(14)
Production	(169)	(12)	(72)	(34)	(26)	(313)	(2)	(0)	(4)	(6)	(320)
At 31 December 2016	1,174	71	221	303	177	1,945	58		30	88	2,033
Revisions and improved recovery	212	2	32	55	54	354	1	0	(28)	(27)	327
Extensions and discoveries	159			31	65	256					256
Purchase of reserves-in-place		34				34					34
Sales of reserves-in-place					(38)	(38)					(38)
Production	(165)	(10)	(68)	(38)	(21)	(302)	(6)	(0)	(2)	(8)	(310)
At 31 December 2017	1,380	97	185	351	237	2,249	53			53	2,302

	Consolidated companies						Equity accounted				Total
	Norway	Eurasia excluding Norway	Africa	US	Americas exclusing US	Subtotal	Norway	Eurasia excluding Norway	Americas exclusing US	Subtotal	Total
Net proved NGL reserves in million barrels oil equivalent											
At 31 December 2014	318		15	69		403					403
Revisions and improved recovery	7	-	3	(20)	-	(10)	-	-	-	-	(10)
Extensions and discoveries	11			16		27					27
Purchase of reserves-in-place				4		4					4
Sales of reserves-in-place	(1)			(5)		(5)					(5)
Production	(44)		(3)	(7)		(54)					(54)
At 31 December 2015	291		15	57		364					364
Revisions and improved recovery	37	-	3	6	-	46	-	-	-	-	46
Extensions and discoveries	5			13		18					18
Purchase of reserves-in-place							2			2	2
Sales of reserves-in-place	(0)					(0)					(0)
Production	(46)		(2)	(9)		(58)	(0)			(0)	(58)
At 31 December 2016	287		16	67		370	2			2	372
Revisions and improved recovery	31	-	(2)	6	0	36	(1)	-	-	(1)	35
Extensions and discoveries	8			25		33					33
Purchase of reserves-in-place											
Sales of reserves-in-place											
Production	(48)		(4)	(9)	(0)	(61)					(61)
At 31 December 2017	278		10	90		378	1			1	379

	Consolidated companies						Equity accounted				Total
	Norway	Eurasia excluding Norway	Africa	US	Americas excluding US	Subtotal	Norway	Eurasia excluding Norway	Americas excluding US	Subtotal	Total
Net proved gas reserves in billion standard cubic feet											
At 31 December 2014	13,694	1,218	299	1,708		16,919					16,919
Revisions and improved recovery	385	(18)	129	(676)	0	(180)	-	-	-	-	(180)
Extensions and discoveries	179			318		497					497
Purchase of reserves-in-place				31		31					31
Sales of reserves-in-place	(10)	(991)		(42)		(1,043)					(1,043)
Production	(1,306)	(16)	(63)	(215)	(0)	(1,600)					(1,600)
At 31 December 2015	12,942	193	366	1,123		14,624					14,624
Revisions and improved recovery	1,160	29	(25)	101	0	1,265	-	-	-	-	1,265
Extensions and discoveries	78			384		462					462
Purchase of reserves-in-place							16	0		16	16
Sales of reserves-in-place	(5)			(65)		(70)					(70)
Production	(1,338)	(34)	(60)	(226)	(0)	(1,659)	(1)	(0)		(2)	(1,661)
At 31 December 2016	12,836	188	280	1,318		14,623	15			15	14,637
Revisions and improved recovery	824	13	102	425	0	1,363	(1)	0	-	(1)	1,363
Extensions and discoveries	198			659		857					857
Purchase of reserves-in-place				90		90					90
Sales of reserves-in-place											
Production	(1,515)	(41)	(72)	(240)	(0)	(1,868)	(4)	(0)		(5)	(1,873)
At 31 December 2017	12,343	159	310	2,252		15,064	9			9	15,073

	Consolidated companies						Equity accounted				Total
	Norway	Eurasia excluding Norway	Africa	US	Americas excluding US	Subtotal	Norway	Eurasia excluding Norway	Americas excluding US	Subtotal	Total
Net proved reserves in million barrels oil equivalent											
At 31 December 2014	3,644	413	364	653	230	5,304			55	55	5,359
Revisions and improved recovery	146	(72)	83	(146)	(48)	(37)	-	-	(5)	(5)	(42)
Extensions and discoveries	480			112	34	627					627
Purchase of reserves-in-place				13		13					13
Sales of reserves-in-place	(6)	(215)		(13)		(235)					(235)
Production	(450)	(16)	(88)	(76)	(27)	(658)			(4)	(4)	(662)
At 31 December 2015	3,814	111	358	542	189	5,014	-	-	46	46	5,060
Revisions and improved recovery	355	11	14	31	10	421	-	-	(12)	(12)	409
Extensions and discoveries	48			127	4	179					179
Purchase of reserves-in-place							65	0		65	65
Sales of reserves-in-place	(15)			(11)		(27)					(27)
Production	(454)	(18)	(85)	(83)	(26)	(666)	(3)	(0)	(4)	(7)	(673)
At 31 December 2016	3,748	104	287	605	177	4,921	62	-	30	92	5,013
Revisions and improved recovery	390	4	48	137	54	633	0	0	(28)	(28)	605
Extensions and discoveries	202			174	65	441					441
Purchase of reserves-in-place		34		16		50					50
Sales of reserves-in-place					(38)	(38)					(38)
Production	(483)	(17)	(85)	(90)	(21)	(696)	(6)	(0)	(2)	(9)	(705)
At 31 December 2017	3,857	125	250	842	237	5,311	56	-	-	56	5,367

	Consolidated companies						Equity accounted				Total
	Norway	Eurasia excluding Norway	Africa	US	Americas excluding US	Subtotal	Norway	Eurasia excluding Norway	Americas excluding US	Subtotal	Total
Net proved oil and condensate reserves in million barrels oil equivalent											
At 31 December 2014											
Developed	559	63	243	139	128	1,133	-	-	24	24	1,156
Undeveloped	327	133	52	140	102	754	-	-	32	32	786
At 31 December 2015											
Developed	505	48	248	163	119	1,083		-	21	21	1,104
Undeveloped	711	29	30	122	70	962		-	25	25	987
At 31 December 2016											
Developed	536	43	200	182	121	1,082	7	-	16	23	1,105
Undeveloped	638	28	22	121	55	863	51	-	13	65	928
At 31 December 2017											
Developed	514	55	173	252	118	1,112		-			1,112
Undeveloped	866	42	12	99	119	1,138	53	-		53	1,191
Net proved NGL reserves in million barrels oil equivalent											
At 31 December 2014											
Developed	258		9	42		310	-	-			310
Undeveloped	60		6	27		93	-	-			93
At 31 December 2015											
Developed	235		9	45		290		-			290
Undeveloped	56		6	12		74		-			74
At 31 December 2016											
Developed	213		10	53		276	1	-		1	277
Undeveloped	74		6	14		94	1	-		1	95
At 31 December 2017											
Developed	199		10	68		278		-			278
Undeveloped	78			21		100	1	-		1	101
Net proved gas reserves in billion standard cubic feet											
At 31 December 2014											
Developed	11,227	312	191	946		12,677	-	-			12,677
Undeveloped	2,467	906	108	762		4,242	-	-			4,242
At 31 December 2015											
Developed	10,664	32	206	999		11,901		-			11,901
Undeveloped	2,278	161	160	124		2,723		-			2,723
At 31 December 2016											
Developed	9,219	188	171	1,002		10,580	4	-		4	10,584
Undeveloped	3,617		110	316		4,043	11	-		11	4,054
At 31 December 2017											
Developed	8,852	159	273	1,675		10,958		-			10,958
Undeveloped	3,492		37	577		4,106	9	-		9	4,115
Net proved oil, condensate, NGL and gas reserves in million barrels oil equivalent											
At 31 December 2014											
Developed	2,818	119	287	350	128	3,701	-	-	24	24	3,725
Undeveloped	826	295	78	303	102	1,603	-	-	32	32	1,635
At 31 December 2015											
Developed	2,641	53	294	386	119	3,494		-	21	21	3,515
Undeveloped	1,173	57	64	156	70	1,521		-	25	25	1,546
At 31 December 2016											
Developed	2,392	76	240	414	121	3,244	8	-	16	24	3,268
Undeveloped	1,357	28	47	191	55	1,678	54	-	13	68	1,746
At 31 December 2017											
Developed	2,290	83	231	619	118	3,342		-			3,342
Undeveloped	1,567	42	19	223	119	1,969	56	-		56	2,025

The conversion rates used are 1 standard cubic meter = 35.3 standard cubic feet, 1 standard cubic meter oil equivalent = 6.29 barrels of oil equivalent (boe) and 1,000 standard cubic meter gas = 1 standard cubic meter oil equivalent.

Capitalised cost related to oil and gas producing activities

Consolidated companies

(in USD million)	2017	2016	At 31 December 2015
Unproved properties	12,627	13,563	13,341
Proved properties, wells, plants and other equipment	173,954	159,284	150,653
Total capitalised cost	186,581	172,847	163,994
Accumulated depreciation, impairment and amortisation	(120,170)	(109,160)	(99,118)
Net capitalised cost	66,411	63,687	64,876

Net capitalised cost related to equity accounted investments as of 31 December 2017 was USD 1,351 million, USD 2,000 million in 2016 and USD 1,000 million in 2015. The decrease is mainly caused by the reclassification of the 9,67% ownership share in the heavy oil project Petrocedeño in Venezuela from an equity accounted investment to a non-current financial investment as of 30 June 2017. The reported figures are based on capitalised costs within the upstream segments in Statoil, in line with the description below for result of operations for oil and gas producing activities.

Expenditures incurred in oil and gas property acquisition, exploration and development activities

These expenditures include both amounts capitalised and expensed.

Consolidated companies

(in USD million)	Norway	Eurasia excluding Norway	Africa	US	Americas excluding US	Total
Full year 2017						
Exploration expenditures	472	223	77	199	264	1,235
Development costs	4,565	599	417	2,146	376	8,102
Acquired proved properties	0	333	0	32	0	365
Acquired unproved properties	1	13	0	122	726	862
Total	5,038	1,168	494	2,499	1,366	10,564
Full year 2016						
Exploration expenditures	495	155	197	202	388	1,437
Development costs	5,245	661	780	1,705	413	8,804
Acquired proved properties	6	0	0	3	0	9
Acquired unproved properties	57	58	0	9	2,353	2,477
Total	5,803	874	977	1,919	3,154	12,727
Full year 2015						
Exploration expenditures	796	213	381	808	661	2,859
Development costs	5,863	1,420	1,315	3,069	531	12,198
Acquired proved properties	0	0	0	79	0	79
Acquired unproved properties	6	77	88	379	(4)	546
Total	6,665	1,710	1,784	4,335	1,188	15,682

Expenditures incurred in development activities related to equity accounted investments was USD 19 million in 2017, USD 1,370 million in 2016 and USD 46 million in 2015.

Results of operation for oil and gas producing activities
As required by Topic 932, the revenues and expenses included in the following table reflect only those relating to the oil and gas producing operations of Statoil.

The result of operations for oil and gas producing activities contains the two upstream reporting segments Exploration & Production Norway (E&P Norway) and Exploration & Production International (E&P International) as presented in note 3 Segments within the Consolidated financial statements. Production cost is based on operating expenses related to production of oil and gas. From the operating expenses certain expenses such as; transportation costs, accruals for over/underlift position, royalty payments and diluent costs are excluded. These expenses and mainly upstream business administration are included as other expenses in the tables below. Other revenues mainly consist of gains and losses from sales of oil and gas interests and gains and losses from commodity based derivatives within the upstream segments.

Income tax expense is calculated on the basis of statutory tax rates adjusted for uplift and tax credits. No deductions are made for interest or other elements not included in the table below.

Consolidated companies

(in USD million)	Norway	Eurasia excluding Norway	Africa	US	Americas excluding US	Total
Full year 2017						
Sales	47	236	1,373	217	0	1,873
Transfers	17,578	518	3,345	2,375	944	24,759
Other revenues	(62)	53	3	186	(15)	164
Total revenues	17,563	806	4,721	2,778	928	26,796
Exploration expenses	(379)	(236)	(143)	25	(327)	(1,059)
Production costs	(2,213)	(157)	(523)	(457)	(259)	(3,610)
Depreciation, amortisation and net impairment losses	(3,874)	(426)	(1,910)	(1,664)	(423)	(8,297)
Other expenses	(742)	(123)	(18)	(680)	(594)	(2,156)
Total costs	(7,207)	(941)	(2,595)	(2,776)	(1,603)	(15,122)
Results of operations before tax	10,356	(135)	2,126	3	(675)	11,674
Tax expense	(7,479)	179	(741)	1	(15)	(8,056)
Results of operations	2,877	44	1,385	3	(690)	3,619
Net income/(loss) from equity accounted investments	129	13	0	10	0	151

Consolidated companies

(in USD million)	Norway	Eurasia excluding Norway	Africa	US	Americas excluding US	Total
Full year 2016						
Sales	57	161	305	241	(15)	749
Transfers	12,962	494	2,803	1,580	886	18,725
Other revenues	136	30	6	259	7	438
Total revenues	13,155	685	3,114	2,080	878	19,912
Exploration expenses	(383)	(274)	(284)	(1,209)	(803)	(2,952)
Production costs	(2,129)	(148)	(629)	(330)	(333)	(3,569)
Depreciation, amortisation and net impairment losses	(5,698)	(130)	(2,181)	(2,354)	(845)	(11,208)
Other expenses	(417)	(81)	(89)	(906)	(415)	(1,908)
Total costs	(8,627)	(633)	(3,183)	(4,799)	(2,395)	(19,637)
Results of operations before tax	4,528	52	(69)	(2,719)	(1,517)	275
Tax expense	(2,760)	272	(123)	0	(26)	(2,636)
Results of operations	1,768	324	(192)	(2,719)	(1,543)	(2,361)
Net income/(loss) from equity accounted investments	(78)	(86)	0	11	(25)	(178)

Consolidated companies

(in USD million)	Norway	Eurasia excluding Norway	Africa	US	Americas excluding US	Total
Full year 2015						
Sales	50	257	(41)	204	(5)	464
Transfers	17,429	480	3,454	1,532	1,232	24,127
Other revenues	(143)	1,169	3	3	5	1,036
Total revenues	17,336	1,906	3,416	1,738	1,231	25,627
Exploration expenses	(576)	(190)	(630)	(2,114)	(362)	(3,872)
Production costs	(2,629)	(160)	(671)	(450)	(345)	(4,254)
Depreciation, amortisation and net impairment losses	(6,379)	(799)	(2,487)	(6,236)	(710)	(16,611)
Other expenses	(594)	(165)	(237)	(788)	(587)	(2,370)
Total costs	(10,178)	(1,314)	(4,025)	(9,587)	(2,003)	(27,107)
Results of operations before tax	7,157	593	(609)	(7,850)	(772)	(1,481)
Tax expense	(4,824)	238	(717)	(0)	(21)	(5,324)
Results of operations	2,333	831	(1,326)	(7,850)	(793)	(6,805)
Net income/(loss) from equity accounted investments	3	32	0	0	(123)	(88)

Average production cost in USD per boe based on entitlement volumes (consolidated)	Norway	Eurasia excluding Norway	Africa	US	Americas excluding US	Total
2017	5	9	6	5	12	5
2016	5	8	7	4	13	5
2015	6	10	8	6	13	6

Production cost per boe is calculated as the production costs in the result of operations table, divided by the produced entitlement volumes (mboe) for the corresponding period.

Standardised measure of discounted future net cash flows relating to proved oil and gas reserves

The table below shows the standardised measure of future net cash flows relating to proved reserves. The analysis is computed in accordance with Topic 932, by applying average market prices as defined by the SEC, year end costs, year end statutory tax rates and a discount factor of 10% to year end quantities of net proved reserves. The standardised measure of discounted future net cash flows is a forward-looking statement.

Future price changes are limited to those provided by existing contractual arrangements at the end of each reporting year. Future development and production costs are those estimated future expenditures necessary to develop and produce year-end estimated proved reserves based on year-end cost indices, assuming continuation of year-end economic conditions. Pre-tax future net cash flow is net of decommissioning and removal costs. Estimated future income taxes are calculated by applying the appropriate year-end statutory tax rates. These rates reflect allowable deductions and tax credits and are applied to estimated future pretax net cash flows, less the tax basis of related assets. Discounted future net cash flows are calculated using a discount rate of 10% per year. Discounting requires a year-by-year estimate of when future expenditures will be incurred and when reserves will be produced. The standardised measure of discounted future net cash flows prescribed under Topic 932 requires assumptions as to the timing and amount of future development and production costs and income from the production of proved reserves. The information does not represent management's estimate or Statoil's expected future cash flows or the value of its proved reserves and therefore should not be relied upon as an indication of Statoil's future cash flow or value of its proved reserves.

(in USD million)	Norway	Eurasia excluding Norway	Africa	US	Americas excluding US	Total
At 31 December 2017						
Consolidated companies						
Future net cash inflows	150,953	6,144	11,504	24,085	10,301	202,987
Future development costs	(15,642)	(1,992)	(594)	(2,020)	(2,499)	(22,747)
Future production costs	(49,229)	(2,792)	(5,240)	(10,342)	(6,564)	(74,167)
Future income tax expenses	(58,774)	(288)	(1,456)	(3,962)	(333)	(64,813)
Future net cash flows	27,307	1,072	4,215	7,761	904	41,259
10% annual discount for estimated timing of cash flows	(10,152)	(315)	(874)	(2,925)	(331)	(14,596)
Standardised measure of discounted future net cash flows	17,155	757	3,341	4,836	573	26,663
Equity accounted investments						
Standardised measure of discounted future net cash flows	333	-	-	-	-	333
Total standardised measure of discounted future net cash flows including equity accounted investments	17,488	757	3,341	4,836	573	26,995

(in USD million)	Norway	Eurasia excluding Norway	Africa	US	Americas excluding US	Total
At 31 December 2016						
Consolidated companies						
Future net cash inflows	120,355	4,032	10,644	14,452	5,582	155,065
Future development costs	(14,572)	(927)	(733)	(2,574)	(985)	(19,791)
Future production costs	(45,357)	(2,101)	(4,909)	(7,837)	(3,864)	(64,069)
Future income tax expenses	(36,268)	(127)	(1,492)	(1,287)	(68)	(39,243)
Future net cash flows	24,158	876	3,510	2,754	664	31,962
10% annual discount for estimated timing of cash flows	(8,729)	(241)	(646)	(1,019)	(236)	(10,870)
Standardised measure of discounted future net cash flows	15,429	635	2,864	1,735	429	21,092
Equity accounted investments						
Standardised measure of discounted future net cash flows	279	-	-	-	127	406
Total standardised measure of discounted future net cash flows including equity accounted investments	15,708	635	2,864	1,735	555	21,498

(in USD million)	Norway	Eurasia excluding Norway	Africa	US	Americas excluding US	Total
At 31 December 2015						
Consolidated companies						
Future net cash inflows	160,277	5,455	17,073	15,542	8,053	206,399
Future development costs	(19,409)	(1,345)	(1,330)	(3,362)	(1,796)	(27,242)
Future production costs	(54,911)	(2,765)	(6,832)	(7,844)	(4,919)	(77,271)
Future income tax expenses	(56,680)	(118)	(3,149)	(632)	(167)	(60,747)
Future net cash flows	29,276	1,226	5,762	3,704	1,171	41,139
10% annual discount for estimated timing of cash flows	(12,011)	(406)	(1,386)	(1,688)	(281)	(15,773)
Standardised measure of discounted future net cash flows	17,264	820	4,375	2,016	890	25,366
Equity accounted investments						
Standardised measure of discounted future net cash flows	-	-	-	-	140	140
Total standardised measure of discounted future net cash flows including equity accounted investments	17,264	820	4,375	2,016	1,030	25,506

Changes in the standardised measure of discounted future net cash flows from proved reserves

(in USD million)	2017	2016	2015
Consolidated companies			
Standardised measure at beginning of year	21,092	25,366	46,270
Net change in sales and transfer prices and in production (lifting) costs related to future production	22,640	(21,148)	(71,817)
Changes in estimated future development costs	(5,572)	(16)	6,739
Sales and transfers of oil and gas produced during the period, net of production cost	(22,446)	(16,824)	(20,803)
Net change due to extensions, discoveries, and improved recovery	3,836	1,099	3,745
Net change due to purchases and sales of minerals in place	(167)	(566)	(1,026)
Net change due to revisions in quantity estimates	10,798	8,163	7,491
Previously estimated development costs incurred during the period	7,597	7,998	10,474
Accretion of discount	4,415	5,949	11,335
Net change in income taxes	(15,530)	11,070	32,958
Total change in the standardised measure during the year	5,571	(4,274)	(20,904)
Standardised measure at end of year	26,663	21,092	25,366
Equity accounted investments			
Standardised measure at end of year	333	406	140
Standardised measure at end of year including equity accounted investments	26,995	21,498	25,506

In the table above, each line item presents the sources of changes in the standardised measure value on a discounted basis, with the accretion of discount line item reflecting the increase in the net discounted value of the proved oil and gas reserves due to the fact that the future cash flows are now one year closer in time.

The standardised measure at the beginning of the year represents the discounted net present value after deductions of both future development costs, production costs and taxes. The 'Net change in sales and transfer prices and in production (lifting) costs related to future production' is, on the other hand, related to the future net cash flows at 31 December 2016. The proved reserves at 31 December 2016 were multiplied by the actual change in price, and change in unit of production costs, to arrive at the net effect of changes in price and production costs. Development costs and taxes are reflected in the line items 'Change in estimated future development costs' and 'Net change in income taxes' and are not included in the 'Net change in sales and transfer prices and in production (lifting) costs related to future production'.

4.3 Parent company financial statements

STATEMENT OF INCOME STATOIL ASA

(in USD million)	Note	Full year 2017	2016
Revenues	3	39,748	31,554
Net income/(loss) from subsidiaries and other equity accounted companies	10	5,051	(2,726)
Other income	10	2	26
Total revenues and other income		44,801	28,854
Purchases [net of inventory variation]		(37,201)	(29,463)
Operating expenses		(1,971)	(1,913)
Selling, general and administrative expenses		(239)	(216)
Depreciation, amortisation and net impairment losses	9	(88)	(97)
Exploration expenses		(71)	(95)
Net operating income/(loss)		5,231	(2,930)
Net financial items	7	312	728
Income/(loss) before tax		5,543	(2,202)
Income tax	8	(229)	(407)
Net income/(loss)		5,314	(2,608)

STATEMENT OF COMPREHENSIVE INCOME

(in USD million)	Note	Full year 2017	2016
Net income/(loss)		5,314	(2,608)
Actuarial gains (losses) on defined benefit pension plans	17	172	(503)
Income tax effect on income and expense recognised in OCI[1)]		(38)	129
Items that will not be reclassified to the Statement of income		134	(374)
Currency translation adjustments		978	(304)
Net gains/(losses) from available for sale financial assets		(64)	0
Share of OCI from equity accounted investments		(40)	0
Items that may subsequently be reclassified to the Statement of income		874	(304)
Other comprehensive income/(loss)		1,009	(677)
Total comprehensive income/(loss)		6,323	(3,286)
Attributable to the equity holders of the company		6,323	(3,286)

1) OCI = Other Comprehensive Income

BALANCE SHEET STATOIL ASA

(in USD million)	Note	At 31 December 2017	2016
ASSETS			
Property, plant and equipment	9	541	571
Intangible assets		0	5
Investments in subsidiaries and other equity accounted companies	10	42,683	39,886
Deferred tax assets	8	711	846
Pension assets	17	1,236	787
Derivative financial instruments	2	1,387	994
Prepayments and financial receivables		516	585
Receivables from subsidiaries and other equity accounted companies	11	25,896	23,644
Total non-current assets		72,972	67,318
Inventories	12	2,417	2,150
Trade and other receivables	13	5,939	4,760
Receivables from subsidiaries and other equity accounted companies	11	2,448	4,305
Derivative financial instruments	2	115	413
Financial investments	11	7,694	7,393
Cash and cash equivalents	14	3,759	4,274
Total current assets		22,372	23,295
Total assets		95,344	90,613

BALANCE SHEET STATOIL ASA

(in USD million)	Note	At 31 December 2017	2016
EQUITY AND LIABILITIES			
Share capital		1,180	1,156
Additional paid-in capital		4,696	3,363
Reserves for valuation variances		5,445	631
Reserves for unrealised gains		748	779
Retained earnings		26,719	28,130
Total equity	15	38,788	34,059
Finance debt	16	24,059	27,883
Liabilities to subsidiaries and other equity accounted companies		19	17
Pension liabilities	17	3,888	3,366
Provisions	18	224	289
Derivative financial instruments	2	900	1,420
Total non-current liabilities		29,090	32,974
Trade, other payables and provisions	19	4,118	2,893
Current tax payable	8	46	(0)
Finance debt	16	3,968	3,661
Dividends payable	15	1,494	1,426
Liabilities to subsidiaries and other equity accounted companies	11	17,459	15,109
Derivative financial instruments	2	380	491
Total current liabilities		27,467	23,580
Total liabilities		56,557	56,554
Total equity and liabilities		95,344	90,613

STATEMENT OF CASH FLOWS STATOIL ASA

(in USD million)	Note	Full year 2017	2016
Income/(loss) before tax		5,543	(2,202)
Depreciation, amortisation and net impairment losses	9	88	97
(Gains) losses on foreign currency transactions and balances		(619)	(471)
(Gains) losses on sales of assets and businesses		13	(1)
(Increase) decrease in other items related to operating activities		(4,289)	5,932
(Increase) decrease in net derivative financial instruments	2	(395)	417
Interest received		1,003	865
Interest paid		(1,196)	(964)
Cash flows provided by operating activities before taxes paid and working capital items		148	3,674
Taxes paid		(24)	5
(Increase) decrease in working capital		(216)	(976)
Cash flows provided by (used in) operating activities		(92)	2,703
Capital expenditures and investments	9	(1,312)	(1,513)
(Increase) decrease in financial investments		485	987
(Increase) decrease in other items interest bearing		170	(11,785)
Proceeds from sale of assets and businesses and capital contribution received		4,315	9,800
Cash flows provided by (used in) investing activities		3,658	(2,511)
New finance debt		0	1,322
Repayment of finance debt		(4,769)	(1,065)
Dividend paid	15	(1,491)	(1,876)
Net current finance debt and other		343	(268)
Increase (decrease) in financial receivables and payables to/from subsidiaries		1,458	(1,422)
Cash flows provided by (used in) financing activities		(4,459)	(3,308)
Net increase (decrease) in cash and cash equivalents		(892)	(3,116)
Effect of exchange rate changes on cash and cash equivalents		377	(81)
Cash and cash equivalents at the beginning of the period	14	4,274	7,471
Cash and cash equivalents at the end of the period	14	3,759	4,274

Notes to the Financial statements Statoil ASA

1 Significant accounting policies and basis of presentation

Statoil ASA is the parent company of the Statoil Group (Statoil), consisting of Statoil ASA and its subsidiaries. Statoil ASA's main activities includes shareholding in group companies, group management, corporate functions and group financing. Statoil ASA also carries out activities related to external sales of oil and gas products, purchased externally or from group companies, including related refinery and transportation activities. Reference is made to disclosure note 1 Organisation and basis of presentation in Statoil's Consolidated financial statements.

The financial statements of Statoil ASA ("the company") are prepared in accordance with simplified IFRS pursuant to the Norwegian Accounting Act §3-9 and regulations regarding simplified application of IFRS issued by the Norwegian Ministry of Finance on 3 November 2014. The presentation currency of Statoil ASA is US dollar (USD), consistent with the presentation currency for the group financial statements and with the company's functional currency.

These parent company financial statements should be read in connection with the Consolidated financial statements of Statoil, published together with these financial statements. With the exceptions described below, Statoil ASA applies the accounting policies of the group, as described in Statoil's disclosure note 2 Significant Accounting Policies, and reference is made to the Statoil note for further details. Insofar that the company applies policies that are not described in the Statoil note due to group level materiality considerations, such policies are included below if necessary for a sufficient understanding of Statoil ASA's accounts.

Subsidiaries, associated companies and joint ventures
Shareholdings and interests in subsidiaries, associated companies (companies in which the company does not have control, or joint control, but has the ability to exercise significant influence over operating and financial policies, generally when the ownership share is between 20% and 50%) and joint ventures are accounted for using the equity method. The company applies the equity method on the basis of the respective entities' financial reporting prepared in compliance with the Statoil group's IFRS accounting principles. Reserves for valuation variances included within the company's equity are established based on the sum of contributions from each individual equity accounted investment, with the limitation that the net amount cannot be negative. Goodwill included in the balance sheets of subsidiaries and associated companies is tested for impairment as part of the related investment in the subsidiary or associated company. Any related impairment expense is included in the company's statement of income under Net income/(loss) from subsidiaries and other equity accounted companies.

Expenses related to the Statoil group as operator of joint operations and similar arrangements (licences)
Indirect operating expenses incurred by the company, such as personnel expenses, are accumulated in cost pools. Such expenses are allocated in part on an hours incurred cost basis to Statoil Petroleum AS, to other group companies and to licences where Statoil Petroleum AS or other group companies are operators. Costs allocated in this manner reduce the expenses in the company's statement of income.

Asset transfers between the company and its subsidiaries
Transfers of assets and liabilities between the company and the entities that it directly or indirectly controls are accounted for at the carrying amounts (continuity) of the assets and liabilities transferred, when the transfer is part of a reorganisation within the Statoil group.

Dividends payable and group contributions
Dividends are reflected as Dividends payable within current liabilities. Group contributions for the year to other entities within Statoil's Norwegian tax group are reflected in the balance sheet as current liabilities within Liabilities to group companies. Under simplified IFRS the presentation of dividends payable and payable group contributions differs from the presentation under IFRS, as it also includes dividends and group contributions payable which at the date of the balance sheet is subject to a future general assembly approval before distribution.

Reserves for unrealised gains
Reserves for unrealised gains included within the Company's equity consists of accumulated unrealised gains on non-exchange traded financial instruments and the fair value of embedded derivatives, with the limitation that the net amount cannot be negative.

2 Financial risk management and measurement of financial instruments

General information relevant to financial risks
Statoil ASA's activities expose the company to market risk, liquidity risk and credit risk, and the management of such risks do not substantially differ from the Group's. See note 5 Financial risk management in the Consolidated financial statements.

Measurement of financial instruments by categories
The following tables present Statoil ASA's classes of financial instruments and their carrying amounts by the categories as they are defined in IAS 39 Financial Instruments: Recognition and Measurement. All financial instruments' carrying amounts are measured at fair value or their carrying amounts reasonably approximate fair value except non-current financial liabilities. See note 18 Finance debt for fair value information of non-current bonds, bank loans and finance lease liabilities and note 25 Financial instruments fair value measurement and sensitivity analysis of market risk in the Consolidated financial statements where fair value measurement is explained in detail.

See note 2 Significant accounting policies in the Consolidated financial statements for further information regarding measurement of fair values.

			Fair value through profit or loss		
(in USD million)	Note	Loans and receivables	Held for trading	Non-financial assets	Total carrying amount
At 31 December 2017					
Assets					
Non-current derivative financial instruments		-	1,387	-	1,387
Prepayments and financial receivables		457	-	60	516
Receivables from subsidiaries and other equity accounted companies	11	25,725	-	171	25,896
Trade and other receivables	13	5,813	-	126	5,939
Receivables from subsidiaries and other equity accounted companies	11	2,448	-	-	2,448
Current derivative financial instruments		-	115	-	115
Current financial investments	11	4,045	3,649	-	7,694
Cash and cash equivalents	14	2,301	1,458	-	3,759
Total		40,788	6,609	357	47,754

			Fair value through profit or loss		
(in USD million)	Note	Loans and receivables	Held for trading	Non-financial assets	Total carrying amount
At 31 December 2016					
Assets					
Non-current derivative financial instruments		-	994	-	994
Prepayments and financial receivables		384	-	201	585
Receivables from subsidiaries and other equity accounted companies	11	23,644	-	-	23,644
Trade and other receivables	13	4,614	-	146	4,760
Receivables from subsidiaries and other equity accounted companies	11	4,305	-	-	4,305
Current derivative financial instruments		-	413	-	413
Current financial investments	11	3,217	4,176	-	7,393
Cash and cash equivalents	14	1,989	2,285	-	4,274
Total		38,153	7,868	347	46,368

(in USD million)	Note	Amortised cost	Fair value through profit or loss	Non-financial liabilities	Total carrying amount
At 31 December 2017					
Liabilities					
Non-current finance debt	16	24,059	-	-	24,059
Liabilities to subsidiaries and other equity accounted companies		19	-	-	19
Non-current derivative financial instruments		-	900	-	900
Trade and other payables	19	4,016	-	103	4,118
Current finance debt	16	3,968	-	-	3,968
Dividend payable		1,494	-	-	1,494
Liabilities to subsidiaries and other equity accounted companies	11	17,459	-	-	17,459
Current derivative financial instruments		-	380	-	380
Total		51,017	1,279	103	52,399

(in USD million)	Note	Amortised cost	Fair value through profit or loss	Non-financial liabilities	Total carrying amount
At 31 December 2016					
Liabilities					
Non-current finance debt	16	27,883	-	-	27,883
Liabilities to subsidiaries and other equity accounted companies		17	-	-	17
Non-current derivative financial instruments		-	1,420	-	1,420
Trade and other payables	19	2,790	-	103	2,893
Current finance debt	16	3,661	-	-	3,661
Dividend payable		1,426	-	-	1,426
Liabilities to subsidiaries and other equity accounted companies	11	15,109	-	-	15,109
Current derivative financial instruments		-	491	-	491
Total		50,886	1,911	103	52,900

Financial instruments from tables above which are recognised in the balance sheet at a net fair value of USD 5,330 million in 2017 and USD 5,957 million in 2016, are mainly determined by Level 2 category in the Fair Value hierarchy.

The following table contains the estimated fair values of Statoil ASA's derivative financial instruments split by type.

(in USD million)	Fair value of assets	Fair value of liabilities	Net fair value
At 31 December 2017			
Foreign currency instruments	54	(73)	(19)
Interest rate instruments	1,327	(900)	427
Crude oil and refined products	38	(30)	8
Natural gas and electricity	84	(277)	(193)
Total	1,502	(1,279)	223
At 31 December 2016			
Foreign currency instruments	365	(28)	337
Interest rate instruments	987	(1,417)	(430)
Crude oil and refined products	13	(39)	(26)
Natural gas and electricity	41	(426)	(385)
Total	1,407	(1,911)	(504)

Sensitivity analysis of market risk

Commodity price risk
Statoil ASA's assets and liabilities resulting from commodity based derivatives contracts consist of both exchange traded and non-exchange traded instruments mainly in crude oil and refined products.

Price risk sensitivities at the end of 2017 at 20%, and at the end of 2016 at 30%, are assumed to represent a reasonably likely change based on the duration of the derivatives.

	2017		2016	
(in USD million)	- 20% sensitivity	20% sensitivity	- 30% sensitivity	30% sensitivity
At 31 December				
Crude oil and refined products net gains (losses)	494	(480)	650	(644)
Natural gas and electricity net gains (losses)	77	(77)	57	(57)

Currency risk

The estimated gains and the estimated losses following from a change in the foreign exchange rates would impact the company's statement of income.

Currency risk sensitivity for Statoil ASA mainly differ from currency risk sensitivity in Group due to interesting bearing receivables from subsidiaries. For more detailed information about these receivables see note 11 Financial assets and liabilities.

	2017		2016	
(in USD million)	-8% sensitivity	8% sensitivity	- 12% sensitivity	12% sensitivity
At 31 December				
NOK net gains (losses)	(1,264)	1,264	(1,691)	1,691

Interest rate risk

The estimated gains following from a decrease in the interest rates and the estimated losses following from an interest rate increase would impact the company's statement of income.

	2017		2016	
(in USD million)	- 0.6 percentage points sensitivity	0.6 percentage points sensitivity	- 0.8 percentage points sensitivity	0.8 percentage points sensitivity
At 31 December				
Interest rate net gains (losses)	620	(620)	817	(817)

3 Revenues

	Full year	
(in USD million)	2017	2016
Revenues third party	35,083	28,333
Intercompany revenues	4,665	3,221
Revenues	39,748	31,554

4 Remuneration

Statoil ASA remuneration in 2017

(in USD million, except average number of employees)	Full year 2017	2016
Salaries[1)]	2,198	2,163
Pension cost	439	631
Social security tax	318	336
Other compensations	253	240
Total	3,208	3,370
Average number of employees[2)]	18,100	18,800

1) Salaries include bonuses, severance packages and expatriate costs in addition to base pay.
2) Part time employees amount to 3% for 2017 and 2016 respectively.

Total payroll expenses are accumulated in cost-pools and charged to partners of Statoil operated licences and group companies on an hours incurred basis. For further information see note 22 Related parties.

Compensation to and share ownership of the corporate assembly, the board of directors (BoD) and the corporate executive committee (CEC)
Compensation to the corporate assembly was USD 129,552 and the total share ownership of the members of the corporate assembly was 30,839 shares. Remuneration to members of the BoD and the CEC during the year and share ownership at the end of the year were as follows:

Members of the board (figures in USD thousand except number of shares)	Total remuneration	Share ownership as of 31 December 2017
Jon Erik Reinhardsen (chair of the board)[1)]	37	2,558
Øystein Løseth (chair of the board)[2)]	52	n.a.
Roy Franklin (deputy chair of the board)[3)]	118	-
Wenche Agerup	67	2,650
Bjørn Tore Godal	67	-
Rebekka Glasser Herlofsen	63	-
Maria Johanna Oudeman	89	-
Jeroen van der Veer	88	-
Per Martin Labråthen[4)]	33	1,343
Lill-Heidi Bakkerud[5)]	25	n.a.
Stig Lægreid	57	1,975
Ingrid Elisabeth di Valerio	63	4,471
Total	760	12,997

1) Chair from September 1, 2017
2) Chair until June 30, 2017 (resigned)
3) Chair between July 1 and August 31, 2017
4) Member from June 8, 2017
5) Member until June 7, 2017 (resigned)

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Members of the corporate executive committee (figures in USD thousand, except no. of shares)[1), 2)]	Fixed remuneration Fixed pay[3)]	Cash allowance[4)]	LTI [5)]	Annual variable pay[6)]	Taxable benefits	2017 Taxable compensation	Non-taxable benefits in kind	Estimated pension cost[7)]	Estimated present value of pension obligation[8)]	2016 Taxable compensation[9)]	Share ownership at 31 December 2017
Eldar Sætre[10)]	1,045	0	149	570	48	1,812	0	0	14,489	1,356	56,896
Margareth Øvrum	494	0	54	253	36	837	24	0	6,912	631	56,125
Timothy Dodson	466	0	52	140	31	689	46	152	4,977	573	34,425
Irene Rummelhoff	381	62	38	154	22	657	0	29	1,404	511	25,081
Jens Økland	396	65	41	145	20	667	0	24	1,067	509	17,207
Arne Sigve Nylund	429	0	50	218	23	720	0	120	4,314	546	13,354
Lars Christian Bacher	447	0	46	193	24	710	58	128	2,733	567	23,309
Hans Jakob Hegge	398	66	44	170	25	703	0	25	1,493	561	32,104
Jannicke Nilsson	401	63	42	147	25	678	24	36	1,315	40	38,491
Torgrim Reitan[11)]	696	0	50	169	143	1,058	0	121	2,712	884	36,235
John Knight[12)]	1,643	0	0	0	181	1,824	0	0	0	1,810	109,901

1) All figures in the table are presented in USD based on average currency rates (2017: USD/NOK = 8.2630, USD/GBP = 1.2882. 2016: USD/NOK = 8.3987, USD/GBP = 1.3538). The figures are presented on accrual basis.
2) All CEC members receive their remuneration in NOK except John Knight who receives the remuneration in GBP.
3) Fixed pay consists of base salary, fixed remuneration element, holiday allowance and other administrative benefits.
4) Cash allowance in lieu of pension accrual above 12 G (G is the base amount in the national insurance scheme).
5) The long-term incentive (LTI) element implies an obligation to invest the net amount in Statoil shares, including a lock-in period. The LTI element is presented the year it is granted for the members of the corporate executive committee employed by Statoil ASA.
6) Annual variable pay includes holiday allowance for corporate executive committee (CEC) members resident in Norway.
7) Estimated pension cost is calculated based on actuarial assumptions and pensionable salary (mainly base salary) at 31 December 2016 and is recognised as pension cost in the statement of income for 2017.
8) Eldar Sætre, Arne Sigve Nylund, Margareth Øvrum and Timothy Dodson are maintained in the closed Defined Benefit Scheme, whereas the remaining members of corporate executive committee employed by Statoil ASA, is covered by the Defined Contribution Pension Scheme.
9) Includes 2016 CEC members who are also CEC members in 2017.
10) Estimated present value of pension obligation for Eldar Sætre is based on retirement at the age of 67. Eldar Sætre has the right to retire at an earlier stage.
11) Terms and conditions for Torgrim Reitan also include compensation according to Statoil's international assignment terms.
12) John Knight's fixed pay includes a fixed remuneration element of USD 143,000 that replaces his defined contribution pension plan and a fixed remuneration element of USD 689,000 replacing his variable pay arrangements.

There are no loans from the company to members of the corporate executive committee.

Remuneration policy and concept

The main elements of Statoil's executive remuneration are described in chapter 3 Governance, section 3.12 Remuneration to the corporate executive committee in this report. Reference is made to the section on Declaration on remuneration and other employment terms for Statoil's Corporate Executive committee for a detailed description of the remuneration and remuneration policy for executive management applicable for the years 2017 and 2018.

5 Share-based compensation

Statoil's share saving plan provides employees with the opportunity to purchase Statoil shares through monthly salary deductions. If the shares are kept for two full calendar years of continued employment, following the year of purchase, the employees will be allocated one bonus share for each one they have purchased.

Estimated compensation expense including the contribution by Statoil ASA for purchased shares, amounts vested for bonus shares granted and related social security tax was USD 55 million in 2017 and USD 54 million in 2016. For the 2018 programme (granted in 2017) the estimated compensation expense is USD 65 million. At 31 December 2017 the amount of compensation cost yet to be expensed throughout the vesting period is USD 128 million.

6 Auditor's remuneration

	Full year	
(in USD million, excluding VAT)	2017	2016
Audit fee	1.4	1.3
Audit related fee	0.4	0.3
Total	1.8	1.7

There are no fees incurred related to other services or to tax services.

7 Financial items

	Full year	
(in USD million)	2017	2016
Foreign exchange gains (losses) derivative financial instruments	(920)	353
Other foreign exchange gains (losses)	1,538	(59)
Net foreign exchange gains (losses)	618	294
Interest income from group companies	798	682
Interest income current financial assets and other financial items	227	298
Interest income and other financial items	1,025	981
Gains (losses) derivative financial instruments	(61)	470
Interest expense to group companies	(142)	(163)
Interest expense non-current finance debt	(1,023)	(850)
Interest expense current financial liabilities and other finance expense	(104)	(3)
Interest and other finance expenses	(1,269)	(1,016)
Net financial items	312	728

Statoil's main financial items relate to assets and liabilities categorised in the held for trading category and the amortised cost category. For more information about financial instruments by category see note 25 Financial instruments: fair value measurement and sensitivity analysis of market risk in the Consolidated financial statements.

The line item interest expense non-current finance debt primarily includes interest expenses of USD 1,103 million and USD 1,039 million for 2017 and 2016, respectively, from the financial liabilities at amortised cost category. This was partially offset by net interest income on related derivatives from the held for trading category, USD 80 million and USD 188 million for 2017 and 2016, respectively.

The line item gains (losses) derivative financial instruments primarily includes fair value loss from the held for trading category of USD 77 million and a gain of USD 454 million for 2017 and 2016, respectively.

Foreign exchange gains (losses) derivative financial instruments include fair value changes of currency derivatives related to liquidity and currency risk. The line item foreign exchange gains (losses) includes a net foreign exchange gain of USD 447 million and a loss of USD 289 million from the held for trading category for 2017 and 2016, respectively.

8 Income taxes

Income tax

(in USD million)	Full year 2017	2016
Current taxes	(134)	92
Change in deferred tax	(95)	(499)
Income tax	(229)	(407)

Reconciliation of Norwegian statutory tax rate to effective tax rate

(in USD million)	2017	Full year 2016
Income/(loss) before tax	5,543	(2,202)
Nominal tax rate in 2017 (24%) and in 2016 (25%)	(1,330)	550
Tax effect of:		
Permanent differences caused by NOK being the tax currency	(35)	(198)
Tax effect of permanent differences related to equity accounted companies	1,204	(671)
Other permanent differences	(87)	(81)
Income tax prior years	(25)	(21)
Change in tax regulations - reduction of nominal tax rate from 24% in 2017 to 23% in 2018	(31)	10
Other	75	4
Total	(229)	(407)
Effective tax rate	4.1%	(18.5%)

Change in tax regulations refers to change in deferred taxes caused by a reduction in Norwegian statutory tax rate from 24% to 23% effective from 2018.

Significant components of deferred tax assets and liabilities were as follows:

(in USD million)	At 31 December 2017	2016
Deferred tax - assets		
Other current items	0	5
Tax losses carry forward	0	22
Pensions	626	627
Long term provisions	73	75
Derivatives	30	122
Other non-current items	47	59
Total deferred tax assets	776	911
Deferred tax - liabilities		
Other current items	14	0
Property, plant and equipment	51	65
Total deferred tax liabilities	65	65
Net deferred tax assets	711	846

At 31 December 2017, Statoil ASA had recognised net deferred tax assets of USD 711 million, as it is considered probable that taxable profit will be available to utilise the deferred tax assets.

Overview showing significant components of deferred tax assets and liabilities at 31 December 2016 is reallocated compared with disclosure for 2016. 38 million USD is reallocated from derivatives and long term debt to other non-current items, 6 million of inventory is reallocated other non-current items and at last a review of long term provisions has resulted in reallocation of 5 million USD to other current items and 25 million USD to other non-current items.

Movement in deferred tax

(in USD million)	2017	2016
Deferred tax assets at 1 January	846	1,183
Charged to the income statement	(95)	(499)
Actuarial losses pension	(44)	126
Group Contribution	4	32
Other	0	4
Deferred tax assets at 31 December	711	846

9 Property, plant and equipment

(in USD million)	Machinery, equipment and transportation equipment	Buildings and land	Vessels	Other	Total
Cost at 31 December 2016	596	273	647	160	1,677
Additions and transfers	40	29	0	0	68
Disposals at cost	(1)	(39)	0	0	(40)
Cost at 31 December 2017	634	263	647	160	1,705
Accumulated depreciation and impairment losses at 31 December 2016	(516)	(107)	(335)	(147)	(1,106)
Depreciation	(40)	(13)	(34)	(1)	(88)
Accumulated depreciation and impairment disposed assets	1	29	0	0	30
Accumulated depreciation and impairment losses at 31 December 2017	(555)	(92)	(369)	(149)	(1,164)
Carrying amount at 31 December 2017	80	172	278	12	541
Estimated useful lives (years)	3 - 10	20 - 33[1)]	15 - 20		

1) Land is not depreciated

10 Investments in subsidiaries and other equity accounted companies

(in USD million)	2017	2016
Investments at 1 January	39,886	51,330
Net income/(loss) from subsidiaries and other equity accounted companies	5,051	(2,726)
Increase (decrease) in paid-in capital	(1,861)	(8,462)
Acquisitions	0	1,199
Distributions	(1,236)	(1,194)
Net gains/(losses) from available for sale financial assets	(64)	0
Share of OCI from equity accounted investments	(40)	0
Translation adjustments	973	(260)
Other	(27)	(1)
Investments at 31 December	42,683	39,886

Reference is made to note 12 Equity accounted investments in the Consolidated financial statements for more information regarding equity accounted companies.

The closing balance of investments at 31 December of USD 42,683 million consists of investments in subsidiaries amounting to USD 41,448 million and investments in other equity accounted companies amounting to USD 1,235 million. In 2016, the amounts were USD 38,660 million and USD 1,226 million respectively.

The foreign currency translation adjustments relate to currency translation effects from subsidiaries with functional currencies other than USD.

In 2017 net income/(loss) from subsidiaries and other equity accounted companies was impacted by net impairment reversal related to property, plant and equipment and exploration assets of USD 447 million after tax. The net impairment reversal is a result of increased production estimates, cost reductions, increased prices and operational improvements in addition to change in US tax legislation. For more information see the Consolidated financial statements note 9 Property, plant and equipment. In 2016 net income/(loss) from subsidiaries and other equity accounted companies was impacted by net impairment losses related to property, plant and equipment and exploration assets of USD 1,678 million after tax, primarily resulting from reduced short term commodity price assumptions.

Increase (decrease) in paid-in capital in 2017 mainly consist of repayment of capital from Statoil Coordination Centre of USD 3,303 million, and group contributions related to 2017 to group companies of USD 278 million after tax.

Distributions during 2017 mainly consist of dividends related to 2016 from group companies of USD 1,236 million. In 2016 distributions mainly consisted of dividends and group contributions related to 2015 from group companies of USD 1,194 million.

In January 2016 Statoil ASA acquired 11.93% of the issued share capital and votes in Lundin Petroleum AB for a total purchase price of SEK 4.6 billion (USD 541 million). In June 2016 Statoil ASA increased ownership share in Lundin Petroleum AB till 68.4 million shares of Lundin, corresponding to 20.1% of the outstanding shares and votes. The consideration for these additional shares consisted of SEK 544 million (USD 64 million) in cash and the conversion of a previous receivable for the amount of USD 496 million.

Up until the transaction on 30 June 2016, the shares were accounted for as a non-current financial investment at fair value with changes in fair value presented in the line item net gains (losses) from available for sale financial assets in the Statoil ASA statement of comprehensive income. Statoil recognised gain of USD 153 million in the line net financial items in the Statoil ASA statement of income.

For further information, see in the Consolidated Financial Statements of Statoil Group note disclosure 4 Acquisitions and divestments.

The acquisition cost for investments in subsidiaries and other equity accounted companies are USD 37,239 million in 2017 and USD 39,254 million in 2016.

The following table shows significant subsidiaries and equity accounted companies directly held by Statoil ASA as of December 2017

Name	in %	Country of incorporation	Name	in %	Country of incorporation
Statholding AS	100	Norway	Statoil Nigeria AS	100	Norway
Statoil Angola Block 15 AS	100	Norway	Statoil North Africa Gas AS	100	Norway
Statoil Angola Block 17 AS	100	Norway	Statoil North Africa Oil AS	100	Norway
Statoil Angola Block 31 AS	100	Norway	Statoil OTS AB	100	Sweden
Statoil Angola Block 40 AS	100	Norway	Statoil Petroleum AS	100	Norway
Statoil Apsheron AS	100	Norway	Statoil Refining Norway AS	100	Norway
Statoil Azerbaijan AS	100	Norway	Statoil Sincor AS	100	Norway
Statoil BTC Finance AS	100	Norway	Statoil SP Gas AS	100	Norway
Statoil Coordination Centre NV	100	Belgium	Statoil Tanzania AS	100	Norway
Statoil Danmark AS	100	Denmark	Statoil Technology Invest AS	100	Norway
Statoil Deutschland GmbH	100	Germany	Statoil UK Ltd	100	United Kingdom
Statoil do Brasil Ltda	100	Brazil	Statoil Venezuela AS	100	Norway
Statoil Egypt El Dabaa Offshore AS	100	Norway	KS Rafinor AS	90	Norway
Statoil Exploration Ireland Ltd.	100	Ireland	Statoil Metanol ANS	82	Norway
Statoil Forsikring AS	100	Norway	Mongstad Terminal DA	65	Norway
Statoil Færøyene AS	100	Norway	Tjeldbergodden Luftgassfabrikk DA	51	Norway
Statoil Hassi Mouina AS	100	Norway	Naturkraft AS	50	Norway
Statoil Indonesia Karama AS	100	Norway	Vestprosess DA	34	Norway
Statoil Kharyaga AS	100	Norway	Lundin Petroleum AB	20	Sweden
Statoil New Energy AS	100	Norway			

11 Financial assets and liabilities

Non-current receivables from subsidiaries and other equity accounted companies

(in USD million)	At 31 December 2017	2016
Interest bearing receivables from subsidiaries and other equity accounted companies	25,668	23,520
Non-interest bearing receivables from subsidiaries	228	124
Receivables from subsidiaries and other equity accounted companies	25,896	23,644

Interest bearing receivables from subsidiaries and other equity accounted companies are mainly related to Statoil Petroleum AS. The remaining amount on financial receivables interest bearing primarily relate to long term funding of other subsidiaries

The total amount of credit facility given to Statoil Petroleum AS is NOK 120 billion (USD 14,625 million) at 31 December 2017 and NOK 135 billion (USD 15,661 million) at 31 December 2016. In 2017 the full facility is utilised while in 2016, USD 14,501 million was drawn. Of the total interest bearing non-current receivables at 31 December 2017, USD 6,703 million (NOK 55 billion) is due within the next five years, but there is no current portion. Remaining amounts fall due beyond five years.

Of the non-interest-bearing receivables from subsidiaries at 31 December 2017, USD 57 million relates to pensions, see also note 17 Pensions. Correspondingly, USD 79 million related to pension at 31 December 2016.

Current receivables from subsidiaries and other equity accounted companies include a positive internal bank balances of USD 603 million at 31 December 2017. Current receivables from subsidiaries and other equity accounted companies at 31 December 2016 include positive internal bank balances of USD 787 million and current portion of credit facility given to Statoil Petroleum AS of USD 1,740 million.

Current financial investments

(in USD million)	At 31 December 2017	2016
Time deposits	4,045	3,217
Interest bearing securities	3,649	4,176
Financial investments	7,694	7,393

Current Financial investments
The cost price for current financial investments was USD 7.7 billion at 31 December 2017 and USD 7.6 billion at 31 December 2016.

In 2017, interest bearing securities were split in seven currencies, the main being: NOK (35%), SEK (25%), EUR (24%) and USD (11%). Time deposits were mainly in EUR (38%), USD (28%), NOK (16%) and SEK (10%). In 2016, interest bearing securities were split in five currencies: EUR (34%), NOK (19%), USD (18%), SEK (16%) and DKK (12%), while time deposits were mainly in EUR (91%) and the rest in NOK (9%).

For more information about financial instruments by category, see note 25 Financial instruments: fair value measurement and sensitivity analysis of market risk in the Consolidated financial statements.

Current liabilities to subsidiaries and other equity accounted companies
Liabilities to subsidiaries and other equity accounted companies include current liabilities to Statoil Petroleum AS of USD 2.9 billion and liabilities related to Statoil groups' internal bank arrangements of USD 7.4 billion at 31 December 2017. The corresponding amounts were USD 2.2 billion and USD 8.5 billion at 31 December 2016.

12 Inventories

(in USD million)	At 31 December 2017	2016
Crude oil	1,697	1,504
Petroleum products	586	478
Natural gas	108	133
Other	26	36
Inventories	2,417	2,150

The write-down of inventories from cost to net realisable value amounts to an expense of USD 11 million and USD 11 million in 2017 and 2016, respectively.

13 Trade and other receivables

(in USD million)	At 31 December 2017	2016
Trade receivables	5,481	3,755
Other receivables	458	1,004
Trade and other receivables	5,939	4,760

14 Cash and cash equivalents

(in USD million)	At 31 December 2017	2016
Cash at bank available	275	128
Time deposits	1,878	1,658
Money market funds	381	65
Interest bearing securities	1,077	2,220
Margin deposits	149	203
Cash and cash equivalents	3,759	4,274

Restricted cash at 31 December 2017 and 2016 consists of margin deposits including both cash and exchange traded derivative products with daily settlement of USD 149 million and USD 203 million, respectively.

15 Equity and shareholders

Change in equity

(in USD million)	At 31 December 2017	2016
Shareholders' equity at 1 January	34,059	39,277
Net income/(loss)	5,314	(2,608)
Actuarial gain (loss) defined benefit pension plans	134	(374)
Foreign currency translation adjustments	978	(304)
Ordinary dividend	(2,943)	(2,838)
Scrip dividend	1,357	904
Net gains/(losses) from available for sale financial assets	(64)	0
Share of OCI from equity accounted investments	(40)	0
Value of stock compensation plan	(30)	(26)
Treasury shares purchased	22	27
Total equity at 31 December	38,788	34,059

The accumulated foreign currency translation effect as of 31 December 2017 decreased total equity by USD 358 million. At 31 December 2016 the corresponding effect was a decrease in total equity of USD 1,338 million. The foreign currency translation adjustments relate to currency translation effects from the subsidiaries.

Common stock

	Number of shares	NOK per value	At 31 December Common stock
Authorised and issued	3,323,167,853	2.50	8,307,919,632.50
Treasury shares	11,243,234	2.50	28,108,085.00
Total outstanding shares	3,311,924,619	2.50	8,279,811,547.50

There is only one class of shares and all the shares have the same voting rights.

During 2017 a total of 3,323,671 treasury shares were purchased for USD 63 million and 3,219,327 treasury shares were allocated to employees participating in the share saving plan. During 2016 a total of 4,011,860 treasury shares were purchased for USD 62 million and 3,882,153 treasury shares were allocated to employees participating in the share saving plan. At 31 December 2017 Statoil had 11,243,234 treasury shares and at 31 December 2016 11,138,890 treasury shares, all of which are related to Statoil's share saving plan. For further information, see note 5 Share-based compensation.

Statoil's general assembly has authorised the company to acquire Statoil shares in the market. The authorisation may be used to acquire Statoil shares with an overall nominal value of up to NOK 35.0 million. Such shares acquired in accordance with the authorisation may only be used for sale and transfer to employees of the Statoil group as part of the group's share saving plan approved by the board. The minimum and maximum amount that may be paid per share will be NOK 50 and NOK 500, respectively. The authorisation is valid until the next ordinary general meeting. For further details, please see note 17 Shareholder's equity of the Consolidated financial statements.

For information regarding the 20 largest shareholders in Statoil ASA, please see Major Shareholders in section 5.1 Shareholder information.

16 Finance debt

Non-current finance debt

(in USD million)	At 31 December 2017	2016
Unsecured bonds	26,524	29,964
Unsecured loans	89	85
Finance lease liabilities	347	382
Total finance debt	26,959	30,432
Less current portion	2,900	2,549
Non-current finance debt	24,059	27,883
Weighted average interest rate (%)	3.33	3.30

Statoil ASA uses currency swaps to manage foreign exchange risk on its non-current financial liabilities. For information about the Statoil Group and Statoil ASA's interest rate risk management, see note 5 Financial risk management in the Consolidated financial statement and note 2 Financial risk management and measurement of financial instruments in the Statoil ASA financial statement.

Substantially all unsecured bond and unsecured bank loan agreements contain provisions restricting future pledging of assets to secure borrowings without granting a similar secured status to the existing bond holders and lenders.

Out of Statoil ASA total outstanding unsecured bond portfolio, 42 bond agreements contain provisions allowing Statoil to call the debt prior to its final redemption at par or at certain specified premiums if there are changes to the Norwegian tax laws. The carrying amount of these agreements is USD 26.158 billion at the 31 December 2017 closing exchange rate.

Statoil ASA has a revolving credit facility of USD 5.0 billion, supported by 21 core banks, maturing in 2022. The facility supports secure access to funding, supported by the best available short-term rating. As at 31 December 2017 and 2016 it has not been drawn.

Non-current finance debt repayment profile

(in USD million)	
2019	1,397
2020	2,114
2021	1,978
2022	1,052
Thereafter	17,519
Total	24,059

More information regarding finance lease liabilities is provided in note 20 Leases.

Current finance debt

(in USD million)	At 31 December 2017	2016
Collateral liabilities and other current financial liabilities	1,068	1,112
Non-current finance debt due within one year	2,900	2,549
Current finance debt	3,968	3,661
Weighted average interest rate (%)	1.69	1.62

Collateral liabilities and other current financial liabilities relate mainly to cash received as security for a portion of Statoil ASA's credit exposure and outstanding amounts on US Commercial paper (CP) programme. At 31 December 2017 USD 448 million were issued on the CP programme. Corresponding at 31 December 2016 were USD 500 million.

17 Pensions

Statoil ASA is subject to the Mandatory Company Pensions Act, and the company's pension scheme follows the requirements of the Act. Reference is made to the Annual notes in the Consolidated financial statements, for a description of the pension scheme in Statoil ASA.

Net pension cost

(in USD million)	2017	2016
Current service cost	241	234
Interest cost	-	182
Interest (income) on plan asset	-	(137)
Losses (gains) from curtailment, settlement or plan amendment	13	123
Actuarial (gains) losses related to termination benefits	(1)	59
Notional contribution plans	51	50
Defined benefit plans	306	512
Defined contribution plans	133	119
Total net pension cost	439	631

In addition to the pension cost presented in the table above, financial items related to defined benefit plans are included in the statement of income within Net financial items. Interest cost and changes in fair value of notional assets of USD 201 million, and interest income of USD 138 million has been recognised in 2017.

(in USD million)	2017	2016
Defined benefit obligations (DBO)		
Defined benefit obligation at 1 January	7,387	6,425
Current service cost	241	234
Interest cost	210	182
Actuarial (gains) losses - Financial assumptions	(42)	792
Actuarial (gains) losses - Experience	(18)	(274)
Benefits paid	(296)	(228)
Losses (gains) from curtailment, settlement or plan amendment	13	182
Paid-up policies	(84)	(131)
Change in receivable from subsidiary related to termination benefits	26	26
Foreign currency translation	375	130
Changes in notional contribution liability	51	50
Defined benefit obligation at 31 December	7,864	7,387
Fair value of plan assets		
Fair value of plan assets at 1 January	4,889	4,803
Interest income	138	137
Return on plan assets (excluding interest income)	263	11
Company contributions	33	0
Benefits paid	(180)	(74)
Paid-up policies and personal insurance	(121)	(92)
Foreign currency translation	247	104
Fair value of plan assets at 31 December	5,269	4,889
Net pension liability at 31 December	(2,595)	(2,498)
Represented by:		
Asset recognised as non-current pension assets (funded plan)	1,236	787
Asset recognised as non-current receivables from subsidiary	57	79
Liability recognised as non-current pension liabilities (unfunded plans)	(3,889)	(3,364)
DBO specified by funded and unfunded pension plans	7,864	7,387
Funded	4,033	4,102
Unfunded	3,831	3,285
Actual return on assets	401	56

Actuarial losses and gains recognised directly in Other comprehensive income (OCI)

(in USD million)	2017	2016
Net actuarial (losses) gains recognised in OCI during the year	310	(472)
Actuarial (losses) gains related to currency effects on net obligation and foreign exchange translation	(137)	(30)
Tax effects of actuarial (losses) gains recognised in OCI	(38)	129
Recognised directly in OCI during the year net of tax	135	(374)
Cumulative actuarial (losses) gains recognised directly in OCI net of tax	(1,053)	(1,188)

Actuarial assumptions and sensitivity analysis
Actuarial assumptions, sensitivity analysis, portfolio weighting and information about pension assets in Statoil Pension are presented in the Pension note in the Financial statement for Statoil Group. The number of employees, including pensioners related to the main benefit plan in Statoil ASA are 9,202. In addition, all employees are members of the AFP plan and different groups of employees are members of other unfunded plans.

18 Provisions

(in USD million)	Provisions
Non-current portion at 31 December 2016	289
Current portion at 31 December 2016	59
Provisions at 31 December 2016	348
New or increased provisions	60
Decrease in estimate	(9)
Amounts charged against provisions	(68)
Reclassification and transfer	(19)
Currency translation	4
Provisions at 31 December 2017	315
Current portion at 31 December 2017	92
Non-current portion at 31 December 2017	224

See also comments on provisions in note 21 Other commitments, contingent liabilities and contingent assets.

19 Trade, other payables and provisions

	At 31 December	
(in USD million)	2017	2016
Trade payables	1,974	1,388
Non-trade payables, accrued expenses and provisions	1,267	890
Equity accounted associated companies and other related party payables	877	615
Trade, other payables and provisions	4,118	2,893

20 Leases

Statoil ASA leases certain assets, notably vessels and office buildings.

In 2017, net rental expenditures were USD 425 million (USD 464 million in 2016) consisting of minimum lease payments of USD 501 million (USD 533 million in 2016) reduced with sublease payments received of USD 77 million in 2017 (USD 70 million in 2016). Contingent rents expensed were immaterial both years.

The information in the table below shows future minimum lease payments under non-cancellable leases at 31 December 2017. Amounts related to finance leases include future minimum lease payments for assets recognised in the financial statements at year end 2017.

			Finance leases		
(in USD million)	Operating leases	Operating sublease	Minimum lease payments	Discount element	Net present value minimum lease payments
2018	435	(25)	53	(2)	50
2019	325	(24)	53	(4)	48
2020	323	(23)	53	(7)	46
2021	301	(22)	53	(8)	44
2022	264	(21)	53	(10)	42
2023-2027	815	(57)	158	(42)	116
2028-2032	314	0	0	0	0
Thereafter	49	0	0	0	0
Total future minimum lease payments	2,828	(170)	421	(74)	347

More information related to the operating leases of vessels and office buildings is found in the Consolidated financial statements.

Statoil ASA leases three LNG vessels on behalf of Statoil and the State's direct financial interest (SDFI). Statoil ASA accounts for the combined Statoil and SDFI share of these agreements as finance leases in the balance sheet, and further accounts for the SDFI related portion as operating sublease. The finance leases included in the balance sheet reflect the original lease term of 20 years from 2006.

Property, plant and equipment includes USD 278 million for leases that have been capitalised at year end 2017 (USD 312 million in 2016), also presented in the category vessels in note 9 Property, plant and equipment.

21 Other commitments, contingent liabilities and contingent assets

Contractual commitments
Statoil ASA had contractual commitments of USD 412 million at 31 December 2017. The contractual commitments reflect the Statoil ASA share and comprise financing commitments related to exploration activities.

Other long-term commitments
Statoil ASA has entered into various long-term agreements for pipeline transportation as well as terminal use, processing, storage and entry/exit capacity commitments and commitments related to specific purchase agreements. The agreements ensure the rights to the capacity or volumes in question, but also impose on the company the obligation to pay for the agreed-upon service or commodity, irrespective of actual use. The contracts' terms vary, with duration of up to 2035.

Take-or-pay contracts for the purchase of commodity quantities are only included in the table below if their contractually agreed pricing is of a nature that will or may deviate from the obtainable market prices for the commodity at the time of delivery.

Obligations payable by Statoil ASA to entities accounted for as associates and joint ventures are included gross in the table below. Obligations payable by Statoil ASA to entities accounted for as joint operations (for example pipelines) are included net (i.e. gross commitment less Statoil ASA's ownership share).

Nominal minimum commitments at 31 December 2017:

(in USD million)	
2018	1,205
2019	1,155
2020	1,086
2021	881
2022	722
Thereafter	3,869
Total	8,917

Guarantees
Statoil ASA has provided parent company guarantees covering liabilities of subsidiaries with operations in Algeria, Angola, Australia, Azerbaijan, Brazil, Colombia, Denmark, Germany, Greenland, India, Ireland, Libya, New Zealand, Nicaragua, Nigeria, Norway, Russia, Sweden, United Kingdom, USA, Uruguay, Venezuela. The company has also counter-guaranteed certain bank guarantees covering liabilities of subsidiaries in Algeria, Argentina, Australia, Brazil, Canada, Colombia, the Faroes, Indonesia, Mexico, Myanmar, the Netherlands, Norway, South Africa, Sweden, United Kingdom, USA, Uruguay.

Statoil ASA has guaranteed for its proportionate portion of an associate's long-term bank debt, amounting to USD 305 million. The book value of the guarantee is immaterial.

Contingencies
Statoil ASA is the participant in certain entities ("DAs") in which the company has unlimited responsibility for its proportionate share of such entities' liabilities, if any, and also participates in certain companies ("ANSs") in which the participants in addition have joint and several liability. For further details, see note 10 Investments in subsidiaries and other equity accounted investments.

Some long-term gas sales agreements contain price review clauses, which in certain cases lead to claims subject to arbitration. The exposure for Statoil related to arbitration has been estimated to an amount equivalent to approximately USD 343 million for gas delivered prior to year-end 2017. Statoil has provided for its best estimate related to contractual gas price disputes in the Consolidated financial statements, with the impact to the Consolidated statement of income reflected as revenue adjustments.

On 6 July 2016, the Norwegian tax authorities issued a deviation notice for the years 2012 to 2014 related to the internal pricing on certain transactions between Statoil Coordination Centre (SCC) in Belgium and Statoil ASA. The main issue relates to SCC`s capital structure and its compliance with the arm's length principle. Statoil ASA is of the view that arm's length pricing has been applied and that Statoil ASA has a strong position, and no amounts have consequently been provided for this issue in the accounts.

During the normal course of its business Statoil ASA is involved in legal proceedings, and several other unresolved claims are currently outstanding. The ultimate liability or asset in respect of such litigation and claims cannot be determined at this time. Statoil ASA has provided in its financial statements for probable liabilities related to litigation and claims based on the company's best judgment. Statoil ASA does not expect that its financial position, results of operations or cash flows will be materially affected by the resolution of these legal proceedings.

Provisions related to claims and disputes are reflected within note 18 Provisions.

22 Related parties

Reference is made to note 24 Related parties in Statoil's Consolidated financial statement for information regarding Statoil ASAs related parties. This include information regarding related parties as a result of Statoil ASA's ownership structure and also information regarding transactions with the Norwegian State.

Transactions with internally owned companies
Revenue transactions with related parties are presented in note 3 Revenues. Total intercompany revenues amounted to USD 4,665 million and USD 3,221 million in 2017 and 2016, respectively. The major part of intercompany revenues is attributed to sales of crude oil and sales of refined products to Statoil Refining Denmark AS, USD 2,220 million and USD 1,443 million in 2017 and 2016, respectively and Statoil Marketing, USD 2,268 million and USD 1,663 million in 2017 and 2016, respectively.

Statoil ASA sells natural gas and pipeline transport on a back-to-back basis to Statoil Petroleum AS. Similarly, Statoil ASA enters into certain financial contracts, also on a back-to-back basis with Statoil Petroleum AS. All of the risks related to these transactions are carried by Statoil Petroleum AS and the transactions are therefore not reflected in Statoil ASA's financial statements.

Statoil ASA buys volumes from its subsidiaries and sells them into the market. Total purchases of goods from subsidiaries amounted to USD 16,555 million and USD 12,511 million in 2017 and 2016, respectively. The major part of intercompany purchases of goods is attributed to Statoil Petroleum AS, USD 10,564 million and USD 8,163 million in 2017 and 2016, respectively.

In relation to its ordinary business operations, Statoil ASA has regular transactions with group companies in which Statoil has ownership interests. Statoil ASA makes purchases from group companies amounting to USD 200 million and USD 490 million in 2017 and 2016, respectively.

Expenses incurred by the company, such as personnel expenses, are accumulated in cost pools. Such expenses are allocated in part on an hours incurred cost basis to Statoil Petroleum AS, to other group companies, and to licences where Statoil Petroleum AS or other group companies are operators. Cost allocated in this manner is not reflected in Statoil ASA's financial statements. Expenses allocated to group companies amounted to USD 4,309 million and USD 4,214 million in 2017 and 2016, respectively. The major part of the allocation is related to Statoil Petroleum AS, USD 3,481 million and USD 3,302 million in 2017 and 2016, respectively.

Other transactions
Reference is made to note 24 Related parties in Statoil's Consolidated financial statement for information regarding Statoil ASAs transactions with related parties based on ordinary business operations.

Current receivables and current liabilities from subsidiaries and other equity accounted companies are included in note 11 Financial assets and liabilities.

Related party transactions with management and management remunerations for 2017 are presented in note 4 Remuneration.

Stavanger, 14 March 2018

THE BOARD OF DIRECTORS OF STATOIL ASA

JON ERIK REINHARDSEN
CHAIR

ROY FRANKLIN
DEPUTY CHAIR

BJØRN TORE GODAL

PER MARTIN LABRÅTEN

JEROEN VAN DER VEER

MARIA JOHANNA OUDEMAN

REBEKKA GLASSER HERLOFSEN

INGRID ELISABETH DI VALERIO

STIG LÆGREID

WENCHE AGERUP

ELDAR SÆTRE
PRESIDENT AND CEO

Additional information

Well head platform at Peregrino.

5.1 SHAREHOLDER INFORMATION

Statoil is the largest company listed on the Oslo Børs where it trades under the ticker code STL. Statoil is also listed on the New York Stock Exchange under the ticker code STO, trading in the form of American Depositary Shares (ADS).

Statoil's shares have been listed on the Oslo Børs and the New York Stock Exchange since our initial public offering on 18 June 2001. The ADSs traded on the New York Stock Exchange are evidenced by American Depositary Receipts (ADR), and each ADS represents one ordinary share.

Statoil Share	2017	2016	2015	2014	2013
Shareprice STL (low) (NOK)	136.00	97.90	116.30	120.00	123.00
Shareprice STL (average) (NOK)	152.98	133.50	137.59	166.41	136.72
Shareprice STL (high) (NOK)	176.90	159.80	160.80	194.80	147.70
Shareprice STL (year-end) (NOK)	175.20	158.40	123.70	131.20	147.00
Shareprice STO (low) (USD)	16.29	11.38	13.42	15.82	20.14
Shareprice STO (average) (USD)	18.50	15.92	17.11	26.52	23.32
Shareprice STO (high) (USD)	21.42	18.51	21.31	31.91	27.00
Shareprice STO (year-end) (USD)	21.42	18.24	13.96	17.61	24.13
STL Market value year-end (NOK billion)	582	514	394	418	469
STL Daily turnover (million shares)	3.14	4.7	5.1	3.7	3.0
Ordinary shares outstanding, year-end	3,323,167,853	3,245,049,411	3,188,647,103	3,188,647,103	3,188,647,103

As of 31 December 2017, Statoil represented 22.96% of the total value of all companies registered on the Oslo Børs, with a market value of NOK 582 billion. Total shareholder return (dividend reinvested) for 2017 is 16.0%.

The graph shows the development of the Statoil share price compared to the oil price and the Oslo Børs Benchmark Index (OSEBX). The turnover of shares is a measure of traded volumes. On average, 3.14 million Statoil shares were traded on the Oslo Børs every day in 2017 compared to 4.7 million shares in 2016. In 2017, Statoil shares accounted for 11,24% of the total market value traded throughout the year.

Statoil ASA has one class of shares, and each share confers one vote at the general meeting. Statoil ASA had 3,323,167,853 ordinary shares outstanding at year end. As of 31 December 2017, Statoil had 89,405 shareholders registered in the Norwegian Central Securities Depository (VPS), down from 91,128 shareholders at 31 December 2016.

The ticker code will be changed in connection with the company's proposed name change to Equinor.

Share prices

These are the reported high and low quotations at market closing for the ordinary shares on the Oslo Børs and New York Stock Exchange for the periods indicated. They are derived from the Oslo Børs Daily Official List, and the highest and lowest sales prices of the ADSs as reported on the New York Stock Exchange composite tape.

ADDITIONAL INFORMATION

Share price	NOK per ordinary share		USD per ADS	
	High	Low	High	Low
Year ended 31 December				
2013	147.70	123.00	27.00	20.14
2014	194.80	120.00	31.91	15.82
2015	160.80	116.30	21.31	13.42
2016	159.80	97.90	18.51	11.38
2017	176.90	136.00	21.42	16.29
Quarter ended				
Thursday, March 31, 2016	135.50	97.90	16.01	11.38
Thursday, June 30, 2016	144.80	122.40	17.68	14.66
Friday, September 30, 2016	149.80	124.00	17.74	15.07
Friday, December 30, 2016	159.80	129.30	18.51	15.86
Friday, March 31, 2017	162.90	142.30	19.21	16.83
Friday, June 30, 2017	153.60	138.40	18.28	16.29
Friday, September 30, 2017	160.20	136.00	20.37	16.32
Friday, December 29, 2017	176.90	158.20	21.42	19.81
Up until March 14, 2018	187.30	172.25	24.26	21.51
Month of				
September 2017	160.20	147.50	20.37	18.96
October 2017	167.90	158.20	20.54	19.88
November 2017	170.80	164.00	21.01	19.81
December 2017	176.90	165.40	21.42	19.95
January 2018	187.30	177.45	24.26	22.00
February 2018	182.60	172.25	23.83	21.51
Up until March 14, 2018	182.10	174.90	23.20	22.61

Dividend policy and dividends

It is Statoil's ambition to grow the annual cash dividend measured in USD per share in line with long-term underlying earnings.

Statoil's board approves first, second and third quarter interim dividends, based on an authorisation from the annual general meeting (AGM), while the AGM approves the fourth quarter dividend and implicitly the total annual dividend based on a proposal from the board. It is Statoil's intention to pay quarterly dividends, although when deciding the interim dividends and recommending the total annual dividend level, the board will take into consideration expected cash flow, capital expenditure plans, financing requirements and appropriate financial flexibility.

In addition to cash dividend, Statoil might buy back shares as part of total distribution of capital to the shareholders. The shareholders at the AGM may vote to reduce, but may not increase, the fourth quarter dividend proposed by the board of directors. Statoil announces dividend payments in connection with quarterly results. Payment of quarterly dividends is expected to take place within six months after the announcement of each quarterly dividend.

The board of directors has proposed to the AGM a dividend of USD 0.23 per share for the fourth quarter 2017 which is an increase from the previous quarter.

The following table shows the cash dividend amounts to all shareholders since 2013 on a per share basis and in aggregate.

ADDITIONAL INFORMATION

									Ordinary dividend per share	
				Ordinary dividend per share						Ordinary dividend per share
Fiscal year	Curr.	Q1	Curr.	Q2	Curr.	Q3	Curr.	Q4	Curr.	share
2013									NOK	7.0000
2014	NOK	1.8000	NOK	1.8000	NOK	1.8000	NOK	1.8000	NOK	7.2000
2015	NOK	1.8000	NOK	-	NOK	-	NOK	-	NOK	1.8000
2015	USD	-	USD	0.2201	USD	0.2201	USD	0.2201	USD	0.6603
2016	USD	0.2201	USD	0.2201	USD	0.2201	USD	0.2201	USD	0.8804
2017	USD	0.2201	USD	0.2201	USD	0.2201	USD	0.2300	USD	0.8903

The proposed fourth quarter 2017 dividend will be considered at the annual general meeting 15 May 2018. The Statoil share will be traded ex dividend 16 May 2018 and the dividend will be disbursed around 30 May 2018. For US ADR holders, the ex-dividend date will be 16 May 2018 and expected payment will be 31 May 2018.

Dividends in NOK per share will be calculated and communicated four business days after record date for shareholders at Oslo Børs. The NOK dividend will be based on average USD/NOK fixing rates from Norges Bank in the period plus/minus three business days from record date, in total seven business dates.

Share repurchase
For the period 2013-2017, the board of directors was authorised by the annual general meeting of Statoil to repurchase Statoil shares in the market for subsequent annulment. Statoil has not undertaken any share repurchase based on this authorisation.

It is Statoil's intention to renew this authorisation at the annual general meeting in May 2018.

ADDITIONAL INFORMATION

SHARES PURCHASED BY ISSUER

Shares are acquired in the market for transfer to employees under the share savings scheme in accordance with the limits set by the board of directors. No shares were repurchased in the market for the purpose of subsequent annulment in 2017.

Statoil's share savings plan

Since 2004, Statoil has had a share savings plan for employees of the company. The purpose of this plan is to strengthen the business culture and encourage loyalty through employees becoming part-owners of the company.

Through regular salary deductions, employees can invest up to 5% of their base salary in Statoil shares. In addition, the company contributes 20% of the total share investment made by employees in Norway, up to a maximum of NOK 1,500 per year (approximately USD 170). This company contribution is a tax-free employee benefit under current Norwegian tax legislation. After a lock-in period of two calendar years, one extra share will be awarded for each share purchased. Under current Norwegian tax legislation, the share award is a taxable employee benefit, with a value equal to the value of the shares and taxed at the time of the award.

The board of directors is authorised to acquire Statoil shares in the market on behalf of the company. The authorization is valid until the next annual general meeting, but not beyond 30 June 2019. This authorisation replaces the previous authorisation to acquire Statoil's own shares for implementation of the share savings plan granted by the annual general meeting 11 May 2017. It is Statoil's intention to renew this authorisation at the annual general meeting.

Period in which shares were repurchased	Number of shares repurchased	Average price per share in NOK	Total number of shares purchased as part of programme	Maximum number of shares that may yet be purchased under the programme authorisation
Jan-17	520,716	162.6375	4,957,941	9,042,059
Feb-17	577,674	147.8341	5,535,615	8,464,385
Mar-17	577,538	148.0420	6,113,153	7,886,847
Apr-17	574,983	148.7173	6,688,136	7,311,864
May-17	558,248	153.3188	7,246,384	6,753,616
Jun-17	594,701	143.6520	594,701	13,405,299
Jul-17	605,735	140.7709	1,200,436	12,799,564
Aug-17	584,442	145.6774	1,784,878	12,215,122
Sep-17	557,325	152.8641	2,342,203	11,657,797
Oct-17	532,356	160.2311	2,874,559	11,125,441
Nov-17	519,650	164.2834	3,394,209	10,605,791
Dec-17	512,546	166.8531	3,906,755	10,093,245
Jan-18	493,678	185.7484	4,400,433	9,599,567
Feb-18	530,143	174.6695	4,930,576	9,069,424
TOTAL	7,739,735 [1)]	156.8071 [2)]		

1) All shares repurchased have been purchased in the open market and pursuant to the authorisation mentioned above.

2) Weighted average price per share.

Statoil ADR programme fees

Fees and charges payable by a holder of ADSs.
As depositary from 31 January 2013, Deutsche Bank Trust Company Americas collects its fees for the delivery and surrender of ADSs directly from investors depositing shares or surrendering ADSs for the purpose of withdrawal, or from intermediaries acting for them.

The depositary collects fees from investors by deducting the fees from the amounts distributed or by selling a portion of distributable property to pay the fees. The depositary may refuse to provide fee-attracting services until its fees for those services are paid.

The charges of the depositary payable by investors are as follows:

Persons depositing or withdrawing shares must pay:	For:
USD 5.00 (or less) per 100 ADSs (or portion of 100 ADSs)	Issuance of ADSs, including issuances resulting from a distribution of shares or rights or other property Cancellation of ADSs for the purpose of withdrawal, including if the deposit agreement terminates
USD 0.02(or less) per ADS, subject to the company's consent	Any cash distribution made made pursuant to the Deposit Agreement
USD 0.05 (or less) per ADS, subject to the company's consent	For the operation and maintenance costs in administering the ADR programme
A fee equivalent to the fee that would be payable if securities distributed to you had been shares and the shares had been deposited for issuance of ADSs	Distribution of securities distributed to holders of deposited securities which are distributed by the Depositary to ADS registered holders
Registration or transfer fees	Transfer and registration of shares on our share register to or from the name of the Depositary or its agent when you deposit or withdraw shares
Expenses of the Depositary	Cable, telex and facsimile transmissions (as provided in the deposit agreement) Converting foreign currency to USD
Taxes and other governmental charges the Depositary or the custodian have to pay on any ADS or share underlying an ADS, for example, stock transfer taxes, stamp duty or withholding taxes	As necessary
Any charges incurred by the Depositary or its agents for servicing the deposited securities	As necessary

Reimbursements and payments made and fee waivers granted by the depositary
The depositary has agreed to reimburse certain company expenses related to the company's ADR programme and incurred by the company in connection with the programme. In the year ended 31 December 2017, the depositary reimbursed approximately USD 2.978 million to the company in relation to certain expenses including investor relations expenses, expenses related to the maintenance of the ADR programme, legal counsel fees, printing and ADR certificates. In addition, 2017 was the first year Statoil claimed dividend fee proceeds which is included here.

The depositary has also agreed to waive fees for costs associated with the administration of the ADR programme, and it has paid certain expenses directly to third parties on behalf of the company. The expenses paid to third parties include expenses relating to reporting services, access charges to its online platform, re-registration costs borne by the custodian and costs in relation to printing and mailing AGM materials. For the year ended 31 December 2017, the depositary paid expenses of approximately USD 211,635 directly to third parties.

TAXATION

This section describes the material Norwegian tax consequences that apply to shareholders resident in Norway and to non-resident shareholders in connection with the acquisition, ownership and disposal of shares and American Depositary Shares (ADS). The term "shareholder" refers to both holders of shares and holders of ADSs, unless otherwise explicitly stated.

Norwegian tax matters

The outline does not provide a complete description of all tax regulations that might be relevant (i.e. for investors to whom special regulations may be applicable), and is based on current law and practice. Shareholders should consult their professional tax adviser for advice about individual tax consequences.

Taxation of dividends received by Norwegian shareholders

Corporate shareholders (i.e. limited liability companies and similar entities) residing in Norway for tax purposes are generally subject to tax in Norway on dividends received from Norwegian companies. The basis for taxation is 3% of the dividends received, which is subject to the standard income tax rate. The standard income tax rate has been reduced from 24% in 2017 to 23% in 2018.

Individual shareholders resident in Norway for tax purposes are subject to the standard income tax rate (reduced from 24% in 2017 to 23% in 2018) in Norway for dividend income exceeding a basic tax free allowance. However, in 2018 dividend income exceeding the basic tax free allowance is grossed up with a factor of 1.33 before included in the ordinary taxable income, resulting in an effective tax rate of 30.59% (23% x 1.33). The tax free allowance is computed for each individual share or ADS and corresponds as a rule to the cost price of that share or ADS multiplied by an annual risk-free interest rate. Any part of the calculated allowance for one year that exceeds the dividend distributed for the share or ADS ("unused allowance") may be carried forward and set off against future dividends received for (or gains upon the realisation of, see below) the same share or ADS. Any unused allowance will also be added to the basis for computation of the allowance for the same share or ADS the following year.

Taxation of dividends received by foreign shareholders

Non-resident shareholders are as a starting point subject to Norwegian withholding tax at a rate of 25% on dividends distributed by Norwegian companies. It is the responsibility of the distributing company to deduct the withholding tax when dividends are paid to non-resident shareholders.

Corporate shareholders that carry on business activities in Norway, and whose shares or ADSs are effectively connected with such activities are not subject to withholding tax. For such shareholders, 3% of the received dividends are subject to the standard income tax rate (reduced from 24% in 2017 to 23% in 2018).

Certain important exceptions and modifications are outlined below.

This withholding tax does not apply to corporate shareholders in the EEA area that are equal to Norwegian private or public limited liability companies or certain other types of Norwegian entities, and that are further able to demonstrate that they are genuinely established and carry on genuine economic business activity within the EEA area, provided that Norway is entitled to receive information from the state of residence pursuant to a tax treaty or other international treaty. If no such treaty exists with the state of residence, the shareholder may instead present confirmation issued by the tax authorities of the state of residence verifying the documentation.

The withholding rate of 25% is often reduced in tax treaties between Norway and other countries. The reduced withholding tax rate will generally only apply to dividends paid on shares held by shareholders who are able to properly demonstrate that they are the beneficial owner and entitled to the benefits of the tax treaty.

Individual shareholders resident for tax purposes in the EEA area may apply to the Norwegian tax authorities for a refund if the tax withheld by the distributing company exceeds the tax that would have been levied on individual shareholders resident in Norway.

Procedure for claiming a reduced withholding tax rate on dividends

A foreign shareholder that is entitled to a reduced withholding tax rate on dividends, may request that the reduced rate is applied at source by the distributor. Such request must be accompanied by satisfactory documentation which supports that the foreign shareholder is entitled to a reduced withholding tax rate. It is expected that specific documentation requirements soon will be implemented in the regulations to the Norwegian Tax Payment Act, and the Norwegian Ministry of Finance has stated that these requirements should apply from 1 January 2019.

For holders of shares and ADSs deposited with Deutsche Bank Trust Company Americas (Deutsche Bank), documentation establishing that the holder is eligible for the benefits under a tax treaty with Norway, may be provided to Deutsche Bank. Deutsche Bank has been granted permission by the Norwegian tax authorities to receive dividends from us for redistribution to a beneficial owner of shares and ADSs at the applicable treaty withholding rate.

Dividends paid to shareholders (either directly or through a depositary) who have not provided the relevant documentation to the relevant party that they are eligible for the reduced rate, will be subject to withholding tax of 25%. The beneficial owners will in this case have to apply to the Central Office - Foreign Tax Affairs for a refund of the excess amount of tax withheld. Please refer to the tax authorities' web page for more information and the requirements of such application: http://www.skatteetaten.no/en/person/Aksjer-og-verdipapirer/withholding-tax-refund-on-dividends/.

Taxation on the realisation of shares and ADSs

Corporate shareholders resident in Norway for tax purposes are not subject to tax in Norway on gains derived from the sale, redemption or other disposal of shares or ADSs in Norwegian companies. Capital losses are not deductible.

Individual shareholders residing in Norway for tax purposes are subject to tax in Norway on the sale, redemption or other disposal of shares or ADSs. Gains or losses in connection with such realisation are included in the individual's ordinary taxable income in the year of disposal, which is subject to the standard income tax rate, being reduced from 24% in 2017 to 23% in 2018. However, in 2018 the taxable gain or deductible loss is grossed up with a factor of 1.33 before included in the ordinary taxable income, resulting in an effective tax rate of 30.59% (23% x 1.33).

The taxable gain or deductible loss (before gross up) is calculated as the sales price adjusted for transaction expenses minus the taxable basis. A shareholder's tax basis is normally equal to the acquisition cost of the shares or ADSs. Any unused allowance pertaining to a share may be deducted from a taxable gain on the same share or ADS, but may not lead to or increase a deductible loss. Furthermore, any unused allowance may not be set off against gains from the realisation of the other shares or ADSs.

If the shareholder disposes of shares or ADSs acquired at different times, the shares or ADSs that were first acquired will be deemed to be first sold (the "FIFO" principle) when calculating gain or loss for tax purposes.

From 2017, individual shareholders may hold listed shares in companies resident within EEA through a stock savings account. If the conditions for the stock savings account are met, taxable gain or loss on shares owned through the stock savings account will be payable when the gain is withdrawn from the account whereas loss on shares will be deductible when the account is terminated. Dividends are not comprised by the stock savings account scheme and will thus be taxed pursuant to the ordinary rules described above.

A corporate shareholder or an individual shareholder who ceases to be tax resident in Norway due to Norwegian law or tax treaty provisions may, in certain circumstances, become subject to Norwegian exit taxation on capital gains related to shares or ADSs.

Shareholders not residing in Norway are generally not subject to tax in Norway on capital gains, and losses are not deductible on the sale, redemption or other disposal of shares or ADSs in Norwegian companies, unless the shareholder carries on business activities in Norway and such shares or ADSs are or have been effectively connected with such activities.

Wealth tax

The shares or ADSs are included in the basis for the computation of wealth tax imposed on individuals resident in Norway for tax purposes. Norwegian limited companies and certain similar entities are not subject to wealth tax. The current marginal wealth tax rate is 0.85% of the value assessed. The assessment value of listed shares (including ADSs) is 80% (reduced from 90% with effect from and including the income year 2018) of the listed value of such shares or ADSs on 1 January in the assessment year.

Non-resident shareholders are not subject to wealth tax in Norway for shares and ADSs in Norwegian limited companies unless the shareholder is an individual and the shareholding is effectively connected with the individual's business activities in Norway.

Inheritance tax and gift tax

No inheritance or gift tax is imposed in Norway.

Transfer tax

No transfer tax is imposed in Norway in connection with the sale or purchase of shares or ADSs.

United States tax matters

This section describes the material United States federal income tax consequences for US holders (as defined below) of owning shares or ADSs. It only applies to you if you hold your shares or ADSs as capital assets for tax purposes and are not a member of a special class of holders subject to special rules, including dealers in securities, traders in securities that elect to use a mark-to-market method of accounting for securities holdings, insurance companies, partnerships, persons liable for the alternative minimum tax, persons that actually or constructively own 10% of the combined power of voting stock of Statoil or of the total value of stock of Statoil, persons that hold shares or ADSs as part of a straddle or a hedging or conversion transaction, persons that purchase or sell shares or ADSs as part of wash sale for tax purposes, or persons whose functional currency is not USD.

This section is based on the Internal Revenue Code of 1986, as amended, its legislative history, existing and proposed regulations, published rulings and court decisions, and the Convention between the United States of America and the Kingdom of Norway for the Avoidance of Double Taxation and the Prevention of Fiscal Evasion with Respect to Taxes on Income and Property (the "Treaty"). These laws are subject to change, possibly on a retroactive basis. In addition, this section is based in part upon the representations of the depositary and the assumption that each obligation in the deposit agreement and any related agreement will be performed in accordance with its terms. For United States federal income tax purposes, if you hold ADRs evidencing ADSs, you will generally be treated as the owner of the ordinary shares represented by those ADRs. Exchanges of shares for ADRs and ADRs for shares will not generally be subject to United States federal income tax.

A "US holder" is a beneficial owner of shares or ADSs that is: (i) a citizen or resident of the United States; (ii) a United States domestic corporation; (iii) an estate whose income is subject to United States federal income tax regardless of its source; or (iv) a trust if a United States court can exercise primary supervision over the trust's administration and one or more United States persons are authorised to control all substantial decisions of the trust.

You should consult your own tax adviser regarding the United States federal, state and local and Norwegian and other tax consequences of owning and disposing of shares and ADSs in your particular circumstances.

Taxation of dividends

The gross amount of any dividend (including any Norwegian tax withheld from the dividend payment) paid by Statoil out of its current or accumulated earnings and profits (as determined for United States federal income tax purposes) is taxable for you when you, in the case of shares, or the depositary, in the case of ADSs, receive the dividend, actually or constructively. If you are a non-corporate US holder, dividends paid to you will be eligible to be taxed at the preferential rates applicable to long-term capital gains as long as, in the year that you receive the dividend, the shares or ADSs are readily tradable on an established securities market in the United States or Statoil is eligible for benefits under the Treaty. To qualify for the preferential rates, you must hold the shares or ADSs for more than 60 days during the 121-day period beginning 60 days before the ex-dividend date and meet certain other requirements. The dividend will not be eligible for the dividends-received deduction generally allowed to United States corporations in respect of dividends received from other United States corporations.

The amount of the dividend distribution that you must include in your income as a US holder will be the value in USD of the payments made in NOK determined at the spot NOK/USD rate on the date the dividend distribution is includible in your income, regardless of whether or not the payment is in fact converted into USD. Distributions in excess of current and accumulated earnings and profits, as determined for United States federal income tax purposes, will be treated as a non-taxable return of capital to the extent of your tax basis in the shares or ADSs and, to the extent in excess of your tax basis, will be treated as capital gain.

Subject to certain limitations, the 15% Norwegian tax withheld in accordance with the Treaty and paid to Norway will be creditable or deductible against your United States federal income tax liability, unless a refund of the tax withheld is available to you under Norwegian law. Special rules apply when determining the foreign tax credit limitation with respect to dividends that are subject to the preferential rates. Dividends will be income from sources outside the United States and will generally, depending on your circumstances, be either "passive" or "general" income for purposes of computing the foreign tax credit allowable to you. Any gain or loss resulting from currency exchange rate fluctuations during the period from the date you include the dividend payment in income until the date you convert the payment into USD will generally be treated as US-source ordinary income or loss and will not be eligible for the special tax rate.

Taxation of capital gains

If you sell or otherwise dispose of your shares or ADSs, you will generally recognise a capital gain or loss for United States federal income tax purposes equal to the difference between the value in USD of the amount that you realise and your tax basis, determined in USD, in your shares or ADSs. A capital gain of a non-corporate US holder is generally taxed at preferential rates if the property is held for more than one year. The gain or loss will generally be income or loss from sources within the United States for foreign tax credit limitation purposes. If you receive any foreign currency on the sale of shares or ADSs, you may recognise ordinary income or loss from sources within the United States as a result of currency fluctuations between the date of the sale of the shares or ADSs and the date the sales proceeds are converted into USD. You should consult your own tax adviser regarding how to account for payments made or received in a currency other than USD.

PFIC rules

We believe that the shares and ADSs should not be treated as stock of a PFIC for United States federal income tax purposes, but this conclusion is a factual determination that is made annually and thus may be subject to change. If we were to be treated as a PFIC, a gain realised on the sale or other disposition of the shares or ADSs would in general not be treated as a capital gain. Instead, unless you elect to be taxed annually on a mark-to-market basis with respect to the shares or ADSs, you would be treated as if you had realised such gain and certain "excess distributions" ratably over your holding period for the shares or ADSs. Amounts allocated to the year in which the gain is realised or the "excess distribution" is received or to a taxable year before we were classified as a PFIC would be subject to tax at ordinary income tax rates, and amounts allocated to all other years would be taxed at the highest tax rate in effect for each such year to which the gain or distribution was allocated, together with an interest charge in respect of the tax attributable to each such year. With certain exceptions, your shares or ADSs will be treated as stock in a PFIC if we were a PFIC at any time during the period you held the shares or ADSs. Dividends that you receive from us will not be eligible for the preferential tax rates if we are treated as a PFIC with respect to you, either in the taxable year of the distribution or the preceding taxable year, but will instead be taxable at rates applicable to ordinary income.

Foreign Account Tax Compliance Withholding

A 30% withholding tax will be imposed on certain payments to certain non-US financial institutions that fail to comply with information reporting requirements or certification requirements in respect of their direct and indirect United States shareholders and/or United States accountholders. To avoid becoming subject to the 30% withholding tax on payments to them, we and other non-US financial institutions may be required to report information to the IRS regarding the holders of shares or ADSs and to withhold on a portion of payments under the shares or ADSs to certain holders that fail to comply with the relevant information reporting requirements (or hold shares or ADSs directly or indirectly through certain non-compliant intermediaries). However, such withholding will not apply to payments made before January 1, 2019. The rules for the implementation of this legislation have not yet been fully finalised, so it is impossible to determine at this time what impact, if any, this legislation will have on holders of the shares and ADSs.

EXCHANGE RATES

The table below shows the high, low, average and end-of-period exchange rates for the Norwegian krone for USD 1.00 as announced by Norges Bank (Norway's central bank).

The average is computed using the monthly average exchange rates announced by Norges Bank during the period indicated.

For the year ended 31 December	Low	High	Average	End of Period
2013	5.4438	6.2154	5.8753	6.0837
2014	5.8611	7.6111	6.3011	7.4332
2015	7.3593	8.8090	8.0637	8.8090
2016	7.9766	8.9578	8.4014	8.6200
2017	7.7121	8.6781	8.2712	8.2050

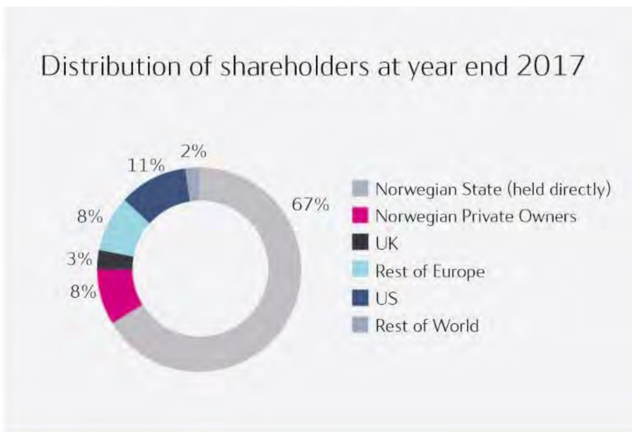
	Low	High
2017		
September	7.7192	7.9726
October	7.8906	8.2161
November	8.1140	8.3043
December	8.2050	8.4103
2018		
January	7.6760	8.1055
February	7.6579	7.9836
March (up to and including 14 March 2018)	7.7393	7.9369

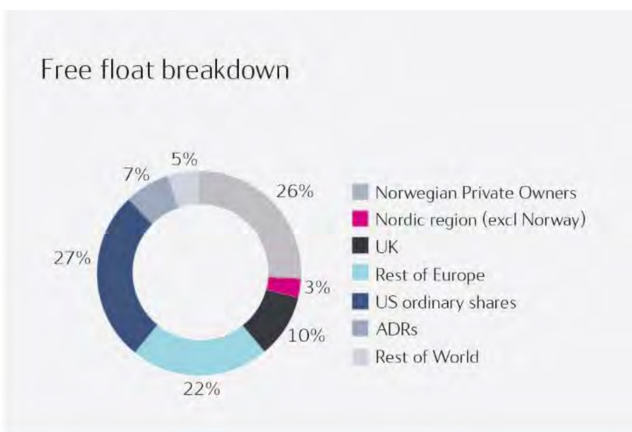
On 14 March 2018, the exchange rate announced by the Norges Bank for the Norwegian krone was USD 1.00 = NOK 7.7393

Fluctuations in the exchange rate between the NOK and USD will affect the amounts in USD received by holders of American Depositary Shares (ADSs) on the conversion of dividends, if any, paid in Norwegian kroner on the ordinary shares, and they may affect the USD price of the ADSs on the New York Stock Exchange.

MAJOR SHAREHOLDERS

The Norwegian State is the largest shareholder in Statoil, with a direct ownership interest of 67%. Its ownership interest is managed by the Norwegian Ministry of Petroleum and Energy.





Pursuant to the exchange ratio agreed in connection with the merger with Hydro's oil and gas activities, the State's ownership interest in the merged company was 62.5%, or 1,992,959,739 shares, on 1 October 2007. In accordance with the Norwegian parliament's decision of 2001 concerning a minimum state shareholding in Statoil of two-thirds, the Government built up the State's ownership interest in Statoil by buying shares in the market during the period from June 2008 to March 2009. In March 2009, the Government announced that the State's direct ownership interest had reached 67% and the Government's direct purchase of Statoil shares was completed.

As of 31 December2017, the Norwegian State had a 67% direct ownership interest in Statoil and a 3.30% indirect interest through the National Insurance Fund (Folketrygdfondet), totaling 70.30%. See note 17 Shareholder's equity and dividends regarding the Norwegian State and the scrip option.

Statoil has one class of shares, and each share confers one vote at the general meeting. The Norwegian State does not have any voting rights that differ from the rights of other ordinary shareholders. Pursuant to the Norwegian Public Limited Liability Companies Act, a majority of at least two-thirds of the votes cast as well as of the votes represented at a general meeting is required to amend our articles of association. As long as the Norwegian State owns more than one-third of our shares, it will be able to prevent any amendments to our articles of association. Since the Norwegian State, acting through the Norwegian Minister of Petroleum and Energy, has in excess of two-thirds of the shares in the company, it has sole power to amend our articles of association. In addition, as majority shareholder, the Norwegian State has the power to control any decision at general meetings of our shareholders that requires a majority vote, including the election of the majority of the corporate assembly, which has the power to elect our board of directors and approve the dividend proposed by the board of directors.

The Norwegian State endorses the principles set out in "The Norwegian Code of Practice for Corporate Governance", and it has stated that it expects companies in which the State has ownership interests to adhere to the code. The principle of ensuring equal treatment of different groups of shareholders is a key element in the State's own guidelines. In companies in which the State is a shareholder together with others, the State wishes to exercise the same rights and obligations as any other shareholder and not act in a manner that has a detrimental effect on the rights or financial interests of other shareholders. In addition to the principle of equal treatment of shareholders, emphasis is also placed on transparency in relation to the State's ownership and on the general meeting being the correct arena for owner decisions and formal resolutions.

	Shareholders at December 2017	Number of Shares	Ownership in %
1	Government of Norway	2,226,522,461	67.00%
2	Folketrygdfondet	109,611,652	3.30%
3	BlackRock Institutional Trust Company, N.A.	38,778,958	1.17%
4	Dodge & Cox	37,602,850	1.13%
5	Lazard Asset Management, L.L.C.	31,942,660	0.96%
6	Fidelity Management & Research Company	29,861,026	0.90%
7	INVESCO Asset Management Limited	28,939,947	0.87%
8	SAFE Investment Company Limited	25,560,235	0.77%
9	The Vanguard Group, Inc.	24,773,677	0.75%
10	KLP Forsikring	17,764,920	0.53%
11	Storebrand Kapitalforvaltning AS	17,202,662	0.52%
12	State Street Global Advisors (US)	16,814,356	0.51%
13	DNB Asset Management AS	14,656,121	0.44%
14	UBS Asset Management (UK) Ltd.	12,027,810	0.36%
15	Northern Cross LLC	11,606,485	0.35%
16	Epoch Investment Partners, Inc.	10,856,350	0.33%
17	Allianz Global Investors GmbH	8,893,846	0.27%
18	Renaissance Technologies LLC	8,454,901	0.25%
19	FMR Investment Management (U.K.) Limited	8,173,719	0.25%
20	AXA Investment Managers UK Ltd.	7,921,254	0.24%

Source: Data collected by third party, authorised by Statoil, December 2017.

EXCHANGE CONTROLS AND LIMITATIONS

Under Norwegian foreign exchange controls currently in effect, transfers of capital to and from Norway are not subject to prior government approval. An exception applies to the physical transfer of payments in currency exceeding certain thresholds, which must be declared to the Norwegian custom authorities. This means that non-Norwegian resident shareholders may receive dividend payments without Norwegian exchange control consent as long as the payment is made through a licensed bank or other licensed payment institution.

There are no restrictions affecting the rights of non-Norwegian residents or foreign owners to hold or vote for our shares.

5.2 USE AND RECONCILIATION OF NON-GAAP FINANCIAL MEASURES

Since 2007, Statoil has been preparing the Consolidated financial statements in accordance with International Financial Reporting Standards (IFRS) as adopted by the European union (EU) and as issued by the International Accounting Standards Board. The IFRS standards have been applied consistently to all periods presented in the 2017 Consolidated financial statements.

Statoil is subject to SEC regulations regarding the use of non-GAAP financial measures in public disclosures. Non-GAAP financial measures are defined as numerical measures that either exclude or include amounts that are not excluded or included in the comparable measures calculated and presented in accordance with generally accepted accounting principles. The following financial measures may be considered non-GAAP financial measures:

a) Net debt to capital employed ratio before adjustments and Net debt to capital employed ratio adjusted
b) Return on average capital employed (ROACE)
c) Organic capital expenditures
d) Free cash flow
e) Adjusted earnings after tax

a) Net debt to capital employed ratio

In Statoil's view, the calculated net debt to capital employed ratio before adjustments and net debt to capital employed ratio adjusted gives an alternative picture of the current debt situation than gross interest-bearing financial debt.

The calculation is based on gross interest bearing financial debt in the balance sheet and adjusted for cash, cash equivalents and current financial investments. Certain adjustments are made, e.g. collateral deposits classified as cash and cash equivalents in the Consolidated balance sheet are considered non-cash in the non-GAAP calculations. The financial investments held in Statoil Forsikring AS are excluded in the non-GAAP calculations as they are deemed restricted. These two adjustments increase net debt and give a more prudent definition of the net debt to capital employed ratio than if the IFRS based definition was to be used. Similarly, certain net interest-bearing debts incurred from activities pursuant to the Owners Instruction from the Norwegian State are set off against receivables on the Norwegian State's direct financial interest (SDFI). Net interest-bearing debt adjusted for these items is included in the average capital employed. The table below reconciles the net interest-bearing debt adjusted, the capital employed and the net debt to capital employed adjusted ratio with the most directly comparable financial measure or measures calculated in accordance with IFRS.

Calculation of capital employed and net debt to capital employed ratio (in USD million, except percentages)	For the year ended 31 December 2017	2016	2015
Shareholders' equity	**39,861**	35,072	40,271
Non-controlling interests	**24**	27	36
Total equity (A)	**39,885**	35,099	40,307
Current finance debt	**4,091**	3,674	2,326
Non-current finance debt	**24,183**	27,999	29,965
Gross interest-bearing debt (B)	**28,274**	31,673	32,291
Cash and cash equivalents	**4,390**	5,090	8,623
Current financial investments	**8,448**	8,211	9,817
Cash and cash equivalents and current financial investment (C)	**12,837**	13,301	18,440
Net interest-bearing debt before adjustments (B1) (B-C)	**15,437**	18,372	13,852
Other interest-bearing elements 1)	**1,014**	1,216	1,111
Marketing instruction adjustment 2)	**(164)**	(199)	(214)
Net interest-bearing debt adjusted (B2)	**16,287**	19,389	14,748
Calculation of capital employed:			
Capital employed before adjustments to net interest-bearing debt (A+B1)	**55,322**	53,471	54,159
Capital employed adjusted (A+B2)	**56,172**	54,488	55,055
Calculated net debt to capital employed:			
Net debt to capital employed before adjustments (B1/(A+B1)	**27.9%**	34.4%	25.6%
Net debt to capital employed adjusted (B2/(A+B2)	**29.0%**	35.6%	26.8%

1) Other interest-bearing elements are cash and cash equivalents adjustments regarding collateral deposits classified as cash and cash equivalents in the Consolidated balance sheet but considered as non-cash in the non-GAAP calculations as well as financial investments in Statoil Forsikring AS classified as current financial investments.

2) Marketing instruction adjustment is an adjustment to gross interest-bearing financial debt due to the SDFI part of the financial lease in the Snøhvit vessels that are included in Statoil's Consolidated balance sheet.

b) Return on average capital employed (ROACE)

This measure provides useful information for both the group and investors about performance during the period under evaluation. Statoil uses ROACE to measure the return on capital employed, regardless of whether the financing is through equity or debt. The use of ROACE should not be viewed as an alternative to income before financial items, income taxes and minority interest, or to net income, which are measures calculated in accordance with GAAP or ratios based on these figures. ROACE was 8.2% in 2017, compared to negative 0.4% in 2016 and 4.1% in 2015. The change from 2016 is due to an increase in adjusted earnings after tax.

Calculated ROACE based on Adjusted earnings after tax and capital employed adjusted (in USD million, except percentages)	For the year ended 31 December 2017	2016	2015
Adjusted earnings after tax (A)	4,528	(208)	2,465
Average capital employed adjusted (B)	55,330	54,772	59,712
Calculated ROACE based on Adjusted earnings after tax and capital employed adjusted (A/B)	8.2%	-0.4%	4.1%

c) Organic capital expenditures

Organic capital expenditures are capital expenditures excluding acquisitions, capital leases and other investments with significant different cash flow pattern. In 2017, a total of USD 1.4 billion were excluded from the organic capital expenditures. Among items excluded from the organic capital expenditure in 2017 were signature bonus for the Carcara North production sharing contract in Brazil, acquisition cost for a 10% stake in the BM-S-8 licence in Brazil and bonus for the extension of the Azeri-Chirag-Deepwater Gunashli (ACG) Production Sharing Agreement in Azerbaijan.

In 2016, a total of USD 4.0 billion were excluded from the organic capital expenditures. Among items excluded from the organic capital expenditure in 2016 were investment in ownership in Lundin Petroleum AB, acquisition of a 66% operated interest in the offshore licence BM-S-8 in Brazil and acquisition of a 50% stake in the Arkona offshore wind farm in Germany.

For more information, see note 3 Segment, line item Additions to PP&E, intangibles and equity accounted investments and, note 4 Acquisitions and divestments to the Consolidated financial statements.

d) Free cash flow

Free cash flow includes the following line items in the Consolidated statement of cash flows: Cash flows provided by operating activities before taxes paid and working capital items, taxes paid, capital expenditures and investments, (increase) decrease in other items interest bearing, proceeds from sale of assets and businesses and dividend paid.

e) Adjusted earnings after tax

Adjusted earnings are based on net operating income and adjusts for certain items affecting the income for the period in order to separate out effects that management considers may not be well correlated to Statoil's underlying operational performance in the individual reporting period. Management considers adjusted earnings to be a supplemental measure to Statoil's IFRS measures that provides an indication of Statoil's underlying operational performance in the period and facilitates an alternative understanding of operational trends between the periods, and uses this metric in determining variable remuneration and awards of LTI grants to members of the corporate executive committee. Adjusted earnings adjust for the following items:

- Certain gas contracts are, due to pricing or delivery conditions, deemed to contain embedded derivatives, required to be carried at fair value. Certain transactions related to historical divestments include contingent consideration, carried at fair value. The accounting impacts of changes in fair value of the aforementioned are excluded from adjusted earnings. In addition, adjustments are also made for changes in the unrealised **fair value of derivatives** related to some natural gas trading contracts. Due to the nature of these gas sales contracts, these are classified as financial derivatives to be measured at fair value at the balance sheet date. Unrealised gains and losses on these contracts reflect the value of the difference between current market gas prices and the actual prices to be realised under the gas sales contracts. Only realised gains and losses on these contracts are reflected in adjusted earnings. This presentation best reflects the underlying performance of the business as it replaces the effect of temporary timing differences associated with the re-measurements of the derivatives to fair value at the balance sheet date with actual realised gains and losses for the period
- **Periodisation of inventory hedging effect**: Commercial storage is hedged in the paper market. Commercial storage is accounted for by using the lower of cost and market price. If market prices increase above cost price, there will be a loss in the IFRS income statement since the derivatives always reflect changes in the market price. An adjustment is made to reflect the unrealised market value of the commercial storage. As a result, loss on derivatives is matched by a similar adjustment for the exposure being managed. If market prices decrease below cost price, the write-down and the derivative effect in the IFRS income statement will offset each other and no adjustment is made
- **Over/underlift** is accounted for using the sales method and therefore revenues are reflected in the period the product is sold rather than in the period it is produced. The over/underlift position depends on a number of factors related to our lifting programme and the way it corresponds to our entitlement share of production. The effect on income for the period is therefore adjusted, to show estimated revenues and associated costs based upon the production for the period which management

believes reflects operational performance and increase comparability with peers

- Statoil holds **operational storage** which is not hedged in the paper market due to inventory strategies. Cost of goods sold is measured based on the FIFO (first-in, first-out) method, and includes realised gains or losses that arise due to changes in market prices. These gains or losses will fluctuate from one period to another and are not considered part of the underlying operations for the period
- **Impairment** and **reversal of impairment** are excluded from adjusted earnings since they affect the economics of an asset for the lifetime of that asset; not only the period in which it is impaired or the impairment is reversed. Impairment and reversal of impairment can impact both the exploration expenses and the depreciation, amortisation and impairment line items
- **Gain or loss from sales of assets** is eliminated from the measure since the gain or loss does not give an indication of future performance or periodic performance; such a gain or loss is related to the cumulative value creation from the time the asset is acquired until it is sold
- **Internal unrealised profit on inventories**: Volumes derived from equity oil inventory will vary depending on several factors and inventory strategies, i.e. level of crude oil in inventory, equity oil used in the refining process and level of in-transit cargoes. Internal profit related to volumes sold between entities in the group, and still in inventory at period end, is eliminated according to IFRS (write down to production cost). The proportion of realised versus unrealised gain will fluctuate from one period to another due to inventory strategies and accordingly impact net operating income. This impact is not assessed to be a part of the underlying operational performance, and elimination of internal profit related to equity volumes is excluded in adjusted earnings
- **Other items of income and expense** are adjusted when the impacts on income in the period are not reflective of Statoil's underlying operational performance in the reporting period. Such items may be unusual or infrequent transactions but they may also include transactions that are significant which would not necessarily qualify as either unusual or infrequent. Other items can include transactions such as provisions related to reorganisation, early retirement, etc

The measure **adjusted earnings after tax** excludes net financial items and the associated tax effects on net financial items. It is based on adjusted earnings less the tax effects on all elements included in adjusted earnings (or calculated tax on operating income and on each of the adjusting items using an estimated marginal tax rate). In addition, tax effect related to tax exposure items not related to the individual reporting period is excluded from adjusted earnings after tax. Management considers adjusted earnings after tax, which reflects a normalised tax charge associated with its operational performance excluding the impact of financing, to be a supplemental measure to Statoil's net income. Certain net USD denominated financial positions are held by group companies that have a USD functional currency that is different from the currency in which the taxable income is measured. As currency exchange rates change between periods, the basis for measuring net financial items for IFRS will change disproportionally with taxable income which includes exchange gains and losses from translating the net USD denominated financial positions into the currency of the applicable tax return. Therefore, the effective tax rate may be significantly higher or lower than the statutory tax rate for any given period.

Management considers that adjusted earnings after tax provides an alternative indication of the taxes associated with underlying operational performance in the period (excluding financing), and therefore facilitates an alternative comparison between periods. However, the adjusted taxes included in adjusted earnings after tax should not be considered indicative of the amount of current or total tax expense (or taxes payable) for the period.

Adjusted earnings and adjusted earnings after tax should be considered additional measures rather than substitutes for net operating income and net income, which are the most directly comparable IFRS measures. There are material limitations associated with the use of adjusted earnings and adjusted earnings after tax compared with the IFRS measures since they do not include all the items of revenues/gains or expenses/losses of Statoil which are needed to evaluate its profitability on an overall basis. Adjusted earnings and adjusted earnings after tax are only intended to be indicative of the underlying developments in trends of Statoil's on-going operations for the production, manufacturing and marketing of its products and exclude pre- and post-tax impacts of net financial items. Statoil reflect such underlying development in its operations by eliminating the effects of certain items that may not be directly associated with the period's operations or financing. However, for that reason, adjusted earnings and adjusted earnings after tax are not complete measures of profitability. The measures should therefore not be used in isolation.

Adjusted earnings equal the sum of net operating income less all applicable adjustments. Adjusted earnings after tax equals the sum of net operating income less income tax in business areas and adjustments to operating income taking the applicable marginal tax into consideration. See the table below for details.

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ADDITIONAL INFORMATION

Calculation of adjusted earnings after tax	For the year ended 31 December	
(in USD million)	2017	2016
Net operating income	**13,771**	**80**
Total revenues and other income	**(405)**	**1,020**
Changes in fair value of derivatives	(197)	738
Periodisation of inventory hedging effect	(43)	360
Impairment from associated companies		25
Over-/underlift	(155)	232
Gain/loss on sale of assets	(10)	(333)
Purchases [net of inventory variation]	**(35)**	**(9)**
Operational storage effects	(94)	(228)
Eliminations	59	219
Operating and administrative expenses	**418**	**617**
Over-/underlift	11	(59)
Other adjustments	9	168
Gain/loss on sale of assets	382	86
Provisions	12	422
Cost accrual changes	4	-
Depreciation, amortisation and impairment	**(1,055)**	**1,300**
Impairment	917	2,946
Reversal of impairment	(1,972)	(1,646)
Exploration expenses	**(56)**	**1,061**
Impairment	435	1,141
Reversal of impairment	(517)	(149)
Other adjustments	0	41
Provisions		28
Cost accrual changes	25	-
Sum of adjustments to net operating income	**(1,133)**	**3,990**
Adjusted earnings	**12,638**	**4,070**
Tax on adjusted earnings	**(8,110)**	**(4,277)**
Adjusted earnings after tax	**4,528**	**(208)**

5.3 LEGAL PROCEEDINGS

Statoil is involved in a number of proceedings globally concerning matters arising in connection with the conduct of its business. No further update is provided on previously reported legal or arbitration proceedings which Statoil does not believe will, individually or in the aggregate, have a significant effect on Statoil's financial position, profitability, results of operations or liquidity. See also note 9 Income taxes and note 23 Other commitments, contingent liabilities and contingent assets to the Consolidated financial statements.

5.4 PAYMENTS TO GOVERNMENTS

Reporting in accordance with the Norwegian transparency rule
Pursuant to Norwegian Accounting Act §3-3d and the Norwegian Security Trading Act §5-5a, Statoil has prepared the report payments to governments. The companies involved in extractive and logging activities are required to disclose payments they made to governments at project and country level and additional contextual information, consisting of certain legal, monetary, numerical and production volume information, related to the extractive part of the operations or to the entire group.

Basis for preparation
The regulation requires Statoil to prepare a consolidated report for the previous financial year on direct payments to governments, including payments made by subsidiaries, joint operations and joint ventures, or on behalf of such entities involved in extractive activities.

Scope and validity
Statoil's extractive activities covering the exploration, prospecting, discovery, development and extraction of oil and natural gas are included in this report. Additional contextual information is disclosed for legal entities engaged in extractive activities or for the entire group, on a country or legal entity basis, as applicable.

Reporting principles
The report includes payments made directly by Statoil to governments, such as taxes and royalties. Payments made by the operator of an oil and/or gas licence on behalf of the licensed partners, such as area fees, are also included in this report. For assets where Statoil is the operator, the full payment made on behalf of the whole partnership (100%) is included. No payment will be disclosed in cases where Statoil is not the operator, unless the operator is a state-owned entity and it is possible to distinguish the payment from other cost recovery items.

Host government production entitlements paid by the licence operator are also included in the report. The size of such entitlements can in some cases constitute the most significant payments to governments.

For some of our projects, we have established a subsidiary to hold the ownership in a joint venture. For these projects, payments may be made to governments in the country of operation as well as to governments in the country where the subsidiary resides.

Payments to governments are reported in the year that the actual cash payment was made (cash principle). Amounts included as contextual information are reported in the year the transaction relates to (accrual principle), regardless of when the cash flows occurred. Amounts are subject to rounding. Rounding differences may occur in summary tables.

Changes from last year
Following the revised Norwegian regulation ("Forskrift om land-for-land rapportering") additional financial contextual information was included from 2017 in the section Contextual information at Statoil group level.

Government
In the context of this report, a government is defined as any national, regional or local authority of a country. It includes any department, agency or undertaking (i.e. corporation) controlled by that government.

Project definition
A project is defined as the operational activity governed by a single contract, licence, lease, concession or similar legal agreement and that forms the basis for payment obligations to a government.

Payments not directly linked to a specific project but levied at the company entity level, are reported at that level.

Materiality
Payments constitute a single payment, or a series of related payments that equal or exceed NOK 800,000 (approximately USD 100,000 at average annual 2017 exchange rates) during the year. Payments below the threshold in a given country will not be included in the overview of projects and payments.

Reporting currency
Payments to governments in foreign currencies (other than USD) are converted to USD using the average annual 2017 exchange rate.

Payment types disclosed at project or legal entity level that are relevant for Statoil
The following payment types are disclosed for legal entities involved in extractive activities. They are presented on a cash basis, net of any interest expenses, whether paid in cash or in-kind. In-kind payments are reported in millions of barrels of oil equivalent and the equivalent cash value.

- Tax levied on the income, production or profits of companies includes severance tax and taxes paid in-kind. The value of taxes paid in-kind is calculated based on the market price at the time of the in-kind payment. Taxes levied on consumption, such as value added tax, personal income tax, sales tax, withholding tax, property tax and environmental tax are excluded. Negative amounts represent tax refunds received from governments
- Royalties are usage-based payments for the right to the ongoing use of an asset
- Fees are typically levied on the right to use a geographical area for exploration, development and production and include rental fees, area fees, entry fees, concession fees and other considerations for licences and/or concessions. Administrative government fees that are not specifically related to the extractive activities or to access extractive resources, are excluded

- Bonuses are payments made when signing an oil and gas lease, when discovering natural resources and/or when production has commenced. Bonuses often include signature, discovery and production bonuses and are a commonly used payment type, depending on the petroleum fiscal regime. Bonuses can also include elements of social contribution
- Host government production entitlements are the host government's share of production after oil production has been allocated to cover costs and expenses under a production sharing agreement (PSA). Host government production entitlements are most often paid in-kind. The value of these payments is calculated based on the market price at the time of the in-kind payment. For some PSAs, the host government production entitlements are sold by the operator, and the related costs are split between the partners. For these contracts, Statoil does not make payments directly to governments, but to the operator.

Contextual information at country level

The report discloses contextual information for legal entities engaged in extractive activities in Statoil, as listed below. All information is disclosed in accordance with the accrual accounting principle.

- Investments are defined as additions to property, plant and equipment (including capitalised finance leases), capitalised exploration expenditures, intangible assets, long-term share investments and investments in associated companies
- Revenues associated with the production of crude oil and natural gas related to our extractive activities. Revenues include third party revenues and other income, inter-segment revenues and net income from equity accounted investments
- Cost shows the sum of operating expenses, SG&A (sales, general and administrative expenses) and exploration expenses, adjusted for net impairments
- Equity production volumes are the volumes that correspond to Statoil's ownership interest in a field and do not include production of the Norwegian State's share of oil and natural gas

Contextual information at entity level

The following contextual information is disclosed for all of Statoil's subsidiaries as of 31 December 2017:

- Country of incorporation is the jurisdiction in which the company is registered
- Country of operation is the country where the company performs its main activities
- Number of employees (per subsidiary) is based on the registered company location. The actual number of employees present in a country can deviate from the reported figures due to expatriation. In some subsidiaries there are no employees. These may purchase man-hours from other companies in the Statoil group, as applicable
- Net intercompany interest is the company's net intercompany interest expense (interest expense minus interest income) to subsidiaries in another jurisdiction. Interest between companies within the same jurisdiction is eliminated. Intercompany interest is the interest levied on long-term and short-term borrowings within the Statoil group
- Total revenue and other income as presented in the Consolidated statement of income, including third party revenues and other income, inter-company revenues and net income from equity accounted investments
- Income before tax as presented in the Consolidated statement of income
- Income tax expense as defined in note 9 to the Consolidated financial statements
- Income taxes paid are reconciled to the amount presented in the Consolidated statement of the cash flows and in addition include taxes paid in-kind in Algeria, Libya and Nigeria
- Retained earnings include the gains and losses accumulated by the companies together with currency translation adjustments and other comprehensive income. Being part of shareholders equity, retained earnings are presented as reported in Statoil accounting system for consolidation purposes
- The description of the core business activity is presented according to the business areas where the business operations take place. Each subsidiary is associated to a business area. Section 2.2 Business overview, Corporate structure under the Strategic report chapter of the annual report provides the descriptions of the business areas

ADDITIONAL INFORMATION

Consolidated overview

The consolidated overview below discloses the sum (total) of Statoil's payments to governments in each country, according to the payment type. The overview is based on the location of the receiving government. The total payments to each country may be different from the total payments disclosed in the overview of payments for each project in the report. This is because payments disclosed for each project relate to the country of operation, irrespective of the location of the receiving government.

In 2017, there is an upward shift in overall payments with increasing taxes and royalties paid following the higher prices and volumes in 2017 compared to 2016 as explained in the chapter 2.9 Financial review of the Strategic report in 20-F.

Payments to governments per country (in USD million)	Taxes	Royalties	Fees	Bonuses	Host government entitlements (value in USD million)	Host government entitlements (mmboe)	Total (value) 2017
Algeria	121	-	0	-	114	3	236
Angola	558	-	-	-	1,153	22	1,710
Australia	-	-	0	0	-	-	0
Azerbaijan	43	-	-	-	621	11	664
Brazil	(0)	61	3	907	-	-	971
Canada	(1)	55	5	-	-	(0)	59
Colombia	0	-	-	-	-	-	0
Iran	5	-	-	-	-	-	5
Ireland	-	-	0	-	-	-	0
Libya	27	-	-	-	32	1	58
Mexico	-	-	3	-	-	-	3
Netherlands	0	-	-	-	-	-	0
Nicaragua	-	-	0	-	-	-	0
Nigeria	282	-	36	-	150	3	469
Norway	5,025	-	59	-	-	-	5,084
Russia	11	10	-	-	68	1	89
South Africa	-	-	0	-	-	-	0
South Korea	0	-	-	-	-	-	0
UK	(8)	-	3	-	-	-	(5)
USA	97	75	0	54	-	-	226
Venezuela	0	-	-	-	-	(0)	0
Total 2017	6,161	202	110	961	2,137	41	9,571
Total 2016	4,607	125	122	16	1,593	40	6,463

This report covers payments made directly by Statoil to governments, such as taxes and royalties. Payments made by the operator of an oil and/or gas licence on behalf of the licensed partners, such as area fees, are included. For assets where Statoil is the operator, the full payment made on behalf of the whole partnership (100%) is reported. In cases, where Statoil is not the operator, payments are not disclosed, unless the operator is a state-owned entity and it is possible to distinguish the payment from other cost recovery items. Host government production entitlements paid by the licence operator are reported.

Country details – payment per project and receiving government entity

Payments to governments per project and receiving government entity (in USD million)	Taxes	Royalties	Fees	Bonuses	Host government entitlements (value in USD million)	Host government entitlements (mmboe)	Total (value) 2017
Algeria							
Payments per project							
Statoil North Africa Gas AS	55.2	-	-	-	-	-	55.2
Statoil North Africa Oil AS	66.2	-	-	-	-	-	66.2
In Amenas	-	-	-	-	75.7	1.8	75.7
In Salah	-	-	-	-	38.2	1.4	38.2
Exploration Algeria	-	-	0.3	-	-	-	0.3
Total	121.4	-	0.3	-	113.9	3.2	235.6
Payments per government							
Direction des Grandes Enterprises	-	-	0.3	-	-	-	0.3
Sonatrach[1)]	121.4	-	-	-	113.9	3.2	235.3
Total	121.4	-	0.3	-	113.9	3.2	235.6
Angola							
Payments per project							
Statoil Angola Block 15 AS	118.8	-	-	-	-	-	118.8
Statoil Angola Block 17 AS	179.7	-	-	-	-	-	179.7
Statoil Angola Block 31 AS	93.8	-	-	-	-	-	93.8
Statoil Dezassete AS	139.6	-	-	-	-	-	139.6
Statoil Quatro AS	27.1	-	-	-	-	-	27.1
Block 15	-	-	-	-	263.0	4.9	263.0
Block 17	-	-	-	-	859.2	16.2	859.2
Block 31	-	-	-	-	30.5	0.6	30.5
Total	559.1	-	-	-	1,152.7	21.7	1,711.8
Payments per government							
Banco Nacional de Angola[2)]	557.6	-	-	-	-	-	557.6
Sonangol EP	-	-	-	-	1,152.7	21.7	1,152.7
Stavanger kemnerkontor	1.6	-	-	-			1.6
Total	559.1	-	-	-	1,152.7	21.7	1,711.8
Azerbaijan							
Payments per project							
Statoil Apsheron AS	39.4	-	-	-	-	-	39.4
Statoil Azerbaijan AS	0.9	-	-	-	-	-	0.9
Statoil BTC Caspian AS	3.5	-	-	-	-	-	3.5
ACG	-	-	-	-	621.1	11.4	621.1
Total	43.8	-	-	-	621.1	11.4	664.9
Payments per government							
Ministry of Taxes Azerbaijan	42.9	-	-	-	-	-	42.9
Stavanger kemnerkontor	1.0	-	-	-			1.0
SOCAR - The State Oil Company of the Azerbaijan Republic	-	-	-	-	621.1	11.4	621.1
Total	43.8	-	-	-	621.1	11.4	664.9
Brazil							
Payments per project							
Carcara	-	-	0.1	-	-	-	0.1
Carcará North	-	-	-	906.9	-	-	906.9
Peregrino	-	61.2	2.1	-	-	-	63.3
Exploration Brazil	-	-	0.7	-	-	-	0.7
Total	-	61.2	2.9	906.9	-	-	971.0
Payments per government							
Agência Nacional do Petróleo, Gás Natural e Biocombustíveis[3)]	-	-	2.9	906.9	-	-	909.8
Ministerio da Fazenda	(0.0)	61.2	-	-	-	-	61.2
Total	(0.0)	61.2	2.9	906.9	-	-	971.0

Payments to governments per project and receiving government entity (in USD million)	Taxes	Royalties	Fees	Bonuses	Host government entitlements (value in USD million)	Host government entitlements (mmboe)	Total (value) 2017
Canada							
Payments per project							
Statoil Canada Ltd.	(1.0)	-	-	-	-	-	(1.0)
Exploration Canada offshore	-	-	3.9	-	-	-	3.9
Hibernia	-	39.5	-	-	-	-	39.5
Leismer	-	0.5	1.1	-	-	-	1.6
Terra Nova	-	15.1	-	-	-	-	15.1
Total	(1.0)	55.2	5.0	-	-	-	59.2
Payments per government							
Alberta Energy Regulator	-	-	0.5	-	-	-	0.5
Canada-Newfoundland and Labrador Offshore Petr. Board	-	-	1.1	-	-	-	1.1
Government of Alberta	-	-	0.6	-	-	-	0.6
Government of Canada	(1.0)	29.9	2.9	-	-	-	31.8
Government of Newfoundland and Labrador	-	24.7	-	-	-	-	24.7
Minister of Finance - PT Mineral	-	0.5	-	-	-	-	0.5
Total	(1.0)	55.2	5.0	-	-	-	59.2
Colombia							
Payments per project							
Statoil Colombia B.V.	0.1	-	-	-	-	-	0.1
Total	0.1	-	-	-	-	-	0.1
Payments per government							-
National Directorate of Taxes and Customs	0.1	-	-	-	-	-	0.1
Total	0.1	-	-	-	-	-	0.1
Iran							
Payments per project							
Statoil SP GAS AS	4.6	-	-	-	-	-	4.6
Statoil Iran AS	0.1	-	-	-	-	-	0.1
Statoil Zagros O&G AS	0.6	-	-	-	-	-	0.6
Total	5.3	-	-	-	-	-	5.3
Payments per government							
Sazmane Omoore Maliatie[4)]	5.1	-	-	-	-	-	5.1
Stavanger kemnerkontor	0.2	-	-	-	-	-	0.2
Total	5.3	-	-	-	-	-	5.3
Ireland							
Payments per project							
Exploration Ireland offshore	-	-	0.2	-	-	-	0.2
Total	-	-	0.2	-	-	-	0.2
Payments per government							
Dept. of Communications, Energy and Natural Resources	-	-	0.2	-	-	-	0.2
Total	-	-	0.2	-	-	-	0.2
Libya							
Payments per project							
Statoil Murzuq AS	26.9	-	-	-	-	-	26.9
Murzuq	-	-	-	-	31.6	0.6	31.6
Total	26.9	-	-	-	31.6	0.6	58.4
Payments per government							
National Oil Corporation	-	-	-	-	-	-	
Tax Department Libya[5)]	26.9	-	-	-	31.6	0.6	58.4
Total	26.9	-	-	-	31.6	0.6	58.4

Payments to governments per project and receiving government entity (in USD million)	Taxes	Royalties	Fees	Bonuses	Host government entitlements (value in USD million)	Host government entitlements (mmboe)	Total (value) 2017
Mexico							
Payments per project							
Statoil E&P Mexico SA	-	-	2.7	-	-	-	2.7
Total	-	-	2.7	-	-	-	2.7
Payments per government							
Servicio de Administración Tributaria	-	-	1.5	-	-	-	1.5
Fondo Monetario del Petroleo	-	-	1.2	-	-	-	1.2
Total	-	-	2.7	-	-	-	2.7
Nicaragua							
Payments per project							
Exploration Nicaragua offshore	-	-	0.1	-	-	-	0.1
Total	-	-	0.1	-	-	-	0.1
Payments per government							
Ministerio de Energia y Minas	-	-	0.1	-	-	-	0.1
Total	-	-	0.1	-	-	-	0.1
Nigeria							
Payments per project							
Statoil Nigeria Ltd.	282.4	-	-	-	-	-	282.4
Agbami	-	-	36.3	-	150.4	2.8	186.7
Total	282.4	-	36.3	-	150.4	2.8	469.1
Payments per government							
Central Bank of Nigeria Education Tax	-	-	21.5	-	-	-	21.5
Central Bank of Nigeria NESS fee	-	-	0.5	-	-	-	0.5
Niger Delta Development Commission	-	-	14.2	-	-	-	14.2
Nigerian National Petroleum Corporation[6)]	282.4	-	-	-	150.4	2.8	432.8
Total	282.4	-	36.3	-	150.4	2.8	469.1
Norway							
Payments per project							
Statoil Petroleum AS	5,022.1	-	-	-	-	-	5,022.1
Exploration Barents Sea	-	-	13.1	-	-	-	13.1
Exploration Norwegian Sea	-	-	8.5	-	-	-	8.5
Exploration North Sea	-	-	36.1	-	-	-	36.1
Other	-	-	1.2	-	-	-	1.2
Total	5,022.1	-	58.9	-	-	-	5,081.0
Payments per government							
Oljedirektoratet	-	-	58.9	-	-	-	58.9
Oljeskattekontoret	5,022.1	-	-	-	-	-	5,022.1
Total	5,022.1	-	58.9	-	-	-	5,081.0
Russia							
Payments per project							
Statoil Sverige Kharyaga	11.4	-	-	-	-	-	11.4
Kharyaga	-	10.1	-	-	67.8	1.3	77.9
Total	11.4	10.1	-	-	67.8	1.3	89.3
Payments per government							
Zarubezhneft-Production Kharyaga LL	11.4	10.1	-	-	-	-	21.5
Treasury of the Russian Federation	-	-	-	-	67.8	1.3	67.8
Total	11.4	10.1	-	-	67.8	1.3	89.3
South Africa							
Payments per project							
Exploration South Africa	-	-	0.1	-	-	-	0.1
Total	-	-	0.1	-	-	-	0.1
Payments per government							
Upstream Training Trust	-	-	0.1	-	-	-	0.1
Total	-	-	0.1	-	-	-	0.1

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ADDITIONAL INFORMATION

Payments to governments per project and receiving government entity (in USD million)	Taxes	Royalties	Fees	Bonuses	Host government entitlements (value in USD million)	Host government entitlements (mmboe)	Total (value) 2017
UK							
Payments per project							
Statoil UK Ltd	(7.6)	-	-	-	-	-	(7.6)
Alfa Sentral	-	-	0.1	-	-	-	0.1
Bressay	-	-	0.3	-	-	-	0.3
Mariner	-	-	0.8	-	-	-	0.8
Mariner East	-	-	0.2	-	-	-	0.2
Exploration UK offshore	-	-	1.5	-	-	-	1.5
Total	(7.6)	-	2.8	-	-	-	(4.8)
Payments per government							
Department of Energy and Climate Change	-	-	1.5	-	-	-	1.5
Health & Safety Executive	-	-	0.2	-	-	-	0.2
HM Revenue & Customs	(7.6)	-	-	-	-	-	(7.6)
Oil and Gas Authority	-	-	1.1	-	-	-	1.1
Total	(7.6)	-	2.8	-	-	-	(4.8)
USA							
Payments per project							
Bakken[7)]	79.7	14.1	0.0	-	-	-	93.9
Ceasar-Tonga	-	11.6	-	-	-	-	11.6
Eagle Ford[7)]	10.5	1.1	0.1	-	-	-	11.7
Heidelberg	-	7.5	-	-	-	-	7.5
Appalachian basin[7)]	6.5	0.4	-	-	-	-	6.9
Tahiti	-	40.7	-	-	-	-	40.7
Exploration USA offshore	-	-	0.3	53.8	-	-	54.1
Total	96.7	75.5	0.4	53.8	-	-	226.4
Payments per government							
City of Kenedy	-	0.2	-	-	-	-	0.2
City of Runge	-	0.3	-	-	-	-	0.3
Commonwealth of Pennsylvania	-	0.1	-	-	-	-	0.1
Montana Dept. of Revenue	1.8	-	-	-	-	-	1.8
North Dakota Office of State Tax	78.0	-	-	-	-	-	78.0
Office of Natural Resources Revenue	-	62.9	0.3	53.8	-	-	117.0
Pennsylvania Game Commision	-	0.1	-	-	-	-	0.1
State of Montana	-	0.1	-	-	-	-	0.1
State of North Dakota	-	10.8	-	-	-	-	10.8
State of Ohio	0.6	-	-	-	-	-	0.6
State of West Virginia	5.9	-	(0.0)	-	-	-	5.9
Texas Comptroller of Public Accounts	10.5	-	-	-	-	-	10.5
Texas General Land Office	-	0.5	-	-	-	-	0.5
Other	-	0.4	0.0	-	-	-	0.5
Total	96.7	75.5	0.4	53.8	-	-	226.4
Venezuela							
Payments per project							
Statoil Int. Venezuela AS	0.5	-	-	-	-	-	0.5
Total	0.5	-	-	-	-	-	0.5
Payments per government							
Tesoro Nacional	0.5	-	-	-	-	-	0.5
Total	0.5	-	-	-	-	-	0.5

1) Algeria - Tax payments in-kind to Sonatrach of 3.6 mmboe were valued at USD 121.4 million.
2) Angola - Taxes paid in Angola include the settlement of dispute with the Angolian Ministry of Finance. For further information please refer to Note 23 Other commitments, contingent liabilities and contingent assets in the Consolidated financial statements
3) Brazil - Statoil paid USD 906.9 million in signature bonus related to the Carcará North block in the Santos basin as an operator on behalf of all partners. Statoil's share is USD 350 million.
4) Iran - National Iranian Oil Company (NIOC) settled, on behalf of Statoil, a prior year tax obligation of USD 5,13 million equivalent in Iranial Rial to the local tax authorities. The amount was settled towards historical recoverable taxes from NIOC to Statoil.
5) Libya - Tax payments in kind to Tax Department Libya of 0.5 mmboe were valued at USD 26.9 million.
6) Nigeria - Tax payments in-kind to Nigerian National Petroleum Corporation (NNPC) of 4.4 mmboe were valued at USD 282.4 million.
7) USA - Bakken is owned by Statoil Oil & Gas LP. Eagle Ford is owned by Statoil Texas Onshore Properties LLC. Appalachian basin is owned by Statoil USA Onshore Properties Inc.

Contextual information at country level

The contextual information on investments, revenues, cost and production volumes is disclosed for each country and relates only to the Statoil's entities engaged in extractive activities, covering the exploration, prospecting, discovery, development and extraction of oil and natural gas. The contextual information reported is based on data collected mainly for the purpose of financial reporting and is reconciled to the numbers reported for the Exploration and Production segments of Statoil.

Contextual information per country for Exploration & Production segments

(in USD million)	Investments	Revenues	Cost[2)]	Production volume(mmboe)
Algeria	135	621	57	23
Angola	208	3,439	419	72
Argentina	-	-	6	-
Australia	0	0	8	-
Azerbaijan	429	392	92	18
Brazil	988	564	389	15
Canada	140	365	633	6
Colombia	-	-	71	-
Faroe Islands	-	0	4	-
Greenland	-	-	6	-
Indonesia	0	-	9	-
Ireland	(1)	278	82	7
Iran	-	1	(2)	-
Libya	3	43	6	1
Mexico	-	-	34	-
Mozambique	-	-	6	-
Myanmar	-	-	7	-
Netherlands	-	0	12	-
New Zealand	-	-	18	-
Nicaragua	-	-	6	-
Nigeria	70	617	125	17
Norway	4,886	17,546	3,426	487
Russia	39	122	99	3
South Africa	15	-	16	-
Suriname	-	-	23	-
Sweden	-	126	5	-
Tanzania	(0)	0	46	-
Turkey	28	-	19	-
UK	563	45	106	1
Uruguay	-	-	11	-
United Arab Emirates	-	0	4	-
USA	2,428	2,788	1,079	107
Venezuela	0	1	7	2
Total[1)]	9,932	26,947	6,825	759

1) The total amounts correspond to the sum of the relevant numbers reported in the Exploration and Production segments in the note 3 of the Consolidated financial statements
2) Cost include operating expenses, SG&A and exploration expenses, without net impairments, as presented in the Consolidated financial statements.

Contextual information at Statoil group level

The table below is an overview of all subsidiaries in the Statoil group by country of incorporation as of 31 December 2017. It presents the following information per each subsidiary: the number of employees, net intercompany interest to companies in other jurisdictions, short description of the company's activity, revenues including intercompany revenues, income before tax, current income tax expense, income tax paid, companies retained earnings. The total amounts are reconciled to the Group Consolidated financial statements prepared in compliance with International Financial Reporting Standards (IFRS).

Contextual information at Statoil group level (in USD million)	Country of operation	Core business activity	Number of employees	Net Intercompany interest	Revenues	Income before tax	Income tax expense[1)]	Income tax paid	Retained earnings[3)]
Belgium									
Statoil Coordination Center NV	Belgium	Finance	13	6	0	10	(3)	(2)	660
Statoil Energy Belgium NV	Belgium	MMP	51	0	0	0	(1)	(0)	8
Total			64	6	0	11	(4)	(2)	668
Brazil									
Statoil Brasil Óleo e Gás Ltda	Brazil	DPI	323	(2)	599	(267)	38	0	(1,450)
Statoil do Brasil Ltda	Brazil	DPI	-	-	(0)	(9)	(0)	(0)	(927)
Total			323	(2)	599	(276)	38	(0)	(2,376)
Canada									
Statoil Canada Holdings Corp.	Canada	DPI	-	-	-	-	0	-	1
Statoil Canada Ltd.	Canada	DPI	131	(1)	377	47	1	1	(2,712)
Total			131	(1)	377	47	1	1	(2,711)
British Virgin Island									
Spinnaker (BVI) 242 LTD	Nigeria	Dormant	-	-	-	-	-	-	-
Spinnaker Exploration (BVI) 256 LTD	Nigeria	Dormant	-	-	-	-	-	-	-
Spinnaker Exploration Holdings (BVI) 256 LTD	Nigeria	Dormant	-	-	-	-	-	-	-
Spinnaker Holdings (BVI) 242 LTD	Nigeria	Dormant	-	-	-	-	-	-	-
Total			-	-	-	-	-	-	-
China									
Statoil (Beijing) Business Consulting Service Co, Ltd.	China	DPI	3	-	0	1	(0)	(0)	1
Total			3	-	0	1	(0)	(0)	1
Denmark									
Statoil Danmark A/S	Denmark	MMP	-	(0)	-	(0)	-	-	132
Statoil Refining Denmark A/S	Denmark	MMP	330	(0)	3,188	213	6	(10)	345
Statoil Wind I A/S	Denmark	NES	-	-	-	-	-	-	-
Statoil Wind II A/S	Denmark	NES	-	-	-	-	-	-	-
Statoil Wind III A/S	Denmark	NES	-	-	-	-	-	-	-
Total			330	(0)	3,188	213	6	(10)	477
Germany									
Statoil Deutschland GmbH	Germany	MMP	7	-	1	(1)	11	(7)	141
Statoil Deutschland Property GmbH	Germany	MMP	-	(0)	0	0	-	-	0
Statoil Deutschland Storage GmbH	Germany	MMP	7	(0)	50	22	(0)	-	35
Total			14	(0)	50	21	11	(7)	175
Indonesia									
PT Statoil Indonesia	Indonesia	EXP	-	-	-	(0)	(0)	-	1
Total			-	-	-	(0)	(0)	-	1

Contextual information at Statoil group level (in USD million)	Country of operation	Core business activity	Number of employees	Net Intercompany interest	Revenues	Income before tax	Income tax expense[1]	Income tax paid	Retained earnings[3]
Ireland									
Petroleum Royalties of Ireland Ltd	Ireland	DPI	2	(0)	1	1	(0)	(0)	1
Statoil Exploration (Ireland) Limited	Ireland	DPI	-	0	277	(37)	(0)	(0)	(925)
Statoil Gas Hibernia Ltd	Ireland	MMP	-	0	(2)	(0)	0	(0)	(1)
Total			2	0	276	(36)	(0)	(0)	(924)
Mexico									
Statoil E&P Mexico, S.A. de C.V.	Mexico	EXP	-	-	-	(32)	0	-	(53)
Total			-	-	-	(32)	0	-	(53)
Netherlands									
Statoil Argentina B.V.	Argentina	DPI	-	0	-	(6)	0	-	(6)
Statoil Algeria B.V.	Algeria	EXP	-	0	-	(2)	0	0	(30)
Statoil Australia Theta B.V.	Australia	EXP	-	(0)	-	(9)	(0)	(0)	(168)
Statoil Zeta Netherlands B.V.	Azerbaijan	EXP	-	-	-	(3)	(0)	-	(3)
Statoil International Netherlands B.V	Canada	DPI	-	0	0	0	(0)	(0)	(1,011)
Statoil Colombia B.V.	Colombia	EXP	-	(0)	-	(71)	(0)	(0)	(120)
Statoil Indonesia Aru Trough I B.V.	Indonesia	EXP	19	0	-	(4)	0	0	(14)
Statoil India Netherlands B.V.	India	EXP	-	0	-	(0)	1	1	(8)
Statoil Middle East Services Netherlands B.V.	Iraq	DPI	-	0	-	(0)	0	0	(202)
Statoil Mozambique A5-A B.V.	Mozambique	EXP	-	(0)	-	(5)	0	0	(6)
Statoil Nicaragua Holdings B.V.	Nicaragua	EXP	-	(0)	-	(9)	0	0	(35)
Redhotpoker Alfa B.V.	Netherlands	NES	-	-	-	-	-	-	-
Redhotpoker Beheer B.V.	Netherlands	NES	-	-	-	-	-	-	-
Redhotpoker Beta B.V.	Netherlands	NES	-	-	-	-	-	-	-
Redhotpoker C.V.	Netherlands	NES	-	-	-	-	-	-	-
Redhotpoker Delta B.V	Netherlands	NES	-	-	-	-	-	-	-
Redhotpoker Epsilon B.V	Netherlands	NES	-	-	-	-	-	-	-
Redhotpoker Gamma B.V.	Netherlands	NES	-	-	-	-	-	-	-
Statoil Energy Netherlands B.V.	Netherlands	Finance	-	62	-	65	(12)	(12)	45
Statoil Energy Ventures Fund B.V.	Netherlands	NES	-	0	(4)	(8)	1	1	(10)
Statoil Holding Netherlands B.V.	Netherlands	DPI	8	2	146	78	(7)	(7)	(984)
Statoil New Zealand B.V.	New Zealand	EXP	-	(0)	-	(18)	0	0	(67)
Statoil Epsilon Netherlands B.V.	Russia	EXP	-	0	-	(0)	(0)	-	(24)
Statoil South Africa B.V.	South Africa	EXP	-	0	-	(16)	0	0	(41)
Statoil Suriname B.V.	Suriname	EXP	-	0	-	(19)	0	0	(33)
Statoil Suriname B59 B.V.	Suriname	EXP	-	0	-	(0)	(0)	(0)	(1)
Statoil Suriname B60 B.V.	Suriname	EXP	-	0	-	(3)	(0)	-	(3)
Statoil Banarli Turkey B.V.	Turkey	EXP	-	0	-	(19)	0	0	(22)
Statoil Abu Dhabi B.V.	United Arab	DPI	3	(0)	0	(4)	0	0	(21)
Statoil Uruguay B.V.	Uruguay	EXP	-	0	-	(11)	0	0	(73)
Statoil Sincor Netherlands B.V.	Venezuela	DPI	-	0	-	9	5	5	(304)
Total			30	64	142	(54)	(13)	(13)	(3,143)
Nigeria									
Spinnaker Exploration 256 LTD	Nigeria	DPUSA	-	-	-	-	-	-	(13)
Spinnaker Nigeria 242 LTD	Nigeria	DPUSA	-	-	-	-	-	-	(16)
Statoil Nigeria Deep Water Limited	Nigeria	DPI	-	0	-	(0)	-	-	(35)
Statoil Nigeria LTD	Nigeria	DPI	12	4	617	347	(175)	(208)	301
Statoil Nigeria Outer Shelf Limited	Nigeria	DPI	-	(0)	-	(0)	-	-	(148)
Total			12	4	617	347	(175)	(208)	89

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ADDITIONAL INFORMATION

Contextual information at Statoil group level (in USD million)	Country of operation	Core business activity	Number of employees	Net Intercompany interest	Revenues	Income before tax	Income tax expense[1)]	Income tax paid	Retained earnings[3)]
Norway									
Statoil Angola AS	Angola	DPI	-	0	2	(5)	2	-	(7)
Statoil Angola Block 15 AS	Angola	DPI	-	3	883	679	(67)	(119)	463
Statoil Angola Block 15/06 Award AS	Angola	DPI	-	0	-	(0)	0	-	(139)
Statoil Angola Block 17 AS	Angola	DPI	15	13	1,235	722	(161)	(180)	2,095
Statoil Angola Block 22 AS	Angola	EXP	-	0	-	(2)	0	-	(220)
Statoil Angola Block 25 AS	Angola	EXP	-	0	-	0	0	-	(190)
Statoil Angola Block 31 AS	Angola	DPI	-	3	375	(48)	(14)	(94)	(778)
Statoil Angola Block 38 AS	Angola	EXP	-	0	-	15	6	-	(767)
Statoil Angola Block 39 AS	Angola	EXP	-	0	-	(6)	1	-	(855)
Statoil Angola Block 40 AS	Angola	EXP	-	0	-	(0)	0	-	(203)
Statoil Dezassete AS	Angola	DPI	-	10	934	571	(135)	(140)	1,373
Statoil Quatro AS	Angola	DPI	-	1	9	9	(25)	(27)	(182)
Statoil Trinta e Quatro AS	Angola	DPI	-	0	-	1	(0)	-	(142)
Statoil Apsheron AS	Azerbaijan	DPI	11	2	363	94	(22)	(39)	908
Statoil Azerbaijan AS	Azerbaijan	MMP	-	1	-	5	(0)	(1)	(3)
Statoil BTC Caspian AS	Azerbaijan	DPI	-	2	29	30	(0)	(4)	160
Statoil BTC Finance AS	Azerbaijan	DPI	-	0	-	1	(0)	(0)	256
Statoil Shah Deniz AS	Azerbaijan	DPI	-	2	0	9	(0)	-	0
Statoil Oil & Gas Brazil AS	Brazil	DPI	-	1	-	(8)	(2)	-	(358)
Statoil China AS	China	DPI	3	0	-	(3)	1	(0)	(48)
Statoil Algeria AS	Algeria	DPI	27	(0)	-	(5)	0	-	(103)
Statoil Hassi Mouina AS	Algeria	DPI	-	0	0	(0)	0	-	(369)
Statoil North Africa Gas AS	Algeria	DPI	-	1	362	73	(9)	(55)	657
Statoil North Africa Oil AS	Algeria	DPI	-	0	258	133	(80)	(66)	61
Statoil Egypt AS	Egypt	EXP	-	0	-	0	(0)	-	(40)
Statoil Egypt El Dabaa Offshore AS	Egypt	EXP	-	0	-	0	0	-	(281)
Statoil Færøyene AS	Faroe Islands	EXP	-	0	0	(4)	(0)	-	(118)
Statoil Global New Ventures AS	Ghana	EXP	-	0	-	1	(0)	-	0
Statoil Greenland AS	Greenland	EXP	-	0	-	(6)	0	-	(69)
Statoil Indonesia Aru AS	Indonesia	EXP	-	0	-	(2)	0	(0)	(8)
Statoil Indonesia AS	Indonesia	EXP	-	0	-	(0)	(0)	-	(83)
Statoil Indonesia Halmahera II AS	Indonesia	EXP	-	0	-	0	0	-	(52)
Statoil Indonesia Karama AS	Indonesia	EXP	-	0	-	1	0	-	(49)
Statoil Indonesia North Ganal AS	Indonesia	EXP	-	0	-	0	0	-	2
Statoil Indonesia North Makassar Strait AS	Indonesia	EXP	-	0	-	(0)	0	-	(41)
Statoil Indonesia Obi AS	Indonesia	EXP	-	0	-	0	0	-	(2)
Statoil Indonesia West Papua IV AS	Indonesia	EXP	-	0	-	(3)	0	-	(14)
Statoil Gas Marketing Europe AS	Ireland	MMP	-	(0)	0	(0)	(0)	-	0
Statoil Iran AS	Iran	DPI	-	0	-	3	(0)	(0)	(8)
Statoil SP Gas AS	Iran	DPI	-	0	1	3	6	(0)	(22)
Statoil Zagros Oil and Gas AS	Iran	EXP	-	0	0	(0)	1	(1)	(61)
Statoil North Caspian AS	Kazakhstan	EXP	1	0	-	(0)	0	-	(42)
Statoil Cyrenaica AS	Libya	EXP	-	0	-	(0)	0	-	(25)
Statoil Kufra AS	Libya	EXP	-	0	-	(0)	0	-	(26)
Statoil Libya AS	Libya	DPI	3	(0)	-	(1)	(0)	-	(31)
Statoil Mabruk AS	Libya	DPI	-	0	-	(3)	0	-	(74)
Statoil Murzuq Area 146 AS	Libya	DPI	-	0	-	0	0	-	(41)
Statoil Murzuq AS	Libya	DPI	-	0	43	26	(22)	(27)	45
Statoil Mexico AS	Mexico	EXP	5	(0)	-	(3)	1	-	(33)

Contextual information at Statoil group level (in USD million)	Country of operation	Core business activity	Number of employees	Net Intercompany interest	Revenues	Income before tax	Income tax expense[1]	Income tax paid	Retained earnings[3]
Statoil Oil & Gas Mozambique AS	Mozambique	EXP	-	0	-	(2)	0	-	(120)
Statoil Nigeria AS	Nigeria	DPI	-	1	-	4	1	-	(73)
Hywind AS	Norway	NES	-	0	-	(0)	0	-	(3)
Mongstad Terminal DA	Norway	MMP	-	0	49	16	0	-	14
Octio AS	Norway	TPD	-	0	4	0	(0)	-	(12)
Statholding AS	Norway	DPI	-	4	-	29	(1)	-	0
Statoil ASA	Norway	Parent	17,618	655	40,011	1,134	(229)	(24)	25,831
Statoil Forsikring as	Norway	Insurance	-	-	-	239	13	(1)	2,075
Statoil GTL AS	Norway	TPD	-	0	-	0	0	-	3
Statoil International Well Response Company AS	Norway	TPD	-	0	-	2	0	-	(8)
Statoil Kapitalforvaltning ASA	Norway	DPI	14	-	12	8	(2)	-	10
Statoil Kazakstan AS	Norway	DPI	-	0	-	(2)	0	-	10
Statoil Metanol ANS	Norway	MMP	-	0	86	12	-	-	24
Statoil Middle East Operations AS	Norway	DPI	-	0	-	0	(0)	-	(20)
Statoil New Energy AS	Norway	NES	-	(0)	-	(0)	0	-	(147)
Statoil Petroleum AS	Norway	DPN	-	(399)	20,579	11,018	(8,094)	(5,065)	22,139
Statoil Refining Norway AS	Norway	MMP	-	1	593	200	(40)	-	347
Statoil Technology Invest AS	Norway	TPD	-	0	3	(5)	1	-	(47)
Statoil Venture AS	Norway	TPD	-	0	-	(0)	(0)	-	(76)
Svanholmen 8 AS	Norway	Admin	-	0	-	4	(1)	-	(0)
Wind Power AS	Norway	NES	-	0	-	(0)	(0)	-	(0)
K/S Rafinor A/S	Norway	MMP	-	0	-	2	-	-	24
Tjeldbergodden Luftgassfabrikk DA	Norway	MMP	-	-	27	2	-	-	10
Rafinor AS	Norway	MMP	-	(0)	0	0	(0)	-	0
Gravitude AS	Norway	TPD	-	0	(1)	(4)	1	-	(1)
Statoil LNG Ship Holding AS	Norway	MMP	-	-	-	-	-	-	-
Statoil Orinoco AS	Venezuela	DPI	-	0	-	0	0	-	(6)
Statoil Global New Ventures 2 AS	Russia	EXP	-	-	-	(12)	(0)	-	(19)
Statoil Kharyaga AS	Russia	DPI	-	0	-	(1)	1	-	(1)
Statoil Russia AS	Russia	DPI	53	(0)	9	(26)	0	-	(47)
Statoil Russia Services AS	Russia	DPI	-	0	1	(0)	0	-	(1)
Statoil Russland AS	Russia	DPI	-	0	-	(0)	(0)	-	1
Statoil Tanzania AS	Tanzania	DPI	21	0	0	(47)	0	-	(456)
Statoil E&P Americas AS	USA	DPUSA	-	1	-	1	(0)	-	19
Statoil Norsk LNG AS	USA	MMP	-	1	-	6	(0)	(13)	0
Statoil International Venezuela AS	Venezuela	DPI	-	0	1	1	(1)	(0)	(88)
Statoil Latin America AS	Venezuela	DPI	-	0	-	3	(0)	-	4
Statoil Sincor AS	Venezuela	DPI	-	0	-	3	(0)	-	41
Statoil Venezuela AS	Venezuela	DPI	22	0	-	(1)	0	-	(603)
Total			17,793	305	65,870	14,862	(8,870)	(5,855)	49,362
Singapore									
Statoil Myanmar Private Limited	Myanmar	EXP	-	0	-	(7)	0	-	(21)
Statoil Asia Pacific PTE Ltd	Singapore	MMP	29	0	0	1	(0)	(0)	(5)
Total			29	0	0	(5)	(0)	(0)	(26)
South Korea									
Statoil South Korea Co., Ltd	South Korea	TPD	-	-	2	0	(0)	(0)	0
Total			-	-	2	0	(0)	(0)	0

Contextual information at Statoil group level (in USD million)	Country of operation	Core business activity	Number of employees	Net Intercompany interest	Revenues	Income before tax	Income tax expense[1)]	Income tax paid	Retained earnings[3)]
Sweden									
Statoil Sverige Kharyaga AB	Russia	DPI	-	(1)	111	41	(15)	(11)	123
Statoil OTS AB	Sweden	MMP	-	(5)	1,290	74	0	-	18
Total			-	(6)	1,401	116	(15)	(11)	142
Switzerland									
Statoil Orient AG	Switzerland	DPI	-	1	-	1	-	-	(4)
Statoil Holding Switzerland AG	Switzerland	DPI	-	-	-	(0)	-	-	0
Total			-	1	-	1	-	-	(4)
UK									
Doggerbank Project 1A Statoil Limited	UK	NES	-	-	-	-	-	-	-
Doggerbank Project 1B Statoil Limited	UK	NES	-	-	-	-	-	-	-
Doggerbank Project 1C Statoil Limited	UK	NES	-	-	-	-	-	-	-
Doggerbank Project 2A Statoil Limited	UK	NES	-	-	-	-	-	-	-
Doggerbank Project 2B Statoil Limited	UK	NES	-	-	-	-	-	-	-
Doggerbank Project 2C Statoil Limited	UK	NES	-	-	-	-	-	-	-
Doggerbank Project 4A Statoil Limited	UK	NES	-	-	-	-	-	-	-
Doggerbank Project 4B Statoil Limited	UK	NES	-	-	-	-	-	-	-
Doggerbank Project 4C Statoil Limited	UK	NES	-	-	-	-	-	-	-
Doggerbank Project 5A Statoil Limited	UK	NES	-	-	-	-	-	-	-
Doggerbank Project 5B Statoil Limited	UK	NES	-	-	-	-	-	-	-
Doggerbank Project 6A Statoil Limited	UK	NES	-	-	-	-	-	-	-
Doggerbank Project 6B Statoil Limited	UK	NES	-	-	-	-	-	-	-
Dudgeon Holdings Limited	UK	NES	-	-	23	23	-	-	102
Statoil (U.K.) Limited	UK	GSB	334	(26)	62	(7)	160	11	321
Statoil Gas Trading Limited	UK	MMP	-	(1)	0	0	(0)	(0)	(93)
Statoil Global Employment Limited	UK	Admin	-	0	(0)	(0)	-	-	0
Statoil Production (UK) Limited	UK	DPI	142	(0)	-	(1)	(0)	(1)	(2)
Statoil UK Properties Limited	UK	DPI	-	0	-	(0)	-	-	(50)
Statoil Wind Limited	UK	NES	-	0	19	19	(4)	(0)	15
Total			476	(27)	103	33	156	10	293
USA									
Statoil South Riding Point, LLC	Bahamas	MMP	54	(0)	40	2	-	-	(263)
North America Properties LLC	USA	DPUSA	-	0	-	(4)	-	-	(6)
Onshore Holdings LLC	USA	DPUSA	-	0	-	(0)	-	-	(149)
Spinnaker FR Spar Co, LLC	USA	DPUSA	-	(0)	-	(0)	-	-	(4)
Statoil E&P Americas Investment LLC	USA	DPUSA	-	-	-	-	-	-	(0)
Statoil E&P Americas LP	USA	DPUSA	-	0	-	0	0	-	16
Statoil Energy Trading Inc.	USA	MMP	-	0	-	0	-	-	1
Statoil Exploration Company	USA	DPUSA	-	0	-	0	-	-	(50)
Statoil Gulf of Mexico Inc.	USA	DPUSA	-	0	-	0	-	-	(11)
Statoil Gulf of Mexico LLC	USA	DPUSA	-	2	1,100	(1)	-	-	(5,914)
Statoil Gulf of Mexico Response Company LLC	USA	DPUSA	-	(0)	-	(12)	-	-	(30)
Statoil Gulf Properties Inc.	USA	DPUSA	-	(0)	-	1	-	-	(225)
Statoil Gulf Services LLC	USA	DPUSA	858	(17)	(0)	(11)	0	-	(870)
Statoil Marketing & Trading (US) Inc.	USA	MMP	-	(3)	9,861	(28)	(1)	-	(352)
Statoil Natural Gas LLC	USA	MMP	-	3	1,556	173	(0)	-	0

ADDITIONAL INFORMATION

Contextual information at Statoil group level (in USD million)	Country of operation	Core business activity	Number of employees	Net Intercompany interest	Revenues	Income before tax	Income tax expense[1)]	Income tax paid	Retained earnings[3)]
Statoil Oil & Gas LP	USA	DPUSA	-	2	658	1,235	-	-	(4,050)
Statoil Oil & Gas Services Inc.	USA	DPUSA	-	(0)	-	(0)	-	-	(0)
Statoil Pipelines LLC	USA	MMP	-	0	278	(79)	-	-	345
Statoil Projects Inc.	USA	DPUSA	-	0	-	0	-	-	4
Statoil Shipping, Inc.	USA	MMP	-	1	161	(9)	-	-	169
Statoil Texas Onshore Properties LLC	USA	DPUSA	-	(2)	241	(969)	-	-	(2,451)
Statoil US Holdings Inc.	USA	DPUSA	126	(327)	-	(325)	1	(1)	(2,214)
Statoil USA E&P Inc.	USA	DPUSA	-	(1)	81	(52)	-	-	(1,422)
Statoil USA Onshore Properties Inc.	USA	DPUSA	-	(2)	539	(29)	-	-	(2,615)
Statoil USA Properties Inc.	USA	DPUSA	-	0	-	0	0	(0)	1,112
Statoil Wind US LLC	USA	NES	-	(1)	-	(7)	-	-	(12)
Total			1,038	(345)	14,516	(114)	0	(1)	(18,992)
Sum before eliminations			20,245	(0)	87,141	15,134	(8,866)	(6,097)	22,979
Consolidation eliminations[2)]					(25,955)	(1,714)	44	(0)	7,770
Statoil group					61,187	13,420	(8,822)	(6,097)	30,748

1) Income tax expense as defined in note and 9 of the Consolidated financial statements
2) All intercompany balances and transactions arising from Statoil's internal transactions, have been eliminated in full. The relevant amounts are included in the consolidation eliminations line. Revenues column: the eliminations of intercompany revenues and netting of some intercompany costs. Income before tax column: the eliminations of intercompany dividend distribution and share impairment as well as foreign exchange gain on intergroup loan. Income tax expense column: tax effects of certain elimination entries. Retained earnings column: the entries here mainly relate to foreign currency translation effects in the consolidation process. Translation of results and financial position to presentation currency of USD is significantly affected by the investment in subsidiary, which has NOK as a functional currency. In turn, that subsidiary includes the results and financial position of its investments in foreign subsidiaries, which have USD functional currency
3) The retained earnings as presented in this report may be different compared to the figures in the statutory financial statement reported to the Norwegian company register (Brønnøysundregistrene). The main reason for the deviations relates to foreign currency translation, classification of capital contributions and differences in accounting principles.

Independent Limited Assurance Report to Statoil ASA on the Payments to governments report

We were engaged by management of Statoil ASA to report on Statoil ASA's Payments to governments report for the year ended 31 December 2017 ("the Report"), in the form of an independent limited assurance conclusion that based on our work performed and evidence obtained, nothing has come to our attention that causes us to believe that the Report, in all material respects, is not fairly stated

Statoil ASA's Responsibilities

The board of directors and management are responsible for properly preparing and presenting the Report that is free from material misstatement in accordance with the Norwegian Accounting Act §3-3d and the detailed regulation included in "Forskrift om land-for-land rapportering" and the reporting principles as set out in the Report and for the information contained therein. This responsibility includes: designing, implementing and maintaining internal control relevant to the preparation and presentation of the Report that is free from material misstatement, whether due to fraud or error.

The board of directors and management are also responsible for ensuring that management and staff involved with the preparation of the Report are properly trained, systems are properly updated and that any changes in reporting encompass all significant business units.

Our Responsibilities

Our responsibility is to examine the Report prepared by Statoil ASA and to report thereon in the form of an independent limited assurance conclusion based on the evidence obtained. We conducted our engagement in accordance with the International Standard for Assurance Engagements (ISAE) 3000: Assurance Engagements other than Audits or Reviews of Historical Financial Information, issued by the International Auditing and Assurance Standards Board. That standard requires that we plan and perform our procedures to obtain a meaningful level of assurance about whether the Report is properly prepared and presented, in all material respects, as the basis for our limited assurance conclusion.

The firm applies International Standard on Quality Control 1 and accordingly maintains a comprehensive system of quality control including documented policies and procedures regarding compliance with ethical requirements, professional standards and applicable legal and regulatory requirements.

We have complied with the Code of Ethics for Professional Accountants (IESBA Code) issued by the International Ethics Standards Board for Accountants, which is founded on fundamental principles of integrity, objectivity, professional competence and due care, confidentiality and professional behavior.

The procedures selected depend on our understanding of the Report prepared by Statoil ASA and other engagement circumstances, and our consideration of areas where material misstatements are likely to arise. In obtaining an understanding of the Report and other engagement circumstances, we have considered the process used to prepare the Report in order to design assurance procedures that are appropriate in the circumstances, but not for the purposes of expressing a conclusion as to the effectiveness of Statoil ASA's process or internal control over the preparation and presentation of the Report.

Our engagement also included: assessing the appropriateness of the Report, the suitability of the criteria used by Statoil ASA in preparing the Report in the circumstances of the engagement, evaluating the appropriateness of the methods and procedures used in the preparation of the Report. The procedures performed included inquiries, inspection of documents, analytical procedures, evaluating the appropriateness of quantification methods and reporting policies and agreeing or reconciling the Report with underlying records.

The procedures performed in a limited assurance engagement vary in nature and timing from, and are less in extent than for, a reasonable assurance engagement. Consequently, the level of assurance obtained in a limited assurance engagement is substantially lower than the assurance that would have been obtained had a reasonable assurance engagement been performed.

We do not express a reasonable assurance conclusion about whether the Report has been prepared and presented, in all material respects, in accordance with the Norwegian Accounting Act §3-3d and the detailed regulation included in "Forskrift om land-for-land rapportering" and the reporting principles as set out in the Report and for the information contained therein.

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ADDITIONAL INFORMATION

Limited Assurance Conclusion
Our conclusion has been formed on the basis of, and is subject to, the matters outlined in this report. We believe that the evidence we have obtained is sufficient and appropriate to provide a basis for our conclusion.

Based on the procedures performed and the evidence obtained nothing has come to our attention that causes us to believe that the Report for the year ended 31 December 2016 is not prepared and presented, in all material respects, in accordance with the Norwegian Accounting Act §3-3d and the detailed regulation included in "Forskrift om land-for-land rapportering" and the reporting principles as set out in the Report.

Stavanger, 14 March 2018
KPMG AS

Ståle Christensen
State Authorised Public Accountant (Norway)

5.5 STATEMENTS ON THIS REPORT

Board statement on Reporting of payments to governments

Today, the board of directors and the chief executive officer have reviewed and approved the board of director's report prepared in accordance with the Norwegian Securities Trading Act section 5-5a regarding Reporting on payments to governments as of 31 December 2017.

To the best of our knowledge, we confirm that:

- The information presented in the report has been prepared in accordance with the requirements of the Norwegian Securities Trading Act section 5-5a and associated regulations

Stavanger, 14 March 2018

THE BOARD OF DIRECTORS OF STATOIL ASA

JON ERIK REINHARDSEN
CHAIR

ROY FRANKLIN
DEPUTY CHAIR

BJØRN TORE GODAL

PER MARTIN LABRÅTEN

JEROEN VAN DER VEER

MARIA JOHANNA OUDEMAN

REBEKKA GLASSER HERLOFSEN

INGRID ELISABETH DI VALERIO

STIG LÆGREID

WENCHE AGERUP

ELDAR SÆTRE
PRESIDENT AND CEO

Statement on compliance

Today, the board of directors, the chief executive officer and the chief financial officer reviewed and approved the 2017 Annual report and Form 20-F, which includes the board of directors' report and the Statoil ASA Consolidated and parent company annual financial statements as of 31 December 2017.

To the best of our knowledge, we confirm that:

- the Statoil Consolidated annual financial statements for 2017 have been prepared in accordance with IFRS and IFRIC as adopted by the European Union (EU), IFRS as issued by the International Accounting Standards Board (IASB) and additional Norwegian disclosure requirements in the Norwegian Accounting Act, and that
- the parent company financial statements for Statoil ASA for 2017 have been prepared in accordance with simplified IFRS pursuant to the Norwegian Accounting Act §3-9 and regulations regarding simplified application of IFRS issued by the Norwegian Ministry of Finance, and that
- the board of directors' report for the group and the parent company is in accordance with the requirements in the Norwegian Accounting Act and Norwegian Accounting Standard no 16 and that
- the information presented in the financial statements gives a true and fair view of the company's and the group's assets, liabilities, financial position and results for the period viewed in their entirety, and that

- the board of directors' report gives a true and fair view of the development, performance, financial position, principle risks and uncertainties of the company and the group

Oslo, 14 March 2018

THE BOARD OF DIRECTORS OF STATOIL ASA

JON ERIK REINHARDSEN
CHAIR

ROY FRANKLIN
DEPUTY CHAIR

BJØRN TORE GODAL

PER MARTIN LABRÅTEN

JEROEN VAN DER VEER

MARIA JOHANNA OUDEMAN

REBEKKA GLASSER HERLOFSEN

INGRID ELISABETH DI VALERIO

STIG LÆGREID

WENCHE AGERUP

HANS JAKOB HEGGE
CHIEF FINANCIAL OFFICER

ELDAR SÆTRE
PRESIDENT AND CEO

Recommendation of the corporate assembly

Resolution:
At its meeting of 22 March 2018, the corporate assembly discussed the 2017 annual accounts of Statoil ASA and the Statoil group, and the board of directors' proposal for the allocation of net income.

The corporate assembly recommends that the annual accounts and the allocation of net income proposed by the board of directors are approved.

Oslo, 22 March 2018

Tone Cathrine Lunde Bakker
Chair of the corporate assembly

Corporate assembly

Sun Lehmann	Greger Mannsverk	Ingvald Strømmen	Siri Kalvig	Lars Olav Grøvik
Nils Bastiansen	Steinar Olsen	Rune Bjerke	Terje Venold	Steinar Kåre Dale
Jarle Roth	Kathrine Næss	Birgitte Ringstad Vartdal	Kjersti Kleven	Dag Unnar Mongstad
Anne K.S. Horneland	Terje Enes	Hilde Møllerstad	Per Helge Ødegård	Dag-Rune Dale
				Tone Cathrine Lunde Bakker

5.6 TERMS AND ABBREVIATIONS

Organisational abbreviations

- ADS - American Depositary Share
- ADR - American Depositary Receipt
- ACG - Azeri-Chirag-Gunashli
- ACQ - Annual contract quantity
- AFP - Agreement-based early retirement plan
- AGM - Annual general meeting
- ÅTS - Åsgard transport system
- APA - Awards in pre-defined areas
- ARO - Asset retirement obligation
- BTC - Baku-Tbilisi-Ceyhan pipeline
- CCS - Carbon capture and storage
- CH4 - Methane
- CO2 - Carbon dioxide
- DKK - Danish Krone
- DPI - Development & Production International
- DPN - Development & Production Norway
- DPUSA - Development & Production USA
- DST - Drill Stem Test
- D&W - Drilling and Well
- EEA - European Economic Area
- EFTA - European Free Trade Association
- EMTN - Euro medium-term note
- EU - European Union
- EU ETS - EU Emissions Trading System
- EUR - Euro
- EXP - Exploration
- FPSO - Floating production, storage and offload vessel
- GAAP - Generally Accepted Accounting Principals
- GBP - British Pound
- GBS - Gravity-based structure
- GDP - Gross domestic product
- GHG - Greenhouse gas
- GSB - Global Strategy & Business Development
- HSE - Health, safety and environment
- HTHP - High-temperature/high pressure
- IASB - International Accounting Standards Board
- ICE - Intercontinental Exchange
- IEA - International Energy Agency
- IFRS - International Financial Reporting Standards
- IOGP - The International Association of Oil & Gas Producers
- IOR - Improved oil recovery
- LNG - Liquefied natural gas
- LPG - Liquefied petroleum gas
- MMP - Marketing, Midstream & Processing
- MPE - Norwegian Ministry of Petroleum and Energy
- MW - Mega watt
- NCS - Norwegian continental shelf
- NES - New Energy Solutions
- NIOC - National Iranian Oil Company
- NOK - Norwegian kroner
- NOx- Nitrogen oxide
- OECD - Organisation of Economic Co-Operation and Development
- OML - Oil mining lease
- OPEC - Organization of the Petroleum Exporting Countries
- OPEX - Operating expense
- OTC - Over-the-counter
- OTS - Oil trading and supply department
- P5+1 - UN Security Council's five permanent members
- PDO - Plan for development and operation
- PDQ - Production drilling quarters
- PIO - Plan for installation and operation
- PRD - Project Development organisation
- PSA - Production sharing agreement
- PSC - Production sharing contract
- PSR - Procurement and Supplier Relations
- RDI - Research, Development and Innovation
- R&D - Research and development
- ROACE - Return on average capital employed
- RRR - Reserve replacement ratio
- SAGD - Steam-assisted gravity drainage
- SCP - South Caucasus Pipeline System
- SDFI - Norwegian State's Direct Financial Interest
- SEC - Securities and Exchange Commission
- SEK - Swedish Krona
- SFR - Statoil Fuel & Retail
- SG&A - Selling, general & administrative
- SIF - Serious Incident Frequency
- TAP - Trans Adriatic Pipeline AG
- TEX - Technology Excellence
- TLP - Tension leg platform
- TPD - Technology, projects and drilling
- TRIF - Total recordable injuries per million hours worked
- TSP - Technical service provider
- UKCS - UK continental shelf
- USD - United States dollar
- WTG - Wind Turbine Generators

Metric abbreviations etc.

- bbl - barrel
- mbbl - thousand barrels
- mmbbl - million barrels
- boe - barrels of oil equivalent
- mboe - thousand barrels of oil equivalent
- mmboe - million barrels of oil equivalent
- mmcf - million cubic feet
- mmBtu - million british thermal units
- bcf - billion cubic feet
- tcf - trillion cubic feet
- scm - standard cubic metre
- mcm - thousand cubic metres
- mmcm - million cubic metres
- bcm - billion cubic metres
- mmtpa - million tonnes per annum
- km - kilometre
- ppm - part per million
- one billion - one thousand million

Equivalent measurements are based upon

- 1 barrel equals 0.134 tonnes of oil (33 degrees API)
- 1 barrel equals 42 US gallons
- 1 barrel equals 0.159 standard cubic metres
- 1 barrel of oil equivalent equals 1 barrel of crude oil
- 1 barrel of oil equivalent equals 159 standard cubic metres of natural gas
- 1 barrel of oil equivalent equals 5,612 cubic feet of natural gas
- 1 barrel of oil equivalent equals 0.0837 tonnes of NGLs
- 1 billion standard cubic metres of natural gas equals 1 million standard cubic metres of oil equivalent
- 1 cubic metre equals 35.3 cubic feet
- 1 kilometre equals 0.62 miles
- 1 square kilometre equals 0.39 square miles
- 1 square kilometre equals 247.105 acres
- 1 cubic metre of natural gas equals 1 standard cubic metre of natural gas
- 1,000 standard cubic meter gas equals 1 standard cubic meter oil equivalent

ADDITIONAL INFORMATION

- 1,000 standard cubic metres of natural gas equals 6.29 boe
- 1 standard cubic foot equals 0.0283 standard cubic metres
- 1 standard cubic foot equals 1000 British thermal units (btu)
- 1 tonne of NGLs equals 1.9 standard cubic metres of oil equivalent
- 1 degree Celsius equals minus 32 plus five-ninths of the number of degrees Fahrenheit

Miscellaneous terms

- Appraisal well: A well drilled to establish the extent and the size of a discovery
- Backwardation and contango are terms used in the crude oil market. Contango is a condition where forward prices exceed spot prices, so the forward curve is upward sloping. Backwardation is the opposite condition, where spot prices exceed forward prices, and the forward curve slopes downward
- Biofuel: A solid, liquid or gaseous fuel derived from relatively recently dead biological material and is distinguished from fossil fuels, which are derived from long dead biological material
- BOE (barrels of oil equivalent): A measure to quantify crude oil, natural gas liquids and natural gas amounts using the same basis. Natural gas volumes are converted to barrels on the basis of energy content
- Clastic reservoir systems: The integrated static and dynamic characteristics of a hydrocarbon reservoir formed by clastic rocks of a specific depositional sedimentary succession and its seal
- Condensates: The heavier natural gas components, such as pentane, hexane, iceptane and so forth, which are liquid under atmospheric pressure - also called natural gasoline or naphtha
- Crude oil, or oil: Includes condensate and natural gas liquids
- Development: The drilling, construction, and related activities following discovery that are necessary to begin production of crude oil and natural gas fields
- Downstream: The selling and distribution of products derived from upstream activities
- Equity and entitlement volumes of oil and gas: Equity volumes represent volumes produced under a production sharing agreement (PSA) that correspond to Statoil's percentage ownership in a particular field. Entitlement volumes, on the other hand, represent Statoil's share of the volumes distributed to the partners in the field, which are subject to deductions for, among other things, royalties and the host government's share of profit oil. Under the terms of a PSA, the amount of profit oil deducted from equity volumes will normally increase with the cumulative return on investment to the partners and/or production from the licence. The distinction between equity and entitlement is relevant to most PSA regimes, whereas it is not applicable in most concessionary regimes such as those in Norway, the UK, Canada and Brazil. The overview of equity production provides additional information for readers, as certain costs described in the profit and loss analysis were directly associated with equity volumes produced during the reported years
- Heavy oil: Crude oil with high viscosity (typically above 10 cp), and high specific gravity. The API classifies heavy oil as crudes with a gravity below 22.3° API. In addition to high viscosity and high specific gravity, heavy oils typically have low hydrogen-to-carbon ratios, high asphaltene, sulphur, nitrogen, and heavy-metal content, as well as higher acid numbers
- High grade: Relates to selectively harvesting goods, to cut the best and leave the rest. In reference to exploration and production this entails strict prioritisation and sequencing of drilling targets
- Hydro: A reference to the oil and energy activities of Norsk Hydro ASA, which merged with Statoil ASA
- IOR (improved oil recovery): Actual measures resulting in an increased oil recovery factor from a reservoir as compared with the expected value at a certain reference point in time. IOR comprises both of conventional and emerging technologies
- Liquids: Refers to oil, condensates and NGL
- LNG (liquefied natural gas): Lean gas - primarily methane - converted to liquid form through refrigeration to minus 163 degrees Celsius under atmospheric pressures
- LPG (liquefied petroleum gas): Consists primarily of propane and butane, which turn liquid under a pressure of six to seven atmospheres. LPG is shipped in special vessels
- Midstream: Processing, storage, and transport of crude oil, natural gas, natural gas liquids and sulphur
- Naphtha: inflammable oil obtained by the dry distillation of petroleum
- Natural gas: Petroleum that consists principally of light hydrocarbons. It can be divided into 1) lean gas, primarily methane but often containing some ethane and smaller quantities of heavier hydrocarbons (also called sales gas) and 2) wet gas, primarily ethane, propane and butane as well as smaller amounts of heavier hydrocarbons; partially liquid under atmospheric pressure
- NGL (natural gas liquids): Light hydrocarbons mainly consisting of ethane, propane and butane which are liquid under pressure at normal temperature
- Oil sands: A naturally occurring mixture of bitumen, water, sand, and clay. A heavy viscous form of crude oil
- Oil and gas value chains: Describes the value that is being added at each step from 1) exploring; 2) developing; 3) producing; 4) transportation and refining; and 5) marketing and distribution
- Organic capital expenditures: Capital expenditures excluding acquisitions, capital leases and other investments with significant different cash flow pattern
- Oslo Børs: Oslo stock exchange
- Peer group: Statoil's peer group consists of Statoil, Shell, ExxonMobil, OMV, ConocoPhillips, BP, Marathon, Chevron, Total, Repsol, Anadarko and Eni
- Petroleum: A collective term for hydrocarbons, whether solid, liquid or gaseous. Hydrocarbons are compounds formed from the elements hydrogen (H) and carbon (C). The proportion of different compounds, from methane and ethane up to the heaviest components, in a petroleum find varies from discovery to discovery. If a reservoir primarily contains light hydrocarbons, it is described as a gas field. If heavier hydrocarbons predominate, it is described as an oil field. An oil field may feature free gas above the oil and contain a quantity of light hydrocarbons, also called associated gas
- Proved reserves: Reserves claimed to have a reasonable certainty (normally at least 90% confidence) of being recoverable under existing economic and political conditions, and using existing technology. They are the only type the US Securities and Exchange Commission allows oil companies to report
- Refining reference margin: Is a typical average gross margin of our two refineries, Mongstad and Kalundborg. The reference margin will differ from the actual margin, due to variations in type of crude and other feedstock, throughput, product yields, freight cost, inventory etc
- Rig year: A measure of the number of equivalent rigs operating during a given period. It is calculated as the number of days rigs are operating divided by the number of days in the period
- Upstream: Includes the searching for potential underground or underwater oil and gas fields, drilling of exploratory wells, subsequent operating wells which bring the liquids and or natural gas to the surface
- VOC (volatile organic compounds): Organic chemical compounds that have high enough vapour pressures under normal conditions to significantly vaporise and enter the earth's atmosphere (e.g. gasses formed under loading and offloading of crude oil)

5.7 FORWARD-LOOKING STATEMENTS

This Annual Report on Form 20-F contains certain forward-looking statements that involve risks and uncertainties, in particular in the sections "Business overview" and "Strategy and market overview". In some cases, we use words such as "aim", "ambition", "anticipate", "believe", "continue", "could", "estimate", "expect", "intend", "likely", "objective", "outlook", "may", "plan", "schedule", "seek", "should", "strategy", "target", "will", "goal" and similar expressions to identify forward-looking statements. All statements other than statements of historical fact, including, among others, statements regarding future financial position, results of operations and cash flows; future financial ratios and information; future financial or operational portfolio or performance; future market position and conditions; future credit rating; future worldwide economic trends and market conditions; future investment in new energy solutions; business strategy; our name change; growth strategy; sales, trading and market strategies; research and development initiatives and strategy; market outlook and future economic projections and assumptions; competitive position; projected regularity and performance levels; expectations related to production levels, investment, exploration and development in connection with our recent transactions and projects, in Brazil, the NCS, Russia, Turkey, the United Kingdom and the United States; discoveries on the NCS and internationally; our joint venture with Rosneft; expectations related to our refining plants and terminals; our ownership share in Gassled; completion and results of acquisitions, disposals and other contractual arrangements and delivery commitments; reserve information; recovery factors and levels; future margins; projected returns; future levels or development of capacity, reserves or resources; future decline of mature fields; planned turnarounds and other maintenance activity; plans for cessation and decommissioning; oil and gas production forecasts and reporting; gas volume; growth, expectations and development of production, projects, pipelines or resources; estimates related to production and development levels and dates; operational expectations, estimates, schedules and costs; exploration and development activities, plans and expectations; projections and expectations for upstream and downstream activities; expectations relating to licences; expectations relating to leases; oil, gas, alternative fuel and energy prices and volatility; oil, gas, alternative fuel and energy supply and demand; renewable energy production, projects, our carbon footprint and carbon dioxide emissions, industry outlook and carbon capture and storage; processes related to human rights laws; organisational structure and policies; planned responses to climate change; technological innovation, implementation, position and expectations; future energy efficiency; projected operational costs or savings; our ability to create or improve value; future sources of financing; expectations regarding board composition, remuneration and application of the company performance modifier future levels of diversity; exploration and project development expenditure; our goal of safe and efficient operations; effectiveness of our internal policies and plans; our ability to manage our risk exposure; our liquidity levels and management; estimated or future liabilities, obligations or expenses; expected impact of currency and interest rate fluctuations; expectations related to contractual or financial counterparties; capital expenditure estimates and expectations; projected outcome, impact or timing of HSE regulations; HSE goals and objectives of management for future operations; expectations related to regulatory trends; impact of PSA effects; projected impact or timing of administrative or governmental rules, standards, decisions, standards or laws (including taxation laws); projected impact of legal claims against us; plans for capital distribution and share buy-backs and amounts of dividends are forward-looking statements. You should not place undue reliance on these forward-looking statements. Our actual results could differ materially from those anticipated in the forward-looking statements for many reasons, including the risks described above in "Risk review", and in "Operational review", and elsewhere in this Annual Report on Form 20-F.

These forward-looking statements reflect current views about future events and are, by their nature, subject to significant risks and uncertainties because they relate to events and depend on circumstances that will occur in the future. There are a number of factors that could cause actual results and developments to differ materially from those expressed or implied by these forward-looking statements, including levels of industry product supply, demand and pricing; exchange rate and interest rate fluctuations; the political and economic policies of Norway and other oil-producing countries; EU directives; general economic conditions; political and social stability and economic growth in relevant areas of the world; Euro-zone uncertainty; global political events and actions, including war, terrorism and sanctions; security breaches, including breaches of our digital infrastructure (cybersecurity); changes or uncertainty in or non-compliance with laws and governmental regulations; the timing of bringing new fields on stream; an inability to exploit growth opportunities; material differences from reserves estimates; unsuccessful drilling; an inability to find and develop reserves; ineffectiveness of crisis management systems; adverse changes in tax regimes; the development and use of new technology, particularly in the renewable energy sector; geological or technical difficulties; operational problems; operator error; inadequate insurance coverage; the lack of necessary transportation infrastructure when a field is in a remote location and other transportation problems; the actions of competitors; the actions of field partners; the actions of the Norwegian state as majority shareholder; counterparty defaults; natural disasters, adverse weather conditions, climate change, and other changes to business conditions; failure to meet our ethical and social standards; an inability to attract and retain personnel and other factors discussed elsewhere in this report.

Although we believe that the expectations reflected in the forward-looking statements are reasonable, we cannot assure you that our future results, level of activity, performance or achievements will meet these expectations. Moreover, neither we nor any other person assumes responsibility for the accuracy and completeness of the forward-looking statements. Unless we are required by law to update these statements, we will not necessarily update any of these statements after the date of this Annual Report, either to make them conform to actual results or changes in our expectations.

5.8 SIGNATURE PAGE

The registrant hereby certifies that it meets all of the requirements for filing on Form 20-F and that it has duly caused and authorised the undersigned to sign this Annual Report on its behalf.

STATOIL ASA
(Registrant)

By: /s/Hans Jakob Hegge
Name: Hans Jakob Hegge
Title: Executive Vice President and Chief Financial Officer

Dated: 23 March 2018

5.9 EXHIBITS

The following exhibits are filed as part of this Annual Report:

Exhibit no	Description
Exhibit 1	Articles of Association of Statoil ASA, as amended, effective from 6 February 2018 (English translation).
Exhibit 2.1	Form of Indenture among Statoil ASA (formerly known as StatoilHydro ASA), Statoil Petroleum AS (formerly known as Statoil Hydro Petroleum AS) and Deutsche Bank Trust Company Americas (incorporated by reference to Exhibit 4.1 of Statoil ASA's and Statoil Petroleum AS's Post - Effective Amendment No.1 to their Registration Statement on Form F-3 (File No. 333-143339) filed with the Commission on 2 April 2009).
Exhibit 2.2	Amended and Restated Agency Agreement, dated as of 5 May 2017, by and among Statoil ASA, as Issuer, Statoil Petroleum AS as Guarantor, the Bank of New York Mellon, as Agent and the Bank of New York Mellon SA/NV, Luxembourg Branch as Paying Agent in respect of a €20,000,000 Euro Medium Term Note Programme.
Exhibit 2.3	Deed of Covenant, dated as of 5 February 2016, of Statoil ASA in respect of a €20,000,000 Euro Medium Term Notes Programme. (incorporated by reference to Exhibit 2.2 of Statoil's Annual Report on Form 20-F for the fiscal year ended December 31, 2016 (File no. 001-15200) (the "2016 20-F") filed with the Commission on March 17, 2017)
Exhibit 2.4	Deed of Guarantee, dated as of 5 February 2016, of Statoil Petroleum AS in respect of a €20,000,000 Euro Medium Term Notes Programme. (incorporated by reference to Exhibit 2.4 of Statoil's 2016 20-F filed with the Commission on March 17, 2017)
Exhibit 4(a)(i)	Technical Services Agreement between Gassco AS and Statoil Petroleum AS, dated November 24, 2010. (incorporated by reference to Exhibit 4(a)(i) of Statoil's 2016 Form 20-F (File no. 001-15200) filed with the Commission on March 17, 2017)
Exhibit 4(a)(ii)	Amendment no. 1, 2, 3, 4, 5 and 6, dated 17 October 2010, 19 February 2013, 15 December 2012, 17 September 2014, 15 December 2017 and 22 December 2017, respectively, to Technical Services Agreement between Gassco AS and Statoil Petroleum AS, dated November 24, 2010.
Exhibit 4(c)	Employment agreement with Eldar Sætre as of 4 February 2015. (incorporated by reference to Exhibit 4(c) of Statoil's 2016 20-F (File no. 001-15200) filed with the Commission on March 17, 2017)
Exhibit 7	Calculation of ratio of earnings to fixed charges.
Exhibit 8	Subsidiaries (see Significant subsidiaries included in section 2.7 Corporate in this Annual Report).
Exhibit 12.1	Rule 13a-14(a) Certification of Chief Executive Officer.
Exhibit 12.2	Rule 13a-14(a) Certification of Chief Financial Officer.
Exhibit 13.1	Rule 13a-14(b) Certification of Chief Executive Officer.[1)]
Exhibit 13.2	Rule 13a-14(b) Certification of Chief Financial Officer.[1)]
Exhibit 15(a)(i)	Consent of KPMG AS.
Exhibit 15(a)(ii)	Consent of DeGolyer and MacNaughton.
Exhibit 15(a)(iii)	Report of DeGolyer and MacNaughton.
Exhibit 101	Interactive Data Files (formatted in XBRL (Extensible Business Reporting Language)). Submitted electronically with the Annual Report on Form 20-F.

1) Furnished only.

The total amount of long term debt securities of Statoil ASA and its subsidiaries authorised under instruments other than those listed above does not exceed 10% of the total assets of Statoil ASA and its subsidiaries on a consolidated basis. The company agrees to furnish copies of any such instruments to the Commission upon request.

5.10 Cross reference to Form 20-F

		Sections
Item 1.	Identity of Directors, Senior Management and Advisers	N/A
Item 2.	Offer Statistics and Expected Timetable	N/A
Item 3.	Key Information	
	A. Selected Financial Data	Key Figures and Highlights; 5.1 (Shareholder information - Exchange rates)
	B. Capitalisation and Indebtedness	N/A
	C. Reasons for the Offer and Use of Proceeds	N/A
	D. Risk Factors	2.11 (Risk review—Risk factors)
Item 4.	Information on the Company	
	A. History and Development of the Company	Statoil at a Glance; 2.2 (Business Overview); 2.3 (E&P Norway - Exploration & Production Norway); 2.4 (E&P International - Exploration & Production international); 2.5 (MMP - Marketing, Midstream & Processing); 2.6 (Other group); 2.10 (Liquidity and capital resources—Reviews of cash flows); 2.10 (Liquidity and Capital Resources—Investments); note 4 (Acquisitions and divestments) to Statoil Consolidated financial statements
	B. Business Overview	2.1 (Strategy and market overview); 2.2 (Business overview); 2.3 (E&P Norway - Exploration & Production Norway); 2.4 (E&P International - Exploration & Production international); 2.5 (MMP - Marketing, Midstream & Processing); 2.6 (Other group); 2.7 (Corporate)
	C. Organisational Structure	2.2 (Business overview—Corporate structure); 2.2 (Business Overview—Segment reporting); 2.7 (Corporate—Subsidiaries and properties)
	D. Property, Plants and Equipment	2.3 (E&P Norway - Exploration & Production Norway); 2.4 (E&P International - Exploration & Production international); 2.5 (MMP - Marketing, Midstream & Processing); 2.7 (Corporate—Property, plant and equipment); 2.10 (Liquidity and Capital Resources—Investments); notes 10 (Property, plant and equipment) and 22 (Leases) to Statoil Consolidated financial statements
	Oil and Gas Disclosures	2.8 (Operational performance—Proved oil and gas reserves); 2.8 (Operational performance—Production volumes and prices); Exhibit 15(a)(iii)
Item 4A.	Unresolved Staff Comments	None
Item 5.	Operating and Financial Review and Prospects	
	A. Operating Results	2.7 (Corporate—Applicable laws and regulations); 2.9 (Financial review); 2.10 (Liquidity and capital resources—Impact of reduced prices); 2.11 (Risk review—Risk management—Managing operational risks); 2.11 (Risk review—Risk management—Managing financial risks); note 25 (Financial instruments: fair value measurement and sensitivity analysis of market risk) to Statoil Consolidated financial statements
	B. Liquidity and Capital Resources	2.10 (Liquidity and capital resources); 2.11 (Risk review—Risk management); notes 5 (Financial risk management), 15 (Trades and other receivables); 16 (Cash and cash equivalents); 18 (Finance debt), 23 (Other commitments, contingent liabilities and contingent assets) and 25 (Financial instruments: fair value measurement and sensitivity analysis of market risk) to Statoil Consolidated financial statements
	C. Research and development, Patents and Licences, etc.	2.2 (Business overview—Research and development); note 7 (Other expenses) to Statoil Consolidated financial statements
	D. Trend Information	passim
	E. Off-Balance Sheet Arrangements	2.10 (Liquidity and capital resources—Principal Contractual obligations); 2.10 (Liquidity and capital resources—Off balance sheet arrangements); notes 22 (Leases) and 23 (Other commitments, contingent liabilities and contingent assets) to Statoil Consolidated financial statements
	F. Tabular Disclosure of Contractual Obligations	2.10 (Liquidity and capital resources—Principal contractual obligations)
	G. Safe Harbor	5.7 (Forward-Looking Statements)
Item 6.	Directors, Senior Management and Employees	

	A. Directors and Senior Management	3.8 (Corporate assembly, board of directors and management)
	B. Compensation	3.11 (Remuneration to the board of directors an corporate assembly); 3.12 (Remuneration to the corporate executive committee);
	C. Board Practices	3.8 (Corporate assembly, board of directors and management); 3.9 (The work of the board of directors—Audit committee; Compensation and executive development committee)
	D. Employees	2.13 (Our people—Employees in Statoil); 2.13 (Our people—Unions and representatives)
	E. Share Ownership	3.11 (Remuneration to the board of directors an corporate assembly); 3.12 (Remuneration to the corporate executive committee); 5.1 (Shareholder information—Shares purchased by the issuer—Statoil's share savings plan)
Item 7.	Major Shareholders and Related Party Transactions	
	A. Major Shareholders	5.1 (Shareholder information—Major shareholders)
	B. Related Party Transactions	2.7 (Corporate—Related party transactions); note 24 (Related parties) to Statoil Consolidated financial statement
	C. Interests of Experts and Counsel	N/A
Item 8.	Financial Information	
	A. Consolidated Statements and Other Financial Information	3.3 (Equity and dividends); 4.1 (Statoil Consolidated financial statements); 5.1 (Shareholder information—Dividend policy and dividends); 5.3 (Legal proceedings)
	B. Significant Changes	Note 28 (Subsequent events) to Statoil Consolidated financial statements)
Item 9.	The Offer and Listing	
	A. Offer and Listing Details	5.1 (Shareholder information); 5.1 (Shareholder information—Share Prices)
	B. Plan of Distribution	N/A
	C. Markets	5.1 (Shareholder Information)
	D. Selling Shareholders	N/A
	E. Dilution	N/A
	F. Expenses of the Issue	N/A
Item 10.	Additional Information	
	A. Share Capital	N/A
	B. Memorandum and Articles of Association	2.11 (Risk review—Risks related to state ownership); 3.1 (Implementation and reporting—Articles of association); 3.6 (General meeting of shareholders); 5.1 (Shareholder information); 5.1 (Shareholder Information—Major Shareholders) and note 17 (Shareholders' Equity and dividends) to Statoil Consolidated financial statements
	C. Material Contracts	N/A
	D. Exchange Controls	5.1 (Shareholder information—Exchange controls and limitations)
	E. Taxation	5.1 (Shareholder information—Taxation)
	F. Dividends and Paying Agents	N/A
	G. Statements by Experts	N/A
	H. Documents On Display	About the Report
	I. Subsidiary Information	N/A
Item 11.	Quantitative and Qualitative Disclosures About Market Risk	2.11 (Risk review—Risk management); notes 5 (Financial risk management) and 25 (Financial instruments: fair value measurement and sensitivity analysis of market risk) to Statoil Consolidated financial statements
Item 12.	Description of Securities Other than Equity Securities	
	A. Debt Securities	N/A
	B. Warrants and Rights	N/A
	C. Other Securities	N/A
	D. American Depositary Shares	5.1 (Shareholder information—Statoil ADR programme fees)
Item 13.	Defaults, Dividend Arrearages and Delinquencies	None
Item 14.	Material Modifications to the Rights of Security Holders and Use of	None

ADDITIONAL INFORMATION

	Proceeds	
Item 15.	Controls and Procedures	3.10 (Risk management and internal control); note 28 Condensed consolidated financial information related to guaranteed debt securities to Statoil Consolidated financial statements
Item 16A.	Audit Committee Financial Expert	3.9 (The work of the board of directors—Audit committee)
Item 16B.	Code of Ethics	3.10 (Risk management and internal control)
Item 16C.	Principal Accountant Fees and Services	3.15 (External Auditor)
Item 16D.	Exemptions from the Listing Standards for Audit Committees	3.1 (Implementation and reporting—Compliance with NYSE listing rules)
Item 16E.	Purchases of Equity Securities by the Issuer and Affiliated Purchases	5.1 (Shareholder Information—Shares purchased by the Issuer)
Item 16F.	Changes in Registrant's Certifying Accountant	N/A
Item 16G.	Corporate Governance	3.1 (Implementation and reporting—Compliance with NYSE listing rules)
Item 16H	Mine Safety Disclosure	None
Item 17.	Financial Statements	N/A
Item 18.	Financial Statements	4.1 (Statoil Consolidated financial statements)

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, DC 20549

FORM 20-F

(Mark One)

☐ **REGISTRATION STATEMENT PURSUANT TO SECTION 12(b) OR 12(g) OF THE SECURITIES EXCHANGE ACT OF 1934**

OR

☒ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the fiscal year ended December 31, 2017

OR

☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the transition period from _________ to _________

OR

☐ **SHELL COMPANY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

Date of event requiring this shell company report _________

Commission file number 1-15200

Statoil ASA

(Exact Name of Registrant as Specified in Its Charter)

N/A

(Translation of Registrant's Name Into English)

Norway

(Jurisdiction of Incorporation or Organization)

Forusbeen 50, N-4035, Stavanger, Norway

(Address of Principal Executive Offices)

Hans Jakob Hegge
Chief Financial Officer
Statoil ASA
Forusbeen 50, N-4035
Stavanger, Norway
Telephone No.: 011-47-5199-0000
Fax No.: 011-47-5199-0050

(Name, Telephone, E-mail and/or Facsimile number and Address of Company Contact Person)

Securities registered or to be registered pursuant to Section 12(b) of the Act:

Title of Each Class	Name of Each Exchange On Which Registered
American Depositary Shares	**New York Stock Exchange**
Ordinary shares, nominal value of NOK 2.50 each	**New York Stock Exchange***

*Listed, not for trading, but only in connection with the registration of American Depositary Shares, pursuant to the requirements of the Securities and Exchange Commission

Securities registered or to be registered pursuant to Section 12(g) of the Act: **None**

Securities for which there is a reporting obligation pursuant to Section 15(d) of the Act: **None**

ADDITIONAL INFORMATION

Indicate the number of outstanding shares of each of the issuer's classes of capital or common stock as of the close of the period covered by the annual report.

Ordinary shares of NOK 2.50 each **3,323,167,853**

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act.

☒ Yes ☐ No

If this report is an annual or transition report, indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934.

☐ Yes ☒ No

Note – Checking the box above will not relieve any registrant required to file reports pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934 from their obligations under those Sections.

Indicate by check mark whether the registrant: (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.

☒ Yes ☐ No

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files).

☒ Yes ☐ No

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, or a non-accelerated filer. See definition of "accelerated filer and large accelerated filer" in Rule 12b-2 of the Exchange Act. (Check one):

Large accelerated filer ☒ Accelerated filer ☐ Non-accelerated filer ☐ Emerging growth company ☐

If an emerging growth company that prepares its financial statements in accordance with U.S. GAAP, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards† provided pursuant to Section 13(a) of the Exchange Act. ☐

† The term "new or revised financial accounting standard" refers to any update issued by the Financial Accounting Standards Board to its Accounting Standards Codification after April 5, 2012.

Indicate by check mark which basis of accounting the registrant has used to prepare the financial statements included in this filing:

U.S. GAAP ☐ International Financial Reporting Standards as issued by the International Accounting Standards Board ☒ Other ☐

If "Other" has been checked in response to the previous question, indicate by check mark which financial statement item the registrant has elected to follow.

Item 17 ☐
Item 18 ☐

If this is an annual report, indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act).

☐ Yes ☒ No

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NORWAY
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www.statoil.com

2016 Annual Report and Form 20-F

2016 Annual Report and Form 20-F

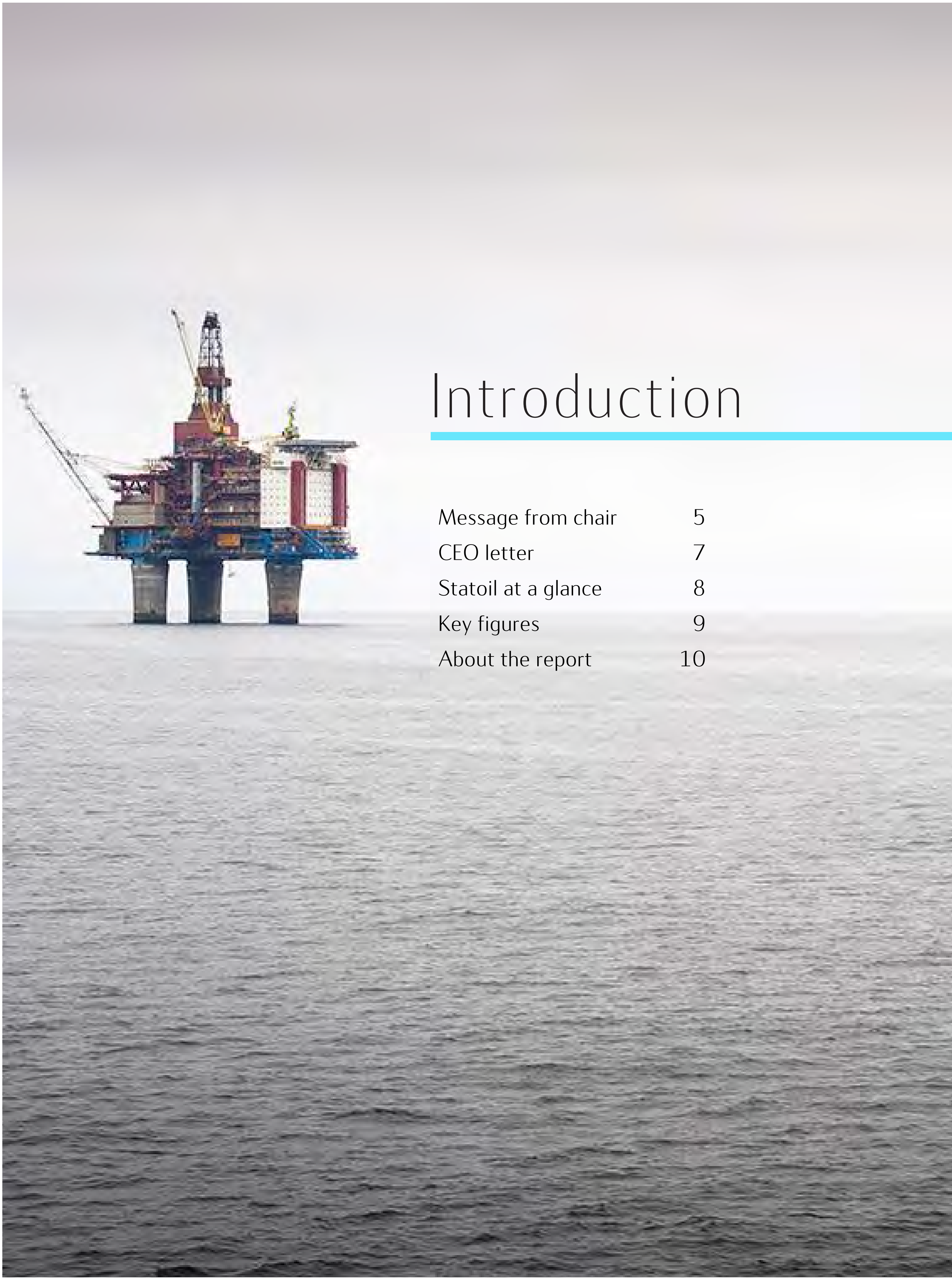
INTRODUCTION

STRATEGIC REPORT

GOVERNANCE

FINANCIAL STATEMENTS AND SUPPLEMENTS

ADDITIONAL INFORMATION



Introduction

MESSAGE FROM CHAIR OF THE BOARD

Dear shareholder,

2016 was a challenging year for the oil and gas industry. Across the industry, the financial results were impacted by the continued low price environment and Statoil ended up with a negative net income of USD 2.9 billion. In this situation, it is encouraging to see how well the company has delivered on its improvement programme and that the operational performance has continued to be strong. Statoil is now well positioned to for the future.

The board of directors has in its work focused both on short term measurements to secure the company's position in a challenging environment, and more long term through the work of sharpening our strategy. Protecting and enhancing shareholder value guides the board of directors in its work and priorities - short and long term.

Strong safety performance is essential for the company's operations. Last year we experienced the worst imaginable, with a fatality on a yard in South Korea and a helicopter crash outside Bergen that took 13 lives.

Further, the serious incident frequency, measured as incidents per million hours worked for both Statoil employees and contractors, increased from 0.6 in 2015 to 0.8 in 2016. Together with the administration, the board of directors has focused on new steps to reinforce safety measures and get back to a positive trend to improve our safety performance.

The response to the market challenge through our improvement programme delivered annualised efficiency gains of USD 3.2 billion measured against a 2013 baseline, USD 700 million above the USD 2.5 billion target. As the company moves from an improvement programme to an improvement culture, new targets are set.

The board of directors have during the year worked closely with the administration to review and confirm Statoil's sharpened strategy. Statoil has set clear principles for the development of a distinct and competitive portfolio. Statoil will develop long-term value on the Norwegian continental shelf, deepen in core areas and develop new growth options internationally, and grow value creation in its marketing and midstream business. The company is making progress in creating a material industrial position in new energy solutions, primarily focused on offshore wind.

Responding to the climate challenge and preparing Statoil for a low carbon future is an integrated part of our strategy. Concrete actions to reduce greenhouse gas emissions in the operations have been implemented, and steps have been taken to build a more resilient portfolio. The updated climate roadmap captures the new set of measurements to be implemented.

Statoil remains committed to shareholder value creation and maintained the dividend during the year. A resolution is proposed to the annual general meeting to maintain the dividend at USD 0.2201 per share in the fourth quarter, and to continue the scrip dividend programme through to the third quarter of 2017.

The board of directors believes the company is well prepared to deal with the current market situation and has the competence, capacity and leadership necessary to create new opportunities and long-term value for our shareholders.

I would like to thank our shareholders for their continued investment, as well as the many employees of Statoil for all the dedication and commitment they show every day.

Øystein Løseth
Chair of the board

CHIEF EXECUTIVE LETTER

DEAR FELLOW SHAREHOLDER,

Safety and security is our top priority in Statoil. And while 2016 was a year of many achievements, we also experienced the worst thinkable. We had a contractor fatality during construction work in South Korea, and on 29 April we lost 13 colleagues when a helicopter crashed on its way from Gullfaks B to Bergen.

For the year as a whole, our serious incident frequency came in at 0.8, an increase from the two previous years. We are not satisfied with this development and have taken several steps to reinforce safety measures throughout the company.

In 2016, we saw oil prices below USD 30 per barrel and while prices increased towards the end of the year, our average realised liquids price was still below USD 40 per barrel for the year as a whole.

We delivered our cost improvement programme above target. The next step will be to go from project mode to a culture of continuous improvement, and we have set a target of achieving USD 1 billion in additional cost improvements in 2017.

By reworking solutions from reservoir to market, we have transformed our opportunity set. The break-even price for our "Next generation" portfolio of projects (those sanctioned since 2015 or planned for sanction with start up by 2022), is now at USD 27 per barrel of oil equivalent (boe).

Organic capex for 2016 was USD 10.1 billion, a USD 3 billion reduction from the original guiding. Production for the full year was 1,978 mboe per day, a slight increase from 2015 due to continued high production efficiency and despite high turnaround activity. Our reserve-replacement ratio (RRR) was 93%.

"High value, low carbon" is at the core of our sharpened strategy. We believe the winners in the energy transition will be the producers which can deliver at low cost and with low carbon emissions.

Statoil is pursuing a distinct and value-driven strategy:

- On the Norwegian continental shelf (NCS) we have a unique position which we will leverage further to build our future business and maximise value
- In our international upstream business, we will focus, deepen and explore further. Brazil is a core area for us, together with our position in the highly flexible US onshore business
- For the Marketing, Midstream and Processing (MMP) business area, the job is to secure flow assurance by accessing premium markets and strengthening asset-backed trading, based on a 'capex light' approach
- In the New Energy Solutions (NES) business area, we are building a profitable business with the long-term potential to account for 15-20% of our capex in 2030, provided that we can access and mature attractive opportunities

Our commitment to long-term sustainable value creation, is in line with the principles of the UN Global Compact.

We believe a low carbon footprint will make us more competitive in the future. We also believe there are attractive business opportunities in the transition to a low-carbon economy. Statoil intends to be part of this transformation in order to fulfil our purpose of turning natural resources into energy for people and progress for society. Our Climate roadmap explains how we plan to achieve this and how we will develop our business, supporting the ambitions of the Paris climate agreement.

I look forward to further strengthening Statoil in 2017, pursuing the priorities set out at our Capital markets update: resetting our cost base, transforming our opportunity set and continuing to chase improvements. We have sharpened our strategy as an energy company towards 2030, and are ready to capitalise on high-value opportunities.

Eldar Sætre
President and Chief Executive Officer
Statoil ASA

STATOIL AT A GLANCE

OUR HISTORY

The company was founded as The Norwegian State Oil company (Statoil) in 1972, and became listed on the Oslo Børs (Norway) and New York Stock Exchange (US) in June 2001. Statoil merged with Hydro`s oil and gas division in October 2007.

Statoil is an international energy company with operations in over 30 countries. We are headquartered in Stavanger, Norway with approximately 20,500 employees worldwide. We create value through safe and efficient operations, innovative solutions and technology. Statoil's competitiveness is founded on our values-based performance culture, with a strong commitment to transparency, cooperation and continuous operational improvement.

OUR SHAREHOLDERS

The Norwegian State is the largest shareholder in Statoil, with a direct ownership interest of 67%. Its ownership interest is managed by the Norwegian Ministry of Petroleum and Energy. US investors hold 9.6%, Norwegian Private owners hold 8.9%, other European investors hold 7.1%, UK investors hold 5.1% and others hold 1.5%.

OUR BUSINESS AREAS

We have eight business areas:

- Development and Production Norway
- Development and Production International
- Development and Production USA
- Marketing, Midstream and Processing
- Technology, Projects and Drilling
- Exploration
- Global Strategy and Business Development
- New Energy Solutions

OUR STRATEGY

Statoil is an energy company committed to long-term value creation in a low carbon future. Statoil will develop and maximise the value of its unique Norwegian continental shelf position, its international oil and gas business and its growing new energy business; focusing on safety, cost and carbon efficiency. Statoil is a values based company where empowered people collaborate to shape the future of energy.

OUR VALUES

Open, Collaborative, Courageous and Caring.

OUR DIVIDEND POLICY

It is Statoil's ambition to grow the annual cash dividend, measured in USD per share, in line with long term underlying earnings. Statoil announces dividends on a quarterly basis. In May 2016, the annual general meeting approved the introduction of a two-year scrip dividend programme commencing from the fourth quarter of 2015.

KEY FIGURES AND HIGHLIGHTS

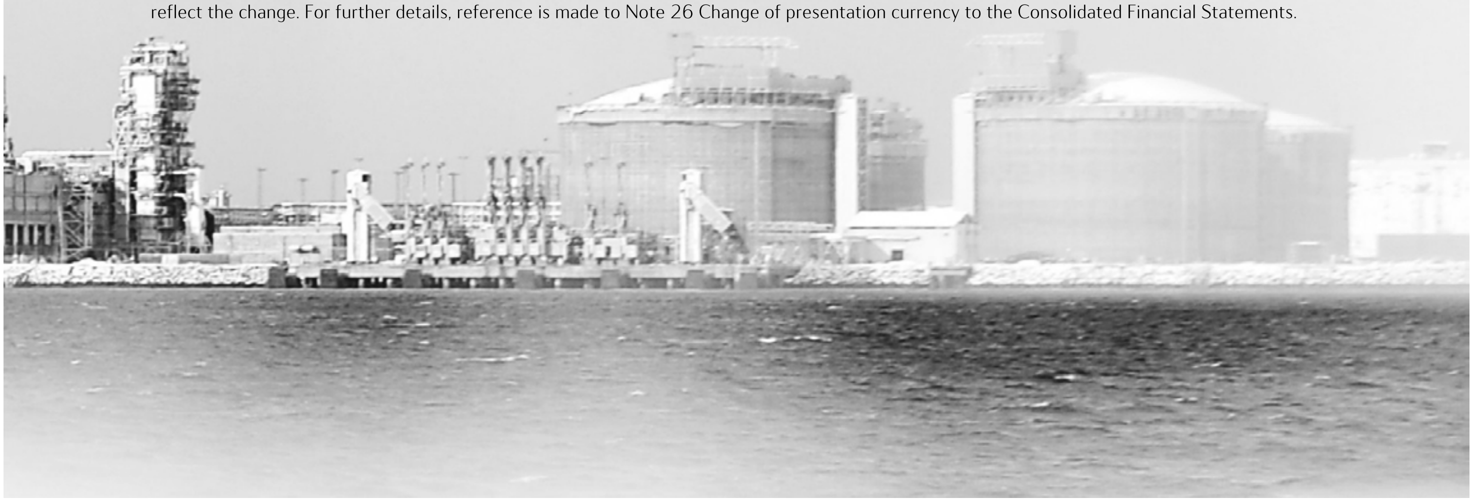
		For the year ended 31 December			
(in USD million, unless stated otherwise)	2016	2015	2014	2013	2012
Financial information[4]					
Total revenues and other income[3]	**45,873**	59,642	99,264	108,318	123,660
Net operating income	**80**	1,366	17,878	26,572	35,808
Operating expenses	**(9,025)**	(10,512)	(11,657)	(12,669)	(10,467)
Net income	**(2,902)**	(5,169)	3,887	6,713	12,234
Non-current finance debt	**27,999**	29,965	27,593	27,197	18,137
Net interest-bearing debt before adjustments	**18,372**	13,852	12,004	9,542	7,057
Total assets	**104,530**	109,742	132,702	145,572	140,921
Share capital	**1,156**	1,139	1,139	1,139	961
Non-controlling interest	**27**	36	57	81	121
Total equity	**35,099**	40,307	51,282	58,513	57,468
Net debt to capital employed ratio before adjustments	**34.4%**	25.6%	19.0%	14.0%	10.9%
Net debt to capital employed ratio adjusted	**35.6%**	26.8%	20.0%	15.2%	12.4%
Calculated ROACE based on Average Capital Employed before adjustments	**(4.7%)**	(8.9%)	3.4%	11.3%	18.7%
Operational information					
Equity oil and gas production (mboe/day)	**1,978**	1,971	1,927	1,940	2,004
Proved oil and gas reserves (mmboe)	**5,013**	5,060	5,359	5,600	5,422
Reserve replacement ratio (annual)	**0.93**	0.55	0.62	1.28	0.99
Reserve replacement ratio (three-year average)	**0.70**	0.81	0.97	1.15	1.01
Production cost equity volumes (USD/boe)	**5.0**	5.9	7.6	7.5	7.2
Share information[1]					
Diluted earnings per share USD	**(0.91)**	(1.63)	1.21	2.14	3.80
Share price at Oslo Børs (Norway) on 31 December in NOK	**158.40**	123.70	131.20	147.00	139.00
Dividend per share USD [2]	**0.88**	1.07	0.97	1.15	1.21
Weighted average number of ordinary shares outstanding (in thousands)	**3,194,880**	3,179,443	3,179,959	3,180,684	3,181,546

1) See section 5.1 Shareholder information for a description of how dividends are determined and information on share repurchases.

2) Proposed cash dividend for the second quarter of 2016. From and including the third quarter of 2015, dividends were declared in USD. Dividends in previous periods were declared in NOK. Figures for 2015 and earlier periods are presented using the Central Bank of Norway year end rates for Norwegian kroner.

3) Total revenues and other income for 2013 and 2012 are restated.

4) On 1 January 2016 Statoil changed its presentation currency from Norwegian kroner (NOK) to US dollar (USD), mainly in order to better reflect the underlying USD exposure of Statoil's business activities and to align with industry practice. Comparative figures have been represented in USD to reflect the change. For further details, reference is made to Note 26 Change of presentation currency to the Consolidated Financial Statements.



ABOUT THE REPORT

This document constitutes the Statutory annual report in accordance with Norwegian requirements and the Annual report on Form 20-F in accordance with the US Securities and Exchange Act of 1934 applicable to foreign private issuers, for Statoil ASA for the year ended 31 December 2016. A cross reference to the Form 20-F requirements are set out in section 5.10 in this report. The Annual report on Form 20-F and other related documents are filed with the US Securities and Exchange Commission (the SEC). The Annual report and Form 20-F are filed with the Norwegian Register of company accounts.

This report presents the Director's report (pages 3-116 and 231-265), the Consolidated Financial Statements of Statoil (pages 119-190) and the Parent company financial statements of Statoil ASA (pages 191-230) according to the Norwegian Accounting Act of 1998. This report also contains the Board Statement on Corporate Governance according to The Norwegian Code of Practice for Corporate Governance (NUES) in chapter 3 Governance (pages 81-116), the Declaration on remuneration for Statoil's corporate executive committee (pages 106 -114) and the Payments to governments report according to Norwegian requirements in section 5.4 (pages 248-264).

Financial reporting terms used in this report are in accordance with International Financial Reporting Standards (IFRS) as adopted by the European union (EU) and also comply with IFRS as issued by the International Accounting Standards Board (IASB), effective at 31 December 2016. This document should be read in conjunction with the cautionary statement in section 5.7 Forward-looking statement.

Specific accounting requirements for Norway

Section 4.2 Parent company financial statements and related notes to such financial statements (pages 191-230), the Payments to governments report (pages 248-264), the Board Statement on Corporate Governance according to The Norwegian Code of Practice for Corporate Governance (NUES)(pages 81-116), the statements on this report in section 5.5 comprising the Statement of directors' responsibilities (pages 264-265), the recommendation of the Corporate Assembly (page 266), the independent auditor's report issued in accordance with law, regulations and auditing standards and practices generally accepted in Norway (pages 226-230) and the going concern assumption (page 55), do not form part of Statoil's Annual report on Form 20-F as filed with the SEC.

In addition, the following sections of this report do not form part of Statoil's Annual report on Form 20-F as filed with the SEC: the second through sixth paragraphs under Employees in Statoil in Section 2.12 Our people (pages 78-79); Nomination and elections in Statoil (page 83), section 3.1 Implementing and reporting (page 84), section 3.2 Business (page 86), section 3.3 Equity and dividends (pages 86-87), section 3.4 Equal treatment of shareholders and transactions with close associates (pages 87-88), section 3.5 Freely negotiable shares (page 88), section 3.10 Risk management and internal controls (page 102), as indicated in the Declaration on remuneration and other employment terms for Statoil's corporate executive committee (pages 106-114), section 3.13 Information and communications (page 114) and section 3.14 Take-overs (page 114).

The Statoil Annual report and Form 20-F may be downloaded from Statoil's website at [Statoil.com/annualreport2016]. No other material on Statoil's website forms any part of such document. References to this document or other documents on Statoil's website are included as an aid to their location and are not incorporated by reference into this document. All of the SEC filings made available electronically by Statoil may be obtained from the SEC at 100 F Street, N.E., Washington D.CC. 20549, United States or on the SEC's website at www.sec.gov.

Strategic report

2.1 STRATEGY AND MARKET OVERVIEW

STATOIL'S BUSINESS ENVIRONMENT

Market overview

2016 was another year of sub-par growth, with global economic GDP growth easing from 2.6% to 2.3%. This was largely driven by the slowdown in OECD economies, with non-OECD economies gaining momentum over the year. In the United States, consumer spending remained healthy, but investment contracted and resulted in GDP growth decelerating from 2.6% in 2015 to 1.6%. Economic expansion continued at a moderate pace in the Euro-zone at 1.7%, supported by private consumption and higher employment. The economy in the United Kingdom held up well despite the EU Leave vote, while in contrast Japan logged relatively modest growth. Emerging markets maintained their growth rate from 2015, partly due to Russia heading towards economic recovery during the year. 2016 saw China's growth stabilise due to intensified stimulus efforts amidst the continued slowdown since 2012, caused by economic rebalancing. India's GDP growth rate eased to 6.6% on the sudden demonetarisation of large currency notes that hampered consumption. Several major forces are at play in the global economy and will continue to affect demand, including relatively low commodity prices, low interest rates, increased policy uncertainty and weak world trade.

Global oil demand grew by a healthy 1.5 mmbbl per day in 2016. Production from non-Opec countries reacted to lower prices and declined by 0.9 mmbbl, with most of the decline taking place in North America and China. However, Opec added 1.1 mmbbl per day to production. This resulted in an oversupplied market throughout 2016, with storage levels moderately increasing.

The first half of 2016 saw a downward trend in gas prices, which reflected both market balance and surrounding competitive fuels. However, in the second half of 2016, markets have strengthened due to a rebounding commodity market and demand responding to weak gas prices in the first half of 2016.

Oil prices and refining margins

Higher than usual volatility characterised the oil market in 2016 as it did in the previous year, with the price of dated Brent moving in a range between USD 26 per barrel to USD 55 per barrel.

Oil prices

The oil market is generally volatile and has been highly volatile since June 2014. The average price for dated Brent crude in 2016 was USD 43.7 per barrel, down USD 10 per barrel from 2015. The dated Brent oil price started the year on a downward trajectory and hit a low of USD 26 per barrel in the second half of January. Positive market sentiment driven by healthy demand growth and significant supply disruptions pushed the price of dated Brent up to around USD 50 per barrel by the end of second quarter. The return of disrupted volumes during the summer and signs of weakening demand growth sent prices down again towards USD 40 per barrel early in August. The price of dated Brent recovered somewhat again in the third quarter after Opec and Russia agreed to come up with a plan to freeze or cut their production. The Opec meeting in late November concluded with an agreement among the members to cut joint output by 1.2 mmbbl per day effective 1 January 2017, alongside a non-Opec cut of around 0.6 mmbbl per day. The immediate effect of this announcement was an increase in the dated Brent price towards USD 53 per barrel. The futures market for Brent at the Intercontinental Exchange (ICE) was in contango throughout 2016.

Over the course of 2016, North American tight oil has provided the largest share of non-Opec declines that offset continued growth in Opec production. While US shale production has been in decline over much of the past two years, productivity gains and cost reductions have accelerated, planting the seeds of future growth. Specifically, enhanced completions and extended-reach laterals have allowed producers to do more with less. Nowhere is this more evident than in the Permian basin of West Texas. As oil prices have increased during the course of the year, the Permian has recorded the largest rebound in drilling rigs. At current levels, the Permian basin is home to almost 50% of all oil rigs in the US, up from 30% in early 2013. From a pricing perspective, declining production, an abundance of infrastructure, and the lifting of the crude export ban have caused most North American grades to price close to their technical refining values, reflective of the ongoing de-bottlenecking of US onshore crude pipeline infrastructure. These narrow differentials relative to global waterborne crudes have caused rail loadings to fall precipitously with all indications being that this trend is set to continue in the years ahead.

Refinery margins

2016 was a solid year for European refinery margins. Through 2015, a surplus of crude oil had been converted to a surplus of products, incentivised by strong margins. By early 2016, diesel stocks were building fast and diesel margins were low. Refineries then shifted to maximise gasoline output, in expectation of a strong summer gasoline market. However, summer gasoline demand disappointed, leading to stocks building and sharply falling gasoline margins. Weak product prices through the summer led to constrained refinery throughput and supported demand. By the fourth quarter, the gasoline market rebalanced and diesel stocks fell again. This caused refinery margins to improve again in the fourth quarter. The average margin for an upgraded refinery in North West Europe was solid and in line with 2014, but well below 2015 margins.

Natural gas prices

Natural gas prices declined throughout 2015 but stabilised in the second quarter of 2016. The fourth quarter of 2016 experienced a robust price recovery due to consumption growth in Asia and Europe. Henry Hub experienced its lowest annual price in over a decade through 2016.

Gas prices - Europe

NBP prices fell from an average of USD 7.5/MMBtu in first quarter 2015 to USD 5.4/MMBtu in fourth quarter 2015. The decline continued in first quarter 2016, averaging USD 4.3/MMBtu, before falling to a decade low of USD 3/MMBtu in August 2016. Since August's low point, average monthly prices have strengthened, closing 2016 at USD 6.2/MMBtu and resulting in an annual 2016 average of USD 5/MMBtu.

EU gas consumption continued to grow in 2016 as power generation responded to higher priced coal and outages of nuclear reactors in France. Furthermore, heating demand has responded to a more normal European weather pattern. EU indigenous gas production held at a record low of 125 bcm as the Dutch government revised the production limit at the Groningen field down to 24 bcm. European imports from Russia were at a record high of 179 bcm and imports from Norway were at the same record level as in 2015, 108 bcm. Record levels of pipeline imports have been encouraged by a small downturn in LNG deliveries to Europe. LNG supplies into North Western Europe have diminished, whilst imports into Southern Europe remain constant.

Gas prices - North America

Gas prices were volatile in 2016, falling below USD 2/MMBtu early in the year, before rising above USD 3/MMBtu at the end of the year. The Henry Hub average of USD 2.4/MMBtu was the lowest annual price in over a decade, down from USD 2.6/MMBtu in 2015 largely as a result of oversupply. US gas producers responded to the falling prices by withdrawing rigs to the lowest level in decades. Gas production fell throughout the year as a result. Demand for gas was strong in 2016, with natural gas replacing coal in the power sector and LNG exports starting from the Gulf Coast.

Global LNG prices

LNG prices fell throughout 2015 from an average of USD 7.3/MMBtu in first quarter 2015 to USD 4.5/MMBtu in first quarter 2016, but stabilised in second quarter of 2016 at an average of USD 4.9/MMBtu. The second half of 2016 experienced robust price recovery to average USD 8/MMBtu in fourth quarter 2016, largely due to consumption growth in Asia and the Middle East, further intensified by lower-than-expected ramp-up of new LNG facilities as well as unplanned outages.

Statoil's corporate strategy

Statoil is an energy company committed to long-term value creation in a low carbon future. Statoil creates value by turning natural resources into energy for people and progress for society. Statoil will develop and maximise the value of its unique NCS position, its international oil and gas business and its growing new energy business, focusing on safety, cost and carbon efficiency. Statoil is a values-based company where empowered people collaborate to shape the future of energy.

To succeed in turning Statoil's vision into reality, Statoil pursues a strategy to:

- Deepen and prolong the NCS position
- Grow material and profitable international positions
- Provide energy for a low-carbon future through growth in New Energy Solutions (NES)
- Focused and value-adding mid- and downstream

In addition, Statoil will research, develop, and deploy technology to create opportunities and enhance the value of Statoil's current and future assets.

Deepen and prolong the NCS position

For more than 40 years, Statoil has explored, developed and produced oil and gas from the NCS. Statoil aims to deepen and prolong its position by accessing and maturing opportunities into valuable production. At the same time, Statoil plans to improve the reliability, efficiency and lifespan of fields already in production. The NCS represents approximately two thirds of Statoil's equity production at 1,235 mboe per day in 2016.

- **Exploration:** Statoil continues to be a committed NCS explorer across mature, growth and frontier areas. In 2016, Statoil participated in 14 exploration wells on the NCS, resulting in 11 discoveries. Statoil was awarded 29 licenses in mature areas in Norway's Awards for Predefined Areas (APA) 2016 round (result announced January 2017), 16 as operator and 13 as non-operating partner, and five licenses in frontier areas in Norway's 23rd concession round, four as operator and one as partner
- **Development:** The Johan Sverdrup Phase 1 project is progressing in line with schedule. Production drilling started in the first quarter of 2016. Pre-sanction for Johan Sverdrup Phase 2 is scheduled for the first quarter of 2017. Statoil increased its equity interest in the UK part of the Utgard license and submitted the Utgard Plan for Development and Operation (PDO) in the second quarter of 2016. The PDOs for Byrding and Trestakk were delivered and the PDO for Oseberg Vestflanken 2 was approved during 2016
- **Production:** Gullfaks Rimfaksdalen came on-stream. Production started at Fram C, tied into existing infrastructure in the Fram and Troll area

Statoil has completed two share transactions resulting in a 20.1 per cent equity ownership in Lundin Petroleum AB. Lundin is our partner in several fields, including a 22.6% interest in the unitised Johan Sverdrup field development. Statoil also acquired 25% of Byrding.

By the end of 2016, Statoil had achieved CO_2 emission reductions in excess of 1 million tonnes per year compared to a 2008 baseline on the NCS, primarily through better energy management and improved energy efficiency. Our 2020 target is to deliver 1.2 million tonnes of CO_2 emission reductions compared to 2008. In August 2016, the Norwegian petroleum industry announced its ambition to implement CO_2 reduction measures corresponding to 2.5 million tonnes on the NCS by 2030 compared to 2020. Statoil's commitment is to deliver 2.0 million tonnes of this CO_2 reduction target.

Grow material and profitable international positions

International oil and gas production represented approximately one third of Statoil's equity production at 744 mboe per day in 2016. Statoil will continue to explore, develop, and produce oil and gas opportunities outside Norway to enhance Statoil's upstream portfolio.

- **Exploration:** Statoil continues to explore internationally for oil and gas. Statoil participated in nine exploration wells internationally, of which three were discoveries, including the Baccalieu discovery in Canada. Statoil added exploration acreage in Brazil, Canada, New Zealand, Russia, the UK and the US Gulf of Mexico, accessed exploration acreage in Ireland and Turkey and entered two new countries, Mexico and Uruguay. A joint venture comprising Statoil, BP and Total was awarded Blocks 1 and 3 in the Saline Basin in Mexico, with Statoil as the operator.
- **Development:** Statoil strengthened its strategic partnership with Petrobras in Brazil. Construction progress continued as planned on Peregrino Phase II
- **Production:** Heidelberg and Julia production came on-stream in the US Gulf of Mexico and, along with operator BP and other

partners, significant advances have been made towards the award of a licence extension for Azeri-Chirag Guneshli (ACG) in Azerbaijan. The In Salah southern fields in Algeria and the Corrib field in Ireland both had major ramp-ups in 2016

In Brazil, Statoil acquired a 66% interest in and became the operator license of BM-S-8, which contains a substantial part of the Carcará field. Operatorship was assumed and appraisal activities began on BM-C-33. In the US, Statoil increased its stake in the Eagle Ford field and assumed full operatorship. Statoil continued to focus its portfolio with a partial divestment of non-core Marcellus acreage and agreeing the sale of its oil sands business in Canada.

Provide energy for a low-carbon future
Statoil recognises that opportunities are increasingly available in producing low carbon energy.

In 2016 Statoil launched Statoil Energy Ventures, a USD 200 million venture capital fund dedicated to investing in attractive and ambitious growth companies in renewable energy. This fund made its first investments in United Wind Inc. and later in ChargePoint Inc., Convergent Energy and Power Inc. and Oxford Photovoltaics Ltd., and is continuing to evaluate market opportunities. Statoil has also continued to explore new business opportunities in carbon capture and storage as well as other potential new energy markets.

- **Development:** The 402 MW Dudgeon Offshore Wind Park development started installation in the first quarter of 2016 and is expected to be fully commissioned by the fourth quarter of 2017
- **Production:** In 2016, Statoil signed a letter of intent to become operator of the Sheringham Shoal Offshore Wind Farm in January 2017; it currently produces from an installed capacity of 317 MW. Statoil has a 40% ownership stake of the Scira consortium which produces electricity from the Sheringham Shoal wind park

Statoil partnered with E.ON to develop the 385 MW Arkona wind farm offshore Germany, with start-up planned for 2019. In the US, Statoil was declared the provisional winner of the US government's wind lease sale offshore New York, with a potential generation capacity of more than 1.8 GW.

Statoil will also start production from the world's first floating windfarm, Hywind Scotland, in the fourth quarter of 2017. Statoil's partner in the 30 MW project is Masdar, which acquired 25% of the project in January 2017. The project will also include an innovative battery storage solution, Batwind, which represents the company's first wind development with integrated energy storage.

Statoil has delivered a feasibility study to the Norwegian government for part of a Norwegian carbon capture and storage (CCS) value chain. The scope has been to find commercial methods to inject CO_2 volumes arriving via ship into an underground reservoir on the NCS. Statoil's long experience with CO_2 storage from Sleipner and Snøhvit has been valuable, finding commercial and technical means to store large volumes of third party CO_2 in order to accommodate the world's need for CCS solutions.

Focused and value-adding mid- and downstream
The prime objective for Statoil's mid- and downstream activities is to process and transport its oil and gas production (including the Norwegian State's petroleum) competitively to premium markets, securing maximum value realisation. The main focus is on:

- Safe and efficient operations
- Continuous improvement in operational regularity, HSE and costs
- Flow assurance and marketing of Statoil's equity production (crude oil, natural gas, related products) and the State's Direct Financial Interest (SDFI) volumes for maximum value creation
- Utilisation of the Asset Backed Trading model across commodities to capture margin opportunities
- Maintaining Statoil's position as a leading European gas supplier
- A capital lean asset structure

Strategic focus is directed at optimising the value of Statoil's flexible Norwegian gas production assets that supply Europe and at Statoil's midstream activities in North America, where Statoil's onshore portfolio is developing. Statoil achieved strong marketing trading results across all commodities.

Research, development, and deployment of technology to unlock opportunities and enhance value
Statoil believes that technology is a critical success factor for value creation. Statoil's technology development activities aim to increase access to new oil and gas resources at competitive cost, reduce field development, drilling and operating costs, and CO_2 and other greenhouse gas emissions. Statoil's technology efforts focus on the following priority areas:

- **Business-critical technologies:** Upstream technologies are prioritised, primarily in the areas of Exploration, Reservoir, Drilling and Well, and Subsea Production Systems. Statoil's main focus has been on cost reduction, for example Statoil's simplified subsea production concept Cap-X™ has been developed to enable possible future development projects in the Barents Sea
- **Strengthening Statoil's licence to operate:** Statoil has strengthened its commitment to sustainability. For the oil & gas and new energy value chains, technology development is concentrated on increased energy efficiency for power generation and reduced CO_2 emissions. For renewables, technological improvements to reduce cost in the areas of construction and maintenance for both fixed and floating offshore wind applications is a priority
- **Expanding Statoil's capabilities:** Statoil continues its broader research efforts for both the oil and gas value chain and new value chains. Work is conducted both in-house and in collaboration with academia, research institutes and suppliers and through venture activities
- **Capturing the value of digitalisation:** Statoil is exploring the opportunities of digitalisation in the energy industry. In 2016, the focus has been determining the optimal approach to accelerate digitalisation to capture a greater value potential

At the capital markets update (CMU) on 7 February 2017, Statoil shared its sharpened strategy to respond to the changing business context. Geopolitical shifts, challenges in accessing new oil and gas resources, changing market dynamics, digitalisation and a global transition towards a low carbon economy are increasing uncertainty and volatility. This change in outlook drives the need to build a more resilient, diverse and option-rich portfolio, delivered by an agile organisation that embraces change and empowers its people. To deliver on the sharpened strategy and fulfill the strategic intent of "high value, low carbon", Statoil will continue to build opportunities to optimise its portfolio around the following pillars:

- **Norwegian continental shelf** - Build on unique position to maximise and develop long-term value
- **International Oil & Gas** - Focus geographically to deepen core areas and develop growth options
- **New Energy Solutions** - Create a new material industrial position
- **Midstream and Marketing** - Secure market access and grow value creation through cycles

The following strategic principles guide Statoil in shaping a robust, balanced and distinct portfolio:

1. **Cash generation capacity**
   Generating positive cash flows from operations, even at low oil and gas prices, in order to sustain dividend and investment capacity through the cycle.
2. **Capex flexibility**
   Having sufficient flexibility in organic capital expenditure to be able to respond to market downturns and avoid value destructive decisions.
3. **Capture value from cycles**
   Ensuring the ability and capacity to act counter-cyclically to capture value through the cycles.
4. **Low-carbon advantage**
   Maintaining competitive advantage as a leading company in carbon efficient oil and gas production, while building a low carbon business to capture new opportunities in the energy transition.

GROUP OUTLOOK

Statoil's plans address the current environment while continuing to invest in high-quality projects. Statoil continues to reiterate its efforts and commitment to deliver on its priorities of high value creation, increased efficiency and competitive shareholder return.

- Organic capital expenditures for 2017 (i.e. excluding acquisitions, capital leases and other investments with significant different cash flow pattern) are estimated at around USD 11 billion
- Statoil intends to continue to mature its large portfolio of exploration assets and estimates a total exploration activity level of around USD 1.5 billion for 2017, excluding signature bonuses
- Statoil expects to achieve an additional USD 1 billion in efficiency improvements in 2017 for a total of USD 4.2 billion
- Statoil's ambition is to keep the unit of production cost in the top quartile of its peer group
- For the period 2016 - 2020, organic production growth is expected to come from new projects resulting in around 3% CAGR (Compound Annual Growth Rate)
- The equity production for 2017 is estimated to be around 4-5% above the 2016 level
- Scheduled maintenance activity is estimated to reduce quarterly production by approximately 10 mboe per day in the first quarter of 2017. In total, maintenance is estimated to reduce equity production by around 30 mboe per day for the full fiscal year 2017, which is lower than the 2016 impact
- Indicative effects from Production sharing agreements (PSA-effect) and US royalties are estimated to be around 150 mboe per day in 2017 based on an oil price of USD 40 per barrel and 165 mboe per day based on an oil price of USD 70 per barrel
- Deferral of production to create future value, gas off-take, timing of new capacity coming on stream and operational regularity represent the most significant risks related to the foregoing production guidance

These forward-looking statements reflect current views about future events and are, by their nature, subject to significant risks and uncertainties because they relate to events and depend on circumstances that will occur in the future. For further information, see section 5.7 Forward-Looking Statements.

2.2 BUSINESS OVERVIEW

HISTORY

On 18 September 1972, Statoil was formed by a decision of the Norwegian parliament and incorporated as a limited liability company under the name Den norske stats oljeselskap AS. Being a company owned 100% by the Norwegian State, Statoil's initial role was to be the government's commercial instrument in the development of the oil and gas industry in Norway. Growing in parallel with the Norwegian oil and gas industry, Statoil's operations have primarily been focused on exploration, development and production of oil and gas on the Norwegian continental shelf (NCS).

During the 1980s, Statoil grew substantially through the development of the NCS. Statoil also became a major player in the European gas market by entering into large sales contracts for the development and operation of gas transport systems and terminals. During the same decade, Statoil was involved in manufacturing and marketing in Scandinavia and established a comprehensive network of service stations. This line of business was fully divested in 2012.

In 2001, Statoil was listed on the Oslo and New York stock exchanges and became a public limited company under the name Statoil ASA, 67% majority owned by the Norwegian State. Since then, substantial investments both on the NCS and internationally, have grown our business. The merger with Hydro's oil and gas division on 1 October 2007 further strengthened Statoil's ability to fully realise the potential of the NCS. Enhanced utilisation of expertise to design and manage operations in various environments have expanded our upstream activities outside our traditional area of offshore production. This includes the development of heavy oil and shale gas projects and projects that focus on other forms of energy, such as offshore wind and carbon capture and storage.

ACTIVITIES

Statoil is an international energy company primarily engaged in oil and gas exploration and production activities, organised under the laws of Norway and subject to the provisions of the Norwegian Public Limited Liability Companies Act. In addition to being the leading operator on the Norwegian continental shelf (NCS), Statoil has also substantial international activities and is present in several of the most important oil and gas provinces in the world. Our activities span operations in more than 30 countries and employs approximately 20,500 employees worldwide.

Our access to crude oil in the form of equity, governmental and third party volumes makes Statoil a large seller of crude oil, and Statoil is the second-largest supplier of natural gas to the European market. Processing and refining are also part of our operations.

Statoil's registered office is at Forusbeen 35, 4035 Stavanger, Norway and the telephone number of its registered office is +47 51 99 00 00.

OUR COMPETITIVE POSITION

Key factors affecting competition in the oil and gas industry are oil and gas supply and demand, exploration and production costs, global production levels, alternative fuels, and environmental and governmental regulations. When acquiring assets and licences for exploration, development and production and in refining, marketing and trading of crude oil, natural gas and related products, Statoil competes with other integrated oil and gas companies.

Statoil's ability to remain competitive will depend, among other things, on continuous focus on reducing costs and improving efficiency. It will also depend on technological innovation to maintain long-term growth in reserves and production and the ability to seize opportunities in new areas.

The information about Statoil's competitive position in the strategic report is based on a number of sources; e.g. investment analyst reports, independent market studies, and our internal assessments of our market share based on publicly available information about the financial results and performance of market players.

Improvement programmes

Improvement programmes are Statoil's response to the industrial challenge that has emerged over the recent years characterised by reducing prices for our products and declining returns. More specifically, the ambition is to realise positive production effects and capex and operating cost savings to improve financial results and cash-flows. For 2017 Statoil targets additional annual efficiency improvements of USD 1 billion on top of the already achieved USD 3.2 billon.

CORPORATE STRUCTURE

Business areas

Statoil's operations are managed through the following business areas:

Development and Production Norway (DPN)

DPN manages Statoil's upstream activities on the Norwegian continental shelf (NCS) and explores for and extracts crude oil, natural gas and natural gas liquids. The business area's ambition is to continue Statoil's leading position on the NCS and ensure maximum value creation through continuously improved HSE and operational performance.

Development and Production International (DPI)

DPI manages Statoil's worldwide upstream activities that are not included in the DPN and Development and Production USA (DPUSA) business areas. It explores for and extracts crude oil, natural gas and natural gas liquids. DPI's ambition is to build a large and profitable international production portfolio comprising activities ranging from accessing new opportunities to delivering on profitable projects in a range of complex environments.

Development and Production United States (DPUSA)

DPUSA manages Statoil's upstream activities in the USA and Mexico. DPUSA's ambition is to develop a material and profitable position in the US and Mexico, including the deep water regions of the Gulf of Mexico and unconventional oil and gas in the US.

Marketing, Midstream and Processing (MMP)

MMP manages Statoil's marketing and trading activities related to oil products and natural gas, transportation, processing and manufacturing, and the development of oil and gas. MMP seeks to maximise value creation in Statoil's midstream and marketing business.

Technology, Projects and Drilling (TPD)
TPD is accountable for the global project portfolio, well deliveries, new technologies and sourcing across Statoil. TPD seeks to provide safe and secure, efficient and cost-competitive global well and project delivery, technological excellence, and research and development. Cost-competitive procurement is an important contributory factor for maximising value for Statoil.

Exploration (EXP)
EXP manages Statoil's worldwide exploration activities with the aim of positioning Statoil as one of the leading global exploration companies and this is achieved through accessing high potential new acreage in priority basins, globally prioritising and drilling more significant wells in growth and frontier basins, delivering near-field exploration on the NCS and other select areas, and achieving step-change improvements in performance.

New Energy Solutions (NES)
NES reflects Statoil's long-term goal to complement our oil and gas portfolio with profitable renewable energy and other low-carbon energy solutions. NES is responsible for wind farms, carbon capture and storage as well as other renewable energy and low-carbon energy solutions.

Global Strategy and Business Development (GSB)
GSB sets the corporate strategy, business development and merger and acquisition activities for Statoil. The ambition of the GSB business area is to closely link corporate strategy, business development and merger and acquisition activities to actively drive Statoil's corporate development.

Reporting segments

Statoil reports its business in the following reporting segments:

- DPN reporting segment - Development and Production Norway – the DPN business area
- DPI reporting segment - Development and Production International, which combines the DPI and the DPUSA business areas
- MMP reporting segment - Marketing, Midstream and Processing – the MMP business area
- Other – which includes activities in NES, TPD, GSB and Corporate staffs and support functions

Activities relating to the EXP business area are fully allocated to - and presented in - the relevant development and production reporting segment. Activities relating to the TPD and GSB business areas are partly allocated to - and presented in - the relevant development and production reporting segments.

Presentation

In the following sections in the report, the operations are reported according to the reporting segment. Underlying activities or business clusters are presented according to how the reporting segment organises its operations.

See note 3 Segments to the Consolidated financial statements for further details.

As required by the SEC, Statoil prepares its disclosures about oil and gas reserves and certain other supplementary oil and gas disclosures based on geographic areas. Statoil's geographical areas are defined by country and continent and consist of Norway, Eurasia excluding Norway, Africa, and the Americas.

SEGMENT REPORTING

Internal transactions in oil and gas volumes occur between our reporting segments before being sold in the market. The pricing policy for internal transfers is based on estimated market prices. See Production volumes and prices in section 2.8 Operating and financial performance for further information.

We eliminate intercompany sales when combining the results of reporting segments. Intercompany sales include transactions recorded in connection with our oil and natural gas production in the DPN or the DPI business areas and also in connection with the sale, transportation or refining of our oil and natural gas production in the MMP business area. Certain types of transportation costs are reported in both the MMP and the DPUSA business areas.

The DPN business area produces oil and natural gas which is sold internally to the MMP business area. A large share of the oil produced by the DPI and DPUSA business areas is also sold through the MMP business area. The remaining oil and gas from the DPI and the DPUSA business areas is sold directly in the market. For intercompany sales and purchases, Statoil has established a market-based transfer pricing methodology for the oil and natural gas that meets the requirements as to applicable laws and regulations.

In 2016, the average transfer price for natural gas was USD 3.42 per mmbtu. The average transfer price was USD 5.17 per mmbtu in 2015 and USD 6.55 in 2014. For oil sold from DPN to MMP, the transfer price is the applicable market-reflective price minus a cost recovery rate.

The following table shows certain financial information for the four reporting segments, including intercompany eliminations for each of the years in the three-year period ending 31 December 2016. For additional information please refer to note 3 Segments to the Consolidated financial statements.

Segment performance (in USD million)	For the year ended 31 December 2016	2015	2014
Development & Production Norway			
Total revenues and other income	**13,077**	17,339	28,926
Net operating income	**4,451**	7,161	17,753
Non-current segment assets[1)]	**27,816**	27,706	35,243
Development & Production International			
Total revenues and other income	**6,657**	8,200	13,661
Net operating income	**(4,352)**	(8,729)	(2,703)
Non-current segment assets[1)]	**36,181**	37,475	44,912
Marketing, Midstream and Processing			
Total revenues and other income	**44,979**	58,106	95,171
Net operating income	**623**	2,931	2,608
Non-current segment assets[1)]	**4,450**	5,588	6,234
Other			
Total revenues and other income	**39**	354	118
Net operating income	**(423)**	(129)	(199)
Non-current segment assets[1)]	**352**	690	688
Eliminations[2)]			
Total revenues and other income	**(18,880)**	(24,357)	(38,612)
Net operating income	**(219)**	133	420
Non-current segment assets[1)]	-	-	-
Statoil group			
Total revenues and other income	**45,873**	59,642	99,264
Net operating income	**80**	1,366	17,878
Non-current segment assets[1)]	**68,799**	71,458	87,077

1) Deferred tax assets, pension assets, equity accounted investments and non-current financial assets are not allocated to segments.

2) Includes elimination of inter-segment sales and related unrealised profits, mainly from the sale of crude oil and products.
Inter-segment revenues are based upon estimated market prices.

The following tables show total revenues by country.

2016 Total revenues and other income by country (in USD million)	Crude oil	Natural gas	Natural gal liquids	Refined products	Other	Total sales
Norway	20,544	7,973	3,580	4,135	(497)	35,735
USA	3,073	957	455	1,110	867	6,463
Sweden	0	0	0	1,379	(53)	1,326
Denmark	0	0	0	1,518	14	1,532
Other	690	272	1	0	(27)	936
Total revenues (excluding net income (loss) from equity accounted investments and other income	24,307	9,202	4,036	8,142	305	45,993

2015 Total revenues and other income by country (in USD million)	Crude oil	Natural gas	Natural gas liquids	Refined products	Other	Total sales
Norway	22,741	10,811	4,932	5,644	1,454	45,582
US	3,718	1,133	532	1,605	933	7,922
Sweden	0	0	0	1,762	115	1,877
Denmark	0	0	0	1,750	8	1,759
Other	1,347	446	17	0	722	2,532
Total revenues (excluding net income (loss) from equity accounted investments and other income	27,806	12,390	5,482	10,761	3,232	59,671

2014 Total revenues and other income by country (in USD million)	Crude oil	Natural gas	Natural gas liquids	Refined products	Other	Total sales
Norway	40,899	12,817	8,799	8,718	2,864	74,096
US	7,933	2,212	643	2,379	1,351	14,518
Sweden	0	0	0	2,636	260	2,896
Denmark	0	0	0	3,050	37	3,087
Other	2,970	704	65	0	963	4,702
Total revenues (excluding net income (loss) from equity accounted investments and other income	51,803	15,732	9,506	16,782	5,475	99,299

RESEARCH AND DEVELOPMENT

Statoil is a technology-intensive company and research and development is an integral part of our strategy. Our technology strategy is about prioritising technology for value creation that enables us to achieve growth and access, and sets the direction for technology development and implementation for the future. Our focus is on low cost, low carbon solutions and re-using standardised technologies.

We continuously research, develop and deploy innovative technologies to create opportunities and enhance the value of Statoil's current and future assets. Statoil's technology development activities aim to reduce field development, drilling and operating costs, and CO_2 and other greenhouse gas emissions. We utilise a range of tools for the development of new technologies:

- In-house research and development (R&D)
- Cooperation with academia and research institutes
- Collaborative development projects with our major suppliers
- Project related development as part of our field development activities
- Direct investment in technology start-up companies through our Statoil Technology Invest venture activities
- Invitation to open innovation challenges as part of Statoil Innovate

Research and development expenditures were USD 298 million, USD 344 million and USD 476 million in 2016, 2015 and 2014, respectively.

2.3 DPN - DEVELOPMENT AND PRODUCTION NORWAY

OVERVIEW

The Development and Production Norway (DPN) reporting segment is responsible for field development and operations on the Norwegian continental shelf (NCS) which includes the North Sea, the Norwegian Sea and the Barents Sea. DPN aims to ensure safe and efficient operations and to maximise the value potential from the NCS. For proved reserves development see Development of reserves in Proved oil and gas reserves in section 2.8 Operating and financial performance.

Key events and portfolio developments in 2016:

- In January, Statoil announced the acquisition of 11.93% of the shares and votes in **Lundin** Petroleum AB (Lundin) for a total cash purchase price of SEK 4.6 billion (USD 0.5 billion), and in May, Statoil announced divestment of its entire 15% interest in Edvard Grieg for an increased shareholding in Lundin. The transaction also included divestment of a 9% interest in the Edvard Grieg oil pipeline and a 6% interest in the Utsira High gas pipeline, and in addition payment of cash consideration of USD 64 million to Lundin. Statoil now owns 20.1% of the shares in Lundin.
- On 1 March, the drilling of the first well of the **Johan Sverdrup** field development commenced.
- On 12 March, the **Goliat** field came on stream with Eni Norge as operator.
- In June, the plan for development and operation for **Oseberg Vestflanken 2** was approved by the Ministry of Petroleum and Energy.
- In June, the **Njord Future** project was established to secure long-term production for both the Njord and Hyme fields. The Njord field was temporarily shut in, and both the Njord A and Njord B platforms were towed to shore.
- On 9 August, Statoil and its partners submitted the plan for development and operation for the **Utgard** gas and condensate discovery to the Norwegian and UK authorities. The plan for development and operation was approved on 17 January 2017.
- On 19 August, Statoil and its partners submitted the plan for development and operation of the **Byrding** oil and gas discovery. On 30 December, Statoil completed the acquisition of Wintershall's 25% interest in Byrding, increasing Statoil's interest to 70%. The plan for development and operation of the Byrding discovery was approved on 17 January 2017.
- **Gullfaks Rimfaksdalen** started production ahead of schedule on 24 August.
- **Volve** ceased production on 17 September.
- The plan for development and operation of the **Trestakk** discovery was submitted on 1 November.
- On 24 December, the **Ivar Aasen** field came on stream with Aker BP as operator.

Fields in production on the NCS

The following table shows DPN's average daily entitlement for the years ending 31 December 2016, 2015 and 2014.
Production level maintained by new fields and new wells from existing fields. See chapter "Fields under development on the NCS" for future production replacement.

	For the year ended 31 December								
	2016			2015			2014		
Area production	Oil and NGL mbbl/day	Natural gas mmcm/day	mboe/day	Oil and NGL mbbl/day	Natural gas mmcm/day	mboe/day	Oil and NGL mbbl/day	Natural gas mmcm/day	mboe/day
Statoil operated fields	511	86	1,049	545	88	1,100	533	78	1,027
Partner operated fields	70	17	177	50	13	132	55	16	157
Equity accounted production	8	-	8	-	-	-	-	-	-
Total	589	103	1,235	595	101	1,232	588	95	1,184

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The following tables show the NCS production by fields in which Statoil was participating during the year ended 31 December 2016.

Field	Geographical area	Statoil's equity interest in %	On stream	Licence expiry date	Average daily production in 2016 mboe/day
Statoil operated fields					
Troll Phase 1 (Gas)	The North Sea	30.58	1996	2030	159.4
Åsgard	The Norwegian Sea	34.57	1999	2027	93.1
Gullfaks	The North Sea	51.00	1986	2036	83.8
Oseberg	The North Sea	49.30	1988	2031	76.2
Kvitebjørn	The North Sea	39.55	2004	2031	63.3
Visund	The North Sea	53.20	1999	2034	59.8
Snøhvit	The Barents Sea	36.79	2007	2035	47.4
Statfjord Unit	The North Sea	44.34	1979	2026	44.8
Tyrihans	The Norwegian Sea	58.84	2009	2029	44.6
Sleipner Vest	The North Sea	58.35	1996	2028	42.5
Grane	The North Sea	36.61	2003	2030	41.5
Troll Phase 2 (Oil)	The North Sea	30.58	1995	2030	39.8
Gudrun	The North Sea	36.00	2014	2028	35.0
Snorre	The North Sea	33.28	1992	2018 1)	32.8
Valemon	The North Sea	53.78	2015	2031	29.0
Kristin	The Norwegian Sea	55.30	2005	2033 2)	19.1
Mikkel	The Norwegian Sea	43.97	2003	2020 3)	17.4
Fram	The North Sea	45.00	2003	2024	16.8
Vigdis area	The North Sea	41.50	1997	2024	13.8
Morvin	The Norwegian Sea	64.00	2010	2027	11.6
Alve	The Norwegian Sea	85.00	2009	2029	10.5
Tordis area	The North Sea	41.50	1994	2024	10.3
Urd	The Norwegian Sea	63.95	2005	2026	10.1
Heidrun	The Norwegian Sea	13.04	1995	2024 4)	9.5
Sleipner Øst	The North Sea	59.60	1993	2028	9.4
Gungne	The North Sea	62.00	1996	2028	5.2
Norne	The Norwegian Sea	39.10	1997	2026	4.0
Volve	The North Sea	59.60	2008	2028	3.5
Veslefrikk	The North Sea	18.00	1989	2020 5)	2.7
Statfjord Nord	The North Sea	21.88	1995	2026	2.4
Hyme	The Norwegian Sea	35.00	2013	2014 6)	2.0
Njord	The Norwegian Sea	20.00	1997	2021 7)	1.4
Fram H Nord	The North Sea	49.20	2014	2024	1.4
Statfjord Øst	The North Sea	31.69	1994	2026 8)	1.3
Gimle	The North Sea	65.13	2006	2034 9)	1.2
Tune	The North Sea	50.00	2002	2032 10)	1.1
Sygna	The North Sea	30.71	2000	2026 11)	0.9
Heimdal	The North Sea	29.44	1985	2021	0.7
Total Statoil operated fields					1,049.4

Field	Geographical area	Statoil's equity interest in %	Operator	On stream	Licence expiry date	Average daily production in 2016 mboe/day
Partner Operated Fields						
Ormen Lange	The Norwegian Sea	25.35	Shell	2007	2041 [12)]	73.9
Skarv	The Norwegian Sea	36.16	Aker BP ASA	2013	2033 [13)]	43.9
Goliat	The Barents Sea	35.00	Eni Norge AS	2016	2042	17.9
Ekofisk area	The North Sea	7.60	ConocoPhillips	1971	2028	13.6
Marulk	The North Sea	50.00	Eni Norge AS	2012	2025	11.6
Sigyn	The North Sea	60.00	ExxonMobil	2002	2022	5.9
Edvard Grieg	The North Sea	0.00	Lundin Norway AS	2015	2035 [14)]	4.8
Vilje	The North Sea	28.85	Aker BP ASA	2008	2021	4.1
Ringhorne Øst	The North Sea	14.82	ExxonMobil	2006	2030	1.4
Ivar Aasen	The North Sea	41.47	Aker BP ASA	2016	2029 [15)]	0.2
Enoch	The North Sea	11.78	Repsol Sinopec	2007	2018	0.1
Total Partner Operated Fields						177.3
Equity accounted production						
Lundin Petroleum AB		20.10	Lundin Petroleum AB			8.1
Total Development and Production Norway (DPN) including share of equity accounted production						1,234.8

1) PL089 expires in 2024 and PL057 expires in 2018 (prolonged from 2016 to 2018).
2) PL134D expires in 2027 and PL199 expires in 2033.
3) PL092 expires in 2020 and PL121 expires in 2022.
4) PL095 expires in 2024 and PL124 expires in 2025.
5) PL052 expires in 2020 and PL053 in 2031.
6) PL348 expires in 2029.
7) PL107 expires in 2021 and PL132 expires in 2023.
8) PL037 expires in 2026 and PL089 expires in 2024.
9) PL120B expires in 2034 and PL050DS expires in 2023.
10) PL034 expires in 2020. PL053 expires in 2031 and PL190 in 2032.
11) PL037 expires in 2026 and PL089 expires in 2024.
12) PL209/250 expires in 2041 and PL208 expires in 2040.
13) PL212/262 expires in 2033 and PL159 expires in 2029.
14) From 1 January to 30 June 2016 Statoil owned a 15% interest in the Edvard Grieg field. On 30 June 2016 this interest was sold to Lundin. The Edvard Grieg swap agreement was a part of Statoil increasing the ownership in Lundin.
15) PL001B, PL452BS and PL242 expire in 2036. PL 338BS expire in 2029.

MAIN PRODUCING FIELDS ON THE NCS

Statoil operated fields

Troll is both the largest gas field on the NCS and a major oil field. The Troll field regions are connected to the Troll A, B and C platforms. Troll gas is mainly exported and produced at Troll A, while oil is mainly produced at Troll B and C. Fram and Fram H Nord are tie-ins to Troll C.

The **Åsgard** field includes the Åsgard A production and storage ship for oil, the Åsgard B semi-submersible floating production platform for gas, and the Åsgard C storage vessel for condensate. In 2015 Statoil started the world first subsea gas compressor train on Åsgard, and the second train was started in February 2016. Mikkel and Morvin are tie-ins to Åsgard. The Trestakk development will be a tie-in to Åsgard A with production start planned in 2019.

Gullfaks has been developed with three large concrete production platforms. Since production started on Gullfaks in 1986, several satellite fields have been developed with subsea wells that are remotely controlled from the Gullfaks A and C platforms.

The **Oseberg** area includes the Oseberg Field Centre, Oseberg C, Oseberg East and Oseberg South production platforms. Oil and gas from the satellites are transported to Oseberg Field Centre for processing and transportation.

Kvitebjørn is a gas and condensate field developed with an integrated accommodation, drilling and processing facility with a steel jacket.

Visund is an oil and gas field that includes a floating drilling, production and living quarter unit and two subsea templates.

Partner-operated fields

Ormen Lange operated by Shell, is a deepwater gas field in the Norwegian Sea. The well stream is transported to an onshore processing and export plant at Nyhamna.

Skarv is an oil and gas field located in the Norwegian Sea, with BP as operator. The field development includes a floating production, storage and offloading vessel (FPSO) and five subsea multi-well installations.

Goliat is the first oil field to be developed in the Barents Sea. The field is being developed by means of 22 subsea wells tied back to a circular floating production, storage and offloading vessel (FPSO). The oil is offloaded to shuttle tankers. The Goliat field is operated by Eni and started production 12 March 2016.

Ekofisk is operated by ConocoPhillips. It consists of the Ekofisk, Tor, Eldfisk and Embla fields. The Eldfisk II project delivered a new PDQ platform early 2015 that will serve as Eldfisk field center.

Marulk is operated by Eni. It is a gas- and condensate field developed as a tie-back to the Norne FPSO.

Ivar Aasen is an oil and gas field located in the North Sea. The development includes a fixed steel jacket with partial processing and living quarters tied in as a satellite to Edvard Grieg for further processing and export. The Ivar Aasen development is operated by Aker BP ASA and started production 24 December 2016.

Exploration on the NCS

Statoil holds exploration acreage and actively explores for new resources in all three regions on the NCS, the Norwegian Sea, the North Sea and the Barents Sea.

In 2016 Statoil was awarded five licences (four as operator) in the **23rd concession round** for frontier areas, 29 licences (16 as operator) in the **Awards for Predefined Areas (APA) round 2016** for mature areas and completed several farm-in transactions with other companies, notably in the Barents Sea.

Throughout 2016, as part of the industry initiative **Barents Sea Exploration Collaboration** (BaSEC), Statoil have been preparing for a drilling campaign of five to seven wells in the Barents Sea that will commence in 2017,

In 2016 Statoil completed a six well appraisal campaign of the Krafla discovery in the North Sea and made five new discoveries. The campaign set a record in drilling efficiency, with the Beerenberg well taking only nine days from spud to reaching total depth of 2,694 meters below the seabed.

In 2016 Statoil and its partners completed 14 exploratory wells and made 11 discoveries in Norway. In 2017 Statoil expects to complete 16 to18 exploration wells on the NCS, with the Barents Sea campaign being at the core of the activity plan.

	Exploratory wells drilled[1]		
	2016	2015	2014
North Sea			
Statoil operated	9	11	11
Partner operated	2	3	7
Norwegian Sea			
Statoil operated	2	5	0
Partner operated	0	1	1
Barents Sea			
Statoil operated	0	0	9
Partner operated	1	1	1
Total (gross)	**14**	**21**	**29**

1) Wells completed during the year, including appraisals of earlier discoveries.

Fields under development on the NCS

Statoil's major development projects on the NCS as of 31 December 2016:

Johan Sverdrup (Statoil 40.03%, operator, with additional 4.54% indirect interest held through Lundin) is an oil discovery in the North Sea. A plan for development and operation was submitted in February 2015 and approved by the Norwegian authorities in August 2015. Phase 1 of the development will consist of 35 production and water injection wells and a field centre with four platforms: A living quarter platform, a wellhead platform with permanent drilling facility, a processing platform and a riser and utility platform. Crude oil will be exported to Mongstad through a 274 km long dedicated pipeline, and gas will be exported to the gas processing facility at Kårstø through a 156 km long pipeline via a subsea connection to the Statpipe pipeline. On 1 March 2016, the drilling of the first well of the Johan Sverdrup field development commenced. Production is expected to start in 2019.

Aasta Hansteen (Statoil 51%, operator) is a deep water gas discovery in the Norwegian Sea. The field development concept includes three subsea templates tied in to a floating processing unit with gas export through a new pipeline, Polarled, to Nyhamna and further exportation through the Langeled pipeline. The Aasta Hansteen processing unit can also serve as a hub for other potential discoveries in the area. On 9 January 2016, the living quarter was lifted onto the topside, which is under construction in South Korea. On 27 July 2016, the final megablock was lifted onto the substructure in South Korea. Production is expected to start in 2018.

Gina Krog (Statoil 58.7%, operator) is an oil and gas discovery in the North Sea. The field development concept includes a steel-jacket platform and a total of 15 wells. Oil will be exported via offshore loading from a floating storage unit. Due to the high condensate content, the rich gas will be exported via Sleipner, where it will be further processed. The development concept also includes gas injection in order to maximise the recovery factor for the field. On 20 July 2015, the drilling of the first well of the Gina Krog field development commenced, and the drilling operations continued in 2016. On 23 August 2016, all the topside modules had been lifted in place, and the Gina Krog platform was complete in the field. Production is expected to start in 2017.

The **Utgard** development (Statoil 38.44% interest in the Norwegian and 38% in the UK sector, operator) will include two wells in a standard subsea concept, with one drilling target on each side of the UK-Norwegian maritime border. Gas and condensate will be piped through a new pipeline to the Sleipner field for processing and further transportation to market. On 17 January 2017, the plan for development and operation and the field development plan were approved by Norwegian and UK authorities. Production is expected to start in 2019.

The **Trestakk** discovery (Statoil 59.1%, operator) will be developed with five wells, three producers and two injectors, to be tied in to the Åsgard A installation for processing, measurement and gas injection. On 1 November, 2016, Statoil, on behalf of the licensees, submitted the plan for development and operation. Production is expected to start in 2019.

Oseberg Vestflanken 2 (Statoil 49.3%, operator) is the development of the oil and gas structures Alfa, Gamma and Kappa. The well stream will be routed to the Oseberg field centre through a new pipeline. The plan for development and operation was approved by the Ministry of Petroleum and Energy in June, 2016. The discoveries will be developed using an unmanned wellhead platform. Production is expected to start in 2018.

Gullfaks C subsea compression (Statoil 51%, operator), an increased gas recovery project for the Gullfaks Sør Brent reservoir, includes the installation of a subsea compressor solution in the vicinity of the L/M template in order to prolong the gas production plateau at Gullfaks C and increase the recoverable reserves from the Gullfaks Sør Brent reservoir. The compressor is expected to come on stream in 2017.

Byrding (Statoil 70%, operator) will be developed as a subsea installation with one well drilled from an existing template on Fram H-Nord. On 17 January 2017, the Norwegian Ministry of Petroleum and Energy approved the plan for development and operation. Production is expected to start in 2017.

Troll B gas module (Statoil 30.58%, operator), a new gas module being installed to increase the processing capacity at Troll B, was sanctioned in September 2016, and is expected to be brought on stream in 2018.

Martin Linge (Statoil 19%) is an oil and gas field operated by Total, near the British sector of the North Sea. The reservoir is complex with gas under high pressure and high temperatures. The development includes a fixed steel jacket platform with processing and export facilities, with electric power to be supplied from Kollsnes. The operator expects production to start in 2018.

Decommissioning on the NCS

Under the Petroleum Act, the Norwegian government has imposed strict procedures for removal and disposal of offshore oil and gas installations. The Convention for the Protection of the Marine Environment of the Northeast Atlantic (OSPAR) stipulates similar procedures.

Huldra ceased production in September 2014, after 13 years in production. The permanent plugging and abandonment of wells has been ongoing in 2016 with removal of topside facilities planned in 2019.

Volve ceased production in September 2016, after more than eight years in production. The permanent plugging of wells was finalised during 2016, and the removal of subsea templates is expected to be completed in 2017.

During 2016, there were permanent plugging and abandonment operations at **Statfjord**, **Visund**, **Tune**, **Kristin** and **Heimdal**. The partner-operated field **Ekofisk** also had ongoing removal and plugging activities.

For further information about decommissioning, see note 2 Significant accounting policies to the Consolidated financial statements.

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2.4 DPI - DEVELOPMENT AND PRODUCTION INTERNATIONAL

DPI overview

Statoil is present in several of the most important oil and gas provinces in the world. The Development and Production International (DPI) reporting segment covers all development and production of oil and gas outside the Norwegian continental shelf (NCS).

DPI is present in more than 20 countries and had production in 11 countries in 2016. DPI produced 38% of Statoil's total equity production of oil and gas in 2016. For information about proved reserves development see section 2.8 Proved oil and gas reserves.

The map shows the countries where DPI has activity.

Key events and portfolio developments in 2016 and early 2017:

- In January, the **Heidelberg** field achieved first oil. The field is located in the Green canyon area of the Gulf of Mexico with Anadarko as the operator. Discovery was made in 2009, and sanctioning took place in 2013
- Operations at the **In Salah Southern Fields** project in Algeria started in March
- In April, the **Julia** field achieved first oil, on time and under budget. Julia is located in the Walker Ridge area of the Gulf of Mexico near Jack and St Malo. ExxonMobil is the operator
- In May, Statoil divested its operated acreage in the **Marcellus West Virginia** to EQT Corporation for USD 407 million in cash. The transaction was completed in July
- In July, Statoil announced acquisition of Petrobras' 66% operated interest in the offshore licence **BM-S-8** in Brazil's Santos Basin. This licence contains a substantial part of the Carcará pre-salt oil discovery. The transaction was completed in November
- The third processing train on the **In Amenas** field in Algeria, which was damaged in the January 2013 terrorist attack, restarted in July, and the **In Amenas Gas Compression project** came into operation in February 2017. The compression project has enabled increased production and thereby capacity to utilize all three trains
- In December, the drilling of the first well of the **Mariner** field development commenced
- In December, Statoil increased its ownership in the deep-water **Vito** discovery from 30.0% to 36.89%, after exercising pre-emption rights on the Freeport-McMoran sale to Anadarko. The field is located in the Mississippi Canyon area. A final investment decision is expected in 2018 with first production in 2021
- In December, on request of US authorities, Statoil has become operator of record for blocks **MC941** and **MC942** in the Gulf of Mexico following the bankruptcy of Bennu Oil & Gas LLC. With the bankruptcy proceedings still ongoing, the full implications for Statoil are still to be determined
- In 2016, Statoil completed transactions to increase its equity interest to 100% in the UK continental shelf licence (P312) of the **Utgard** field, which spans the UK-Norway maritime border. In March 2016, Statoil's purchase of a 31% equity interest from Talisman Sinopec North Sea Limited was completed, and

in June the purchase of a 45% operated equity share from JX Nippon was completed. In January 2017, the plan for development and operation for the Utgard field was approved by the Norwegian and UK authorities. For more information, see Fields under development on the NCS in section 2.3 DPN - Development and production Norway

- In December, Statoil signed an agreement to divest its 100% owned **Kai Kos Dehseh (KKD) oil sands** projects in the Canadian province of Alberta to Athabasca Oil Corporation. The transaction covers the producing Leismer demonstration plant and the undeveloped Corner project, along with a number of midstream contracts associated with Leismer's production. Following this transaction, Statoil will no longer own or operate any oil sands assets. As part of the transaction, Statoil will own just below 20% of Athabasca's shares, and this will be managed as a financial investment. The transaction was completed 31 January 2017. For more information about the transaction see note 4 Acquisitions and disposals to the Consolidated financial statements.

International production

Statoil's entitlement production outside Norway was about 32% of Statoil's total entitlement production in 2016.

The following table shows DPI's average daily entitlement production of liquids and natural gas for the years ending 31 December 2016, 2015 and 2014. Entitlement production volumes are Statoil's share of the volumes distributed to the partners according to production sharing agreement (PSA) (see section 5.6 Terms and abbreviations). For US assets entitlement production is expressed net of royalty interests. For all other countries royalties paid in-cash are included in entitlement production and royalties payable in-kind are excluded.

	For the year ended 31 December								
	2016			2015			2014		
Production area	Oil and NGL mboe/day	Natural gas mmcm/day	mboe/day	Oil and NGL mboe/day	Natural gas mmcm/day	mboe/day	Oil and NGL mboe/day	Natural gas mmcm/day	mboe/day
Americas	189	18	299	177	17	283	155	19	272
Africa	203	5	232	211	5	241	179	3	198
Eurasia	32	3	50	36	1	44	37	4	64
Equity accounted production	10	-	10	12	-	12	12	-	12
Total	435	25	592	436	23	580	383	26	546

The table below provides information about the fields that contributed to production in 2016

Field	Country	Statoil's equity interest in %	Operator	On stream	Licence expiry date	Average daily equity production in 2016 mboe/day
Americas						341.5
Marcellus [1]	US	Varies	Statoil/others	2008	HBP[2]	119.7
Bakken [1]	US	Varies	Statoil/others	2011	HBP[2]	51.1
Eagle Ford [1]	US	Varies	Statoil/others	2010	HBP[2]	40.8
Peregrino	Brazil	60.00	Statoil	2011	2034	37.5
Leismer Demo	Canada	100.00	Statoil	2010	HBP[2]	20.4
Tahiti	US	25.00	Chevron	2009	HBP[2]	17.3
Caesar Tonga	US	23.55	Anadarko	2012	HBP[2]	12.6
St. Malo	US	21.50	Chevron	2014	HBP[2]	12.2
Jack	US	25.00	Chevron	2014	HBP[2]	9.3
Hibernia/Hibernia Southern Extension[3]	Canada	Varies	HMDC	1997	2027	8.9
Julia	US	50.00	ExxonMobil	2016	HBP[2]	5.1
Terra Nova	Canada	15.00	Suncor	2002	2022	4.9
Heidelberg	US	12.00	Anadarko	2016	HBP[2]	1.6
Africa						308.0
Block 17	Angola	23.33	Total	2001	2022-34[4]	146.1
Agbami	Nigeria	20.21	Chevron	2008	2024	46.3
Block 15	Angola	13.33	ExxonMobil	2004	2026-32[4]	42.1
In Salah	Algeria	31.85	Sonatrach/BP/Statoil	2004	2027	38.4
Block 31	Angola	13.33	BP	2012	2031	21.7
In Amenas	Algeria	45.90	Sonatrach/BP/Statoil	2006	2022	13.4
Eurasia						83.6
ACG	Azerbaijan	8.56	BP	1997	2024	53.9
Corrib	Ireland	36.50	Shell	2015	2031	17.6
Kharyaga	Russia	30.00	Zarubezhneft	1999	2032	9.4
Alba	UK	17.00	Chevron	1994	HBP[2]	2.6
Jupiter	UK	30.00	ConocoPhillips	1995	HBP[2]	0.2
Total Development and Production International (DPI)						733.0
Equity accounted production						
Petrocedeño[5]	Venezuela	9.68	Petrocedeño	2008	2033	10.3
Total Development and Production International (DPI) including share of equity accounted production						743.4

1) Statoil's actual equity interest can vary depending on wells and area.
2) Held by Production (HBP): A company's right to own and operate an oil and gas lease is perpetuated beyond its original primary term, as long thereafter as oil and gas is produced in paying quantities. In the case of Canada, in addition to continuing to be in production, other regulatory requirements must be met.
3) Statoil's equity interests are 5.0% in Hibernia and 9.0% in Hibernia Southern Extension.
4) Varies by field.
5) Petrocedeño is a non-consolidated company and accounted for pursuant to the equity accounting method. It produces extra-heavy crude oil from the Junin area in the Orinoco Belt.

Americas

Statoil has had strong growth in production and continues to optimize its portfolio within US shale since entering the first play in 2008. Statoil entered the **Marcellus** shale gas play, located in the Appalachian region in north east US, in 2008 through a partnership with Chesapeake Energy Corporation; Statoil has continued to optimize its North America onshore portfolio through acreage acquisition and divestments since 2008. In 2012, Statoil became an operator in the Marcellus through the purchase of additional acreage in the State of West Virginia and Ohio. The most recent divestments occurred in 2016 with divestment of West Virginia to EQT and Antero Resources. At the end of 2016, Statoil continues operatorship in the State of Ohio.

Statoil entered the **Bakken** tight oil play through the acquisition of Brigham Exploration Company in December 2011. Statoil's net acreage position in Bakken and Three Forks shale formation at the end of 2016 was 241,000 acres.

Statoil entered the **Eagle Ford** shale formation located in southwest Texas in 2010. In 2013, Statoil became operator for 50% of the Eagle Ford acreage. As part of a global transaction in December 2015 with Repsol, which acquired Talisman in May 2015, Statoil increased its working interest and took full operatorship of all of the assets in the Eagle Ford Shale. As a result, Statoil has a total working interest of 63%. Our joint venture partner, Repsol, continues to hold 37% working interest.

US gathering system

Statoil's participates in gathering and facilities for initial processing of oil and gas in the **Bakken**, **Eagle Ford** and **Marcellus** assets in the US. This includes crude and natural gas gathering systems, fresh water supply systems, salt water disposal wells, oil and gas treatment and processing facilities to provide flow assurance for Statoil's upstream production. Midstream assets in Bakken are owned and operated 100% by Statoil. In Eagle Ford, Statoil is the operator for 100% of the midstream assets outside of the Oak, Karnes, DeWitt and Bee (KDB) area with a working interest of 63%. In the KDB area of Eagle Ford, Statoil has an ownership interest of 25.2% in Edwards Lime Gathering LLC, which is operated by Energy Transfer Partners L.P. For Marcellus, Statoil has operated assets in Marcellus South in Monroe Country, Ohio while in the Marcellus non-operated areas both in the North and South, Statoil's working interest ranges from 16.25% to 32.5% depending on gathering system and number of JV partners which include Williams Energy and Anadarko.

As of 1 January 2016 responsibility for the US gathering system has been transferred from MMP to DPI North America.

Statoil is positioned in the Gulf of Mexico for the following offshore developments:
The **Tahiti** oil field is located in the Green Canyon area and is produced through a floating spar facility. As of 31 December 2016, there were 12 production wells in operation, and additional wells will be phased in over time to fully develop the field.

The **Caesar Tonga** oil field is located in the Green Canyon area. As of 31 December 2016, there were seven producing wells tied back to the Anadarko-operated Constitution spar host, and additional production wells will be phased in over time.

The **Jack** and **St. Malo** oil fields are located in the Walker Ridge area. The fields are subsea tie-backs to the Chevron operated Walker Ridge Regional Host facility. First production was achieved in December 2014. As of 31 December 2016, there were three wells producing on Jack and six wells producing for St. Malo. Additional production wells will be phased in over time.

The **Julia** oil field is located in the Walker Ridge area of the Gulf of Mexico near Jack and St Malo. First oil was in April 2016 and two wells are currently online. Additional production wells are currently being drilled and completed and will come online in 2017.

The **Heidelberg** oil field is located in the Green Canyon area. First oil was on January 2016 and four wells are currently online.

Canada

Statoil has interests in the Jeanne d'Arc Basin offshore the province of Newfoundland and Labrador in the partner operated producing oil fields **Terra Nova**, **Hibernia** and **Hibernia Southern Extension**. In January 2017, Statoil completed the transaction to fully divest the 123,200 net acres of oil sands leases in Alberta which form the **Kai Kos Dehseh** project to Athabasca Oil Corporation.

Brazil

The **Peregrino** field is a heavy oil field located in the Campos Basin, about 85 kilometres off the coast of Rio de Janeiro. The field came on stream in 2011. The oil is produced from two wellhead platforms with drilling capability and it is processed on the Peregrino FPSO and offloaded to shuttle tankers. Statoil holds a 60% ownership interest in the field and is operator.

Africa

Angola

The deep water blocks 17, 15 and 31 contributed with 38% of Statoil's equity liquid production outside Norway in 2016. Each block is governed by a PSA which sets out the rights and obligations of the participants, including mechanisms for sharing of the production with the Angolan state oil company Sonangol.

Block 17 has production from four FPSOs; CLOV, Dalia, Girassol and Pazflor.

Block 15 has production from four FPSOs: Kizomba A, Kizomba B, Kizomba C-Mondo, and Kizomba C-Saxi Batuque.

Block 31 has production from the PSVM FPSO.

The FPSOs serve as production hubs and each receives oil from more than one field and a large number of wells. In 2016, new wells were added and set into production on all three blocks.

Nigeria

Statoil has a 20.2% interest in the **Agbami** deep water field which is located 110 km off the coast of the Central Niger Delta region. The field is developed with subsea wells connected to an FPSO. The Agbami field straddles the two licences OML 127 and OML 128 and is operated by Chevron under a Unit Agreement. Statoil has 53.85% interest in OML 128.

For information related to the Agbami redetermination process and the dispute between the Nigerian National Petroleum Corporation and the partners in Oil Mining Lease (OML) 128 concerning certain terms of the OML 128 Production Sharing Contract (PSC), see note

23 Other commitments and contingencies to the Consolidated financial statements.

Algeria
The **In Salah** onshore gas development is a joint operatorship between Sonatrach, BP and Statoil. The Northern fields have been operating since 2004, and the **Southern fields project** started production from two fields (Garet el Befinat and Hassi Moumene) in March 2016. The remaining two fields (Gour Mahmoud and In Salah) will start production in 2017. The Southern fields are tied back into the Northern fields' existing facilities.

The **In Amenas** onshore development is a gas development which contains significant liquid volumes. The In Amenas infrastructure includes a gas treatment plant composed of three processing trains. The production facility is connected to the Sonatrach distribution system. The facilities are operated through a joint operatorship between Sonatrach, BP and Statoil. The third processing train, which was damaged in the January 2013 terrorist attack, restarted in July 2016. The **In Amenas Gas Compression project**, which was led by BP, came into operation in February 2017. The compressors will make it possible to reduce wellhead pressure and thereby increase production.

Separate PSAs including mechanisms for revenue sharing, govern the rights and obligations of the Parties and establish joint operatorships between Sonatrach, BP and Statoil for In Salah and In Amenas.

Eurasia

Production largely consists of the output from the **Azeri-Chirag-Gunashli** oil field in the Caspian Sea and the **Corrib** gas field off Ireland's northwest coast, which has successfully ramped up production since its start up in December 2015. The cessation of production from **Jupiter** in the UK North Sea has been declared and the decommissioning of the wells started in fourth quarter of 2016.

International exploration

Statoil has reduced exploration drilling activity outside Norway in 2016 and prioritised new access efforts and prospect maturation to support an increased drilling activity in 2017 and onwards.

Brazil is one of Statoil's core exploration areas, where in 2016 Statoil successfully completed an appraisal program in BM-C-33, which includes the Pao de Acucar, Seat and Gavea discoveries.

In **Canada** Statoil and its partners completed a 19-month drilling campaign in the Bay du Nord area, making two new oil discoveries, Baccalieu and Bay de Verde.

In 2016 Statoil secured a position in **Turkey** through a partnership with Valeura Energy Inc. in the Thrace region in the European north-western part of Turkey.

In December 2016, **Mexico**'s deepwater bidding round, Round 1.4, took place in Mexico City. A joint venture comprised of Statoil, BP and Total was awarded 2 licenses in Block 1 and Block 3 in the Saline Basin, with Statoil as the operator.

In 2016 Statoil and its partners completed nine exploratory wells and made three discoveries internationally. In 2017 Statoil's international exploration drilling activity will comprise growth opportunities in basins where Statoil already is established with discoveries and producing fields, such as Canada, Brazil and the UK as well as new frontier opportunities like Suriname and Indonesia. Statoil expects to complete 12 to 14 exploration wells internationally in 2017.

	Exploratory wells drilled[1]		
	2016	2015	2014
Americas			
Statoil operated	5	8	4
Partner operated	2	2	5
Africa			
Statoil operated	0	3	7
Partner operated	0	3	4
Other regions			
Statoil operated	0	2	2
Partner operated	2	0	1
Total (gross)	**9**	**18**	**23**

1) Wells completed during the year, including appraisals of earlier discoveries.

Fields under development internationally

This section covers all the sanctioned projects and selected pre-sanctioned projects.

Americas

US
The **Stampede** oil field is located in the Green Canyon area. The development includes a tension-leg platform (TLP) with downhole gas lift and water injection from start of production. Hess is the operator, and Statoil has a 25% working interest. Start of production is expected in 2018.

TVEX is an extension to Tahiti field, targeting shallower reservoirs above the existing main Tahiti reservoir, which is located in Green Canyon in Gulf of Mexico. Chevron is the operator, and Statoil has a 25% working interest. Start of production is expected in fourth quarter of 2018.

The **Big Foot** oil field is located in Walker Ridge area. The development includes a dry tree TLP with a drilling rig. Chevron is the operator, and Statoil has a 27.5% working interest. Start of production is expected in 2018. Initial plans called for production to start in late 2015, however, installation was halted and the TLP moved to sheltered waters following damage to subsea installation tendons in late May 2015

US Onshore operations use hydraulic fracturing to recover resources. Despite reduction in investment and activity level in recent years in shale plays Bakken, Eagle Ford and Marcellus, production growth continues. The increase in onshore production despite investment reduction is attributed to higher recovery per well due to enhanced completion and improved operational efficiency.

Canada

The **Hebron** field, operated by Exxon Mobil, is located in the Jeanne d'Arc basin offshore Newfoundland near the partner-operated producing fields Terra Nova, Hibernia and Hibernia Southern Extension. The Hebron field will be developed using a fixed gravity base structure (GBS) and first oil is expected in late 2017. The topside was constructed in Korea and was transported to Newfoundland during 2016, whereas the GBS was constructed in Newfoundland. The topside and GBS were successfully tested and mated in December 2016. Statoil working interest was reduced from 9.7% to 9.01% effective 1 January 2016 due to a redetermination process.

Statoil has made oil discoveries in the Flemish Pass offshore Newfoundland comprising the **Bay du Nord** project, and work is on-going to assess options for developing Bay du Nord. Statoil is the operator of Bay du Nord and holds a 65% working interest.

Brazil

Peregrino phase II (Statoil 60%, operator) includes the Peregrino South and Southwest discoveries. The development consists of one wellhead platform tied back to the existing floating production, storage and offloading vessel. In December 2014, Statoil approved the investment decision for the development of the second phase of the Peregrino oil field. Following a programme improving project economics, project execution started in April, 2016. In September 2016, the plan for development was formally approved by the Brazilian national agency of petroleum, natural gas and biofuels (ANP). Production is expected to start in late 2020.

In November 2016, Statoil completed the acquisition of 66% operated share from Petrobras in licence **BM-S-8** in the Santos basin. This licence contains a substantial part of the pre-salt discovery Carcará. Carcará straddles both BM-S-8 and open acreage to the north. The definition of the development concept and the subsequent development of licence are dependent on ownership of the open acreage. The open acreage is expected to be included in the licencing round in 2017.

In August 2016, Statoil took over the operatorship of licence **BM-C-33** from Repsol Sinopec Brasil. Statoil has 35% equity interest in this licence which is located in the Campos basin. Work is on-going to assess options for developing the discoveries in the licence. For information regarding exploration activity in BM-C-33 see International exploration earlier in this section.

Africa

Tanzania

Statoil has made several large gas discoveries in **Block 2** offshore Tanzania. Statoil is the operator of Block 2 and holds a 65% working interest. The licence is located in the Indian Ocean 100 km off the southern part of Tanzania. Work is on-going to assess options for developing the discoveries, including the construction of an onshore LNG plant jointly with the co-venturers in Blocks 1 and 4 which are operated by BG Tanzania (100% owned by Shell).

Eurasia

United Kingdom

Mariner (Statoil 65.11%, operator) is a heavy oil development in the UK, where Statoil is the operator. The field development concept includes a production, drilling and living quarter platform based on a steel jacket. Oil will be exported by offshore loading from a floating storage unit. The development concept includes a possible future subsea tie-in of Mariner East, a small heavy oil discovery. The Mariner B storage vessel arrived Scotland on 26 August 2016, after a two-month voyage from South Korea. On 1 December 2016, the drilling of the first well of the Mariner field development commenced. Production from Mariner is expected to start in 2018.

Bressay (Statoil 81.6%, operator) is also a heavy oil discovery. In February 2016, Statoil decided to pause the concept selection work on Bressay. The partnership has agreed an extension of the licence period until end 2019 with the UK Oil and Gas Authority (OGA).

2.5 MMP - MARKETING, MIDSTREAM AND PROCESSING

MMP overview

The Marketing, Midstream and Processing (MMP) reporting segment is responsible for marketing, trading, processing and transporting of crude oil and condensate, natural gas, NGL and refined products, including operation of Statoil operated refineries, terminals and processing plants. In addition, MMP is responsible for developing transportation solutions for natural gas, liquids and crude oil from Statoil assets including pipelines, shipping, trucking and rail. The business activities are organised in the following business clusters: Marketing and Trading, Asset Management and Processing and Manufacturing.

Key events in 2016:

- Statoil had a strong increase in delivered sales of crude oil into Asia during 2016, based on West African equity production and shipping capability
- The South Riding Point Terminal in Grand Bahamas sustained damage in the hurricane Matthew in October and was closed to traffic for a period
- Major planned turnarounds at both Kalundborg and Mongstad refineries, Tjeldbergodden methanol plant and Gassled facilities

Marketing and Trading

The Marketing and Trading business cluster (MT) is responsible for the marketing, trading and transportation of all products from Statoil's upstream, processing and refining business and for power and emissions trading.

MMP handles Statoil's own volumes, the Norwegian state's direct financial interest (SDFI) equity production of crude oil and NGL and third-party volumes, representing approximately 50% of all Norwegian liquids exports. MMP is also responsible for marketing SDFI's gas together with Statoil's own volumes and third party gas, representing approximately 70% of all Norwegian gas exports. See the Norwegian state's participation and SDFI oil and gas marketing and sale in Applicable laws and regulations in section 2.7 Corporate.

Marketing and trading of gas and LNG

Statoil's gas marketing and trading business is conducted from Norway and from offices in Belgium, the UK, Germany, the USA and Singapore.

Europe

The major export markets for gas from the NCS are Germany, France, the UK, Belgium, the Netherlands, Italy and Spain. LNG from the Snøhvit field, combined with third party LNG cargoes, allow Statoil to reach global gas markets. The major part of the gas is sold to counterparties through bi-lateral sales and the remaining volumes over the trading desk through all the main European trading hubs. The bi-lateral sales are mainly carried out with large industrial customers, power producers and local distribution companies. A few of Statoil's long-term gas contracts contain contractual price review mechanisms that can be triggered by the buyer or seller at regular intervals, or under certain given circumstances.

Statoil is active on both physical and exchange markets such as the Intercontinental Exchange (ICE). Statoil expects to continue to optimise the market value of the gas through a mix of bi-lateral contracts and trading via its production, transportation systems and downstream assets.

USA

Statoil Natural Gas LLC (SNG), a wholly-owned subsidiary, has a gas marketing and trading organization in Stamford, Connecticut that markets natural gas to local distribution companies, industrial customers and power generators. SNG also markets equity production volumes from the Gulf of Mexico, Eagle Ford and Marcellus and transports some of the northern Marcellus production to New York City and to Niagara, providing access to the greater Toronto area.

In addition, SNG has long-term capacity contracts with Dominion Resources Inc., which owns the Cove Point LNG re-gasification terminal in Maryland. LNG is sourced from the Snøhvit LNG facility in Norway. Due to continuing low gas prices in the US, almost all of Statoil's LNG cargoes have been diverted away from the US and delivered into higher-priced markets in Europe, South-America and Asia.

Marketing and trading of liquids

MMP is responsible for the sale of Statoil's and the SDFI's crude oil and NGL, in addition to commercial optimisation of the refineries and terminals. The liquids marketing and trading business is conducted from Norway, UK, Singapore, US and Canada. The main crude oil market for Statoil is northwest Europe.

MMP also markets equity volumes from DPI assets located in Canada, US, Brazil, Angola, Nigeria, Algeria, Azerbaijan and UK, as well as third party volumes. Value is maximised through marketing, physical and financial trading and through optimisation of own and leased capacity such as refineries, processing, terminals, storages, pipelines, railcars and vessels.

Production plants

Statoil owns and is operator of the Mongstad refinery in Norway including the Mongstad Heat and Power Plant (MHPP). The refinery is a medium-sized refinery built in 1975, with a crude oil and condensate distillation capacity of 226,000 barrels per day. The refinery is directly linked to offshore fields through two crude oil pipelines, to the crude oil terminal at Sture and the gas processing plant at Kollsnes through an NGL/condensate pipeline, and to Kollsnes by a gas pipeline. MHPP produces heat and power from gas received from Kollsnes and from the refinery. It has capacity of approximately 280 megawatts of electric power and 350 megawatts of process heat.

Statoil has an ownership interest of 34% in Vestprosess, which transports and processes NGL and condensate. The Vestprosess pipeline connects the Kollsnes and Sture plants to Mongstad.

Statoil owns and is operator of the Kalundborg refinery in Denmark, which has a crude oil and condensate distillation capacity of

108,000 barrels per day. The refinery is connected via one gasoline and one gas oil pipeline to the terminal at Hedehusene near Copenhagen, and most of its products are sold locally.

Statoil has an ownership interest of 82% in the methanol plant at Tjeldbergodden. It receives natural gas from the Norwegian Sea through the Haltenpipe pipeline. In addition, Statoil holds a 50.9% ownership interest in the air separation unit Tjeldbergodden Luftgassfabrikk DA.

The following table shows operating statistics for the plants at Mongstad, Kalundborg and Tjeldbergodden.

	Throughput[1]			Distillation capacity[2]			On stream factor %[3]			Utilisation rate %[4]		
Refinery	2016	2015	2014	2016	2015	2014	2016	2015	2014	2016	2015	2014
Mongstad	**9.8**	11.9	9.2	**9.3**	9.3	9.3	**94.4**	97.6	93.4	**93.9**	93.4	90.0
Kalundborg	**5.0**	5.2	4.5	**5.4**	5.4	5.4	**98.0**	98.5	91.8	**91.0**	91.0	82.0
Tjeldbergodden	**0.76**	0.92	0.83	**0.95**	0.95	0.95	**94.8**	98.5	88.4	**94.8**	98.5	97.1

1) Actual throughput of crude oils, condensates, NGL, feed and blendstock, measured in million tonnes.
Higher than distillation capacity for Mongstad due to high volumes of fuel oil and NGL not going through the crude distillation unit.
Higher than distillation capacity for Kalundborg, due to volumes of kero, naphta, gasoil and biodiesel-additive not going through the crude-/condensate units.
2) Nominal crude oil and condensate distillation capacity, and methanol production capacity, measured in million tonnes.
3) Composite reliability factor for all processing units, excluding turnarounds.
4) Composite utilisation rate for all processing units, stream day utilisation.

Terminals and storage

Statoil has a 65% ownership interest in Mongstad crude oil terminal. Crude oil is landed at Mongstad through pipelines from the NCS and by crude tankers from the market. The Mongstad terminal has a storage capacity of 9.4 million barrels of crude oil.

The Sture crude oil terminal receives crude oil through pipelines from the North Sea. The terminal is part of the Oseberg Transportation System (Statoil interest 36.2%). The processing facilities at Sture stabilise Oseberg crude oil and recover LPG mix (propane and butane) and naphtha.

Statoil operates the South Riding Point Terminal, which is located on Grand Bahamas Island and consists of two shipping berths and ten storage tanks, with a storage capacity of 6.75 million barrels of crude oil. The terminal has facilities to blend crude oils, including heavy oils. The main damages suffered in the Matthew hurricane in October were related to the loading infrastructure at the Sea Island, and Berth 2 is still out of operation. Statoil is in the process of scoping the reconstruction.

Statoil UK holds one third share of the interests in the Aldbrough Gas Storage in UK, operated by SSE Hornsea Ltd.

Statoil Deutschland Storage GmbH holds a 23.7% stake in the Etzel Gas Lager in the northern part of Germany which has a total of nineteen caverns and secures regularity for gas deliveries from the NCS.

Statoil UK holds a 27.3% stake in the Teesside terminal, which stabilises unstable oil from the Ekofisk area and several other Norwegian and UK fields and recovers NGL.

Pipelines

Statoil is a significant shipper in the NCS gas pipeline system. Most gas pipelines on the NCS that are accessed by third-party customers are owned by a single joint venture, Gassled, with regulated third-party access. The Gassled system is operated by the independent system operator Gassco AS, which is wholly owned by the Norwegian state. Statoil's current ownership share in Gassled is 5%. See Gas sales and transportation from the NCS in section 2.7 Corporate for further information.

MMP is technical service provider (TSP) for the Kårstø and Kollsnes gas processing plants in accordance with the technical service agreement between Statoil and Gassco AS, included as Exhibit 4(a)(i) to Form 20-F. MMP also performs the TSP role for the larger share of the Gassco operated gas pipeline infrastructure.

In addition, MMP manages Statoil's ownership in the following pipelines in the Norwegian gas transportation system: Oseberg oil transportation system, Grane oil pipeline, Kvitebjørn oil pipeline, Troll oil pipeline I and II, Edvard Grieg oil pipeline, Utsira High gas pipeline, Valemon rich gas pipeline, Haltenpipe, Norpipe and Mongstad gas pipeline.

Statoil Deutschland GmbH held a 30.8% stake in the Norddeutsche Erdgas Transversale (NETRA) overland gas transmission pipeline via Jordgas Transport GmbH, which was sold during 2016 to Open Grid Europe GmbH and Gasuni Deutschland Transport Services GmbH.

Polarled (Statoil 37.1%, operator) will secure a gas export pipeline for fields in the Norwegian Sea. The project is aligned with the Aasta Hansteen field development.

The **Johan Sverdrup oil and gas export pipelines** (Statoil 40.0%, operator) will provide export from the Johan Sverdrup field.

2.6 OTHER GROUP

The Other reporting segment includes activities in New Energy Solutions (NES), Global Strategy and Business Development (GSB), Technology, Projects and Drilling (TPD) and corporate staffs and support functions.

New Energy Solutions (NES)

The NES business area reflects Statoil's aspirations to gradually complement its oil and gas portfolio with profitable renewable energy and other low-carbon energy solutions. Offshore wind and carbon capture and storage have been key focus areas in 2016.

Key events in 2016:

- Acquisition of a 50% stake in the Arkona asset in the German part of the Baltic Sea
- Launch of Statoil Energy Venture Fund and 4 subsequent investments
- Agreement to increase UK presence through increasing owner share in the Dogger Bank projects
- Signed a letter of intent to take over as operator of the Sheringham Shoal wind farm in 2017
- Statoil has concluded a 25% farm down in the Hywind Scotland project
- Winner of US Government's wind lease sale of 79,350 acres offshore New York

The **Sheringham Shoal** offshore wind farm (Statoil 40%, operator from 2017) located off the coast of Norfolk, UK, was formally opened in September 2012. The wind farm is in full production with 88 turbines and an installed capacity of 317 megawatt (MW). Following divestment in 2014, it is now owned 40% by Statkraft, a Norwegian wholly state-owned company, 40% by Statoil and 20% by the UK Green Investment Bank (GIB). The wind farm's annual production is approximately 1.1 terawatt hours (TWh) and it has the capacity to provide power to approximately 220,000 households. Statkraft and Statoil have signed a letter of intent that Statoil takes over as operator of Sheringham Shoal in 2017.

The **Dudgeon** offshore wind farm (Statoil 35%, operator) is located in the Greater Wash area off the English east coast, short distance from Sheringham Shoal. A final investment decision for the 402 MW project was made in July 2014. The wind farm is expected to produce 1.7 TWh yearly from 67 turbines, with the capacity to provide power for around 410,000 households. On 7 January 2017, the first turbine was energised. On 7 February 2017, the first turbine was set in production, delivering electric power to the UK national grid. The wind farm is expected to be in full operation in fourth quarter 2017.

The **Dogger Bank** area has a total consented capacity of 4.8 GW and is potentially the largest offshore wind farm development in the world. Statoil and Statkraft, together with RWE and SSE, are partners in the Forewind consortium, each with a 25% equity stake. In February and August 2015, the consortium received consent from the UK authorities for four projects, each with a capacity of 1200 MW. Statoil has recently signed an agreement to acquire Statkraft's share in Dogger Bank, the final shareholding is pending, among other things, partner approval.

The **Arkona** offshore wind farm (Statoil 50%) is being developed in the German part of the Baltic Sea, and the operations and maintenance base will be located in Sassnitz on the island of Rügen. In April 2016, Statoil acquired a 50% share in AWE-Arkona-Windpark Entwicklungs-GmbH from E.ON Climate & Renewables. A final investment decision for the up to 385 MW project was made in April 2016. All main construction contracts have been awarded, and fabrication has started. The wind farm is expected to supply approximately 400,000 German households from 60 turbines, and to be in full operation in 2019.

The **Hywind Scotland pilot** wind park (Statoil 75%, operator) is a floating wind pilot park using the Hywind concept, developed and owned by Statoil. The project is located at Buchan Deep, approximately 25 km off Peterhead on the east coast of Scotland. Statoil will install 5 Siemens 6MW turbines, a total capacity of 30MW. Production is expected to be 0.14 TWh/year, powering around 20,000 households. The project was sanctioned in October 2015. The planned first deliveries to the grid are in fourth quarter 2017. This is the next step in Statoil's strategy towards deployment of the first utility scale floating wind farms.

Statoil is the winner of the New York Wind Energy Area lease, following the December 2016 BOEM lease sale, with a winning bid of USD 42.5 million. The lease is 321 km^2, large enough to support one or more offshore wind developments with a total capacity of more than 1GW. The lease is located approximately 20 km directly south of Long Island. The project will be further matured during 2017.

Since 1996, Statoil has proven experience in **carbon capture and storage** (CCS) and has continued to develop competence through research engagement in the Technical Centre Mongstad (TCM) and offshore operations in Sleipner and Snøhvit. Statoil will seek to deploy our competence and experience in other CCS projects, continue to evaluate opportunities to reduce carbon dioxide emissions and explore carbon dioxide for enhanced oil recovery (EOR) possibilities. Statoil has on behalf of the Norwegian Ministry of Petroleum and Energy (MPE) performed a feasibility study for establishing a CO2 storage on the NCS. The MPE intends to issue a tender process at the end of this year for planning, construction and operation of such CO2 storage as a part of a full CCS value chain from three industrial sources in Norway.

In February 2016, Statoil launched the Statoil Energy Ventures Fund, a new energy investment fund dedicated to investing in attractive and ambitious growth companies in low carbon energy, supporting Statoil's strategy of growth in new energy solutions. The Statoil Energy Ventures Fund, will invest up to USD 200 million over a period of four to seven years. During 2016, the fund made four investments in four different segments. United Wind is a distributed wind generation company based in New York that offers to install wind turbines on small property owner's land in exchange for a 20-year lease arrangement. ChargePoint is the largest electric vehicle charging infrastructure company in the USA with plans to expand globally in light of the growth in electric vehicles sales. Convergent Energy & Power is a US based energy storage project developer that builds, finances, owns and operates storage projects on behalf of large utilities and commercial and industrial customers. Oxford PV is a third generation solar technology company based in Oxford, UK that is developing a perovskites material that has the potential to make a significant increase in the efficiency of silicon photovoltaic panels.

Global Strategy and Business Development (GSB)

The Global Strategy and Business Development (GSB) business area is Statoil's functional centre for strategy and business development. GSB is responsible for Statoil's global strategy processes and identifies and delivers inorganic business development opportunities, including corporate mergers and acquisitions. This is achieved through close collaboration across geographic locations and business areas. Statoil's strategy forms the basis for guiding the company's business development focus.

GSB also hosts a number of corporate functions including Statoil's Corporate Sustainability function, which is shaping the company's strategic response to sustainability issues and reporting on Statoil's sustainability performance.

Corporate staffs and support functions

Corporate Staffs and support functions comprise the non-operating activities supporting Statoil, and include headquarters and central functions that provide business support such as finance and control, corporate communication, safety, audit, legal services and people and organisation.

Technology, Projects and Drilling (TPD)

The business area **Technology, Projects and Drilling (TPD)** is responsible for the development and execution of projects, well deliveries, procurement, research and technology in Statoil.

The TPD organisation was restructured 1 January 2016 to reduce cost, increase efficiency and secure high quality execution. All project expertise was integrated in one Project development organisation (PRD), and all expertise within technology, research and innovation was integrated in one Research and technology organisation (R&T).

Research and Technology (R&T) delivers technical expertise to projects, business developments and assets. Further, R&T drives research, innovation and implementation of new technology across Statoil, to secure both short and long term business needs.

Project Development (PRD) develops and executes all major facility developments, modifications and field decommissioning.

Drilling and Well (D&W) provides cost efficient well deliveries and rig management, including expertise and support to drilling and well operations globally in Statoil.

Procurement and Supplier Relations (PSR) manages the supply chain, conducts all procurements and provides management of contracts in accordance with business needs.

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Project startups and completions 2016	Statoil's interest	Operator	Area	Type
Heidelberg	12.00%	Anadarko	Gulf of Mexico	Oil
Snorre A drilling facilities upgrade	33.28%	Statoil	North Sea	Improved oil recovery
Goliat	35.00%	Eni	Barents Sea	Oil and gas
In Salah Southern fields	31.85%	Sonatrach/BP/Statoil	Algeria	Gas
Julia	50.00%	ExxonMobil	Gulf of Mexico	Oil
Gullfaks Rimfaksdalen	51.00%	Statoil	North Sea	Oil
B11 removal	5.00%	Gassco[1)]	North Sea	Field decommissioning
Ivar Aasen	41.47%	Aker BP	North Sea	Oil and gas
- held through Lundin	0.28%			

1) Statoil is technical operator

Ongoing projects with expected startups and completions 2017-2020	Statoil's interest	Operator	Area	Type
Gina Krog	58.70%	Statoil	North Sea	Oil and gas
Gullfaks C subsea compression	51.00%	Statoil	North Sea	Improved gas recovery
Dudgeon offshore wind farm	35.00%	Statoil	North Sea, off English coast	Wind
Hywind Scotland pilot wind park	75.00%	Statoil	North Sea, off Scottish coast	Wind
Volve decommissioning	59.60%	Statoil	North Sea	Field decommissioning
Byrding	70.00%	Statoil	North Sea	Oil and associated gas
Hebron	9.01%	ExxonMobil	Newfoundland, Canada	Oil
Tahiti vertical expansion	25.00%	Chevron	Gulf of Mexico	Oil
Aasta Hansteen	51.00%	Statoil	Norwegian Sea	Gas
Polarled	37.10%	Statoil	Norwegian Sea	Gas export pipeline
Oseberg Vestflanken 2	49.30%	Statoil	North Sea	Oil and gas
Mariner	65.11%	Statoil	North Sea	Oil
Troll B gas module	30.58%	Statoil	North Sea	Increased processing capacity
Big Foot	27.50%	Chevron	Gulf of Mexico	Oil
Martin Linge	19.00%	Total	North Sea	Oil and gas
Stampede	25.00%	Hess	Gulf of Mexico	Oil
Arkona offshore wind farm	50.00%	E.ON	Baltic Sea, off German coast	Wind
Johan Sverdrup	40.03%	Statoil	North Sea	Oil and associated gas
- held through Lundin	4.54%			
Johan Sverdrup export pipelines, JoSEPP	40.03%	Statoil	North Sea	Oil and gas export pipelines
- held through Lundin	4.54%			
Utgard Norwegian sector	38.44%	Statoil	North Sea	Gas and condensate
UK sector	38.00%			
Trestakk	59.10%	Statoil	North Sea	Oil and associated gas
Huldra decommissioning	19.87%	Statoil	North Sea	Field decommissioning
Peregrino phase II	60.00%	Statoil	Brazil	Oil

Startups beyond 2020
In our world-class portfolio, an additional 35-40 projects are in the early phase.

2.7 CORPORATE

APPLICABLE LAWS AND REGULATIONS

Statoil operates in more than 30 countries and is exposed to, and committed to compliance with, a number of laws and regulations globally.

This article focuses primarily on Norwegian laws specific for Statoil`s core activities, taking into account that the majority of Statoil's production is produced on the NCS, the ownership structure of the company and that Statoil is registered and has its headquarters in Norway.

Norwegian petroleum laws and licensing system

The principal laws governing Statoil's petroleum activities in Norway are the Norwegian Petroleum Act and the Norwegian Petroleum Taxation Act.

Norway is not a member of the European Union (EU), but Norway is a member of the European Free Trade Association (EFTA). The EU and the EFTA Member States have entered into the Agreement on the European Economic Area, referred to as the EEA Agreement, which provides for the inclusion of EU legislation in the national law of the EFTA Member States (except Switzerland). Statoil's business activities are subject to both the EFTA Convention and EU laws and regulations adopted pursuant to the EEA Agreement.

For further information about the jurisdictions in which Statoil operates, see sections 2.2 Business overview and 2.10 Risk review.

Under the Petroleum Act, the Norwegian Ministry of Petroleum and Energy ("MPE") is responsible for resource management and for administering petroleum activities on the NCS. The main task of the MPE is to ensure that petroleum activities are conducted in accordance with the applicable legislation, the policies adopted by the Norwegian Parliament (the Storting) and relevant decisions of the Norwegian State.

The Storting's role in relation to major policy issues in the petroleum sector can affect Statoil in two ways: firstly, when the Norwegian State acts in its capacity as majority owner of Statoil shares and, secondly, when the Norwegian State acts in its capacity as regulator:

- The Norwegian State's shareholding in Statoil is managed by the Ministry of Petroleum and Energy. The Ministry of Petroleum and Energy will normally decide how the Norwegian State will vote on proposals submitted to general meetings of the shareholders. However, in certain exceptional cases, it may be necessary for the Norwegian State to seek approval from the Storting before voting on a certain proposal. This will normally be the case if Statoil issues additional shares and such issuance would significantly dilute the Norwegian State's holding, or if such issuance would require a capital contribution from the Norwegian State in excess of government mandates. A decision by the Norwegian State to vote against a proposal on Statoil's part to issue additional shares would prevent Statoil from raising additional capital in this manner and could adversely affect Statoil's ability to pursue business opportunities. For more information about the Norwegian State's ownership, see Risks related to state ownership in section 2.10 Risk review and Major shareholders in section 5.1 Shareholder information
- The Norwegian State exercises important regulatory powers over Statoil, as well as over other companies and corporations on the NCS. As part of its business, Statoil or the partnerships to which Statoil is a party, frequently need to apply for licences and other approval of various kinds from the Norwegian State. Although Statoil is majority-owned by the Norwegian State, it does not receive preferential treatment with respect to licences granted by or under any other regulatory rules enforced by the Norwegian State

The principal laws governing Statoil's petroleum activities in Norway and on the NCS are the Norwegian Petroleum Act of 29 November 1996 (the "Petroleum Act") and the regulations issued thereunder, and the Norwegian Petroleum Taxation Act of 13 June 1975 (the "Petroleum Taxation Act"). The Petroleum Act sets out the principle that the Norwegian State is the owner of all subsea petroleum on the NCS, that exclusive right to resource management is vested in the Norwegian State and that the Norwegian State alone is authorised to award licences for petroleum activities as well as determine its terms. Licensees are required to submit a plan for development and operation (PDO) to the Ministry of Petroleum and Energy for approval. For fields of a certain size, the Storting has to accept the PDO before it is formally approved by the Ministry of Petroleum and Energy. Statoil is dependent on the Norwegian State for approval of its NCS exploration and development projects and its applications for production rates for individual fields.

Production licences are the most important type of licence awarded under the Petroleum Act and are normally awarded for an initial exploration period, which is typically six years, but which can be shorter. The maximum period is ten years. During this exploration period, the licensees must meet a specified work obligation set out in the licence. If the licensees fulfil the obligations set out in the initial license period, they are entitled to require that the licence be prolonged for a period specified at the time when the licence is awarded, typically 30 years.

The terms of the production licences are decided by the Ministry of Petroleum and Energy. A production licence grants the holder an exclusive right to explore for and produce petroleum within a specified geographical area. The licensees become the owners of the petroleum produced from the field covered by the licence. Production licences are awarded to group of companies forming a joint venture at the Ministry's discretion. The members of the joint venture are jointly and severally responsible to the Norwegian State for obligations arising from petroleum operations carried out under the licence. The Ministry of Petroleum and Energy decides the form of the joint operating agreements and accounting agreements.

The governing body of the joint venture is the management committee. In licences awarded since 1996 where the state's direct financial interest (SDFI) holds an interest, the Norwegian State, acting through Petoro AS, may veto decisions made by the joint venture management committee, which, in the opinion of the Norwegian State, would not be in compliance with the obligations of the licence with respect to the Norwegian State's exploitation policies or financial interests. This power of veto has never been used.

Interests in production licences may be transferred directly or indirectly subject to the consent of the Ministry of Petroleum and Energy and the approval of the Ministry of Finance of a corresponding tax treatment position. In most licences, there are no pre-emption rights in favour of the other licensees. However, the SDFI, or the Norwegian State, as appropriate, still holds pre-emption rights in all licences.

The day-to-day management of a field is the responsibility of an operator appointed by the Ministry of Petroleum and Energy. The operator is in practice always a member of the joint venture holding the production licence, although this is not legally required. The terms of engagement of the operator are set out in the joint operating agreement.

Licensees are required to submit a plan for development and operation (PDO) to the Ministry of Petroleum and Energy for approval. For fields of a certain size, the Storting has to accept the PDO before it is formally approved by the Ministry of Petroleum and Energy.

If important public interests are at stake, the Norwegian State may instruct Statoil and other licensees on the NCS to reduce the production of petroleum. The last time the Norwegian State instructed a reduction in oil production was in 2002.

A licence from the Ministry of Petroleum and Energy is also required in order to establish facilities for the transportation and utilisation of petroleum. Ownership of most facilities for the transportation and utilisation of petroleum in Norway and on the NCS is organised in the form of joint ventures. The participants' agreements are similar to the joint operating agreements.

Licensees are required to prepare a decommissioning plan before a production licence or a licence to establish and use facilities for the transportation and utilisation of petroleum expires or is relinquished, or the use of a facility ceases. On the basis of the decommissioning plan, the Ministry of Petroleum and Energy makes a decision as to the disposal of the facilities.

For an overview of Statoil's activities and shares in Statoil's production licences on the NCS, see section 2.5 Development and Production Norway (DPN).

Gas sales and transportation from the NCS

Statoil markets gas from the NCS on its own behalf and on the Norwegian State's behalf. Gas is transported through the Gassled pipeline network to customers in the UK and mainland Europe.

Most of Statoil's and the Norwegian State's gas produced on the NCS is sold under gas contracts to customers in the European Union (EU), and changes in EU legislation may affect Statoil's marketing of gas.

The Norwegian gas transport system, consisting of the pipelines and terminals through which licensees on the NCS transport their gas, is owned by a joint venture called Gassled. The Norwegian Petroleum Act of 29 November 1996 and the pertaining Petroleum Regulation establish the basis for non- discriminatory third-party access to the Gassled transport system.

The tariffs for the use of capacity in the transport system are determined by applying a formula set out in separate tariff regulations stipulated by the Ministry of Petroleum and Energy. The tariffs are paid on the basis of booked capacity, not on the basis of the volumes actually transported.

For further information, see Pipelines in section 2.5 MMP - Marketing, Midstream and Processing.

The Norwegian State's participation

The Norwegian State's policy as a shareholder in Statoil has been and continues to be to ensure that petroleum activities create the highest possible value for the Norwegian State.

In 1985, the Norwegian State established the State's direct financial interest (SDFI) through which the Norwegian State has direct participating interests in licences and petroleum facilities on the NCS. As a result, the Norwegian State holds interests in a number of licences and petroleum facilities in which Statoil also hold interests. Petoro AS, a company wholly owned by the Norwegian State, was formed in 2001 to manage the SDFI assets.

SDFI oil and gas marketing and sale

Statoil markets and sells the Norwegian State's oil and gas together with Statoil's own production. The arrangement has been implemented by the Norwegian State.

At an extraordinary general meeting held on 25 May 2001, the Norwegian State, as sole shareholder, approved an instruction to Statoil setting out specific terms for the marketing and sale of the Norwegian State's oil and gas. This resolution is referred to as the Owner's instruction.

Statoil is obliged under the Owner's instruction to jointly market and sell the Norwegian State's oil and gas as well as Statoil's own oil and gas. The overall objective of the marketing arrangement is to obtain the highest possible total value for Statoil's oil and gas and the Norwegian State's oil and gas, and to ensure an equitable distribution of the total value creation between the Norwegian State and Statoil.

Withdrawal or amendment

- The Norwegian State may at any time utilise its position as majority shareholder of Statoil to withdraw or amend the marketing instruction

HSE regulation

Statoil's petroleum operations are subject to extensive laws and regulations relating to health, safety and the environment (HSE).

With business operations in more than 30 countries, Statoil is subject to a wide variety of HSE laws and regulations concerning its products, operations and activities. Laws and regulations may be jurisdiction specific, but also international regulations, conventions or treaties, as well as EU directives and regulations, are relevant.

As a result of the Macondo incident, in 2011, the US Department of the Interior created two new agencies to administer operations and activities in the Gulf of Mexico - the Bureau of Safety and Environmental Enforcement (BSEE) and the Bureau of Offshore

Energy Management (BOEM). The department also issued new regulations to address the respective roles of the new agencies. Application of these regulations has the potential to affect Statoil's operations in the US. Similarly, the effects from implementing the EU offshore Safety Directive in EU-member states' legislation will affect operations in relevant EU member countries.

See also Risk factors in section 2.10 Risk review.

Taxation of Statoil

Statoil is subject to ordinary Norwegian corporate income tax and to a special petroleum tax relating to its offshore activities in Norway. Statoil's profits, both from offshore oil and natural gas activities and from onshore activities, are subject to Norwegian corporate income tax. The standard corporate income tax rate has been reduced from 25% in 2016 to 24% in 2017. In addition, a special petroleum tax is levied on profits from petroleum production and pipeline transportation on the NCS. The special petroleum tax rate has been increased from 53% in 2016 to 54% in 2017. The special petroleum tax rate is applied to relevant income in addition to the standard income tax rate, resulting in a 78% marginal tax rate on income subject to the special petroleum tax. For further information, see note 9 Income taxes to the Consolidated financial statements.

Statoil's international petroleum activities are subject to tax pursuant to local legislation. Fiscal regulation of Statoil's upstream operations is generally based on corporate income tax regimes and/or PSAs.

SUBSIDIARIES AND PROPERTIES

Significant subsidiaries

The following table shows significant subsidiaries and equity accounted companies directly held by Statoil ASA as of 31 December 2016.

Our voting interest in each company is equivalent to our equity interest.

Ownership in certain subsidiaries and other equity accounted companies

Name	in %	Country of incorporation	Name	in %	Country of incorporation
Statholding AS	100	Norway	Statoil Nigeria Deep Water AS	100	Norway
Statoil Angola Block 15 AS	100	Norway	Statoil Nigeria Outer Shelf AS	100	Norway
Statoil Angola Block 15/06 Award AS	100	Norway	Statoil Norsk LNG AS	100	Norway
Statoil Angola Block 17 AS	100	Norway	Statoil North Africa Gas AS	100	Norway
Statoil Angola Block 31 AS	100	Norway	Statoil North Africa Oil AS	100	Norway
Statoil Angola Block 38 AS	100	Norway	Statoil Orient AG	100	Switzerland
Statoil Angola Block 39 AS	100	Norway	Statoil OTS AB	100	Sweden
Statoil Angola Block 40 AS	100	Norway	Statoil Petroleum AS	100	Norway
Statoil Apsheron AS	100	Norway	Statoil Refining Norway AS	100	Norway
Statoil Azerbaijan AS	100	Norway	Statoil Shah Deniz AS	100	Norway
Statoil BTC Finance AS	100	Norway	Statoil Sincor AS	100	Norway
Statoil Coordination Centre NV	100	Belgium	Statoil SP Gas AS	100	Norway
Statoil Danmark AS	100	Denmark	Statoil Tanzania AS	100	Norway
Statoil Deutschland GmbH	100	Germany	Statoil Technology Invest AS	100	Norway
Statoil do Brasil Ltda	100	Brazil	Statoil UK Ltd	100	United Kingdom
Statoil Exploration Ireland Ltd.	100	Ireland	Statoil Venezuela AS	100	Norway
Statoil Forsikring AS	100	Norway	Statoil Metanol ANS	82	Norway
Statoil Færøyene AS	100	Norway	Mongstad Terminal DA	65	Norway
Statoil Hassi Mouina AS	100	Norway	Tjeldbergodden Luftgassfabrikk DA	51	Norway
Statoil Indonesia Karama AS	100	Norway	Naturkraft AS	50	Norway
Statoil New Energy AS	100	Norway	Vestprosess DA	34	Norway
Statoil Nigeria AS	100	Norway	Lundin Petroleum AB	20	Sweden

PROPERTY, PLANT AND EQUIPMENT

Statoil has interests in real estate in many countries throughout the world. However, no individual property is significant. The largest office buildings are the Statoil's head office located at Forusbeen 50, NO-4035, Stavanger, Norway which comprises approximately 135,000 square meters of office space, and the 65,500-square-metre office building located at Fornebu on the outskirts of Norway's capital Oslo. Both office buildings are leased.

For a description of our significant reserves and sources of oil and natural gas, see Proved oil and gas reserves in section 2.8 Operating and financial performance below, and note 27 Supplementary oil and gas information (unaudited) to the Consolidated financial statements. For a description of our operational refineries, terminals and processing plants, see section 2.5 MMP - Marketing, midstream and processing.

RELATED PARTY TRANSACTIONS

See note 24 Related parties to the Consolidated financial statements for information concerning related parties.

INSURANCE

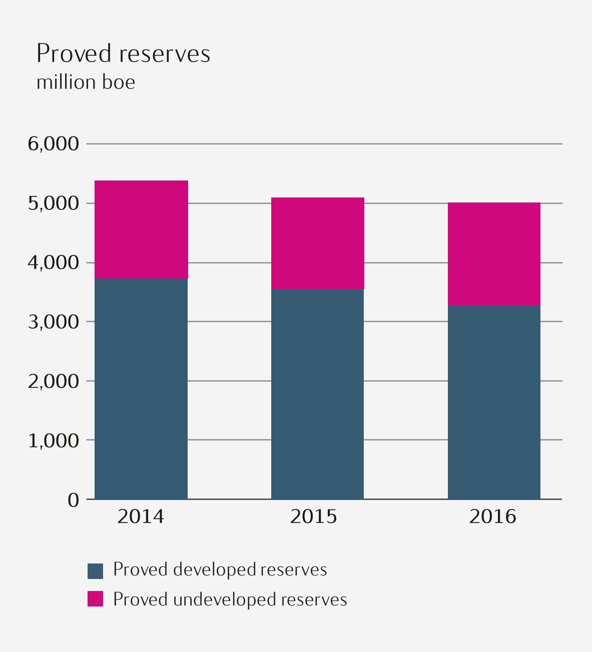
Statoil maintains insurance coverage that includes coverage for physical damage to its oil and gas properties, third-party liability, workers' compensation and employers' liability, general liability, sudden pollution and other coverage.

Statoil's insurance coverage includes deductibles that must be met prior to recovery. Statoil's external insurance is subject to caps, exclusions and limitations, and there is no assurance that such coverage will adequately protect Statoil against liability from all potential consequences and damages.

2.8 OPERATING AND FINANCIAL PERFORMANCE

PROVED OIL AND GAS RESERVES

Proved oil and gas reserves were estimated to be 5,013 mmboe at year end 2016, compared to 5,060 mmboe at the end of 2015.



Statoil's proved reserves are estimated and presented in accordance with the Securities and Exchange Commission (SEC) Rule 4-10 (a) of Regulation S-X, revised as of January 2009, and relevant Compliance and Disclosure Interpretations (C&DI) and Staff Accounting Bulletins, as issued by the SEC staff. For additional information, see Proved oil and gas reserves in note 2 Significant accounting policies to the Consolidated financial statements. For further details on proved reserves, see also note 27 Supplementary oil and gas information (unaudited) in the Consolidated financial statements.

Changes in proved reserves estimates are most commonly the result of revisions of estimates due to observed production performance, extensions of proved areas through drilling activities or the inclusion of proved reserves in new discoveries through the sanctioning of new development projects. These are sources of additions to proved reserves that are the result of continuous business processes and can be expected to continue to add reserves in the future.

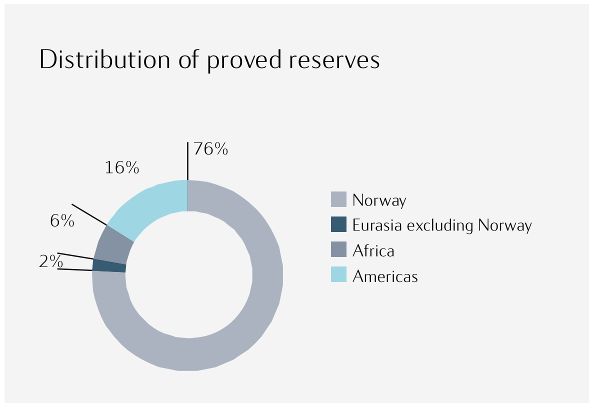
Proved reserves can also be added or subtracted through the acquisition or disposal of assets. Changes in proved reserves can also be due to factors outside management control, such as changes in oil and gas prices. Lower oil and gas prices normally allow less oil and gas to be recovered from the accumulations. However, for fields with PSAs and similar contracts, a reduced oil price may result in higher entitlement to the produced volume. These changes are included in the revisions category in the table below.

The principles for booking proved gas reserves are limited to contracted gas sales or gas with access to a robust gas market.

In Norway and the UK, Statoil recognises reserves as proved when a development plan is submitted, as there is reasonable certainty that such a plan will be approved by the regulatory authorities. Outside these territories, reserves are generally booked as proved when regulatory approval is received, or when such approval is imminent. Reserves from new discoveries, upward revisions of reserves and purchases of proved reserves are expected to contribute to maintaining proved reserves in future years. Undrilled well locations US onshore are generally booked as proved undeveloped reserves when a development plan has been adopted and the well locations are scheduled to be drilled within five years,

Approximately 91% of our proved reserves are located in OECD countries. Norway is by far the most important contributor in this category, followed by the United States (US), Canada and Ireland.

Of Statoil's total proved reserves, 7% are related to PSAs in non-OECD countries such as Azerbaijan, Angola, Algeria, Nigeria, Libya and Russia. Other non-OECD reserves are related to concessions in Brazil and Venezuela, representing less than 2% of Statoil's total proved reserves. These are included in proved reserves in the Americas.



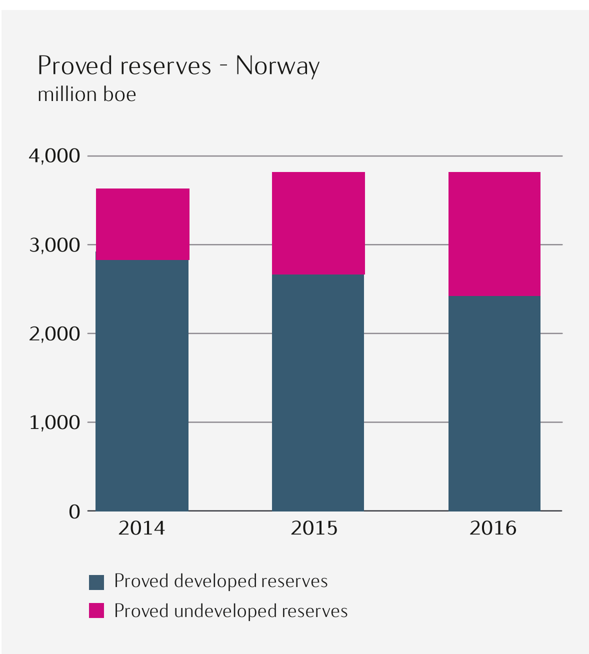
Significant changes in our proved reserves in 2016 were:

- Negative revisions due to lower commodity prices compared to last year, resulted in a reduction of approximately 60 million boe
- The negative revisions are more than offset by positive revisions due to better performance of producing fields, maturing of improved recovery projects, and reduced uncertainty due to further drilling and production experience. The net effect of the positive and negative revisions is an increase of 409 million boe in 2016. A significant part of these positive revisions are related to large, producing fields offshore Norway where production is declining less than previously assumed for the proved reserves due to continuous improvement activities

- Proved reserves from new discoveries have also been added through the sanctioning of new field development projects in 2016, Svale Nord, Trestakk and Utgard in Norway and Julia in US. The new projects added a total of 66 million boe. New discoveries with proved reserves booked in 2016 are all expected to start production within a period of five years
- Further drilling in the Bakken, Marcellus and Eagle Ford onshore plays in the US increased the proved reserves in 2016, and some of these additions are presented as extensions. Extension of proved area on existing fields added a total of 112 million boe of new proved reserves in 2016
- The net effect of purchase and sale increased the reserves by 39 million boe in 2016

The 2016 entitlement production was 673 million boe, an increase of 1.6% compared to 2015.

Proved reserves as of 31 December 2016	Proved reserves Oil and Condensate (mmboe)	NGL (mmboe)	Natural Gas (bcf)	Total oil and gas (mmboe)
Developed				
Norway	543	213	9,223	2,399
Eurasia excluding Norway	43	-	188	76
Africa	200	10	171	240
Americas	320	53	1,002	552
Total Developed proved reserves	1,105	277	10,584	3,268
Undeveloped				
Norway	689	76	3,628	1,411
Eurasia excluding Norway	28	-	-	28
Africa	22	6	110	47
Americas	190	14	316	260
Total Undeveloped proved reserves	928	95	4,054	1,746
Total proved reserves	2,033	372	14,637	5,013



Proved reserves in Norway
A total of 3,811 million boe is recognised as proved reserves in 61 fields and field development projects on the NCS, representing 76% of Statoil's total proved reserves. Of these, 54 fields and field areas are currently in production, 35 of which are operated by Statoil.

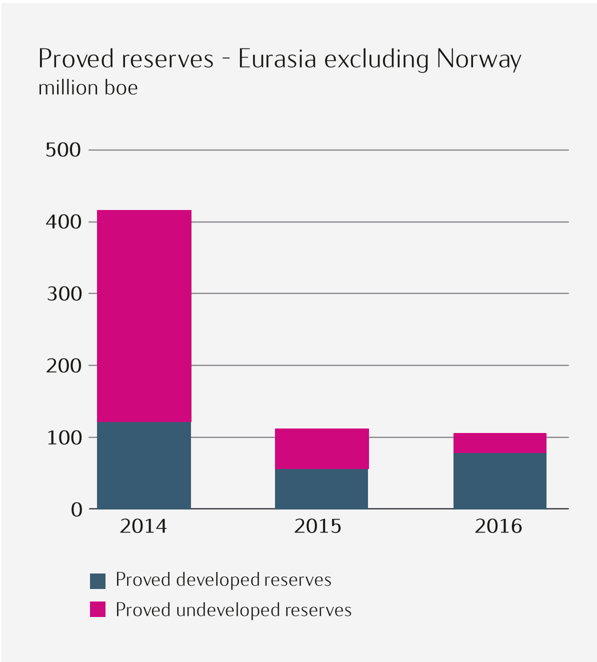
Three new field development projects added reserves categorised as extensions and discoveries during 2016, Svale Nord, Trestakk and Utgard. Production experience, further drilling and improved recovery on several of Statoil's producing fields in Norway also contributed positively to the revisions of the proved reserves in 2016.

The net effect of the transaction with Lundin Petroleum AB (Lundin), including sale of Statoil's equity share in the Edvard Grieg field and acquisition of a 20.1% share in Lundin, results in an increase in Statoil's proved reserves of 50 million boe. The volume corresponding to our relative share of Lundin's share in fields carrying proved reserves is included as reserves in an equity accounted company.

Of the proved reserves on the NCS, 2,399 million boe, or 63%, are proved developed reserves. Of the total proved reserves in this area, 60% are gas reserves related to large offshore gas fields such as Troll, Snøhvit, Oseberg, Ormen Lange, Tyrihans, Visund, Aasta Hansteen and Åsgard and 40% are liquid reserves.

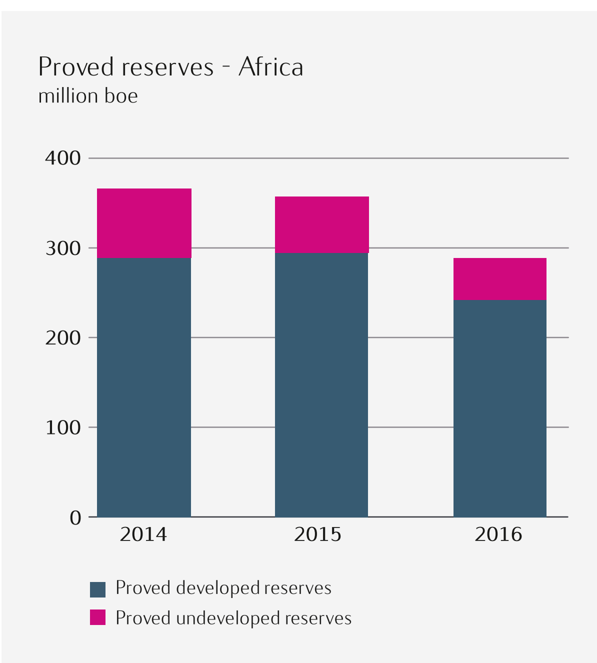
Proved reserves in Eurasia, excluding Norway
In this area, Statoil has proved reserves of 104 million boe related to three fields and field developments in Azerbaijan, Ireland and Russia. Eurasia excluding Norway represents 2% of Statoil's total proved reserves, Azerbaijan being the main contributor with the Azeri-Chirag-Gunashli fields. All fields are producing. Of the proved reserves in Eurasia, 76 million boe or 73% are proved developed reserves.

Of the total proved reserves in this area, 68% are liquid reserves and 32% are gas reserves.



Proved reserves in Africa

Statoil recognises proved reserves of 287 million boe related to 28 fields and field developments in several West and North African countries, including Algeria, Angola, Libya and Nigeria. Africa represents 6% of Statoil's total proved reserves. Angola is the primary contributor to the proved reserves in this area, with 24 of the 28 fields.



In Angola, Statoil has proved reserves in Block 15, Block 17 and Block 31, with production from all three blocks.

In Algeria and Nigeria, all fields are in production. Murzuq and Mabruk did not have any production in 2016 due to the political unrest in Libya.

The disputed equity determination at Agbami will potentially alter Statoil's equity share in this field. The effect on the proved reserves will be included once the redetermination is finalised and the effect is known.

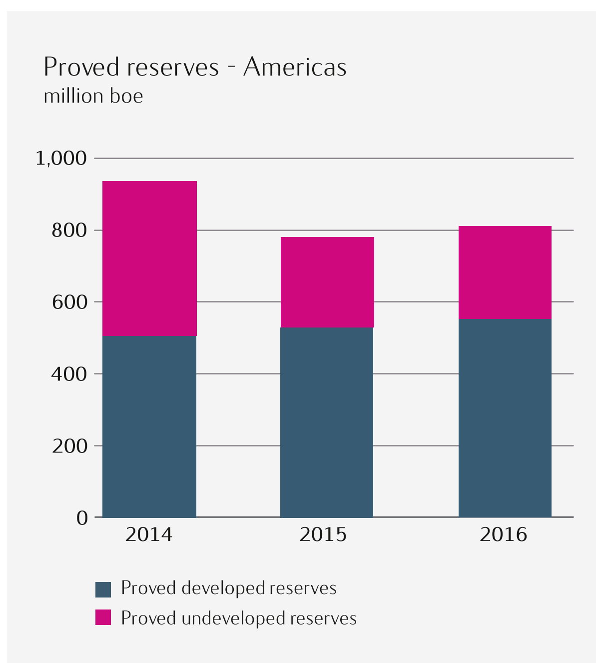
Of the total proved reserves in Africa, 240 million boe, or 84%, are proved developed reserves. Of the total proved reserves in this area, 83% are liquid reserves and 17% are gas reserves.

Proved reserves in the Americas

In North and South America, Statoil has proved reserves equal to 812 million boe in a total of 18 fields and field development projects. This represents 16% of Statoil's total proved reserves. Eleven of these fields are located in the US, eight of which are offshore field developments in the Gulf of Mexico and three are onshore tight reservoir assets. Five are located in Canada and two in South America.

In the US, six of the eight fields in the Gulf of Mexico are producing. Field development is ongoing on Big Foot and Stampede. The onshore tight reservoir assets Marcellus, Eagle Ford and Bakken are all in production. In Canada, proved reserves are related both to offshore field developments, and to the Leismer field in the Kai Kos Dehseh oil sands project in Alberta. The effect of the divestment of the oil sands projects will be included in 2017.

Of the total proved reserves in the Americas, 552 million boe, or 68%, are proved developed reserves. Of the total proved reserves in this area, 71% are liquid reserves and 29% gas reserves.



Reserves replacement

The reserves replacement ratio is defined as the sum of additions and revisions of proved reserves divided by produced volumes in any given period. The following table presents the changes in reserves in each category relating to the reserve replacement ratio for the years 2016, 2015 and 2014. For additional information regarding changes in proved reserves, see note 27 Supplemental oil and gas information (unaudited) to the Consolidated financial statements. The usefulness of the reserves replacement ratio is limited by the volatility of oil prices, the influence of oil and gas prices on PSA reserve booking, sensitivity related to the timing of project sanctions and the time lag between exploration expenditure and the booking of reserves.

	For the year ended 31 December		
Change in proved reseres (million boe)	2016	2015	2014
Revisions and improved recovery	**409**	(42)	356
Extensions and discoveries	**179**	627	253
Purchase of petroleum-in-place	**65**	13	20
Sales of petroleum-in-place	**(27)**	(235)	(233)
Total reserve additions	**626**	363	395
Production	**(673)**	(662)	(635)
Net change in proved reserves	**(47)**	(299)	(240)

	For the year ended 31 December		
Reserves replacement ratio (including purchases and sales)	2016	2015	2014
Annual	**0.93**	0.55	0.62
Three-year-average	**0.70**	0.81	0.97

Development of reserves

In 2016, approximately 299 million boe were converted from undeveloped to developed proved reserves. The start-up of production from Ivar Aasen, Goliat, Gullfaks Rimfaksdalen and Svale Nord in Norway, together with Julia and Heidelberg in the US increased the proved developed reserves by 127 million boe during 2016. The remaining 172 million boe of the converted volume is related to development activities on producing fields. Over the last five years Statoil has converted 1,962 million boe of proved undeveloped reserves to proved developed reserves.

Net proved reserves in million barrels oil equivalent	Total	Developed	Undeveloped
At 31 December 2015	5,060	3,515	1,546
Revisions and improved recovery	409	138	271
Extensions and discoveries	179	-	179
Purchase of reserves-in-place	65	2	63
Sales of reserves-in-place	(27)	(13)	(14)
Production	(673)	(673)	-
Moved from undeveloped to developed	-	299	(299)
At 31 December 2016	5,013	3,268	1,746

The new development projects added a total of 66 million boe of proved undeveloped reserves in 2016. Further drilling in the Bakken, Marcellus and Eagle Ford onshore plays in the US increased the proved area and added proved undeveloped reserves. These additions are categorized as extensions and together with extensions on other existing fields, this added a total of 112 million boe of proved undeveloped reserves. In total this adds up to an increase of 179 million boe from Extensions and discoveries.

Lower commodity prices had an effect on both undeveloped and developed reserves resulting in earlier economic cut-off. The negative revisions are more than offset by positive revisions based on new information available either from drilling of new wells or from production experience, resulting in an improved understanding of the fields. The net effect of revision of estimate on existing fields added 138 million boe proved developed reserves and 271 million boe proved undeveloped reserves.

The net effect of the purchase and sale transactions done in 2016, increased the proved undeveloped reserves by 49 million boe.

		Oil and Condensate (mmboe)	NGL (mmboe)	Natural gas (bcf)	Total (mmboe)
2016	**Proved reserves end of year**	**2,033**	**372**	**14,637**	**5,013**
	Developed	1,105	277	10,584	3,268
	Undeveloped	928	95	4,054	1,746
2015	**Proved reserves end of year**	**2,091**	**364**	**14,624**	**5,060**
	Developed	1,104	290	11,901	3,515
	Undeveloped	987	74	2,723	1,546
2014	**Proved reserves end of year**	**1,942**	**403**	**16,919**	**5,359**
	Developed	1,156	310	12,677	3,725
	Undeveloped	786	93	4,242	1,635

As of 31 December 2016, the total proved undeveloped reserves amounted to 1,746 million boe, 81% of which are related to fields in Norway. The Troll and Snøhvit fields, which have continuous development activities, represent the largest undeveloped assets in Norway together with fields not yet in production, such as Johan Sverdrup, Aasta Hansteen and Gina Krogh. The largest assets with respect to proved undeveloped reserves outside Norway are Stampede, Marcellus and Bakken in the US.

All these fields are either producing, or will start production within the next five years. For fields with proved reserves where production has not yet started, investment decisions have already been sanctioned and investments in infrastructure and facilities have commenced. Some development activities will take place more than five years from the disclosure date, but these are mainly related to incremental type of spending, such as drilling of additional wells from existing facilities, in order to secure continued production. There are no material development projects, which would require a separate future investment decision by management, included in our proved reserves. For our onshore plays in the USA, Marcellus, Eagle Ford and Bakken, all proved undeveloped reserves are limited to wells that are scheduled to be drilled within five years.

In 2016, Statoil incurred USD 8,115 million in development costs relating to assets carrying proved reserves, USD 6,188 million of which was related to proved undeveloped reserves.

Additional information about proved oil and gas reserves is provided in note 27 Supplementary oil and gas information (unaudited) to the Consolidated financial statements.

Preparations of reserves estimates

Statoil's annual reporting process for proved reserves is coordinated by a central corporate reserves management (CRM) team consisting of qualified professionals in geosciences, reservoir and production technology and financial evaluation. The team has an average of more than 21 years' experience in the oil and gas industry. CRM reports to the senior vice president of finance and control in the Technology, Drilling and Projects business area and is thus independent of the Development & Production business areas in Norway, North America and International. All the reserves estimates have been prepared by Statoil's technical staff.

Although the CRM team reviews the information centrally, each asset team is responsible for ensuring that it is in compliance with the requirements of the SEC and Statoil's corporate standards. Information about proved oil and gas reserves, standardised measures of discounted net cash flows related to proved oil and gas reserves and other information related to proved oil and gas reserves, is collected from the local asset teams and checked by CRM for consistency and conformity with applicable standards. The final numbers for each asset are quality-controlled and approved by the responsible asset manager, before aggregation to the required reporting level by CRM.

The aggregated results are submitted for approval to the relevant business area management teams and the corporate executive committee.

The person with primary responsibility for overseeing the preparation of the reserves estimates is the manager of the CRM team. The person who presently holds this position has a bachelor's degree in earth sciences from the University of Gothenburg, and a master's degree in petroleum exploration and exploitation from Chalmers University of Technology in Gothenburg, Sweden. She has 31 years' experience in the oil and gas industry, 30 of them with Statoil. She is a member of the Society of Petroleum Engineering (SPE) and vice-chair of the UNECE Expert Group on Resource Classification (EGRC).

DeGolyer and MacNaughton report

Petroleum engineering consultants DeGolyer and MacNaughton have carried out an independent evaluation of Statoil's proved reserves as of 31 December 2016 using Statoil provided data. The evaluation accounts for 100% of Statoil's proved reserves. The aggregated net proved reserves estimates prepared by DeGolyer and MacNaughton do not differ materially from those prepared by Statoil when compared on the basis of net equivalent barrels.

Net proved reserves at 31 December 2016	Oil and Condensate (mmbbls)	NGL/LPG (mmbbl)	Sales Gas (bcf)	Oil Equivalent (mmboe)
Estimated by Statoil	2,033	372	14,637	5,013
Estimated by DeGolyer and MacNaughton	2,244	324	13,685	5,007

A reserves audit report summarising this evaluation is included as Exhibit 15 (a)(iii).

Operational statistics

Developed and undeveloped acreage

The table below shows the total gross and net developed and undeveloped oil and gas acreage, in which Statoil had interests at 31 December 2016.

A gross value reflects wells or acreage in which Statoil has interests (presented as 100%). The net value corresponds to the sum of the fractional working interests owned in gross wells or acreages.

At 31 December 2016 (in thousands of acres)		Norway	Eurasia excluding Norway	Africa	Americas	Oceania 1)	Total
Developed and undeveloped oil and gas acreage							
Acreage developed	- gross	915	90	823	845	-	2,673
	- net	339	21	267	240	-	868
Acreage undeveloped	- gross	12,485	40,593	17,922	32,665	18,125	121,789
	- net	5,127	18,275	7,420	13,425	9,052	53,299

1) Acreage in Australia

The largest concentrations of developed acreage in Norway are in the Troll, Skarv, Snøhvit, Oseberg area and Ormen Lange. In Africa, the Algerian gas development projects In Amenas and In Salah represent the largest concentrations of developed acreage (gross and net).

Statoil's largest undeveloped acreage concentration is in Russia with 16% of the total acreage and 48% of the total acreage in Eurasia excluding Norway. A large part of the net acreage in Russia represents Statoil's share of a joint venture with Rosneft. The largest concentration of undeveloped acreage in the Americas is Canada, with 33% of the total for this geographic area. In Africa, the largest acreage concentration is in South Africa, representing 38% of the total for this geographic area. In Oceania Statoil holds undeveloped acreage in Australia and New Zealand.

Statoil holds acreage in numerous concessions, blocks and leases. The terms and conditions regarding expiration dates vary significantly from property to property. Work programs are designed to ensure that the exploration potential of any property is fully evaluated before expiration.

Acreage related to several of these concessions, blocks and leases are scheduled to expire within the next three years. Any acreage which has already been evaluated to be non-profitable may be relinquished prior to the current expiration date. In other cases, Statoil may decide to apply for an extension if more time is needed in order to fully evaluate the potential of the properties. Historically, Statoil has generally been successful in obtaining such extensions.

Most of the undeveloped acreage that will expire within the next three years is related to early exploration activities where no production is expected in the foreseeable future. The expiration of these leases, blocks and concessions will therefore not have any material impact on our reserves.

Productive oil and gas wells

The number of gross and net productive oil and gas wells, in which Statoil had interests at 31 December 2016, are shown in the table below.

At 31 December 2016		Norway	Eurasia excluding Norway	Africa	Americas	Total
Number of productive oil and gas wells						
Oil wells	- gross	865	175	480	3,337	4,857
	- net	293.5	25.4	72.4	817.2	1,208.4
Gas wells	- gross	202	6	97	2,049	2,354
	- net	88.6	2.2	37.5	509.8	638.1

The total gross number of productive wells as of end 2016 includes 404 oil wells and 15 gas wells with multiple completions or wells with more than one branch.

Net productive and dry oil and gas wells drilled

The following tables show the net productive and dry exploratory and development oil and gas wells completed or abandoned by Statoil in the past three years. Productive wells include exploratory wells in which hydrocarbons were discovered, and where drilling or completion has been suspended pending further evaluation. A dry well is one found to be incapable of producing sufficient quantities to justify completion as an oil or gas well.

	Norway	Eurasia excluding Norway	Africa	Americas	Oceania	Total
Year 2016						
Net productive and dry exploratory wells drilled	5.5	0.7	-	6.4	-	12.6
- Net dry exploratory wells drilled	1.4	0.7	-	1.9	-	3.9
- Net productive exploratory wells drilled	4.1	-	-	4.6	-	8.7
Net productive and dry development wells drilled	47.4	1.6	5.2	133.5	-	187.8
- Net dry development wells drilled	4.2	0.2	0.2	-	-	4.6
- Net productive development wells drilled	43.3	1.5	4.9	133.5	-	183.2
Year 2015						
Net productive and dry exploratory wells drilled	10.2	1.0	2.5	2.6	-	16.3
- Net dry exploratory wells drilled	4.6	0.4	0.5	0.9	-	6.4
- Net productive exploratory wells drilled	5.6	0.7	2.0	1.7	-	9.9
Net productive and dry development wells drilled	32.1	4.1	10.6	228.8	-	275.6
- Net dry development wells drilled	3.6	-	4.3	0.3	-	8.2
- Net productive development wells drilled	28.6	4.1	6.3	228.5	-	267.4
Year 2014						
Net productive and dry exploratory wells drilled	12.0	1.0	4.7	3.4	3.6	24.7
- Net dry exploratory wells drilled	3.4	1.0	2.7	1.6	3.6	12.2
- Net productive exploratory wells drilled	8.6	-	2.0	1.9	-	12.5
Net productive and dry development wells drilled	26.9	2.7	8.5	386.1	-	424.2
- Net dry development wells drilled	3.5	-	1.1	1.2	-	5.8
- Net productive development wells drilled	23.4	2.7	7.4	384.9	-	418.4

Exploratory and development drilling in process

The following table shows the number of exploratory and development oil and gas wells in the process of being drilled by Statoil at 31 December 2016.

At 31 December 2016		Norway	Eurasia excluding Norway	Africa	Americas	Total
Number of wells in progress						
Development wells	- gross	52	8	16	355	431
	- net	18.6	0.9	3.6	113.7	136.8
Exploratory wells	- gross	3	-	-	1	4
	- net	1.6	-	-	0.2	1.8

Delivery commitments

On behalf of the Norwegian State's direct financial interest (SDFI), Statoil is responsible for managing, transporting and selling the Norwegian state's oil and gas from the Norwegian continental shelf (NCS). These reserves are sold in conjunction with Statoil's own reserves. As part of this arrangement, Statoil delivers gas to customers under various types of sales contracts. In order to meet the commitments, we utilize a field supply schedule that ensures the highest possible total value for Statoil and SDFI's joint portfolio of oil and gas.

The majority of our gas volumes in Norway are sold under long-term contracts with take-or-pay clauses. Statoil's and SDFI's annual delivery commitments under these agreements are expressed as the sum of the expected off-take under these contracts. As of 31 December 2016, the long-term commitments from NCS for the Statoil/SDFI arrangement totaled approximately 329 bcm.

Statoil and SDFI's delivery commitments, expressed as the sum of expected off-take for the calendar years 2017, 2018, 2019 and 2020, are 57.2, 44.6, 39.3 and 37.3 bcm, respectively. Any remaining volumes after covering our bilateral agreements, will be sold by trading activities at the hubs.

Statoil's currently developed gas reserves in Norway are more than sufficient to meet our share of these commitments for the next four years.

PRODUCTION VOLUMES AND PRICES

The business overview is in accordance with our segment's operations as of 31 December 2016, whereas certain disclosures on oil and gas reserves are based on geographical areas as required by the Securities and Exchange Commission (SEC). For further information about extractive activities, see sections 2.3 DPN - Development and Production Norway and 2.4 DPI - Development and Production International.

Statoil prepares its disclosures for oil and gas reserves and certain other supplemental oil and gas disclosures by geographical area, as required by the SEC. The geographical areas are defined by country and continent. They are Norway, Eurasia excluding Norway, Africa and the Americas.

For further information about disclosures concerning oil and gas reserves and certain other supplemental disclosures based on geographical areas as required by the SEC, see note 27 Supplementary Oil and Gas Information (unaudited) to the Consolidated financial statements.

Entitlement production

The following table shows Statoil's Norwegian and international entitlement production of oil and natural gas for the periods indicated. The stated production volumes are the volumes to which Statoil is entitled, pursuant to conditions laid down in licence agreements and production-sharing agreements. The production volumes are net of royalty oil paid in kind, and of gas used for fuel and flaring. Our production is based on our proportionate participation in fields with multiple owners and does not include production of the Norwegian State's oil and natural gas. Production of an immaterial quantity of bitumen is included as oil production. NGL includes both LPG and naphtha. For further information on production volumes see section 5.6 Terms and abbreviations.

	Consolidated companies					Equity accounted				
	Norway	Eurasia excluding Norway	Africa	Americas	Subtotal	Norway	Eurasia excluding Norway	Americas	Subtotal	Total
Oil and Condensate (mmbbls)										
2014	173	14	64	51	301	-	-	4	4	306
2015	174	13	75	57	319	-	-	4	4	324
2016	169	12	72	60	313	2	0	4	6	320
NGL (mmbbls)										
2014	42	-	2	7	51	-	-	-	-	51
2015	44	-	3	7	54	-	-	-	-	54
2016	46	-	2	9	58	0	-	-	0	58
Natural gas (bcf)										
2014	1,229	56	38	242	1,565	-	-	-	-	1,565
2015	1,306	16	63	215	1,600	-	-	-	-	1,600
2016	1,338	34	60	227	1,659	1	0	-	2	1,661
Combined oil, condensate, NGL and gas (mmboe)										
2014	434	24	72	102	631	-	-	4	4	635
2015	450	16	88	103	658	-	-	4	4	662
2016	454	18	85	110	666	3	0	4	7	673

The only field containing more than 15% of total proved reserves based on oil equivalent barrels is the Troll field.

Entitlement production	2016	2015	2014
Troll field 1)			
Oil and Condensate (mmbbls)	15	14	14
NGL (mmbbls)	2	2	2
Natural gas (bcf)	321	386	317
Combined oil, condensate, NGL and gas (mmboe)	74	85	73

1) Note that Troll is also included in Norway stated above.

Operational data	For the year ended 31 December 2016	2015	2014	16-15 change	15-14 change
Prices					
Average Brent oil price (USD/bbl)	43.7	52.4	98.9	(17%)	(47%)
Development and Production Norway average liquids price (USD/bbl)	39.4	48.2	90.6	(18%)	(47%)
Development and Production International average liquids price (USD/bbl)	35.8	42.9	85.6	(17%)	(50%)
Group average liquids price (USD/bbl)	37.8	45.9	88.6	(18%)	(48%)
Group average liquids price (NOK/bbl)	317	371	559	(14%)	(34%)
Transfer price natural gas (USD/mmbtu)	3.42	5.17	6.55	(34%)	(21%)
Average invoiced gas prices - Europe (USD/mmbtu)	5.17	7.08	9.54	(27%)	(26%)
Average invoiced gas prices - North America (USD/mmbtu)	2.13	2.62	4.39	(19%)	(40%)
Refining reference margin (USD/bbl)	4.8	8.0	4.7	(40%)	70%
Entitlement production (mboe per day)					
Development and Production Norway entitlement liquids production	589	595	588	(1%)	1%
Development and Production International entitlement liquids production	435	436	383	(0%)	14%
Group entitlement liquids production	1,024	1,032	971	(1%)	6%
Development and Production Norway entitlement gas production	646	637	595	1%	7%
Development and Production International entitlement gas production	157	144	163	9%	(12%)
Group entitlement gas production	803	781	758	3%	3%
Total entitlement liquids and gas production	1,827	1,812	1,729	1%	5%
Equity production (mboe per day)					
Development and Production Norway equity liquids production	589	595	588	(1%)	1%
Development and Production International equity liquids production	555	569	538	(2%)	6%
Group equity liquids production	1,144	1,165	1,127	(2%)	3%
Development and Production Norway equity gas production	646	637	595	1%	7%
Development and Production International equity gas production	188	170	205	11%	(17%)
Group equity gas production	834	806	801	3%	1%
Total equity liquids and gas production	1,978	1,971	1,927	0%	2%
Liftings (mboe per day)					
Liquids liftings	1017	1,035	967	(2%)	7%
Gas liftings	824	802	779	3%	3%
Total liquids and gas liftings	1842	1,837	1,746	0%	5%
Marketing, Midstream and Processing sales volumes					
Crude oil sales volumes (mmbl)	811	829	811	(2%)	2%
Natural gas sales Statoil entitlement (bcm)	44.3	44.0	43.1	1%	2%
Natural gas sales third-party volumes (bcm)	8.6	8.6	8.1	0%	6%
Production cost (USD/boe)					
Production cost entitlement volumes	5.4	6.5	8.5	(17%)	(24%)
Production cost equity volumes	5.0	5.9	7.6	(17%)	(22%)

Sales prices

The following tables present realised sales prices.

	Norway	Eurasia excluding Norway	Africa	Americas
Year ended 31 December 2016				
Average sales price oil and condensate in USD per bbl	43.1	42.0	41.4	32.9
Average sales price NGL in USD per bbl	24.4	-	21.9	13.1
Average sales price natural gas in USD per mmbtu	5.2	4.8	4.0	2.1
Year ended 31 December 2015				
Average sales price oil and condensate in USD per bbl	52.2	50.7	49.4	39.4
Average sales price NGL in USD per bbl	30.1	-	26.2	12.5
Average sales price natural gas in USD per mmbtu	7.1	4.6	5.6	2.6
Year ended 31 December 2014				
Average sales price oil and condensate in USD per bbl	98.3	101.3	95.6	78.3
Average sales price NGL in USD per bbl	59.3	-	59.7	37.3
Average sales price natural gas in USD per mmbtu	9.5	5.4	9.2	4.4

Sales volumes

Sales volumes include lifted entitlement volumes, the sale of SDFI volumes and marketing of third-party volumes. In addition to Statoil's own volumes, we market and sell oil and gas owned by the Norwegian State through the Norwegian State's share in production licences. This is known as the State's Direct Financial Interest or SDFI. For additional information, see section SDFI oil and gas marketing and sale in Applicable laws and regulations in section 2.7 Corporate. The following table shows the SDFI and Statoil sales volume information on crude oil and natural gas for the periods indicated. The Statoil natural gas sales volumes include equity volumes sold by the MMP segment, natural gas volumes sold by the DPI segment and ethane volumes.

	For the year ended 31 December		
Sales Volumes	2016	2015	2014
Statoil:[1]			
Crude oil (mmbbls)[2]	**372**	378	353
Natural gas (bcm)	**48**	47	45
Combined oil and gas (mmboe)	**674**	671	637
Third party volumes:[3]			
Crude oil (mmbbls)[2]	**294**	290	304
Natural gas (bcm)	**9**	9	8
Combined oil and gas (mmboe)	**348**	344	355
SDFI assets owned by the Norwegian State:[4]			
Crude oil (mmbbls)[2]	**148**	149	148
Natural gas (bcm)	**40**	42	37
Combined oil and gas (mmboe)	**398**	412	379
Total:			
Crude oil (mmbbls)[2]	**814**	816	805
Natural gas (bcm)	**96**	97	90
Combined oil and gas (mmboe)	**1,420**	1,427	1,371

1) The Statoil volumes included in the table above are based on the assumption that volumes sold were equal to lifted volumes in the relevant year. Volumes lifted by DPI but not sold by MMP, and volumes lifted by DPN or DPI and still in inventory or in transit may cause these volumes to differ from the sales volumes reported elsewhere in this report by MMP.

2) Sales volumes of crude oil include NGL and condensate. All sales volumes reported in the table above include internal deliveries to our manufacturing facilities.

3) Third party volumes of crude oil include both volumes purchased from partners in our upstream operations and other cargos purchased in the market. The third party volumes are purchased either for sale to third parties or for our own use. Third party volumes of natural gas include third party LNG volumes related to our activities at the Cove Point regasification terminal in the US.

4) SDFI volumes in columns 2015 and 2014 are updated to reflect total sales volumes natural gas (bcm). Previously third party volumes sold from storage were excluded.

FINANCIAL REVIEW - GROUP PROFIT AND LOSS ANALYSIS

Our **results** over the last years have been heavily influenced by the drop in prices, leading to lower earnings and impairment losses, while at the same time achievements from our improvement programme affected earnings positively.
Total equity liquids and gas production was 1,978 mboe, 1,971 mboe, 1,927 mboe per day in 2016, 2015 and 2014, respectively.

From 2015 to 2016, the average daily total equity production level was maintained. Increased production from new fields coming on stream, ramp-up on various existing fields and high operational performance, was offset by reduced ownership shares as a result of divestments, expected natural decline at mature fields and operational challenges. The 2% increase in total equity production from 2014 to 2015 was primarily due to start-up and ramp-up on various fields and higher gas sales from the NCS, partially offset by expected natural decline and divestments and redeterminations.

Total entitlement liquids and gas production was 1,827 mboe per day in 2016 compared to 1,812 mboe in 2015 and 1,729 mboe per day in 2014. The total entitlement production in 2016 was up 1% and the development was almost flat for the same reasons as described above. The benefit of a lower effect from production sharing agreements (PSA effect) mainly driven by the reduction in prices, added to the slight increase in entitlement production. From 2014 to 2015, entitlement production was up 5% for the same reasons as described above and the benefit from lower PSA effects.

The PSA effect was 109 mboe, 116 mboe and 157 mboe per day in 2016, 2015 and 2014, respectively. Over time, the volumes lifted and sold will equal the entitlement production, but they may be higher or lower in any period due to differences between the capacity and timing of the vessels lifting our volumes and the actual entitlement production during the period.

Income statement under IFRS (in USD million)	For the year ended 31 December 2016	2015	2014	16-15 change	15-14 change
Revenues	**45,688**	57,900	96,708	(21%)	(40%)
Net income from equity accounted investments	**(119)**	(29)	(34)	>(100%)	17%
Other income	**304**	1,770	2,590	(83%)	(32%)
Total revenues and other income	**45,873**	59,642	99,264	(23%)	(40%)
Purchases [net of inventory variation]	**(21,505)**	(26,254)	(47,980)	(18%)	(45%)
Operating expenses and selling, general and administrative expenses	**(9,787)**	(11,433)	(12,815)	(14%)	(11%)
Depreciation, amortisation and net impairment losses	**(11,550)**	(16,715)	(15,925)	(31%)	5%
Exploration expenses	**(2,952)**	(3,872)	(4,666)	(24%)	(17%)
Net operating income	**80**	1,366	17,878	(94%)	(92%)
Net financial items	**(258)**	(1,311)	20	80%	N/A
Income before tax	**(178)**	55	17,898	N/A	(100%)
Income tax	**(2,724)**	(5,225)	(14,011)	(48%)	(63%)
Net income	**(2,902)**	(5,169)	3,887	44%	N/A

On 1 January 2016 Statoil changed its presentation currency from Norwegian kroner (NOK) to US dollar (USD), mainly in order to better reflect the underlying USD exposure of Statoil's business activities and to align with industry practice.

Total revenues and other income amounted to USD 45,873 million in 2016 compared to USD 59,642 million in 2015 and USD 99,264 million in 2014.

Revenues are generated from both the sale of lifted crude oil, natural gas and refined products produced and marketed by Statoil, and from the sale of liquids and gas purchased from third parties. In addition, we market and sell the Norwegian State's share of liquids from the NCS. All purchases and sales of the Norwegian State's production of liquids are recorded as purchases [net of inventory variations] and revenues, respectively, while sales of the Norwegian State's share of gas from the NCS are recorded net. For additional information regarding sales, see the Sales volume table in section 2.8 above.

The 21% decrease in **revenues** from 2015 to 2016 was mainly due to the drop in liquids and gas prices, lower refinery margins and increased losses from reflecting the changes in fair value of derivatives and market value of storage and physical contracts. The 40% decrease in revenues from 2014 to 2015 was mainly due to the significant reduction in both liquids and gas prices. Stronger refinery margins in 2015 and higher volumes of both liquids and gas sold partially offset the decrease.

Other income was USD 304 million in 2016 compared to USD 1,770 million in 2015 and USD 2,590 million in 2014. Other income in 2016 was mainly related to gain from sale of the Edvard Grieg field on the NCS and proceeds from an insurance settlement. In both 2015 and 2014, other income mainly consisted of gain from the two step divestments of the ownership interest in the Shah Deniz project in Azerbaijan. In addition, a settlement following an arbitration ruling in Statoil's favour, impacted other income in 2014.

As a result of the factors explained above, **total revenue and other income** decreased by 23% in 2016. In 2015, the decrease was 40%.

Purchases [net of inventory variation] include the cost of liquids purchased from the Norwegian State, which is pursuant to the Owner's instruction, and the cost of liquids and gas purchased from third parties. See SDFI oil and gas marketing and sale in section 2.7 Corporate for more details.

Purchases [net of inventory variation] amounted to USD 21,505 million in 2016 compared to USD 26,254 million in 2015 and USD 47,980 million in 2014. The 18% decrease from 2015 to 2016 was mainly related to the decrease in liquids and gas prices. The 45% decrease from 2014 to 2015 was mainly related to the decrease in prices for liquids and gas and other oil products and lower volumes of crude, other oil products and gas sold.

Operating expenses and selling, general and administrative expenses amounted to USD 9,787 million in 2016 compared to USD 11,433 million in 2015, and USD 12,815 million in 2014.

The 14% decrease from 2015 to 2016 was mainly as a result of the on-going cost improvement initiatives and the NOK/USD exchange rate development. Lower operation and maintenance costs, decreased diluent cost and reduced transportation costs added to the decrease. Higher provisions, ramp-up and start-up of production on new fields partially offset the decrease in operating costs.

The 11% decrease from 2014 to 2015 was mainly due to lower operation and maintenance costs, reduced royalties due to lower liquids prices, decreased transportation costs in addition to positive effects from on-going cost initiatives. A curtailment gain related to the change of pension plan included in 2014, partially offset the decrease.

Depreciation, amortisation and net impairment losses amounted to USD 11,550 million in 2016 compared to USD 16,715 million in 2015 and USD 15,925 million in 2014. Included in these totals were net impairment losses of USD 1,301 million, USD 5,526 million and USD 4,134 million for 2016, 2015 and 2014 respectively, primarily triggered by the reduced commodity price assumption and commodity forward prices.

The net impairment losses of USD 1,301 million in 2016 were mainly related to impairment of unconventional onshore assets in the USA, including an impairment of the held for sale Kai Kos Dehseh oil sands project in Canada, and conventional offshore assets in the development phase in the DPN segment. Net reversals related to other conventional assets in the DPI segment (USD 19 million) and a refinery in the MMP segment (USD 74 million) had an offsetting effect. See note 10 Property, plant and equipment to the Consolidated financial statements.

Compared to 2015, the 31% decrease was mainly due to lower impairment of assets in 2016 and reduced depreciation on mature fields. Higher proved reserves estimate and the NOK/USD exchange rate development in 2016 added to the decrease, partially offset by start-up and ramp-up of production on several fields.

Compared to 2014, the 5% increase in 2015 was mainly due to increased impairment charges and start-up and ramp-up of production of several fields. Reduced overall depreciation because of net impairments of assets in both 2014 and 2015 with a corresponding lower basis for depreciation partially offset the increase.

Exploration expenses (in USD million)	For the year ended 31 December 2016	2015	2014	16-15 change	15-14 change
Exploration expenditures (activity)	**1,437**	2,860	3,730	(50%)	(23%)
Expensed, previously capitalised exploration expenditures	**808**	213	369	>100%	(42%)
Capitalised share of current period's exploration activity	**(285)**	(1,151)	(1,161)	(75%)	(1%)
Impairments, net of reversals	**992**	1,951	1,728	(49%)	13%
Exploration expenses	**2,952**	3,872	4,666	(24%)	(17%)

In 2016, **exploration expenses** were USD 2,952 million, a 24% decrease compared with 2015 when exploration expenses were USD 3,872 million. Exploration expenses were USD 4,666 million in 2014.

The 24% decrease in exploration expenses in 2016 was mainly due to lower net impairment of exploration prospects and signature bonuses, lower drilling activity and less expensive wells being drilled. The decrease was partially offset by a higher portion of expenditures capitalised in previous years being expensed in 2016 and a lower capitalisation rate on exploration expenditures incurred in 2016 compared to 2015.

In 2015, exploration expenses were down 17% compared to 2014 mainly due to a lower level of drilling activity and a lower portion of previously capitalised expenditures being expensed in 2015. Increased impairment of exploration prospects and signature bonuses in 2015 compared to 2014 partially offset the increase.

As a result of the factors explained above, **net operating income** was USD 80 million in 2016, compared to USD 1,366 million in 2015. In 2014, net operating income was USD 17,878 million. The significant decrease in 2016 was primarily driven by the drop in liquids and gas prices, lower refinery margins and lower gains on sale of assets. The decrease was partially offset by lower net impairment charges in 2016 compared to 2015 and a reduction in operating, depreciation and exploration costs. The decrease in net operating income from 2014 to 2015 was mainly due to the drop in prices in 2015 leading to lower earnings and increased impairment charges.

Net financial items amounted to a loss of USD 258 million in 2016, compared to a loss of USD 1,311 million in 2015 and a gain of USD 20 million in 2014. The reduced loss of USD 1,053 million in 2016 is mainly due to gain on derivatives due to decrease in EUR and GBP interest rates related to our long term debt portfolio of USD 470 million for 2016, compared to a loss of USD 491 million for 2015. The decrease in 2015 was mainly related to loss of USD 491 million on derivatives related to the long term debt portfolio in 2015, compared to a gain of USD 904 million in 2014, mainly due to changes in the interest yield curves.

Income taxes were USD 2,724 million in 2016, equivalent to an effective tax rate of more than 100%, compared to USD 5,225 million, equivalent to an effective tax rate of more than 100% in 2015. In 2014, income taxes were USD 14,011 million, equivalent to an effective tax rate of 78%.

In 2016 and 2015 our group income before tax (a loss of USD 178 million in 2016 and a profit of USD 55 million in 2015) is a combination of large profits in territories with higher statutory tax rates (taking account of Norwegian Petroleum Tax including uplift) and approximately the same amount of losses in territories with lower statutory tax rates and so our effective tax rate is distorted. In addition, the "weighted average statutory tax rate" (which we calculate before taking into account Norwegian Petroleum Tax including uplift for comparability) is also distorted.

In 2016, the effective rate of tax on the profit earned by our DPN business approximated the statutory tax rate (taking account of Norwegian Petroleum Tax including uplift) but the effective tax rate on DPI losses was negative due to the inability to currently recognise tax losses and other deferred tax assets arising from those losses, primarily in the USA. Overall this results in a significant income tax charge on a relatively small group loss before tax.

The **effective tax rate** in 2015 was primarily influenced by losses, mainly caused by impairments recognised in countries where deferred tax assets could not be recognised, partially offset by tax exempted gains on sale of assets including Statoil's interest in the Shah Deniz project. The effective tax rate in 2015 was also influenced by the de-recognition of deferred tax assets within the DPI segment due to uncertainty related to future taxable income.

The decrease from 2014 to 2015 was mainly caused by losses, impairments and provisions in entities with higher than average statutory tax rates. Effective tax rate in 2014 was primarily influenced by losses, mainly caused by impairments, recognised in countries where deferred tax assets could not be recognised partially offset by tax exempted gains on sale of assets. The effective tax rate in 2014 was also influenced by the recognition of a non-cash tax income following a verdict in the Norwegian Supreme Court in February 2014.

The effective tax rate is calculated as income taxes divided by income before taxes. Fluctuations in the effective tax rates from year to year are principally the result of non-taxable items (permanent differences) and changes in the relative composition of income between Norwegian oil and gas production, taxed at a marginal rate of 78%, and income from other tax jurisdictions. Other Norwegian income, including the onshore portion of net financial items, is taxed at 25% (27% in 2014 and 2015), and income in other countries is taxed at the applicable income tax rates in the various countries.

In 2016, **net income** was negative USD 2,902 million compared to negative USD 5,169 million in 2015 and positive USD 3,887 million in 2014. The increase was mainly due to lower income taxes and lower loss on net financial items, partially offset by the decrease in net operating income as explained above. The significant decrease from 2014 to 2015 was mainly due to the drop in prices, leading to lower earnings and impairment losses. Increased losses on net financial items related to derivatives added to the decrease, which was partially offset by the reduction in income taxes.

The board of directors proposes to the annual general meeting (AGM) to maintain a **dividend** of USD 0.2201 per ordinary share for the fourth quarter, and continue the scrip programme giving shareholders the option to receive the dividend for the fourth quarter in cash or newly issued shares in Statoil at a 5% discount. The **Annual ordinary dividends** for 2016 amounted to an aggregate total of USD 1,934 million. Considering the proposed dividend, USD 4,543 million will be transferred from retained earnings in the parent company. For 2015, annual ordinary dividends amounted to an aggregate total of USD 2,860 million and USD 3,628 million in 2014.

In 2014, following a regular review process of Statoil's 2012 Consolidated financial statements, the Financial Supervisory Authority of Norway (the FSA), ordered Statoil to change the timing of a Cove Point related onerous contract provision to a financial period prior to the first quarter of 2013, in which Statoil originally reflected the provision. Statoil did not accept the FSA's conclusion and appealed the order to the Norwegian Ministry of Finance in accordance with due process for such matters under Norwegian regulation. In 2016, the Norwegian Ministry of Finance denied Statoil's appeal. Statoil has decided not to pursue the matter further, as it does not impact any comparative financial periods presented in the annual Consolidated financial statements of 2016. Further reference is made to Note 23 Other commitments, contingent liabilities and contingent assets of Statoil's 2015 Financial Statements.

In accordance with §3-3 of the Norwegian Accounting Act, the board of directors confirms that the going concern assumption on which the financial statements have been prepared, is appropriate.

FINANCIAL REVIEW – SEGMENTS PERFORMANCE

DPN profit and loss analysis

Net operating income in 2016 was USD 4,451 million, compared to USD 7,161 million in 2015 and USD 17,753 million in 2014. The USD 2,710 million decrease from 2015 to 2016 was mainly due to lower prices on liquids and gas, partly offset by reduced operating expenses, decreased depreciation and net impairment losses. The USD 10,592 million decrease from 2014 to 2015 was mainly due to lower prices on liquids and increased depreciation and net impairment losses.

The average daily production of liquids and gas was 1,235 mboe, 1,232 mboe and 1,184 mboe per day in 2016, 2015 and 2014, respectively.

The average daily total production level was maintained from 2015 to 2016 by high operational performance, new fields on stream and new wells from existing fields.

The average daily total production of liquids and gas increased by 4% from 2014 to 2015, mainly due to ramp up of new fields, increased sales gas and good operational performance, partly offset by expected natural decline and divestments.

Over time, the volumes lifted and sold will equal entitlement production, but may be higher or lower in any period due to differences between the capacities and timing of the vessels lifting the volumes and the actual entitlement production during the period.

Income statement under IFRS (in USD million)	For the year ended 31 December 2016	2015	2014	16-15 change	15-14 change
Revenues	**13,036**	17,170	27,914	(24%)	(38%)
Net income from equity accounted investments	**(78)**	3	11	N/A	(70%)
Other income	**119**	166	1,002	(28%)	(83%)
Total revenues and other income	**13,077**	17,339	28,926	(25%)	(40%)
Operating expenses and selling, general and administrative expenses	**(2,547)**	(3,223)	(4,034)	(21%)	(20%)
Depreciation, amortisation and net impairment losses	**(5,698)**	(6,379)	(6,301)	(11%)	1%
Exploration expenses	**(383)**	(576)	(838)	(34%)	(31%)
Net operating income	**4,451**	7,161	17,753	(38%)	(60%)

Total revenues and other income were USD 13,077 million in 2016, USD 17,339 million in 2015 and USD 28,926 million in 2014.

The 24% decrease in **revenues** from 2015 to 2016 was mainly due to reduced liquids and gas prices. The 38% decrease in **revenues** from 2014 to 2015 was mainly due to reduced liquids prices and exchange rate development (NOK/USD). In addition, in 2015 a re-assessed valuation estimate of earn-out derivatives resulted in an unrealised fair value loss on derivatives and impacted revenues negatively.

Other income in 2016 was impacted by gain from sale of Edvard Grieg of USD 114 million. Other income in 2015 was impacted by gain from the sale of certain ownership interests on the NCS to Repsol of USD 142 million. Other income in 2014 was impacted by gain from the sale of certain ownership interests on the NCS to Wintershall of USD 861 million.

Operating expenses and selling, general and administrative expenses were USD 2,547 million in 2016, compared to USD 3,223 million in 2015 and USD 4,034 million in 2014. In 2016, expenses decreased compared to 2015 mainly due to cost improvements and exchange rate development (NOK/USD). In 2015, expenses decreased compared to 2014 mainly due to exchange rate development (NOK/USD), cost improvements and reduced turnaround activity. This was partly offset by gain related to changes in pension scheme in 2014 and ramp up of new fields during 2015.

Depreciation, amortisation and net impairment losses were USD 5,698 million in 2016, compared to USD 6,379 million in 2015 and USD 6,301 million in 2014. The decrease of 11% from 2015 to 2016 was mainly due to reduced net impairments, exchange rate development (NOK/USD) and increased reserves, partly offset by ramp up of new fields in 2016. The increase from 2014 to 2015 was mainly due to net impairments of USD 1,074 million in 2015 and ramp-up of new fields in 2015, offset by exchange rate development (NOK/USD).

Exploration expenses were USD 383 million in 2016, compared to USD 576 million in 2015 and USD 838 million in 2014. The reduction from 2015 to 2016 was mainly due to lower drilling activity and more expensive wells being drilled in 2015, partially offset by a lower portion of current exploration expenditures being capitalised. The reduction in exploration expenses from 2014 to 2015 was mainly due to lower drilling activity, a lower portion of previously capitalised exploration expenditures being expensed in 2015 and idle rig costs in 2014.

DPI profit and loss analysis

Net operating income in 2016 was negative USD 4,352 million, compared to negative USD 8,729 million in 2015 and negative USD 2,703 million in 2014. The positive development from 2015 to 2016 was caused primarily by less impairment losses, and also by lower operating expenses. The negative development from 2014 to 2015 was caused primarily by lower realised liquids and gas prices and more impairment losses.

The average daily equity liquids and gas production (see section 5.6 Terms and abbreviations) was 743 mboe per day in 2016, compared to 739 mboe per day in 2015 and 744 mboe per day in 2014. The increase of 0.5% from 2015 to 2016 was driven primarily by the effect of the ramp-up of fields, mainly in Ireland, Algeria, and the US. The increase was partly offset by the divestment of Shah Deniz (Azerbaijan), natural decline primarily at mature fields in Angola as well as some operational challenges in 2016. The decrease of 0.7% from 2014 to 2015 was driven primarily by the effect of the divestment of Shah Deniz and a portion of Marcellus (US), and natural decline, primarily at mature fields in Angola. The decrease was partly offset by the ramp-up of fields in Angola and the US. Divestment of Shah Deniz occurred in both 2014 and 2015.

The average daily entitlement liquids and gas production (see section 5.6 Terms and abbreviations) was 592 mboe per day in 2016, compared to 580 mboe per day in 2015, and 546 mboe per day in 2014. Entitlement production in 2016 was up by 2% due to the increased equity production as described above and a relatively lower effect from production sharing agreements (PSA effect), mainly driven by the decrease in prices. The increase from 2014 to 2015 was driven by lower PSA effect. The PSA effect was 109 mboe, 116 mboe and 157 mboe per day in 2016, 2015 and 2014, respectively.

Over time, the volumes lifted and sold will equal our entitlement production, but they may be higher or lower in any period due to differences between the capacity and timing of the vessels lifting our volumes and the actual entitlement production during the period. See section 5.6 Terms and abbreviations for more information.

Income statement under IFRS (in USD million)	For the year ended 31 December 2016	2015	2014	16-15 change	15-14 change
Revenues	**6,623**	7,135	12,823	(7%)	(44%)
Net income from equity accounted investments	**(100)**	(91)	(113)	(10%)	20%
Other income	**134**	1,156	951	(88%)	22%
Total revenues and other income	**6,657**	8,200	13,661	(19%)	(40%)
Purchases [net of inventory]	**(7)**	(10)	(2)	(28%)	>100%
Operating expenses and selling, general and administrative expenses	**(2,923)**	(3,391)	(3,654)	(14%)	(7%)
Depreciation, amortisation and net impairment losses	**(5,510)**	(10,231)	(8,885)	(46%)	15%
Exploration expenses	**(2,569)**	(3,296)	(3,824)	(22%)	(14%)
Net operating income	**(4,352)**	(8,729)	(2,703)	50%	>(100%)

DPI generated **total revenues and other income** of USD 6,657 million in 2016 compared to USD 8,200 million in 2015 and USD 13,661 million in 2014.

Revenues in 2016 were negatively impacted by lower realised liquids and gas prices, partly offset by lower provisions relating to commercial disputes in 2016 compared to 2015. The decrease from 2014 to 2015 was mainly caused by lower realised liquids and gas prices, partly offset by an increase in lifted volumes. In addition, higher provisions relating to commercial disputes in 2015 compared to 2014 negatively impacted revenues. For information related to the disputes see note 23 Other commitments and contingencies to the Consolidated financial statements.

Other income was positively impacted by gains from sales of assets of USD 1,156 million in 2015 and USD 961 million in 2014, related primarily to the sale of ownership interest in the Shah Deniz project and the South Caucasus Pipeline.

As a result of the factors explained above, **total revenues and other income** decreased by 19% in 2016. In 2015, total revenues and other income decreased by 40%.

Operating expenses and selling, general and administrative expenses were USD 2,923 million in 2016, compared to USD 3,391 million in 2015 and USD 3,654 million in 2014. The 14% decrease from 2015 to 2016 was mainly due to lower operating and maintenance costs for various fields, in addition to lower diluent expenses. The decreases were partially offset by operating and transportation costs for the new fields coming on stream. The 7% decrease from 2014 to 2015 was mainly due to reduced operations and maintenance costs, lower royalties caused by lower prices, and portfolio changes. Production ramp-up and start-up of new fields partially offset the decrease.

Depreciation, amortisation and net impairment losses were USD 5,510 million in 2016, compared to USD 10,231 million in 2015 and USD 8,885 million in 2014. The 46% decrease was primarily caused by lower net impairment losses in 2016 compared to 2015. Net impairment losses amounted to USD 541 million in 2016, and resulted mainly from reduced long-term price assumptions with the largest effect being on the unconventional onshore assets in North America. In addition, depreciations decreased due to higher reserves estimates. The decreases were partially offset by start-up and ramp-up of production from new fields.

The 15% increase from 2014 to 2015 was primarily caused by net impairment losses of USD 5,416 million in 2015, mainly related to unconventional onshore assets in North America and certain conventional upstream assets. The impairment losses resulted primarily from reduced short-term forward prices in combination with reduced long-term oil price forecasts. In addition, depreciation increased due to higher production from start-up and ramp-up on various fields. The increases were partly offset by effect on depreciations from net impairments in 2014 and 2015 and reduced depreciations from higher reserves estimates.

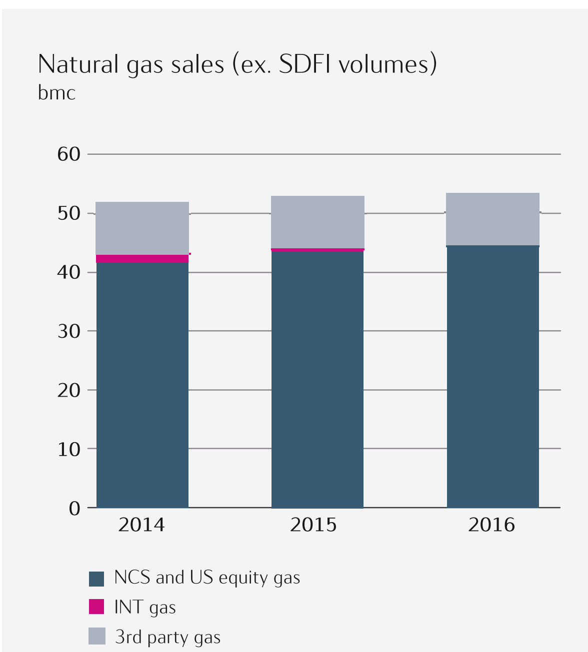
Exploration expenses were USD 2,569 million in 2016, compared to USD 3,296 million in 2015 and USD 3,824 million in 2014. The 22% reduction from 2015 to 2016 was primarily due to lower impairments, lower drilling activity and lower well costs in 2016. Higher portion of wells capitalised in previous periods being expensed this year and a lower capitalisation rate in 2016 partially offset the decrease. The reduction from 2014 to 2015 was mainly due to lower drilling activity partly offset by increased impairments of oil and gas prospects in the Gulf of Mexico.

MMP profit and loss analysis

Net operating income was USD 623 million, USD 2,931 million and USD 2,608 million in 2016, 2015 and 2014, respectively. 2016 net operating income was positively impacted by solid liquids trading results as in 2015. The decrease of USD 2,308 million from 2015 to 2016 was mainly due to lower fair value of certain derivatives of USD 713 million as a result of increased forward curve. In addition, refining and gas marketing margins were reduced and production from processing plants lower than in 2015.

The increase of USD 324 million from 2014 to 2015 was mainly due to higher refining margins and solid liquids trading results and net reversal of impairment charges of USD 421 million. These increases were partially offset by the impact by Sonatrach Arbitration Settlement of USD 463 million in Statoil's favour in 2014.

Total natural gas sales volumes were 52.9 bcm in 2016, 52.6 bcm in 2015 and 51.2 bcm in 2014. The 0.5% increase in total gas volumes sold from 2015 to 2016 was related to higher entitlement production on the NCS, partially offset by lower entitlement production internationally. The 3% increase in total gas volumes sold from 2014 to 2015 was related to higher entitlement production on the NCS in addition to higher third party volumes in Europe, partially offset by lower entitlement production internationally and lower third party volumes in the US. The chart does not include any volumes sold on behalf of the Norwegian State's direct financial interest (SDFI).

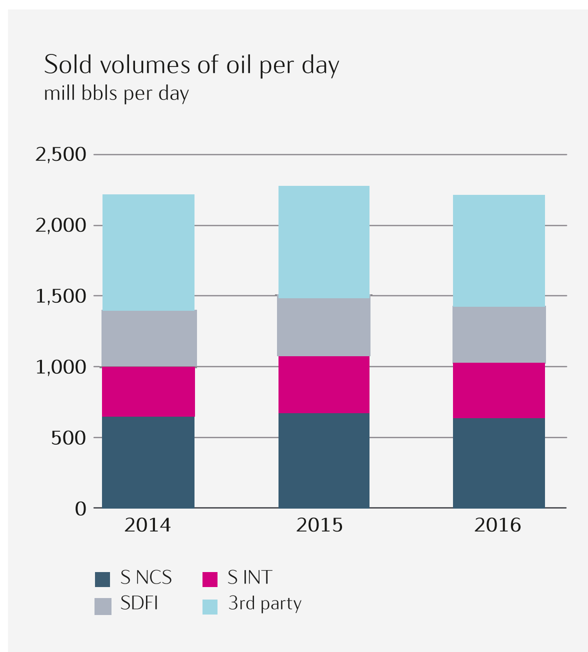


In 2016, the average invoiced natural gas sales price in Europe was USD 5.17 per MMBtu compared to USD 7.08 per MMBtu in 2015, a decrease of 27%. Abundant gas supply in the first three quarters together with a mild winter had a negative influence on the prices. For the fourth quarter the market situation tightened and prices increased. LNG price has continued its downward trend, and only had a marginal positive effect on the European gas price in 2016. The average invoiced natural gas sales price in Europe was approximately 26% lower in 2015 than in 2014, mainly due to higher share of gas indexation in the gas contract portfolio.

In 2016, the average invoiced natural gas sales price in North Americas was USD 2.12 per MMBtu compared to USD 2.62 per MMBtu in 2015, a decrease of 19% due to significantly warmer weather first quarter 2016 than in 2015, and an abundant gas supply in the second quarter. In the third and fourth quarter prices rose due to cooler weather in New York and Toronto. The average invoiced natural gas sales price in North Americas was approximately 40% lower in 2015 than in 2014, mainly due to high market prices in first quarter 2014 as a result of exceptionally cold weather in North East combined with long term pipeline capacity agreements enabling access to premium markets in Toronto and Manhattan.

All of Statoil's gas produced on the NCS is sold by MMP, purchased from DPN at the fields' lifting point at a market-based internal price with deduction for the cost of bringing gas from the field to market and a marketing fee element. Our average internal purchase price for gas was USD 3.42 per MMBtu in 2016, a decrease of 34% compared to USD 5.17 per MMBtu in 2015.

Average crude, condensate and NGL sales were 2.2 mmbbl per day in 2016 of which approximately 1.01 mmbbl were sales of our equity volumes, 0.80 mmbbl sales of third-party volumes and 0.40 mmbbl sales of volumes purchased from SDFI. Our average sales volumes were 2.3 and 2.2 mmbbl per day in 2015 and 2014. The average daily third-party volumes sold were 0.79 and 0.83 mmbbl in 2015 and 2014.



MMPs refining margins were considerably lower the first three quarters 2016 compared to 2015, and results were impacted by lower production from the refineries. The average refining margin was at the same level in fourth quarter 2015 and 2016. Statoil's refining reference margin was 4.8 USD/bbl in 2016, compared to 8.0 USD/bbl in 2015, a decrease of 40%. The refining reference margin was 4.7 USD/bbl in 2014.

Income statement under IFRS (in USD million)	For the year ended 31 December 2016	2015	2014	16-15 change	15-14 change
Revenues	**44,847**	57,873	94,483	(23%)	(39%)
Net income from equity accounted investments	**61**	55	73	12%	(25%)
Other income	**72**	178	615	(60%)	(71%)
Total revenues and other income	**44,979**	58,106	95,171	(23%)	(39%)
Purchases [net of inventory]	**(39,696)**	(50,547)	(86,689)	(21%)	(42%)
Operating expenses and selling, general and administrative expenses	**(4,439)**	(4,664)	(5,287)	(5%)	(12%)
Depreciation, amortisation and net impairment losses	**(221)**	37	(583)	>(100%)	>(100%)
Net operating income	**623**	2,931	2,608	(79%)	12%

Total revenues and other income were USD 44,979 million in 2016, compared to USD 58,106 million in 2015 and USD 95,171 million in 2014.

The decrease in **revenues** from 2015 to 2016 was mainly due to decrease in crude and gas prices. The average crude price in USD declined by approximately 17% in 2016 compared to 2015. Revenues in 2016 were negatively impacted by loss from derivatives mainly related to hedges of physical positions due to significant increase in the forward curve in the oil and gas market.

The decrease in revenues from 2014 to 2015 was mainly due to decrease in crude and gas prices, partially offset by higher volumes for crude, other oil products and gas sold. The average crude price in USD declined by approximately 47% in 2015 compared to 2014. Revenues in 2015 were positively impacted by gains from derivatives, mainly due to significant drop in the forward curve in the oil and gas market.

Other income in 2016 was positively impacted by gain on sale of assets of USD 72 million. In 2015, other income was positively impacted by gain on sale of assets of USD 178 million.

As a result of the factors explained above, **total revenues and other income** decreased by 23% and 39% in 2016 and 2015, respectively.

Purchases [net of inventory] were USD 39,696 million in 2016, compared to USD 50,547 million in 2015 and USD 86,689 million in 2014. The decrease from 2015 to 2016 was mainly due to decrease in crude and gas prices. The decrease from 2014 to 2015 was mainly due to decrease in gas and crude prices and lower volumes of crude, other oil products and gas sold.

Operating expenses and selling, general and administrative expenses were USD 4,439 million in 2016, compared to USD 4,664 million in 2015 and USD 5,287 million in 2014. The decrease from 2015 to 2016 was mainly due to lower transportation cost and the ongoing cost reduction initiatives in 2016.

The decrease from 2014 to 2015 was mainly due to the ongoing cost reduction initiatives and a positive USD/NOK currency effect added to the decrease of USD 622 million.

Depreciation, amortisation and net impairment losses amounted to a loss of USD 221 million in 2016, compared to an income of USD 37 million in 2015 and a loss of USD 583 million in 2014. The increase in depreciation, amortisation and net impairment losses from 2015 to 2016 was mainly caused by lower reversal of impairments in 2016 compared to 2015. Net reversal of impairments in 2016 was mainly related to a refinery asset, impacted by expected lower cost base in the future cash flows. The decrease in depreciation, amortisation and net impairment losses from 2014 to 2015 was mainly caused by net reversal of impairment charges of USD 421 million in 2015 triggered by increased refinery margins and operational improvement.

Other operations

The Other reporting segment includes activities within New Energy Solutions; Global Strategy and Business Development; Technology, Projects and Drilling; and Corporate staffs and support functions.

In 2016, the Other reporting segment recorded a net operating loss of USD 423 million compared to a net operating loss of USD 129 million in 2015 and a net operating loss of USD 199 million in 2014.

2.9 LIQUIDITY AND CAPITAL RESOURCES

REVIEW OF CASH FLOWS

Statoil`s cash flows in 2016 reflect a solid cash flow in a low price environment.

CONSOLIDATED STATEMENT OF CASH FLOWS

(in USD million)	Note	2016	Full year 2015	2014
Income before tax		(178)	55	17,898
Depreciation, amortisation and net impairment losses	10, 11	11,550	16,715	15,925
Exploration expenditures written off	11	1,800	2,164	2,097
(Gains) losses on foreign currency transactions and balances		(137)	1,166	883
(Gains) losses on sales of assets and businesses	4	(110)	(1,716)	(1,998)
(Increase) decrease in other items related to operating activities		1,076	558	(1,671)
(Increase) decrease in net derivative financial instruments	25	1,307	1,551	254
Interest received		280	363	341
Interest paid		(548)	(443)	(551)
Cash flows provided by operating activities before taxes paid and working capital items		15,040	20,414	33,178
Taxes paid		(4,386)	(8,078)	(15,308)
(Increase) decrease in working capital		(1,620)	1,292	2,335
Cash flows provided by operating activities		9,034	13,628	20,205
Additions through business combinations	4	0	(398)	0
Capital expenditures and investments		(12,191)	(15,518)	(19,497)
(Increase) decrease in financial investments		877	(2,813)	(1,919)
(Increase) decrease in other non-current items		107	(22)	128
Proceeds from sale of assets and businesses	4	761	4,249	3,514
Cash flows used in investing activities		(10,446)	(14,501)	(17,775)
New finance debt	18	1,322	4,272	3,010
Repayment of finance debt		(1,072)	(1,464)	(1,537)
Dividend paid	17	(1,876)	(2,836)	(5,499)
Net current finance debt and other		(333)	(701)	(2)
Cash flows provided by (used in) financing activities		(1,959)	(729)	(4,028)
Net increase (decrease) in cash and cash equivalents		(3,371)	(1,602)	(1,598)
Effect of exchange rate changes on cash and cash equivalents		(152)	(871)	(1,329)
Cash and cash equivalents at the beginning of the period (net of overdraft)	16	8,613	11,085	14,013
Cash and cash equivalents at the end of the period (net of overdraft)	16	5,090	8,613	11,085

Cash flows provided by operations
The most significant drivers of cash flows provided by operations were the level of production and prices for liquids and natural gas that impact revenues, purchases [net of inventory], taxes paid and changes in working capital items.

Cash flows provided by operating activities were reduced by USD 4,594 million compared to the full year 2015. The decrease was mainly due to reduced liquids and gas prices, partially offset by lower taxes paid.

Cash flows provided by operating activities were USD 13,628 million in 2015 compared to USD 20,205 million in 2014, which is a decrease of USD 6,577 million driven by a significant reduction in both liquids and gas prices. The decrease was partially offset by positive changes in working capital and lower taxes paid in 2015 compared to 2014.

Cash flows used in investing activities
Cash flows used in investing were reduced by USD 4,055 million compared to the full year 2015. The decrease was due to significantly lower capital expenditures, lower financial investments and reduced proceeds from sale of assets.

Cash flows used in investing activities were USD 14,501 million in 2015 compared to USD 17,775 million in 2014, a decrease of USD 3,274 million mainly due to reduced capital expenditures. The proceeds from sale of assets in 2015 of USD 4,249 million were mainly related to the divestment of the remaining interests in the Shah Deniz field and the South Caucasus pipeline, sale of office buildings, sale of interest in the Marcellus onshore play, sale of interests in Trans Adriatic pipeline AG and the sale of interests in licenses on the NCS.

Cash flows provided by (used in) financing activities
Cash flows used in financing activities increased by USD 1,230 million compared to the full year 2015. The change is mainly due to reduced cash flow from finance debt, partially offset by reduced cash dividend due to the scrip dividend.

Cash flows used in financing activities were USD 729 million in 2015 and were mainly related to payments of dividends USD 2,836 million and repayments of debt USD 1,464 million, partially offset by issuance of new debt of USD 4,272 million. Cash flows used in financing activities were USD 4,028 million in 2014 and were mainly related to payments of dividends and repayments of debt, partly offset by issuance of new debt in November 2014 of USD 3,010 million.

FINANCIAL ASSETS AND DEBT

Statoil's financial position is strong although its net debt to capital employed ratio before adjustments at year end increased from 25.6% in 2015 to 34.4% in 2016. See section 5.2 for non-GAAP measures for net debt ratio. Net interest-bearing debt increased from USD 13.9 billion to USD 18.4 billion. During 2016 Statoil's total equity decreased from USD 40.3 billion to USD 35.1billion, mainly due to impairments recognised in 2016 and dividend paid. Cash flows provided by operating activities were reduced in 2016 mainly due to lower prices. Cash flows used in investing activities reduced in 2016. Statoil has paid out four quarterly dividends in 2016. For the fourth quarter of 2016 the board of directors will propose to the annual general meeting (AGM) to maintain a dividend of USD 0.2201 per share and to maintain the scrip dividend program initiated from the fourth quarter 2015. For details, see note 17 Shareholders equity and dividends to the Consolidated financial statements.

Statoil believes that, given its current liquidity reserves, including committed credit facilities of USD 5.0 billion and its access to various capital markets, Statoil has sufficient funds available to meet its liquidity needs, including working capital.

Funding needs arise as a result of Statoil's general business activities. Statoil generally seeks to establish financing at the corporate (top company) level. Project financing may also be used in cases involving joint ventures with other companies. Statoil aims to have access at all times to a variety of funding sources in respect of markets and instruments; as well as maintaining relationships with a core group of international banks that provide a wide range of banking services.

Moody's and Standard & Poor's (S&P) provide credit ratings on Statoil. Statoil's current long-term ratings are A+ and Aa3 from S&P and Moody's, respectively. The rating from S&P was revised from AA- credit watch negative to A+ with a stable outlook on 22 February 2016 while the rating from Moody's was revised from Aa2 on review for downgrade to Aa3 with stable outlook on 21 March 2016. Both rating agency revisions were triggered by the low commodity price environment, and similar downgrades were seen across the sector around that time. The short-term ratings are P-1 from Moody's and A-1 from S&P. In order to maintain financial flexibility going forward, Statoil intend to keep key financial ratios at levels consistent with our objective of maintaining Statoil's long-term credit rating at least within the single A category on a stand-alone basis.

The management of financial assets and liabilities takes into consideration funding sources, the maturity profile of non-current debt, interest rate risk, currency risk and available liquid assets. Statoil's borrowings are denominated in various currencies and normally swapped into USD. In addition, interest rate derivatives, primarily interest rate swaps, are used to manage the interest rate risk of our long-term debt portfolio. The Group's Capital Markets unit manages the funding and liquidity activities at Group level.

Statoil has diversified its cash investments across a range of financial instruments and counterparties to avoid concentrating risk in any one type of investment or any single country. As of 31 December 2016, approximately 7% of Statoil's liquid assets were held in USD-denominated assets, 21% in NOK, 58% in EUR, 5% in DKK and 9% in SEK, before the effect of currency swaps and forward contracts. Approximately 56% of Statoil's liquid assets were held in treasury bills and commercial paper, 42% in time deposits, 1% in money market funds and 1% at in bank deposits. As of 31 December 2016, approximately 4.7% of Statoil's liquid assets were classified as restricted cash (including collateral deposits).

Statoil's general policy is to keep a liquidity reserve in the form of cash and cash equivalents or other current financial investments in Statoil's balance sheet, as well as committed, unused credit facilities and credit lines in order to ensure that Statoil has sufficient financial resources to meet short-term requirements.

Long-term funding is raised when a need is identified for such financing based on Statoil's business activities, cash flows and required financial flexibility or when market conditions are considered to be favourable.

The Group's borrowing needs are usually covered through the issuance of short-, medium- and long-term securities, including utilisation of a US Commercial Paper Programme (programme limit USD 5.0 billion) and a Shelf Registration Statement (unlimited) filed with the Securities and Exchange Commission (SEC) in the USA as well as through issues under a Euro Medium-Term Note (EMTN) Programme (updated 28 October 2016 with a limit of EUR 20.0 billion) listed on the London Stock Exchange. Committed credit facilities and credit lines may also be utilised. After the effect of currency swaps, the major part of Statoil's borrowings is in USD.

During 2016, Statoil issued bonds with 10 and 20 year maturities for a total amount of EUR 1.2 billion (USD 1.3 billion). All the bonds are unconditionally guaranteed by Statoil Petroleum AS. For more information, see note 18 Finance debt to the Consolidated financial statements.

Statoil issued new debt securities in 2015 equivalent to USD 4.3 billion and in 2014 equivalent to USD 3.0 billion.

Financial indicators

Financial indicators (in USD million)	For the year ended 31 December 2016	2015	2014
Gross interest-bearing financial liabilities [1]	**31,673**	32,291	31,154
Net interest-bearing liabilities before adjustments	**18,372**	13,852	12,004
Net debt to capital employed ratio [2]	**34.4%**	25.6%	19.0%
Net debt to capital employed ratio adjusted [3]	**35.6%**	26.8%	20.0%
Cash and cash equivalents	**5,090**	8,623	11,182
Current financial investments	**8,211**	9,817	7,968
ROACE [4]	**(8.0%)**	2.7%	11.3%
Ratio of earnings to fixed charges [5]	**0.9**	1.0	7.0

1) Defined as non-current and current finance debt.

2) As calculated according to IFRS. Net debt to capital employed ratio is the net debt divided by capital employed. Net debt is interest-bearing debt less cash and cash equivalents and current financial investments. Capital employed is net debt, shareholders' equity and minority interest.

3) In order to calculate the net debt to capital employed ratio adjusted, Statoil makes adjustments to capital employed as it would be reported under IFRS. Restricted funds held as financial investments in Statoil Forsikting AS and Collateral deposits has been added to the net debt whilst the SDFI part of the financial lease in the Snøhvit vessel has been taken out of the net debt. See section 5.2 Net debt to capital employed ratio for a reconciliation of capital employed and a description of why Statoil considers this measure to be useful.

4) ROACE is equal to net income adjusted for financial items after tax, divided by average capital employed over the last 12 months. See section 5.2 Return on average capital employed (ROACE) for a reconciliation of ROACE and a description of why Statoil considers this measure to be useful.

5) Based on IFRS. For the purpose of these ratios, earnings consist of the income before (i) tax, (ii) minority interest, (iii) amortisation of capitalised interest and (iv) fixed charges (which have been adjusted for capitalised interest) and after adjustment for unremitted earnings from equity accounted entities. Fixed charges consist of interest (including capitalised interest) and estimated interest within operating leases.

Gross interest-bearing debt

Gross interest-bearing debt was USD 31.7 billion, USD 32.3 billion and USD 31.2 billion at 31 December 2016, 2015 and 2014, respectively. The USD 0.6 billion net decrease from 2015 to 2016 was due to a decrease in non-current finance debt of USD 2.0 billion, offset by an increase in current finance debt of USD 1.4 billion. The USD 1.1 billion increase from 2014 to 2015 was due to an increase in non-current finance debt of USD 2.4 billion offset by a decrease in current finance debt of USD 1.3 billion. Our weighted average annual interest rate was 3.41%, 3.39% and 3.78% at 31 December 2016, 2015 and 2014, respectively. Statoil's weighted average maturity on finance debt was nine years at 31 December 2016, nine years at 31 December 2015 and nine years at 31 December 2014.

Net interest-bearing debt

Net interest-bearing debt before adjustments were USD 18.4 billion, USD 13.9 billion and USD 12.0 billion at 31 December 2016, 2015 and 2014, respectively. The increase of USD 4.5 billion from 2015 to 2016 was mainly related to a decrease in cash and cash equivalents of USD 3.5 billion, a decrease of current financial investments of USD 1.6 billion offset by a USD 0.6 billion decrease in gross interest-bearing debt. Negative cash flow in 2016 is the main reason. The increase of USD1.8 billion from 2014 to 2015 was related to an increase in gross interest-bearing debt of USD 1.1 billion offset and a decrease in cash and cash equivalents and current financial investments of USD 0.7 billion.

The net debt to capital employed ratio

The net debt to capital employed ratio before adjustments was 34.4%, 25.6% and 19.0% in 2016, 2015 and 2014 respectively.

The net debt to capital employed ratio adjusted (non-GAAP financial measure, see footnote three above) was 35.6%, 26.8% and 20.0% in 2016, 2015, and 2014, respectively.

The 8.8 percentage points increase in net debt to capital employed ratio before adjustments from 2015 to 2016 was related to the increase in net interest-bearing debt adjusted of USD 4.5 billion in combination with a decrease in capital employed adjusted of USD 0.7 billion. The 6.6 percentage points increase in net debt to capital employed ratio before adjustments from 2014 to 2015 was related to an increase in net interest-bearing debt adjusted of USD 1.8

billion in combination with a decrease in capital employed adjusted of USD 9.1 billion.

The 8.8 percentage points increase in net debt to capital employed ratio adjusted from 2015 to 2016 was related to the increase in net interest-bearing debt adjusted of USD 4.6 billion in combination with a decrease in capital employed adjusted of USD 0.6 billion. The 6.8 percentage points increase in net debt to capital employed ratio adjusted from 2014 to 2015 was related to an increase in net interest-bearing debt adjusted of USD 1.9 billion in combination with a decrease in capital employed adjusted of USD 9.1 billion.

Cash, cash equivalents and current financial investments
Cash and cash equivalents were USD 5.1 billion, USD 8.6 billion and USD 11.2 billion at 31 December 2016, 2015 and 2014 respectively. See note 16 Cash and cash equivalents to the Consolidated financial statements for information concerning restricted cash. Current financial investments, which are part of Statoil's liquidity management, amounted to USD 8.2 billion, USD 9.8 billion and USD 8.0 billion at 31 December 2016, 2015 and 2014, respectively.

INVESTMENTS

In 2016, capital expenditures, defined as additions to property, plant and equipment (including capitalised financial leases), capitalised exploration expenditures, intangible assets, long-term share investments and investments in equity accounted companies, amounted to USD 14.1 billion, of which USD 10.1 billion were organic capital expenditures (excluding acquisitions, capital leases and other investments with significant different cash flow pattern). Among items excluded from the organic capital expenditure in 2016 were investment in ownership in Lundin Petroleum AB, acquisition of a 66% operated interest in the offshore licence BM-S-8 in Brazil and acquisition of a 50% stake in the Arkona offshore wind farm in Germany.

In 2015, capital expenditures were USD 15.5 billion, of which organic capital expenditures amounted to USD 14.7 billion.

In Norway, a substantial proportion of our 2017 capital expenditures will be spent on ongoing development projects such as Johan Sverdrup, Gina Krog and Aasta Hansteen, in addition to various extensions, modifications and improvements on currently producing fields like Gullfaks, Oseberg and Troll.

Internationally, we currently estimate that a substantial proportion of our 2017 capital expenditure will be spent on the following ongoing and planned development projects: Mariner in UK, Peregrino in Brazil, Stampede and onshore activity in the US.

In the area of renewable energy, a substantial proportion of our 2017 capital expenditure is expected to be spent on the following offshore wind projects: Arkona in Germany and Hywind in the UK.

Statoil finances its capital expenditures both internally and externally. For more information, see Financial assets and debt earlier in this section.

As illustrated in Principal contractual obligations later in this section, Statoil have committed to certain investments in the future. The further into the future, the more flexibility we will have to revise expenditure. This flexibility is partly dependent on the expenditure our partners in joint ventures agree to commit to. A large part of the capital expenditure for 2017 is committed.

Statoil may alter the amount, timing or segmental or project allocation of our capital expenditures in anticipation of or as a result of a number of factors outside our control.

IMPACT OF REDUCED PRICES

Our results are affected by the development in the price of raw materials and services that are necessary for the development and operation of oil and gas producing assets.

Cost development in the prices of goods, raw materials and services that are necessary for the development and operation of oil and gas producing assets can vary considerably over time and between each market segment.

Prices in supplier markets have been reduced and in several supplier market segments Statoil has achieved reduced rates compared to the 2014/2015 level. Such savings have been achieved both in new and renegotiated contracts.

See the analysis of profit and loss in section 2.8 Operating and financial performance as well section 2.1 Group Outlook.

PRINCIPAL CONTRACTUAL OBLIGATIONS

The table summarises our principal obligations and includes contractual obligations, but excludes derivatives and other hedging instruments as well as asset retirement obligations, as these obligations for the most part are expected to lead to cash disbursements more than five years in the future. Obligations payable by Statoil to unconsolidated equity affiliates are included gross in the table. Where Statoil includes both an ownership interest and the transport capacity cost for a pipeline in the consolidated accounts, the amounts in the table include the transport commitments that exceed Statoil's ownership share. See Disclosures about market risk in section 2.10 Risk review for more information.

Contractual obligations (in USD million)	As at 31 December 2016 Payment due by period [1] Less than 1 year	1-3 years	3-5 years	More than 5 years	Total
Undiscounted non-current finance debt	3,554	4,641	9,133	23,822	41,151
Minimum operating lease payments	1,993	2,693	1,657	2,306	8,649
Nominal minimum other long-term commitments[2]	1,483	2,657	2,200	5,513	11,853
Total contractual obligations	7,030	9,992	12,990	31,642	61,653

1) "Less than 1 year" represents 2016; "1-3 years" represents 2017 and 2018, "3-5 years" represents 2019 and 2020, while "More than 5 years" includes amounts for later periods.

2) For further information see note 23 Other commitments and contingencies to the Consolidated financial statements.

Non-current finance debt in the table represents principal payment obligations. For information on interest commitments relating to long-term debt, reference is made to note 18 Finance debt and note 22 Leases to the Consolidated financial statements.

Statoil had contractual commitments of USD 6,889 million at 31 December 2016. The contractual commitments reflect Statoil's share and mainly comprise construction and acquisition of property, plant and equipment.

Statoil's projected pension benefit obligation was USD 7,791 million, and the fair value of plan assets amounted to USD 5,250 million as of 31 December 2016. Company contributions are mainly related to employees in Norway. See note 19 Pensions to the Consolidated financial statements for more information.

OFF BALANCE SHEET ARRANGEMENTS

Statoil is party to various agreements, such as operational leases and transportation and processing capacity contracts, that are not recognised in the balance sheet. For more information, see Principal contractual obligations in section 2.9 Liquidity and capital resources, and note 22 Leases to the Consolidated financial statements. Statoil is also party to certain guarantees, commitments and contingencies that, pursuant to IFRS, are not necessarily recognised in the balance sheet as liabilities. See note 23 Other commitments and contingencies to the Consolidated financial statements for more information.

2.10 RISK REVIEW

Statoil's overall risk management includes identifying, evaluating and managing risk in all its activities to ensure safe operations and to achieve Statoil's corporate goals.

RISK FACTORS

Statoil is exposed to a number of risks that could affect its operational and financial performance. In this section, some of the key risk factors are addressed.

Risks related to our business

This section describes the most significant potential risks relating to Statoil's business:

A prolonged period of low oil and/or natural gas prices would have a material adverse effect on Statoil

The prices of oil and natural gas have fluctuated greatly in response to changes in many factors. We have experienced a situation where oil and natural gas prices declined substantially compared to levels seen over the last few years. There are several reasons for this decline, but fundamental market forces beyond the control of Statoil or other similar market participants have impacted and can continue to impact oil and natural gas prices in the future. Recently, as a consequence of agreements within Opec and also between Opec and some non-Opec countries, oil prices have increased due to expectations of an earlier tightening of market balances. However, the uncertainty about future developments still prevails.

Generally, Statoil does not and will not have control over the factors that affect the prices of oil and natural gas. These factors include:

- economic and political developments in resource-producing regions
- global and regional supply and demand
- the ability of the Organisation of the Petroleum Exporting Countries (Opec) and/or other producing nations to influence global production levels and prices
- prices of alternative fuels that affect the prices realised under Statoil's long-term gas sales contracts
- government regulations and actions; including changes in energy and climate policies
- global economic conditions
- war or other international conflicts
- changes in population growth and consumer preferences
- the price and availability of new technology and
- weather conditions

It is impossible to predict future price movements for oil and/or natural gas with certainty. A prolonged period of low oil and natural gas prices will adversely affect Statoil's business, the results of operations, financial condition, liquidity and Statoil's ability to finance planned capital expenditure, including possible reductions in capital expenditures which could lead to reduced reserve replacement. In addition to the adverse effect on revenues, margins and profitability from any fall in oil and natural gas prices, a prolonged period of low prices or other indicators could, if deemed to have longer term impact, lead to further reviews for impairment of the group's oil and natural gas properties. Such reviews would reflect the management's view of long-term oil and natural gas prices and could result in a charge for impairment that could have a significant effect on the results of Statoil's operations in the period in which it occurs. Changes in management's view on long-term oil and/or natural gas prices or further material reductions in oil, gas and/or product prices could have an adverse impact on the economic viability of projects that are planned or in development.

Statoil's crude oil and natural gas reserves are only estimates and Statoil's future production, revenues and expenditures with respect to its reserves may differ materially from these estimates.

The reliability of proved reserve estimates depends on:

- the quality and quantity of Statoil's geological, technical and economic data
- the production performance of Statoil's reservoirs
- extensive engineering judgments and
- whether the prevailing tax rules and other government regulations, contracts and oil, gas and other prices will remain the same as on the date estimates are made

Proved reserves are calculated based on the U.S. Securities and Exchange Commission (SEC) requirements and may therefore differ substantially from Statoil's view on expected reserves.

Many of the factors, assumptions and variables involved in estimating reserves are beyond Statoil's control and may prove to be incorrect over time. The results of drilling, testing and production after the date of the estimates may require substantial upward or downward revisions in Statoil's reserve data. The prices used for proved reserves are defined by the SEC and are calculated based on a 12 month un-weighted arithmetic average of the first-day-of-the-month price for each month during the reporting year, leading to a forward price strongly linked to last year's price environment. Fluctuations in oil and gas prices will have a direct impact on Statoil's proved reserves. For fields governed by production sharing agreements (PSAs), a lower price may lead to higher entitlement to the production and increased reserves for those fields. Adversely, a lower price environment may also lead to lower activity resulting in reduced reserves. For PSAs these two effects may to some degree offset each other. In addition a low price environment may result in earlier shutdown due to uneconomic production. This will affect both PSAs and fields with concession types of agreement.

Statoil is engaged in global exploration activities that involve a number of technical, commercial and country specific risks. General risks are technical risks related to Statoil's ability to conduct its seismic and drilling operations in a safe and efficient manner and to encounter commercially productive oil and gas reservoirs and commercial risks related to Statoil's ability to secure access to new acreage in an uncertain global competitive and political environment and competent personnel to perform exploration activities and mature resources along the value-chain. Country specific risks are related to security threats and compliance with and understanding of local laws or license agreements. These risks may adversely affect Statoil's current operations and financial results, and its long-term replacement of reserves.

If Statoil fails to acquire or discover and develop additional reserves, its reserves and production will decline materially from their current levels

Successful implementation of Statoil's group strategy for value growth is critically dependent on sustaining its long-term reserve replacement. If upstream resources are not progressed to proved reserves in a timely manner, Statoil's reserve base and thereby future production will gradually decline and future revenue will be reduced.

Statoil's future production is highly dependent on its success in acquiring or finding and developing additional reserves adding value. If unsuccessful, future total proved reserves and production will decline.

If the low price environment continues for a substantial time, this may result in undeveloped acreage not being considered economically viable and consequently discovered resources not being matured to reserves. This may also lead to exploration areas not being explored for new resources and subsequently not being matured for development resulting in less future proved reserves.

In a number of resource-rich countries, national oil companies control a significant proportion of oil and gas reserves that remain to be developed. To the extent that national oil companies choose to develop their oil and gas resources without the participation of international oil companies, or if Statoil is unable to develop partnerships with national oil companies, its ability to find and acquire or develop additional reserves will be more limited.

Statoil is exposed to a wide range of health, safety and environmental risks that could result in significant losses.

Exploration, development, production, processing and transportation related to oil and natural gas, as well as development and operation of renewable energy production, can be hazardous. Technical integrity failures, operational failures, natural disasters or other occurrences can result in: loss of life, oil spills, gas leaks, loss of containment of hazardous materials, water contamination, blowouts, cratering, fires and equipment failure, among other things.

The risks associated with Statoil's activities are affected by the difficult geographies, climate zones and environmentally sensitive regions in which Statoil operates. All modes of transportation of hydrocarbons - including road, rail, sea or pipeline - are particularly susceptible to a loss of containment of hydrocarbons and other hazardous materials, and, given the high volumes involved, these could represent a significant risk to people and the environment. Offshore operations and transportation are subject to marine perils, including severe storms and other adverse weather conditions and vessel collisions. Onshore operations and transportation are subject to adverse weather conditions and accidents. Both onshore and offshore operations and transportation are subject to interruptions, restrictions or termination by government authorities based on safety, environmental or other considerations.

Policy and regulatory change due to rising climate change concerns, and the physical effects of climate change, could impact Statoil's business and related costs

The transition to a low-carbon energy future poses fundamental strategic challenges for the oil and gas industry.

Statoil monitors and assesses risks related to climate change, whether political, regulatory, market or physical, including reputation impact.

Statoil expects and is preparing for policy and regulatory changes targeted at reducing greenhouse gas emissions. This could impact Statoil's financial outlook, whether directly through changes in taxation and regulation, or indirectly through changes in consumer behaviour.

There is continuing uncertainty over climate policy developments in various jurisdiction, and hence the long-term implications to costs and constraints. Statoil expects greenhouse gas emission costs to increase from current levels beyond 2020 and to have a wider geographical range than today.

Climate related policy changes may also reduce access to prospective geographical areas for exploration and production in the future.

Regulatory changes encouraging the development of low-carbon energy technologies such as renewable energy or other potentially disruptive technologies, could impact the demand for oil and gas. As an example, development of battery technologies could allow more intermittent renewables to be used in the power sector. This could impact Statoil's gas sales, particularly if subsidies of renewable energy in Europe were to increase.

Statoil has analysed the sensitivity of its project portfolio (equity production and expected production from accessed exploration acreage) against the assumptions regarding commodity and carbon prices in the International Energy Agency's (IEA) energy scenarios, as laid out in their "World Economic Outlook 2016" report. The analysis demonstrated that the IEA's "450 ppm scenario", which is at large compatible with a global warming of maximum of two degrees Celsius with more than 50% probability, could have a positive impact of approximately 6% on Statoil's net present value compared to Statoil's internal planning assumptions as of December 2016. This assessment is based on Statoil's and the IEA's assumptions which may not be accurate and which are likely to develop over time as new information becomes available. Accordingly, there can be no assurance that the assessment, which is presented in Statoil ASA's 2016 Sustainability report, is a reliable indicator of the actual impact of climate change on Statoil.

Changes in physical climate parameters could impact Statoil's operations, for example through restrained water availability, rising sea level, changes in sea currents and increasing frequency of extreme weather events.

Statoil is exposed to risks as a result of its hydraulic fracturing usage

Statoil's US operations use hydraulic fracturing which is subject to a range of applicable federal, state and local laws, including those discussed under the heading "Legal and Regulatory Risks". Fracturing is an important and common practice that is used to stimulate production of crude oil and/or natural gas from dense subsurface rock formations. Statoil's hydraulic fracturing and fluid handling operations are designed and operated to minimise the risk, if any, of subsurface migration of hydraulic fracturing fluids and spillage or mishandling of hydraulic fracturing fluids, however, a proven case of subsurface migration of hydraulic fracturing fluids or a case of spillage or mishandling of hydraulic fracturing fluids during these activities could potentially subject Statoil to civil and/or criminal liability and the possibility of substantial costs, including environmental remediation, depending on the circumstances of the underground migration, spillage, or mishandling, the nature and scope of the underground migration, spillage, or mishandling, and the applicable laws and regulations.

In addition, various states and local governments have implemented, or are considering, increased regulatory oversight of hydraulic fracturing through additional permit requirements, operational restrictions, disclosure requirements and temporary or permanent bans. New or further changes in laws and regulations imposing reporting obligations on, or otherwise banning or limiting, the hydraulic fracturing process could make it more difficult to complete oil and natural gas wells in shale formations, cause operational delays, increase costs of regulatory compliance or in exploration and production, which could adversely affect Statoil's US onshore business and the demand for fracturing services.

Statoil is exposed to security threats that could have a materially adverse effect on Statoil's results of operations and financial condition

Security threats such as acts of terrorism and cyber-attacks against Statoil's production and exploration facilities, offices, pipelines, means of transportation or computer systems or breaches of Statoil's security system, could result in losses. No assurances can be made that such attacks will not occur in the future and adversely impact its operations. Failure to manage the foregoing risks could result in injury or loss of life, damage to the environment, damage to or the destruction of wells and production facilities, pipelines and other property. Statoil could face, among other things, regulatory action, legal liability, damage to its reputation, a significant reduction in revenues, an increase in costs, a shutdown of operations and a loss of its investments in affected areas.

Statoil's crisis management systems may prove inadequate

Statoil has plans and capability to deal with crisis and emergencies at every level of its operations (ie; plant fires, terror, well instability etc). If Statoil does not respond or is perceived not to have responded in an appropriate manner to either an external or internal crisis, or if its plans to carry on or recover operations following a disruption or incident are not effected quickly enough, its business, operations and reputation could be severely affected. Inability to restore or replace critical capacity to an agreed level within an agreed time frame could prolong the impact of any disruption and could severely affect Statoil's business and operations.

Statoil encounters competition from other oil and gas companies in all areas of its operations

Statoil may experience increased competition from larger players with stronger financial resources and smaller ones with increased agility and flexibility. Gaining access to commercial resources via license acquisition, exploration, or development of existing assets is key to ensuring the long-term economic viability of the business and failure to address this could negatively impact future performance.

Technology is a key competitive advantage in Statoil's industry and our competition may be able to invest more in developing or acquiring intellectual property rights to technology that Statoil may require to remain competitive. Should Statoil's innovation and digitalisation lag behind the industry, its performance could be impeded.

Statoil's development projects and production activities involve many uncertainties and operating risks that can prevent Statoil from realising profits and cause substantial losses

Oil and gas projects may be curtailed, delayed or cancelled for many reasons, including equipment shortages or failures, natural hazards, unexpected drilling conditions or reservoir characteristics, irregularities in geological formations, accidents, mechanical and technical difficulties or challenges due to new technology. This is particularly relevant because of the physical environments in which some of Statoil's projects are situated. Many of Statoil's development and production projects are located in deep waters or other harsh environments or have challenging field characteristics. In US onshore, low regional prices may cause certain areas to be unprofitable and the company may curtail production until prices recover. There is therefore a risk that prolonged low oil and gas prices, combined with the relatively high levels of tax and government take in several jurisdictions, could erode the profitability of some of Statoil's projects.

Statoil faces challenges in achieving its strategic objective of successfully exploiting profitable growth opportunities

Statoil intends to continue to nurture attractive commercial opportunities in order to sustain future growth. This may involve acquisition of new businesses or properties to expand the existing portfolio or to move into new markets. This challenge will grow as global competition for access to new opportunities rises.

Statoil's ability to increase this optionality depends on several factors; including the ability to:

- maintain and impart Statoil's zero-harm safety culture
- identify suitable opportunities
- negotiate favourable terms
- develop new market opportunities or acquire properties or businesses in an agile and efficient way
- effectively integrate acquired properties or businesses into Statoil's operations
- arrange financing, if necessary and
- comply with legal regulations

Statoil anticipates significant investments and costs as it cultivates business opportunities in new and existing markets, and this process may incur or assume unanticipated liabilities, losses or costs associated with assets or businesses acquired. Failure by Statoil to successfully pursue and exploit new business opportunities could result in financial losses and inhibit growth. New projects may have different risk profiles than Statoil's existing portfolio. These and other effects of such acquisitions could result in Statoil having to revise its forecasts either or both with respect to unit production costs and production.

In addition, the pursuit of acquisitions or new business opportunities could divert financial and management resources away from Statoil's day-to-day operations to the integration of acquired operations or properties. Statoil may require additional debt or equity financing to undertake or consummate future acquisitions or projects, and such financing may not be available on terms satisfactory to Statoil, if at all, and it may, in the case of equity, be dilutive to Statoil's earnings per share.

The profitability of Statoil's oil and gas production may be affected by limited transportation infrastructure when a field is in a remote location

Statoil's ability to exploit economically any discovered petroleum resources beyond its proved reserves will depend, among other factors, on the availability of the infrastructure required to transport oil and gas to potential buyers at a commercially acceptable price. Oil is transported by vessels, rail or pipelines to refineries, and natural gas is usually transported by pipeline or by vessels (for liquid natural gas) to processing plants and end users. Statoil may not be successful in its efforts to secure transportation and markets for all of its potential production.

Statoil is exposed to security threats on its information systems and digital infrastructure that could harm its assets and operations
Statoil's security barriers are intended to protect its information systems and digital infrastructure from being compromised by unauthorised parties. Failure to maintain and develop these barriers may affect the confidentiality, integrity and availability of its information systems and digital infrastructure, including those critical to Statoil's operations. Threats to Statoil's information systems could result in significant financial damage to Statoil. Threats to Statoil's industrial control systems are not limited by geography as Statoil's digital infrastructure is accessible globally, and incidents in the industry in recent years have shown that parties who are able to circumvent barriers aimed at securing industrial control systems are capable and willing to perform attacks that destroy, disrupt or otherwise compromise operations. Such attacks could result in material losses or loss of life with consequent financial implications.

Some of Statoil's international interests are located in regions where political, social and economic instability could adversely impact Statoil's business
Statoil has assets and operations located in diverse regions globally where potentially negative economic, social, and political developments could occur. These political risks and security threats require continuous monitoring. Adverse and hostile actions against Statoil's staff, its facilities, its transportation systems and its digital infrastructure (cybersecurity) may cause harm to people and disrupt Statoil's operations and further business opportunities in these or other regions, lead to a decline in production and otherwise adversely affect Statoil's business. This could have a materially adverse effect on Statoil's operations' results and its financial condition.

Statoil's operations are subject to dynamic political and legal factors in the countries in which it operates
Statoil has assets in a number of countries with emerging or transitioning economies that, in part or in whole, lack well-functioning and reliable legal systems, where the enforcement of contractual rights is uncertain or where the governmental and regulatory framework is subject to unexpected change. Statoil's exploration and production activities in these countries are often undertaken together with national oil companies and are subject to a significant degree of state control. In recent years, governments and national oil companies in some regions have begun to exercise greater authority and to impose more stringent conditions on companies engaged in exploration and production activities. Intervention by governments in such countries can take a wide variety of forms, including:

- restrictions on exploration, production, imports and exports
- the awarding or denial of exploration and production interests
- the imposition of specific seismic and/or drilling obligations
- price and exchange controls
- tax or royalty increases, including retroactive claims
- nationalisation or expropriation of Statoil's assets
- unilateral cancellation or modification of Statoil's licence or contractual rights
- the renegotiation of contracts
- payment delays and
- currency exchange restrictions or currency devaluation

The likelihood of these occurrences and their overall effect on Statoil vary greatly from country to country and are hard to predict. If such risks materialise, they could cause Statoil to incur material costs and/or cause Statoil's production to decrease, potentially having a materially adverse effect on Statoil's operations or financial condition.

Statoil is exposed to potentially adverse changes in the tax regimes of each jurisdiction in which Statoil operates
Statoil has business operations in many countries around the world. Changes in the tax laws of the countries in which Statoil operates could have a material adverse effect on its liquidity and results of operations.

Statoil faces foreign exchange risks that could adversely affect the results of Statoil's operations
Statoil's business faces foreign exchange risks and this is managed with USD as the base currency. Statoil has a large percentage of its revenues and cash receipts denominated in USD and sales of gas and refined products are mainly denominated in EUR and GBP. Further, Statoil pays a large portion of its income taxes, and a share of our operating expenses and capital expenditures, in NOK. The majority of Statoil's long term debt has USD exposure.

Statoil is exposed to risks relating to trading and supply activities
Statoil is engaged in substantial trading and commercial activities in the physical markets. Statoil also uses financial instruments such as futures, options, over-the-counter (OTC) forward contracts, market swaps and contracts for differences related to crude oil, petroleum products, natural gas and electricity in order to manage price volatility. Statoil also uses financial instruments to manage foreign exchange and interest rate risk. Trading activities involve elements of forecasting, and Statoil bears the risk of market movements, the risk of losses if prices develop contrary to expectations, and the risk of default by counterparties.

Non-compliance with anti-bribery, anti-corruption and other applicable laws, including failure to meet Statoil's ethical requirements, exposes Statoil to legal liability and damage to its reputation, business and shareholder value
Statoil has activities in countries which present corruption risks and which may have weak legal institutions, lack of control and transparency. In addition, governments play a significant role in the oil and gas sector, through ownership of resources, participation, licensing and local content which leads to a high level of interaction with public officials. Statoil is, through its international activities, subject to anti-corruption and bribery laws in multiple jurisdictions, including the Norwegian Penal code, the US Foreign Corrupt Practices Act and the UK Bribery Act. A violation of any applicable anti-corruption and bribery laws could expose Statoil to investigations from multiple authorities, and any violations of laws may lead to criminal and/or civil liability with substantial fines. Incidents of non-compliance with applicable anti-corruption and bribery laws and regulations and the Statoil Code of Conduct could be damaging to Statoil's reputation, competitiveness and shareholder value.

Statoil's insurance coverage may not provide adequate protection
Statoil maintains insurance coverage that includes coverage for physical damage to its oil and gas properties, third-party liability, workers' compensation and employers' liability, general liability, sudden pollution and other coverage. Statoil's insurance coverage includes deductibles that must be met prior to recovery. Statoil's

external insurance is subject to caps, exclusions and limitations, and there is no assurance that such coverage will adequately protect Statoil against liability from all potential consequences and damages.

Statoil's future performance depends on efficient operations and the ability to develop and deploy new technologies and new products
Our ability to remain efficient, to develop and adapt to new technology, to seek profitable renewable energy and other low-carbon energy solutions, are key success factors for future business. There is a possibility of Statoil not being able to define and implement the necessary changes due to the organisation's capability, external competition or underestimated cost of implementing new technology. Any of these factors may have an adverse effect on Statoil's future business goals.

Statoil may fail to secure the right level of workforce competence and capacity over the short and medium term
The uncertainty of the future of the oil industry in light of reduced oil and natural gas prices and climate policy changes, creates a risk in ensuring a robust workforce through industry cycles. The oil industry is a long term business and needs to take a long term perspective on workforce capacity and competence. Given the current extensive change agenda there is a risk that Statoil will fail to secure the right level of workforce competence and capacity.

Statoil's activities may be affected by international sanctions and trade restrictions
Statoil, like other major international energy companies, has a geographically diverse portfolio of reserves and operational sites, which may expose its business and financial affairs to political and economic risks, including operations in areas subject to international restrictions and sanctions.

Legislation and rules governing sanctions and trade restrictions are complex and constantly evolving. Moreover, changes in these laws and regulations can be unpredictable and happen swiftly. In addition, Statoil's business will constantly be subject to change. Accordingly, it should be understood that the below description does not reflect all parts of Statoil's business where sanctions and trade restrictions are relevant, and that Statoil in the future could decide to take part in additional business activity where such laws and regulations are particularly relevant. While Statoil remains committed to doing business in compliance with all applicable sanctions and trade restrictions, there can be no assurance that no Statoil entity, officer, director, employee or agent is not in violation of such laws. Any such violation could result in substantial civil and/or criminal penalties and might materially adversely affect Statoil's business and results of operations or financial condition.

Statoil holds an interest in several different oil and gas projects in Russia both onshore and offshore. The majority of these projects result from a strategic cooperation with Rosneft Oil Company (Rosneft) initiated in 2012, some of these projects are located Arctic offshore and/or deepwater. In each of these projects, Rosneft holds the majority interest, while Statoil holds a minority interest. Sanctions imposed by Norway, the EU and the USA target, among others, Russia's financial and energy sectors, including certain companies such as Rosneft and various affiliates, and specific activities related to oil exploration and production in the Arctic offshore area, and in deepwater or shale formation projects. Accordingly, aspects of the sanctions targeting Russia also affect Statoil's business activity in the country. The continued progress of Statoil's projects in Russia is, in part, dependent on various government authorisations and also the future development of sanctions and trade controls. Statoil continues to pursue its Russia business within the limitations of existing sanctions and trade controls. However, due to possible future developments there is no certainty that the projects can be progressed and concluded as initially planned.

Disclosure Pursuant to Section 13 (r) of the Exchange Act

Statoil is providing the following disclosure pursuant to Section 13(r) of the Exchange Act.

Statoil is a party to agreements with the National Iranian Oil Company (NIOC), namely, a Development Service Contract for South Pars Gas Phases 6, 7 & 8 (offshore part), an Exploration Service Contract for the Anaran Block and an Exploration Service Contract for the Khorramabad Block, which are located in Iran. Statoil's operational obligations under these agreements have terminated and the licenses have been abandoned. The cost recovery program for these contracts was completed in 2012, except for the recovery of tax and obligations to the Social Security Organisation (SSO). Since 2013, after closing Statoil's office in Iran, Statoil's activity was focused on a final settlement with the Iranian tax and SSO authorities relating to the above mentioned agreements.

During 2016 Statoil paid the equivalent of USD 0.13 million in tax to Iranian authorities. Also during 2016 Statoil paid the equivalent of USD 153 in stamp duty to Iran Tax Organisation. All payments were made in local currency (Iranian Rials). The funds utilised for these purposes were held by Statoil in EN Bank (Iran). Additionally, NIOC, on behalf of Statoil, in 2016 paid a tax obligation of USD 2.47 million equivalent in Iranian Rial to the local tax authorities. The amount was settled towards recoverable costs from NIOC to Statoil.

Since 2009 Statoil has transparently and regularly provided information about its Iran related activity to the US State Department as well as to the Norwegian Ministry of Foreign Affairs. In a letter from the US State Department of 1 November 2010, Statoil was informed that the company was not considered to be a company of concern based on its previous Iran-related activities.

Statoil generated no net profit from the aforementioned 2016 activities. Payments of the above mentioned nature are expected to be made also in 2017, in relation to Statoil's continued efforts to settle all remaining obligations related to its above mentioned historic activity in Iran.

Legal and regulatory risks

Compliance with health, safety and environmental laws and regulations that apply to Statoil's operations could materially increase its costs. The enactment of such laws and regulations in the future is uncertain.
Statoil incurs, and expects to continue to incur, substantial capital, operating, maintenance and remediation costs relating to compliance with increasingly complex laws and regulations for the protection of the environment and human health and safety, including:

- higher price on greenhouse gas emissions
- costs of preventing, controlling, eliminating or reducing certain types of emissions to air and discharges to the sea
- remediaying of environmental contamination and adverse impacts caused by Statoil's activities
- compensation of cost related to persons and/or entities claiming damages as a result of Statoil's activities

Statoil`s activity is increasingly subject to statutory strict liability in respect of losses or damage suffered as a result of pollution caused by spills or discharges of petroleum from petroleum facilities.

Compliance with laws, regulations and obligations relating to climate change and other environmental regulations could result in substantial capital expenditure, reduced profitability as a result of changes in operating costs, and adverse effects on revenue generation and strategic growth opportunities. Statoil regularly assesses how changes in regulations, including introduction of stringent climate policies, may impact the oil price, the costs of developing new oil and gas assets, and the demand for oil and gas.

Statoil's operations in Norway are subject to emissions taxes as well as emissions allowances granted for Statoil's larger European operations under the EU Emissions Trading System. The agreed strengthening of the European Union's emission trading scheme may result in higher costs for installations at the NCS as the price of the EU ETS emissions allowances is expected to increase significantly towards 2030.

The Paris Agreement on climate change entered into force in November 2016. Norway, collectively with the European Union, intends to deliver 40% reductions in greenhouse gas emissions by 2030. The national targets are intended to be strengthened every five years. Additionally, Norway has set an ambition to achieve close to net zero emissions by 2050. The implications for the industry are not clear, however requirements to reduce emissions could result in increased costs.

Statoil's investments in North American onshore producing assets will be subject to evolving regulations that could affect these operations and their profitability (see also the risks related to hydraulic fracturing above). In the United States, the US Environmental Protection Agency (EPA) has taken steps to regulate greenhouse gas emissions under the Clean Air Act, including methane emissions from upstream oil and gas production. In 2016 the EPA finalized new source performance standards for methane emissions and began a process of information collection to inform further methane-related rulemaking. Statoil could incur higher operating costs in order to comply with any such new regulations and data gathering requirements.

Statoil is exposed to risk of supervision, review and sanctions for violations of regulatory laws at the supranational and national level. These include, among others, competition and antitrust laws and financial and trading.
Statoil's products are marketed and traded worldwide and therefore subject to competition and antitrust laws at the supranational and national level in multiple jurisdictions. Statoil is exposed to investigations from competition and antitrust authorities, and violations of the applicable laws and regulations may lead to substantial fines.

Statoil is also exposed to financial review from financial supervisory authorities such as the Norwegian Financial Supervisory Authority (FSA) and the US Securities and Exchange Commission (the SEC). Reviews performed by these authorities could result in changes to previous accounts and future accounting policies.

Statoil is listed on both the Oslo Børs and New York Stock Exchange (NYSE), and is registered with the SEC. Statoil is required to comply with the continuing obligations of these regulatory authorities, and violation of these obligations may result in imposition of fines or other sanctions.

The Norwegian Petroleum Supervisor (PSA) supervises all aspects of Statoil's operations, from exploration drilling through development and operation, to cessation and removal. Its regulatory authority covers the whole NCS as well as petroleum-related plants on land in Norway. Statoil is exposed to supervision from PSA, and as its business grows internationally other regulators, and such supervision could result in audit reports, orders and investigations.

The formation of a competitive internal gas market within the European Union (EU) and the general liberalisation of European gas markets could adversely affect Statoil's business.
The continuing liberalisation of EU gas markets following legislative instruments rolled out in 2011 and the implementation of these legislative instruments by member states, could affect Statoil's market position or result in a reduction in prices in Statoil's gas sales contracts. Statoil's exposure to hub gas prices has increased and correspondingly increased Statoil's exposure to price volatility. Statoil continually monitors its contractual obligations and makes efforts to negotiate the most competitive pricing and other conditions available in the market.

The EU-wide quantity of carbon allowances issued each year under the Emission Trading Scheme (ETS) for greenhouse gas emission allowances began to decrease in a linear manner in 2013. The ETS can have a positive or negative impact on Statoil, depending on the price of carbon, which will consequently have an impact on the development of gas-fired power generation in the EU. Until now, the carbon price has been too low to replace coal with gas fired generation capacity. This effect has been worsened by heavy subsidising of renewables which has caused gas fired power plants to shut down. Current EU climate and energy policies do not address this problem, but there is a tendency towards more market based subsidies in the new guidelines on environment and energy aid.

Political and economic policies of the Norwegian State could affect Statoil's business.
The Norwegian State plays an active role in the management of NCS hydrocarbon resources. In addition to its direct participation in petroleum activities through the State's direct financial interest (SDFI) and its indirect impact through legislation, such as tax and environmental laws and regulations, the Norwegian State, among other things, awards licences for exploration, production and transportation, approves exploration and development projects and applications for production rates for individual fields and may, if important public interests are at stake, also instruct Statoil and other oil companies to reduce petroleum production. Furthermore, in the production licences in which the SDFI holds an interest, the Norwegian State has the power to direct petroleum licences' actions in certain circumstances.

If the Norwegian State were to take additional action under its activities on the NCS or to change laws, regulations, policies or practices relating to the oil and gas industry, Statoil's NCS exploration, development and production activities and the results of its operations could be affected.

Risks related to state ownership

This section discusses some of the potential risks relating to Statoil's business that could derive from the Norwegian State's majority ownership and from Statoil's involvement in the SDFI.

The interests of Statoil's majority shareholder, the Norwegian State, may not always be aligned with the interests of Statoil's other shareholders, and this may affect Statoil's decisions relating to the NCS

The Norwegian Parliament, known as the Storting, and the Norwegian State have resolved that the Norwegian State's shares in Statoil and the SDFI's interest in NCS licences must be managed in accordance with a coordinated ownership strategy for the Norwegian State's oil and gas interests. Under this strategy, the Norwegian State has required Statoil to continue to market the Norwegian State's oil and gas together with Statoil's own oil and gas as a single economic unit.

Pursuant to this coordinated ownership strategy, the Norwegian State requires Statoil, in its activities on the NCS, to take account of the Norwegian State's interests in all decisions that may affect the development and marketing of Statoil's own and the Norwegian State's oil and gas.

The Norwegian State directly held 67% of Statoil's ordinary shares as of 31 December 2016. Based on the Norwegian Public Limited Companies Act, the Norwegian State effectively has the power to influence the outcome of any vote of shareholders due to the percentage of Statoil's shares it owns, including amending its articles of association and electing all non-employee members of the corporate assembly. The employees are entitled to be represented by up to one-third of the members of the board of directors and one third of the corporate assembly.

The corporate assembly is responsible for electing Statoil's board of directors. It also makes recommendations to the general meeting concerning the board of directors' proposals relating to the company's annual accounts, balance sheet, allocation of profit and coverage of loss. The interests of the Norwegian State in deciding these and other matters and the factors it considers when casting its votes, especially under the coordinated ownership strategy for the SDFI and Statoil's shares held by the Norwegian State, could be different from the interests of Statoil's other shareholders.

If the Norwegian State's coordinated ownership strategy is not implemented and pursued in the future, then Statoil's mandate to continue to sell the Norwegian State's oil and gas together with its own oil and gas as a single economic unit is likely to be prejudiced. Loss of the mandate to sell the SDFI's oil and gas could have an adverse effect on Statoil's position in the markets in which it operates.

For further information about the mandate to sell the Norwegian State's oil and gas, see SDFI oil and gas marketing and sale in section 2.7 Corporate.

RISK MANAGEMENT

Statoil's overall risk management approach includes identifying, evaluating and managing risk in all its activities. In order to achieve optimal corporate solutions, Statoil bases its risk management on an enterprise-wide risk management approach. Statoil defines risk as a deviation from a specified reference value and the uncertainty associated with it. A positive deviation is defined as an upside risk, while a negative deviation is a downside risk. The reference value is most commonly a forecast, percentile or target. Statoil has an enterprise risk management (ERM) approach, which means that:

- focus is on the value impact for Statoil
- risk is managed to make sure that Statoil's operations are safe and in compliance with Statoil's requirements and
- focus is on risk and reward at all levels in the organisation

Risk is managed in the business line and is an integral part of any manager's responsibility. However, some risks are managed at corporate level. This includes oil and natural gas price risks, interest and currency risks, risk dimension in the strategy work, prioritisation processes and capital structure discussions.

Statoil's corporate risk committee (CRC) is headed by the chief financial officer and its members include representatives of the principal business areas. It is an enterprise risk management advisory body that primarily advises the chief financial officer, but also the business areas' management on specific issues. The CRC assesses and advises on measures aimed at managing the overall risk to the group, and it proposes appropriate measures to adjust risk at the corporate level. The CRC is also involved in reviewing and developing Statoil's risk policies. The committee meets regularly during the year to support Statoil's risk management strategies, including hedging and trading strategies, as well as risk management methodologies. It regularly receives risk information that is relevant to it from Statoil's corporate risk department.

- The following section describes how Statoil manages the market risks to which Statoil is exposed

Managing operational risk

Statoil manages risk in order to ensure safe operations and to achieve its corporate goals in compliance with its requirements

- All risks are related to Statoil's value chain, which denotes the value that is added in each step - from access, maturing, project execution and operation to market. In addition to the economic impact these risks could have on Statoil's cash flows, Statoil has a strong focus on avoiding HSE and integrity-related incidents (such as accidents, fraud and corruption). Most of the risks are managed by the principal business area line managers. Some operational risks are insurable and insured by Statoil's captive insurance company operating in the Norwegian and international insurance markets
- Statoil's risk management process is based on ISO31000 Risk management – principles and guidelines. The process provides a standardised framework and methodology for assessing and managing risk. A standardisation of the process across Statoil ASA and its subsidiaries allows for comparable risk levels and efficiency in decisions and it enables the organisation to create sustainable value while seeking to avoid incidents. The process seeks to ensure that risks are identified, analysed, evaluated and managed. Risk adjusting actions are subject to a cost benefit evaluation (except certain safety related risks which are subject to specific regulations)

Managing financial risk

The results of Statoil's operations depend on a number of factors, most significantly those that affect the price it receives for the products

Statoil has developed policies aimed at managing the financial volatility inherent in some of the business exposures. In accordance with these policies, Statoil enters into various financial and commodity-based transactions (derivatives). While the policies and mandates are set at the company level, the business areas are responsible for marketing and trading commodities and for managing commodity-based price risks within mandates. Interest, liquidity, liability and credit risks are managed by the company's central finance department.

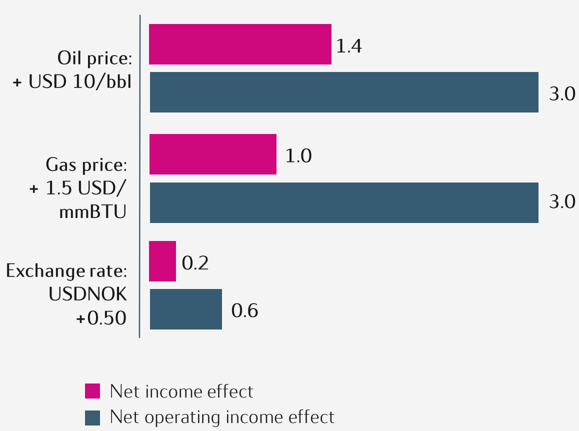
The factors that influence the results of Statoil's operations include: the level of crude oil and natural gas prices, trends in the exchange rate between mainly the USD, EUR, GBP and NOK; Statoil's oil and natural gas production volumes, which in turn depend on entitlement volumes under PSAs and available petroleum reserves, and Statoil's own, as well as partners' expertise and cooperation in recovering oil and natural gas from those reserves; and changes in Statoil's portfolio of assets due to acquisitions and disposals.

Statoil's results will also be affected by trends in the international oil industry, including possible actions by governments and other regulatory authorities in the jurisdictions in which Statoil operates, or possible or continued actions by members of the Organization of Petroleum Exporting Countries (OPEC) and/or other producing nations that affect price levels and volumes, refining margins, the cost of oilfield services, supplies and equipment, competition for exploration opportunities and operatorships, and deregulation of the natural gas markets, all of which may cause substantial changes to existing market structures and to the overall level and volatility of prices and price differentials.

The following table shows the yearly averages for quoted Brent Blend crude oil prices, natural gas average sales prices, refining reference margins and the USD/NOK exchange rates for 2016, 2015 and 2014.

Yearly average	2016	2015	2014
Average Brent oil price (USD/bbl)	43.7	52.4	98.9
Average invoiced gas prices - Europe (USD/mmbtu)	5.2	7.1	9.5
Refining reference margin (USD/bbl)	4.8	8.0	4.7
USD/NOK average daily exchange rate	8.4	8.1	6.3

Indicative effects on 2017 results
(USD billion)



The sensitivity analysis shows the estimated 12-month effects on net operating income and net income from change in parameters. The sensitivities do not have the same probability.

The illustration shows the indicative full-year effect on the financial result for 2017 given certain changes in the crude oil price, natural gas contract prices and the USD/NOK exchange rate. The estimated price sensitivity of Statoil's financial results to each of the factors has been estimated based on the assumption that all other factors remain unchanged. The estimated indicative effects of the negative changes in these factors are not expected to be materially asymmetric to the effects shown in the illustration.

Significant downward adjustments of Statoil's commodity price assumptions will result in impairment losses on certain producing and development assets in the portfolio. See note 10 Property, plant and equipment and note 11 Intangible assets to the Consolidated financial statements for sensitivity analysis related to impairment losses.

Statoil assesses oil and gas price hedging opportunities on a regular basis as a tool with regard to financial robustness and flexibility.

Fluctuating foreign exchange rates can have a significant impact on the operating results. Statoil's revenues and cash flows are mainly denominated in or driven by USD, while a large portion of the operating expenses, capital expenditures and income taxes payable accrue in NOK. Statoil seeks to manage this currency mismatch by issuing or swapping non-current financial debt in USD. This long-term funding policy is an integrated part of our total risk management programme. Statoil also engages in foreign currency management in order to cover the non-USD needs, which are primarily in NOK. In general, an increase in the value of USD in relation to NOK can be expected to increase Statoil's reported earnings.

Historically, Statoil's revenues have largely been generated by the production of oil and natural gas on the NCS. Norway imposes a 78% marginal tax rate on income from offshore oil and natural gas activities (a symmetrical tax system). For further information, see Taxation of Statoil in section 2.7 Corporate.

Statoil's earnings volatility is moderated as a result of the significant proportion of its Norwegian offshore income that is subject to a 78% tax rate in profitable periods, and the significant tax assets generated by its Norwegian offshore operations in any loss-making periods. The basis for taxation is 3% of the dividend received, which is subject to the standard income tax rate (reduced from 25% in 2016 to 24% in 2017). Dividends received from Norwegian companies and from similar companies resident in the EEA for tax purposes, in which the recipient holds more than 90% of the shares and votes, are fully exempt from tax. Dividends from companies resident in the EEA that are not similar to Norwegian companies, companies in low-tax countries and portfolio investments outside the EEA will, under certain circumstances, be subject to the standard income tax rate (reduced from 25% in 2016 to 24% in 2016) based on the full amounts received.

Financial risk management

Statoil's business activities naturally expose the group to financial risk. The group's approach to risk management includes identifying, evaluating and managing risk in all activities using a top-down approach for the purpose of avoiding sub-optimisation and utilising correlations observed from a group perspective. Summing up the different market risks without including the correlations will overestimate Statoil's total market risk. For this reason, Statoil utilises correlations between all of the most important market risks, such as oil and natural gas prices, product prices, currencies and interest rates, to assess the overall market risk. This approach also reduces the number of unnecessary transactions, which reduces transaction costs and avoids sub-optimisation.

In order to achieve the above effects, Statoil has centralised trading mandates (financial positions taken to achieve financial gains, in addition to established policies) so that all major/strategic transactions are coordinated through the CRC. Local trading mandates are therefore relatively small.

Statoil's activities expose the company to the following financial risks: market risks (including commodity price risk, interest rate risk and currency risk), liquidity risk and credit risk. For a discussion of financial risk management see note 5 Financial risk management in the Consolidated financial statements.

Disclosures about market risk

Statoil uses financial instruments to manage commodity price risks, interest rate risks, currency risks and liquidity risks. Significant amounts of assets and liabilities are accounted for as financial instruments.

See note 25 Financial instruments: fair value measurement and sensitivity analysis of market risk in the Consolidated financial statements, for details of the nature and extent of such positions, and for qualitative and quantitative disclosures of the risks associated with these instruments.

2.11 SAFETY, SECURITY AND SUSTAINABILITY

Safety and security
Safety and security risks are particularly relevant for the oil and gas industry, because our core activities involve the risk of accidents and incidents. We work with flammable hydrocarbons at high pressure, often in harsh offshore environments and at height or depths. Oil spills are a major risk we need to handle in both our offshore and onshore oil and gas operations. To this end we have established a global oil spill response system, which includes close collaboration with industry peers and national and local communities.

We focus on identifying safety and security risks and having in place procedures and work processes to control them. Our objective is to be an industry leader in ensuring safe and secure operations that protect our people, the environment, the communities we work with and our assets.

For Statoil, 2016 was marked by two accidents with fatalities. A helicopter accident, in April, at Turøy in Norway in which 13 people were killed while travelling from the Gullfaks B platform in the North Sea. In May, one person was killed in an accident while working on the fabrication of a Statoil rig at the Samsung shipyard in Geoje, South Korea.

We also experienced a number of serious incidents in 2016, two of which had a major accident potential. At the Sture terminal (Norway) five people were exposed to H_2S gas (hydrogen sulphide) in October while working at a treatment facility for oily water inside the terminal area. All affected workers have since recovered after this incident. Statoil implemented immediate actions to avert this problem at all Statoil onshore plants where H_2S could cause a hazard.

Also in October, complications occurred during work to remove the production string from a well on the drilling rig Songa Endurance in the Troll field (Norway). There were no personal injuries, but drill mud containing gas was released. Procedures for handling well barriers have been strengthened.

All serious incidents are investigated in order to understand the causes and extract lessons learned to improve safety in the future. We use serious incident frequency (SIF) as a key indicator to monitor safety performance.

Our total serious incident frequency (SIF), including both actual and potential incidents, increased in 2016, with 0.8 incidents per million hours worked, compared to 0.6 in 2014 and 2015.

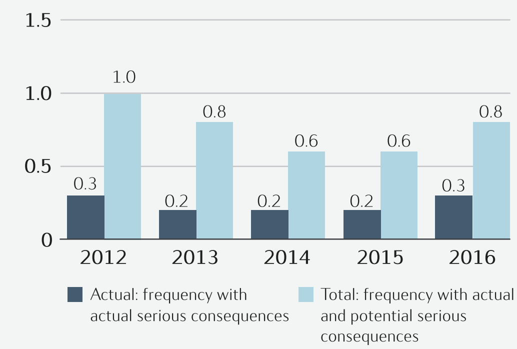
Total recordable injuries per million hours worked (TRIF) was 2.9 in 2016, compared to 2.7 in 2015.

The decline in our safety performance experienced in 2016 follows a decade of solid safety improvement.

Statoil has implemented a safety performance improvement programme to deal with this development. The main elements of the programme address risk management, safety guidance and practice, working safely with suppliers, safety leadership and engagement of the whole organisation.

In 2016, the total number of serious oil and gas leakages (with a leakage rate above 0.1 kg per second) was 18, down from 21 in 2015. Preventing oil and gas leakages is important to avoid of major accidents.

Total and actual serious incident frequency
(number per million hours worked)



Our performance over the past five years, related to oil spills, shows a significant reduction in the number of oil spills per year. From 2015 to 2016 there was a reduction in the number of oil spills from 172 to 148 spills. However, the total volume of oil spilt increased from 31 m³ in 2015 to 61 m³ in 2016. The largest oil spills in 2016 were in Norway. They included a 35 m³ oil spill from the Mongstad refinery, due to corrosion in a pipe and a 7 m³ oil spill from a leak in the export pipeline from Troll B.

Security is an important consideration for the energy industry. We assess security threats and risks on a continuous basis in order to achieve effective and proportionate security risk management. The terrorist attack against the Krechba plant in Algeria, in March, highlighted the security situation in North Africa. This was the single incident with the most significant impact for Statoil during 2016. In 2016 we continued our improvement programme in accordance with our road map to further strengthen our security culture and capabilities by 2020, focusing on areas such as competence and awareness, working with our suppliers and improving compliance.

Health and work environment
Statoil is committed to providing a healthy working environment for its employees. Systematic efforts are made to design and improve working conditions in order to prevent occupational injuries, work-related illness and sickness absence, due to both physical and psychosocial risk factors. A proactive psychosocial risk indicator is used to monitor health and work environment risk factors, in addition to the work related illness frequency indicator.

The most significant risk factors related to the work environment are noise, ergonomics, chemical risk as well as psychosocial conditions. In 2016, Statoil continued to fund research into exposure control for noise and chemicals, and research in to stroke treatment during evacuation from offshore facilities.

The sickness absence rate for Statoil ASA employees increased slightly from 4.1% in 2015 to 4.3% in 2016.

Climate change

Statoil supports the ambition set by the Paris Climate Agreement of December 2015 to limit the average global temperature rise to well below two degrees centigrade compared to pre-industrial levels by 2100. Our corporate ambition is to develop our business in support of the Paris Climate Agreement

Statoil's approach to climate change as outlined in our climate roadmap focuses on:

- building a high value, low carbon oil and gas portfolio
- creating a material industrial position in new energy solutions
- accountability and collaboration.

Climate change is complex and requires global and cross sector cooperation. We are committed to working with our suppliers, customers, governments and peers to find innovative and commercially viable ways to reduce emissions across the oil and gas value chain. To spur technology development, for example, we continued through 2016 with our research and development (R&D) partnership with GE. In November 2016 we launched the USD 1 billion Climate Investments partnership with our global peers through the CEO-led Oil and Gas Climate Initiative (OGCI). And through our participation in the government-led Climate and Clean Air Coalition's Oil and Gas Methane Partnership (OGMP) we continued our efforts to systematically address methane emissions and report on annual progress.

We work with governments and other organisations to support climate and energy policies that encourage fuel switching from coal to gas, growth in renewables, the deployment of carbon capture usage and storage (CCUS) and other low carbon solutions, and efficient production, distribution and use of energy globally. We have also teamed up with global peers through OGCI to help shape the industry's climate response. Through the World Bank led Carbon Pricing Leadership Coalition and our membership of the International Emission Trading Association we continued our advocacy for a price on carbon during 2016. And through our membership in the OGCI and World Business Council for Sustainable Development (WBCSD) we expressed our continued support for the ambitions of the Paris climate agreement. Statoil is an endorser of the World Bank Global Gas Flaring Reduction Partnership and we have made a commitment to contribute to stopping routine flaring by 2030 through the World Bank Zero Routine Flaring by 2030 initiative.

The corporate executive committee and board of directors' review climate change related business risks and opportunities, including market, regulatory and physical risk factors. We use tools such as internal carbon pricing, scenario planning and stress testing of projects against various oil and gas price assumptions. Statoil routinely tracks technology developments and changes in regulations, including the introduction of stringent climate policies, and assesses how these may impact the oil price, the costs of developing new oil and gas assets, and the demand for oil and gas.

Statoil initiated stress testing of our project portfolio against the International Energy Agency (IEA) and our own energy scenarios, in 2015, in response to a shareholder request. The stress test includes a range of price assumptions for oil, gas and carbon. Both Statoil's and the IEA's price assumptions may differ from actual and future oil, gas and carbon prices. As such, there can be no assurance that the analysis is a reliable indicator of the actual future impact of climate change on Statoil.

Statoil's efforts to reduce direct greenhouse gas emissions include improving energy efficiency; reducing methane emissions; eliminating routine flaring and scaling up carbon capture usage and storage (CCUS).

One of the most significant contributions to our emissions reductions in 2016 has been our efforts to reduce flaring at our Bakken (USA) asset. This contributed around 100 thousand tonnes to the total emission reductions. Energy efficiency improvements at our onshore facilities in Norway and the Kalundborg refinery in Denmark realised an additional 100 thousand tonnes in carbon dioxide (CO_2) reductions in 2016.

For our offshore operations in Norway we set a target in 2008 to achieve improved energy efficiency by 2020 equivalent to 800 thousand tonnes of CO_2 emissions (the so called Konkraft target). This was already achieved during 2015 through the implementation of energy efficiency projects. So we have raised the target to a total of 1.2 million tonnes of CO_2 emissions for the period 2008 to 2020.

The production from Statoil operated assets decreased from 1,073 million boe in 2015 to 1,030 million boe in 2016[1]. The corresponding greenhouse gas emissions (so called Scope 1 emissions) decreased from 16.3 million tonnes CO_2 equivalents in 2015 to 15.4 million tonnes in 2016. Greenhouse gas emissions include carbon CO_2 and methane (CH_4), where CO_2 constitutes the largest part (14.8 million tonnes in 2016 compared to 15.4 tonnes in 2015). Methane (CH_4) emissions decreased from 36.3 thousand tonnes in 2015 to 24.2 thousand tonnes in 2016.

The decrease in CO_2 emissions in 2016, relative to 2015, was the result of emissions reductions efforts, reduced exploration activity and operational disruptions associated with turnarounds at our facilities on the Norwegian continental shelf and our onshore oil refining and gas processing facilities in Norway and Denmark. The 33% decrease in methane emissions in 2016, compared to 2015, was largely due to a change in methodology for the estimation of fugitive emissions for our Norwegian continental shelf assets, and updated fugitive emissions measurements for our oil refining and gas processing facilities.

In 2016, we introduced a 2030 carbon intensity target of 8 kg CO_2 per boe for our upstream exploration and production activities. This supplements the 2020 carbon intensity target of 9 kg of CO_2 per boe by 2020 established in 2015. These targets are based on production and emission forecasts and emission reduction targets for each business area. Our targets are subject to significant uncertainty because they relate to events and circumstances that will occur in the future. Changes in our asset portfolio and production can also affect the result for a particular year.

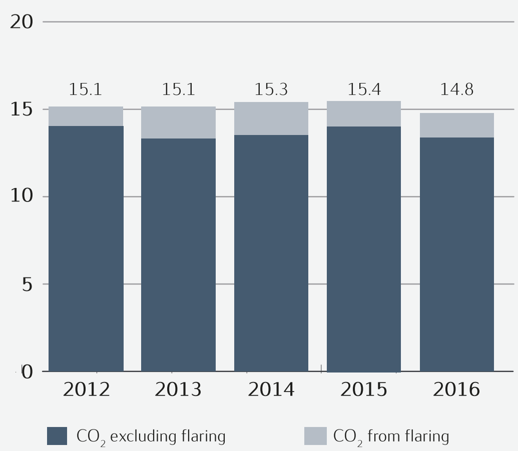
Upstream carbon intensity was established as a corporate-wide key performance indicator in 2016. It was included in the assessment of reward for the CEO. Statoil's upstream carbon intensity in 2016 was

[1] Climate and environmental performance data represent the total for Statoil operated assets (i.e. reflecting operational control rather than equity share), except for scope 3 emissions.

10 kg CO_2 per boe, less than 60% of the industry average of 17 kg as measured by the International Association of Oil and Gas Producers (Environmental Performance Indicators, 2015 data).

Statoil's operations in Europe are subject to emissions allowances according to the EU Emissions Trading System (EU ETS). Statoil's Norwegian operations are subject to both the Norwegian offshore CO_2 tax and EU ETS quotas. In 2016, Statoil paid some USD 496 million in CO_2 tax and quotas compared to USD 476 million in 2015.

CO_2 emissions from Statoil operated assets
(million tonnes)



Growth opportunities for Statoil within renewables and new energy solutions include both commercial investments and research and development (R&D). To date Statoil has invested USD 2.3 billion in offshore wind projects and is engaged in carbon capture usage and storage. In 2016 approximately 17% (USD 52.4 million) of Statoil's spend on R&D efforts addressed energy efficiency, carbon capture and renewables.

Environmental impact and resource efficiency
Statoil is committed to using resources efficiently and responsible management of waste, emissions to air and impacts on ecosystems. This reduces the impact on the local environment and can also save costs.

Responsible water management is important for Statoil. Total *fresh water consumption* decreased from 14.5 million cubic metres in 2015 to 13.5 million cubic metres in 2016. The main contributor to this decrease in water consumption was the lower number of wells fracked, relative to 2015, in our US onshore shale and tight oil assets. We work actively to improve water efficiency in our onshore activities in North America, through means such as water recycling and substituting fresh water with brackish water.

Nitrogen oxide emissions were 39 thousand tonnes in 2016, down from 42 thousand tonnes in 2015. *Sulphur oxide emissions* were 1.8 thousand tonnes, down from 2.5 thousand tonnes in 2015. Total emissions of *non-methane volatile organic compounds were 49 thousand tonnes in 2016, down from 60* thousand tonnes in 2015.

Statoil is concerned with valuing and protecting biodiversity and ecosystems and follows precautionary principles to minimise potential negative effects of the company's activities. Statoil supports research programmes to increase knowledge about ecosystems and biodiversity and collaborates with industry peers to share knowledge and develop tools for biodiversity management. In addition, Statoil works with our suppliers to minimise invasive aquatic species and reduce risks pertaining to accidental spills related to shipping transportation.

During 2016 we saw a 42% rise in the volume of hazardous waste generated, from 309 thousand tonnes in 2015 to 438 thousand tonnes in 2016. The main contributor to this volume increase was drilling and well start-up activities, on the Norwegian continental shelf, at locations without treatment facilities for oil contaminated water. As such the untreated oil contaminated water was sent to shore for treatment.

A change was made, in 2016, to the definitions we use for reporting of hazardous waste recovery. Previously, treated oil contaminated water was not included in our categorisation of recovered hazardous waste. From 2016, treated oil contaminated water will be included in our hazardous waste recovery calculations. The rationale for this change is alignment with the way both our peers and the contractors handling our waste are reporting. It also serves to highlight the company's efforts to treat hazardous waste. The impact on our waste recovery rate is significant, with a rise from 16% in 2015 to 84% for 2016.

For our US onshore operations drill cuttings and produced and flow-back water are exempt from hazardous waste regulations. Consequently, these exempt wastes are not included in the hazardous waste generation or recovery figures. For our US onshore operations in 2016 81 thousand tonnes of drill cuttings and solid waste were sent to landfill, and 4.3 million cubic meters of produced and flow back water was directed to deep well disposal.

In 2016 the volume of non-hazardous waste generated for all Statoil operated assets was 50 thousand tonnes, and the recovery rate was 56% in 2016 compared to 63% in 2015. Regular discharges of oil to water were 1.4 thousand tonnes in 2016, the same as for 2015.

Working with suppliers
Statoil is committed to using suppliers who operate in accordance with Statoil's values and who maintain high standards of safety, security and sustainability. These aspects are incorporated in all phases of the procurement process. Potential suppliers must meet Statoil's minimum requirements in order to qualify as a supplier, including those related to safety, security and sustainability.

Statoil expect our suppliers to comply with applicable laws, respect internationally recognised human rights and adhere to ethical standards which are consistent with our ethical requirements, when working for Statoil. Potential suppliers for contracts valued at more than USD 800 thousand are, in addition, required to sign Statoil's *Supplier Declaration*, which establishes minimum requirements for ethics, anti-corruption, environment, health, safety, respect for human rights, and for further promoting these requirements among their own suppliers. Potential suppliers are also screened for integrity risk, in accordance with our procedures for integrity due diligence.

Human rights
Statoil seeks to conduct its business in a way that is consistent with the UN Guiding Principles on Business and Human Rights (the UN Guiding Principles), the ten UN Global Compact principles and the Voluntary Principles on Security and Human Rights. Statoil is committed to respecting internationally recognised human rights as laid out in the International Bill of Human Rights, the International Labour Organization's 1998 Declaration on Fundamental Rights and Principles at Work, and applicable standards of international humanitarian law.

Labour rights and working conditions for our workforce and suppliers, human rights of individuals in communities and human rights in security arrangements are the three broad focus areas for human rights for Statoil's activities.

Human rights aspects are integrated into relevant internal management processes, tools and training. On-going activities, business relationships and new business opportunities are assessed for potential human rights impacts and aspects, following a risk-based approach. In 2016, supplier screening and verification practices were strengthened.

In 2016 Statoil focused on strengthening its processes for managing human rights in our supply chain and on raising awareness through training. We strengthened our human rights risk screening and verification tools and conducted 65 supplier verifications across 21 countries in 2016. Over 800 employees attended classroom training about human rights in the supply chain.

During 2016 Statoil's Human Rights Steering Committee (HRSC), responsible for overseeing the development and implementation of Statoil's human rights policy, closely followed the ongoing implementation efforts and provided guidance on human rights related reporting requirements.

Statoil recognises that a company-wide commitment to respect human rights requires continuous training and awareness raising in order to embed good practices throughout the organisation. To this effect additional human rights training materials, including a human rights e-learning programme were developed in 2016. During 2016 over 3,000 staff and hired contractors have registered for the e-learning course.

The context of Statoil's operations requires that security services are engaged to safeguard Statoil's people and property. Particular focus is needed to ensure respect for human rights in security arrangements, in jurisdictions where security services are not well regulated or security personnel are not adequately trained. Statoil follows international standards of good practices in security and human rights. Statoil's commitment to the *Voluntary Principles on Security and Human Rights* is reflected in policies and procedures for risk assessment, deployment, training and follow-up of private and public security providers.

Transparency, ethics and anti-corruption
Transparency is a cornerstone of good governance. It is embodied in our corporate values. Transparency allows business to prosper in a predictable and competitive environment and enables society to hold governments and business accountable. Statoil supports and promotes effective, transparent and accountable management of wealth derived from the extractives industries.

Statoil supports and engages in global transparency initiatives through its membership in the Extractive Industries Transparency Initiative (EITI), the United Nations Global Compact Anti-Corruption Working Group and the World Economic Forum's Partnering Against Corruption Initiative (PACI). Statoil was one of the first major oil and gas companies to voluntarily start disclosing payments to governments on a country-by-country basis. Our 2016 *Payments to Governments* report discloses payments per project for our extractive activities, in accordance with mandatory requirements in Norway.

Statoil believes that doing business in an ethical and transparent manner is a prerequisite for sustainable business. Statoil's Code of Conduct (the Code) prohibits all forms of corruption, including facilitation payments. Statoil maintains a robust company-wide anti-corruption compliance programme to implement our zero-tolerance policy. A global network of compliance officers is integrated into our business activities to ensure the appropriate consideration is given to ethics and anti-corruption in Statoil's business activities, regardless of where they take place.

The Code reflects Statoil's values and the commitment to high ethical standards in business activities. It describes our requirements in areas such as anti-corruption, fair competition, human rights and a non-discriminatory working environment with equal opportunities. It applies to Statoil employees, board members and hired personnel.

Statoil seeks to work with others who share the company's commitment to business integrity and who have codes of conduct consistent with Statoil's Code. Before entering into a new business relationship, or extending an existing one, the relationship has to satisfy Statoil's integrity due diligence requirements. Statoil have a process to develop in-depth knowledge of our suppliers, partners, and the markets in which we work. Our vetting process is risk-based, allowing us to target resources where we see potential concerns. In joint ventures and business partnerships that are not controlled by Statoil, Statoil encourages the adoption of ethics and anti-corruption policies and procedures that are consistent with the company's standards.

All employees have to confirm annually that they understand and will comply with the Code. The purpose of this confirmation is to remind the individual about their duty to comply with Statoil's values and ethical requirements. Disciplinary measures are in place for anyone working for Statoil who does not comply with the code. This may entail termination of their contract.

The Code requires reporting of possible violations of our ethical requirements or other unethical misconduct. Concerns can be reported through internal channels or through the publicly available Ethics Helpline, which allows for anonymous reporting. The number and types of cases from the helpline is reported quarterly to the board of directors. In 2016 we received 51 cases through the Ethics Helpline.

Other relevant reports
More information about Statoil's policies and approach taken to manage safety and sustainability performance is available on our corporate website. Information on our activities, plans and performance in 2016 is available in Statoil ASA's 2016 Sustainability Report, which has been prepared with reference to the Global Reporting Initiative G4 Guidelines. This report is also available on our corporate website: www.statoil.com.

2.12 OUR PEOPLE

In Statoil we work together to shape the future of energy in a partnership between the organisation and the individual. We all apply our skills and personal commitment to help Statoil towards achieving our vision.

Statoil aims to offer challenging and meaningful job opportunities that attract and retain the right people. Through our engagement, creativity and collaboration, we aim to build a better Statoil for tomorrow. We are committed to creating a caring and inspiring working environment, promoting diversity and equal opportunities for all employees.

At the same time, given the current commercial environment, the company continues to focus on efficiency. We are committed to doing this in a way that is respectful and considerate to those affected. In particular, employees are involved in initiatives to increase efficiency. Employees have demonstrated strong engagement in this process, which is also confirmed by the high employee engagement score of 4.6 (6 being the highest) in the 2016 Global People Survey (GPS).

Learning and development is at the core of Statoil. We encourage our employees to take responsibility for their own learning and development, continuously build new skills and share knowledge. Our corporate university is our platform for learning. It enables the company to build the capabilities needed to deliver on its strategy, continuously improve, and take the lead in developing leadership and technology. People@Statoil is our common process for people development, deployment, performance and reward. It is an integrated part of performance management and applies to all employees.

EMPLOYEES IN STATOIL

The Statoil group employs 20,539 employees. Of these, approximately 18,000 are employed in Norway and approximately 2,500 outside Norway.

Permanent employees and percentage of women in the Statoil group	Number of employees 2016	2015	2014	Women 2016	2015	2014
Norway	18,034	18,977	19,670	30%	30%	30%
Rest of Europe	838	855	909	28%	29%	31%
Africa	78	98	117	36%	35%	34%
Asia	73	97	135	59%	36%	52%
North America	1,230	1,265	1,375	35%	35%	34%
South America	286	289	310	37%	38%	40%
Total	20,539	21,581	22,516	31%	30%	31%
Non-OECD	541	590	677	40%	40%	40%

Total workforce by region, employment type and new hires in the Statoil group in 2016

Geographical Region	Permanent employees	Consultants	Total Workforce[1]	Consultants (%)	Part time (%)	New hires
Norway	18,034	321	18,355	2%	3%	81
Rest of Europe	838	82	920	9%	2%	66
Africa	78	3	81	4%	NA	6
Asia	73	2	75	3%	NA	2
North America	1,230	94	1,324	7%	0%	89
South America	286	2	288	1%	2%	7
Total	20,539	504	21,043	2%	3%	251
Non-OECD	541	7	548	1%	NA	24

1) Contractor personnel, defined as third-party service providers who work at our onshore and offshore operations, are not included. These were roughly estimated to be around 30,000 in 2016.

Statoil works systematically to build a diverse workforce by attracting, recruiting, developing and retaining people of both genders and different nationalities and age groups across all types of positions. In 2016, 19% of employees and 23% of our managerial staff held nationalities other than Norwegian. Outside Norway,

Statoil aims to increase the number of people and managers who are locally recruited and to reduce the long-term use of expats in business operations. In 2016, 73% of new hires in Statoil were non-Norwegians and 34% were women.

Our annual intake of apprentices reflects our long-term commitment to the education and training of young technicians and operators in our industry. In 2016, we awarded 132 apprenticeships, of which 45 were to women. The total number of apprentices at year end was 271 (including 81 women).

In Statoil, the total turnover rate for 2016 was 3.6%. On 31 December 2016, the Statoil group employed 20,539 permanent employees and 3% of the workforce worked part-time. In the annual organisational and working environment survey, which continued to have a high response rate of 84%, our employees reported an overall satisfaction of 4.6, maintaining the high score from 2015.

Our people performance data relates to permanent employees in our direct employment. Statoil defines consultants as contracted personnel that are mainly based in our offices. Temporary employees and contractor personnel, defined as third party service providers to our onshore and offshore operations, are not included in the table. These were roughly estimated to be around 30,000 in 2016. The information about people policies applies to Statoil ASA and its subsidiaries.

Equal opportunities

We are committed to building a workplace that promotes diversity and inclusion through its people processes and practices. The importance of diversity is stated explicitly in Statoil's values and Code of Conduct. Our goal is to create the same opportunities for everyone and do not tolerate discrimination or harassment of any kind in our workplace. In 2016, we continued to focus on strengthening women in leadership and professional positions and on building broad international experience in our workforce. The results from the Global People Survey for 2016 indicate that employees strongly agree that there is a zero tolerance for discrimination and harassment in Statoil. The scoring for the 2016 GPS was 5.1 (6 being the highest), maintaining the high score from 2015.

In 2016, the overall percentage of women in the company was 31%. The percentage of women in the board of directors is 50% (67% among the employee representatives and 43% among members elected by the shareholders). In the corporate executive committee, the female representation has increased from last year's 18% to 27% in 2016. We continue to focus on increasing the number of female managers through our development programmes, and in 2016 the share of women in management was 29%, an increase of 1% from 2015. We are committed to maintaining the positive trend in 2017. We pay close attention to male-dominated positions and discipline areas, and in 2016 the proportion of female engineers remained stable at 27% in Statoil ASA.

We reward our people on the basis of their performance, giving equal emphasis to what we deliver and how we deliver. Our approach is transparent, non-discriminatory and supports equal opportunities. Given the same position, experience and performance, our employees will be at the same remuneration level relative to the local market. This is demonstrated in the salary ratio between women and men at different levels, which remained at an average of 98% for Statoil ASA, which represents the 85% of our workforce.

Unions and representatives

We respect our employees' right to freedom of association and thereby their right to negotiate and cooperate through relevant representative bodies. The specific ways in which we involve our employees and/or their appropriate representatives in business and organisational issues may vary according to local laws and practices in specific geographical locations.

In Statoil ASA, 73% of the employees in the parent company are members of a trade union. Work councils and working environment committees are established where required by law or agreement.

In Norway, the formal basis for collaboration with labour unions is established in the Basic Agreements between the Confederation of Norwegian Enterprise (NHO) and the corresponding respective national labour confederations (unions). We have local collective wage agreements with five trade unions in Statoil ASA.

The European Works Council continues to be an important forum for collaboration between the company and our European employees.

Statoil promotes good employee and industrial relations practices through various networks and forums, including IndustriALL Global Union (IndustriAll) and the International Labour Organisation (ILO).

In 2016 we prolonged the temporary collaboration forum set up in 2015 with trade unions and safety delegates in Norway specifically to engage in the Organisational efficiency programme. Under a common framework, we have relied largely on the internal job market to find new employment opportunities and measures such as severance pay and early retirement.

More information about Statoil's people is available in the 2016 Sustainability Report.

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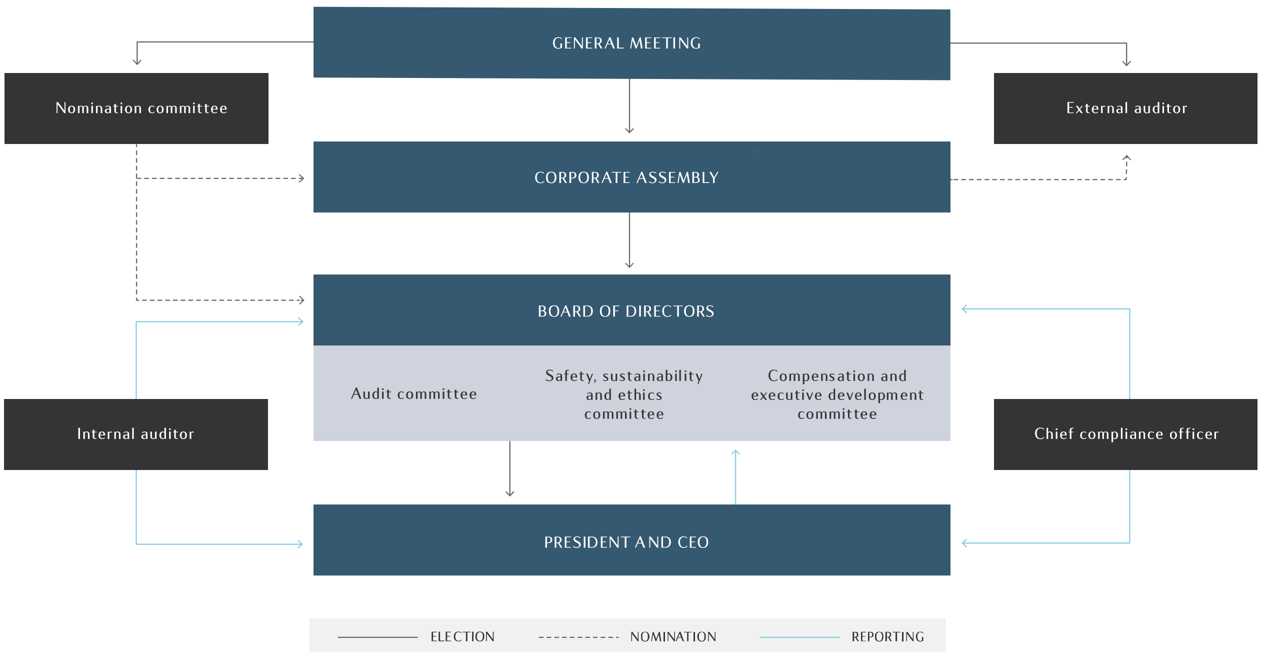
Governance

BOARD STATEMENT ON CORPORATE GOVERNANCE

Nomination and elections in Statoil ASA



Statoil's board of directors actively adheres to good corporate governance standards and will at all times ensure that Statoil either complies with the Norwegian Code of Practice for Corporate Governance (the "Code") or explains possible deviations from the Code. The topic of corporate governance is subject to regular assessment and discussion by the board, which has also considered the text of this chapter at a board meeting. The Code can be found at www.nues.no.

The Code covers 15 topics, and the board statement covers each of these topics and describes Statoil's adherence to the Code. The statement describes the foundation and principles for Statoil's corporate governance structure, more detailed factual information can be found on our website, in our Annual Report on Form 20-F and in our Sustainability Report.

The information concerning corporate governance required to be disclosed according to the Accounting Act Section 3-3b is included in this statement as follows:

1. "An overview of the recommendations and regulations concerning corporate governance that the enterprise is subject to or otherwise chooses to comply with": Described in this introduction as well as in section 1 below, "Implementation and reporting".
2. "Information on where the recommendations and regulations mentioned in no 1 are available to the public": Described in this introduction.
3. "Reasons for any non-conformance with recommendations and regulations mentioned in no 1"; There are two deviations from the Code's recommendations, one in section 6 "General meetings" and the other in section 14 "Take-overs". The reasons for these deviations are described under the respective sections of this statement.
4. "A description of the main elements in the enterprise's, and for entities that prepare consolidated financial statements, also the Group's (if relevant) internal control and risk management systems linked to the financial reporting process": Described in section 10 "Risk management and internal control".
5. "Articles of Association which entirely or partly expand or depart from provisions of Chapter 5 of the Public Limited Liability Companies Act": Described in section 6 "General meetings".
6. "The composition of the board of directors, the Corporate Assembly, the Committee of Shareholders' Representatives and the Control Committee and any working committees related to these bodies, as well as a description of the main instructions and guidelines that apply to the work of the bodies and any committees": Described in section 8 "Corporate assembly and board" and section 9 "The work of the board of directors".
7. "Articles of Association governing the appointment and replacement of Directors": Described in section 8 "Corporate assembly and board" under the sub-heading "Composition of the board of directors".
8. "Articles of Association and authorisations empowering the board of directors to decide that the enterprise is to buy back or issue its own shares or equity certificates": Described in section 3 "Equity and dividends".

3.1 IMPLEMENTATION AND REPORTING

Introduction

Statoil ASA is a Norwegian-registered public limited liability company with its primary listing on Oslo Børs, and the foundation for the Statoil group's governance structure is Norwegian law. Our share is also listed on the New York Stock Exchange (NYSE), and we are subject to the listing requirements of NYSE and the requirements of the US Securities and Exchange Commission.

The board of directors focuses on maintaining a high standard of corporate governance in line with Norwegian and international standards of best practice. Good corporate governance is a prerequisite for a sound and sustainable company, and our corporate governance is based on openness and equal treatment of our shareholders. Our governing structures and controls help to ensure that we run our business in a justifiable and profitable manner for the benefit of our employees, shareholders, partners, customers and society. We continuously consider prevailing international standards of best practice when defining and implementing company policies, as we believe that there is a clear link between high-quality governance and the creation of shareholder value.

At Statoil, the way we deliver is as important as what we deliver. The Statoil Book, which addresses all Statoil employees, sets the standards for our behaviour, our delivery and our leadership.

Our values guide the behaviour of all Statoil employees. Our corporate values are "courageous", "open", "collaborative" and "caring". Both our values and ethics are treated as an integral part of our business activities. Our Ethics Code of Conduct is further described under the heading Risk management and internal control.

We also focus on managing the impacts of our activities on people, society and the environment, in line with our corporate policies for health, safety, security, human rights, ethics and sustainability, including corporate social responsibility (CSR). Areas covered by these policies include labour standards, transparency and anti-corruption, local hiring and procurement, health and safety, the working environment, security and broader environmental issues.

Our governance and management system is further elaborated on our website at www.statoil.com/cg, where shareholders and other stakeholders can explore any topic of particular interest in more detail and easily navigate to related documentation.

Statoil's objective and principles

Statoil's objective is to create long-term value for its shareholders through the exploration for and production, transportation, refining and marketing of petroleum and petroleum-derived products and other forms of energy.

In pursuing its corporate objective, Statoil is committed to the highest standard of governance and to cultivating a values-based performance culture that rewards exemplary ethical practices, respect for the environment and personal and corporate integrity. Statoil believes that there is a link between high-quality governance and the creation of shareholder value.

The work of the board of directors is based on the existence of a clearly defined division of roles and responsibilities between the shareholders, the board of directors and the company's management.

Statoil's governing structures and controls help to ensure that Statoil runs its business in a profitable manner for the benefit of shareholders, employees and other stakeholders in the societies in which Statoil operates.

The following principles underline Statoil's approach to corporate governance:

- All shareholders will be treated equally
- Statoil will ensure that all shareholders have access to up-to-date, reliable and relevant information about its activities
- Statoil will have a board of directors that is independent (as defined by Norwegian Standards) of the group's management. The board focuses on preventing conflicts of interest between shareholders, the board of directors and the company's management
- The board of directors will base its work on the principles for good corporate governance applicable at all times

Corporate governance in Statoil is subject to regular review and discussion by the board of directors.

Articles of association

Statoil's current articles of association were adopted at the annual general meeting of shareholders on 14 May 2013, and last changed on 26 October 2016 following a share capital increase in connection to Statoil's scrip dividend program.

Summary of Statoil's articles of association:

Name of the company
The registered name is Statoil ASA. Statoil is a Norwegian public limited company.

Registered office
Statoil's registered office is in Stavanger, Norway, registered with the Norwegian Register of Business Enterprises under number 923 609 016.

Objective of the company
The objective of Statoil is, either by itself or through participation in or together with other companies, to engage in the exploration, production, transportation, refining and marketing of petroleum and petroleum-derived products, and other forms of energy, as well as other business.

Share capital
Statoil's share capital is NOK 8,112,623,528 divided into 3,245,049,411 ordinary shares.

Nominal value of shares
The nominal value of each ordinary share is NOK 2.50.

Board of directors
Statoil's articles of association provide that the board of directors shall consist of nine to 11 directors. The board, including the chair and the deputy chair, shall be elected by the corporate assembly for a period of up to two years.

Corporate assembly
Statoil has a corporate assembly comprising 18 members who are normally elected for a term of two years. The general meeting elects 12 members with four deputy members, and six members with deputy members are elected by and from among the employees.

General meetings of shareholders
Statoil's annual general meeting is held no later than 30 June each year. The meeting will consider the annual report and accounts, including the distribution of any dividend, and any other matters required by law or the articles of association.

Documents relating to matters to be dealt with at general meetings do not need to be sent to all shareholders if the documents are accessible on Statoil's website. A shareholder may nevertheless request that such documents be sent to him/her.

Shareholders may vote in writing, including through electronic communication, for a period before the general meeting. In order to practise advance voting, the board of directors must stipulate applicable guidelines. Statoil's board of directors adopted guidelines for such advance voting in March 2012, and these guidelines are described in the notices of the annual general meetings.

Marketing of petroleum on behalf of the Norwegian State
Statoil's articles of association provide that Statoil is responsible for marketing and selling petroleum produced under the SDFI's shares in production licences on the Norwegian continental shelf as well as petroleum received by the Norwegian State paid as royalty together with its own production. Statoil's general meeting adopted an instruction in respect of such marketing on 25 May 2001, as most recently amended by authorisation of the annual general meeting on 11 May 2016.

Nomination committee
The tasks of the nomination committee are to make recommendations to the general meeting regarding the election of and fees for shareholder-elected members and deputy members of the corporate assembly, to make recommendations to the corporate assembly regarding the election of and fees for shareholder-elected members of the board of directors, to make recommendations to the corporate assembly regarding the election of the chair and the deputy chair of the board and to make recommendations to the general meeting regarding the election of and fees for members of the nomination committee. The general meeting may adopt instructions for the nomination committee.

The articles of association are available at www.statoil.com/articlesofassociation.

Compliance with NYSE listing rules

Statoil's primary listing is on the Oslo Børs, but Statoil is also registered as a foreign private issuer with the US Securities and Exchange Commission and listed on the New York Stock Exchange.

American Depositary Shares represent the company's ordinary shares listed on the New York Stock Exchange (NYSE). While Statoil's corporate governance practices follow the requirements of Norwegian law, Statoil is also subject to the NYSE's listing rules.

As a foreign private issuer, Statoil is exempted from most of the NYSE corporate governance standards that domestic US companies must comply with. However, Statoil is required to disclose any significant ways in which its corporate governance practices differ from those applicable to domestic US companies under the NYSE rules. A statement of differences is set out below:

Corporate governance guidelines
The NYSE rules require domestic US companies to adopt and disclose corporate governance guidelines. Statoil's corporate governance principles are developed by the management and the board of directors, in accordance with the Norwegian Code of Practice for Corporate Governance and applicable law. Oversight of the board of directors and management is exercised by the corporate assembly.

Director independence
The NYSE rules require domestic US companies to have a majority of "independent directors". The NYSE definition of an "independent director" sets out five specific tests of independence and also requires an affirmative determination by the board of directors that the director has no material relationship with the company.

Pursuant to Norwegian company law, Statoil's board of directors consists of members elected by shareholders and employees. Statoil's board of directors has determined that, in its judgment, all of the shareholder-elected directors, except one, are independent. In making its determinations of independence, the board focuses inter alia on there not being any conflicts of interest between shareholders, the board of directors and the company's management. It does not strictly make its determination based on the NYSE's five specific tests, but take into consideration all relevant circumstances which may in the board's view affect the directors' independence. The directors elected from among Statoil's employees would not be considered independent under the NYSE rules because they are employees of Statoil. None of the employee-elected directors are an executive officer of the company.

For further information about the board of directors, see the section Board of directors.

Board committees
Pursuant to Norwegian company law, managing the company is the responsibility of the board of directors. Statoil has an audit committee, a safety, sustainability and ethics committee and a compensation and executive development committee. They are responsible for preparing certain matters for the board of directors. The audit committee and the compensation and executive development committee operate pursuant to charters that are broadly comparable to the form required by the NYSE rules. They report on a regular basis to, and are subject to, continuous oversight by the board of directors. For further information about the board's sub-committees, see the section Board of directors.

Statoil complies with the NYSE rule regarding the obligation to have an audit committee that meets the requirements of Rule 10A-3 of the US Securities Exchange Act of 1934.

As required by Norwegian company legislation, the members of Statoil's audit committee include an employee-elected director. Statoil relies on the exemption provided for in Rule 10A-3(b)(1)(iv)(C) from the independence requirements of the US Securities Exchange Act of 1934 with respect to the employee-elected director. Statoil does not believe that its reliance on this exemption will materially adversely affect the ability of the audit committee to act independently or to satisfy the other requirements of Rule 10A-3 relating to audit committees. The other members of the audit committee meet the independence requirements under Rule 10A-3.

Among other things, the audit committee evaluates the qualifications and independence of the company's external auditor. However, in accordance with Norwegian law, the auditor is elected by the annual general meeting of the company's shareholders.

Statoil does not have a nominating/corporate governance sub-committee formed from its board of directors. Instead, the roles prescribed for a nominating/corporate governance committee under the NYSE rules are principally carried out by the corporate assembly and the nomination committee which is elected by the general meeting of shareholders. NYSE rules require the compensation committee of US companies to comprise independent directors under the NYSE rules, recommend senior management remuneration and make a determination on the independence of advisors when engaging them. Statoil, as foreign private issuer, is exempt from complying with these rules and is permitted to follow its home country regulations. Statoil considers all, but one, its compensation committee members to be independent (under Statoil's framework which, as discussed above, is not identical to that of NYSE). Statoil's compensation committee makes recommendations to the board about management remuneration, including that of the CEO. The compensation committee assesses its own performance and has the authority to hire external advisors. The nomination committee, which is elected by the general meeting of shareholders, recommends to the corporate assembly the candidates and remuneration of the board of directors. Also, the nomination committee recommends to the general meeting of shareholders the candidates and remuneration of the corporate assembly and the nomination committee.

Shareholder approval of equity compensation plans

The NYSE rules require that, with limited exemptions, all equity compensation plans must be subject to a shareholder vote. Under Norwegian company law, although the issuance of shares and authority to buy back company shares must be approved by Statoil's annual general meeting of shareholders, the approval of equity compensation plans is normally reserved for the board of directors.

Deviations from the Code: None

3.2 BUSINESS

Statoil is an international energy company with headquarters in Stavanger, Norway, and the company has business operations in more than 30 countries and territories and approximately 20,500 employees worldwide. Statoil ASA is a public limited liability company organised under the laws of Norway and subject to the provisions of the Norwegian Public Limited Liability Companies Act. The Norwegian State is the largest shareholder in Statoil ASA, with a direct ownership interest of 67%. Statoil is the leading operator on the Norwegian continental shelf (NCS) and is also expanding its international activities.

Statoil is among the world's largest net sellers of crude oil and condensate and is the second-largest supplier of natural gas to the European market. Statoil also has substantial processing and refining operations, contributes to the development of new energy resources, has on-going offshore wind activities internationally and is at the forefront of the implementation of technology for carbon capture and storage (CCS).

Statoil's objective is defined in the articles of association (www.statoil.com/articlesofassociation). We shall, either on our own or through participation in or together with other companies, engage in exploration, production, transportation, refining and marketing of petroleum and petroleum-derived products, and other forms of energy, as well as other business.

Statoil's vision is to "shape the future of energy". The board and the administration have formulated a corporate strategy to deliver on this vision. It has been translated into concrete objectives and targets to align strategy execution across the company.

To succeed going forward in turning our vision into reality, we pursue a strategy around the following pillars:

- Norwegian continental shelf - Build on unique position to maximise and develop long-term value
- International Oil & Gas - Deepen core areas and develop growth options
- New Energy Solutions - Create a new material industrial position
- Midstream and Marketing - Secure market access and grow value creation through cycles

To enable strategy execution, Statoil will research, develop, and deploy technology to create opportunities and enhance the value of our current and future assets.

In pursuing our vision and strategy, we are committed to the highest standard of governance and to cultivating a values-based performance culture that rewards exemplary ethical practices, respect for the environment and personal and corporate integrity. We believe that there is a link between high-quality governance and the creation of shareholder value.

Deviations from the Code: None

3.3 EQUITY AND DIVIDENDS

It is Statoil's ambition to grow the annual cash dividend, measured in USD per share, in line with long term underlying earnings. Statoil announces dividends on a quarterly basis.

Shareholders' equity

The company's shareholders' equity at 31 December 2016 amounted to USD 35,072 million (excluding USD 27 million in non-controlling interest, minority interest), equivalent to 33.6% of the company's total assets. The board considers this to be satisfactory given the company's requirement for financial soundness in relation to its expressed goals, strategy and risk profile.

Any increase of the company's share capital must be mandated by the general meeting. If a mandate was to be granted to the board of directors to increase the company's share capital, such mandate would be restricted to a defined purpose. If the general meeting is to consider mandates to the board of directors for the issue of shares for different purposes, each mandate would be considered separately by the meeting.

Dividend policy

It is Statoil's ambition to grow the annual cash dividend, measured in USD per share, in line with long term underlying earnings. Statoil announces dividends on a quarterly basis. The board approves first, second and third quarter interim dividends based on an authorisation from the general meeting, while the annual general meeting approves the fourth quarter (and total annual) dividend based on a proposal from the board. When deciding the interim dividends and recommending the total annual dividend level, the board will take into consideration expected cash flow, capital expenditure plans, financing requirements and appropriate financial flexibility. In addition to cash dividend, Statoil might buy back shares as part of total distribution of capital to the shareholders.

The shareholders at the AGM may vote to reduce, but may not increase, the fourth quarter dividend proposed by the board of directors. It is Statoil's intention to have this authorization approved by the AGM. Statoil announces dividend payments in connection with quarterly results. Payment of quarterly dividends is expected to take place approximately five months after the announcement of each quarterly dividend.

From the second quarter of 2015 Statoil started declaring dividends in USD. Dividends in NOK per share will be calculated and communicated four business days after record date for shareholders at Oslo Børs.

The board of directors will propose to the annual general meeting to maintain a dividend of USD 0.2201 per share fourth quarter 2016 and to continue the two-year scrip dividend programme introduced from the fourth quarter 2015. The scrip programme gives shareholders the option to receive quarterly dividends in cash or in newly issued shares in Statoil, at a 5% discount for the fourth quarter 2016. On May 2016, Statoil and the Norwegian state entered into a two-year agreement whereby the Norwegian state shall use its quarterly dividend to subscribe for the number of shares that is required to maintain its ownership of 67%.

Buy-back of own shares for subsequent annulment

In addition to a cash dividend, Statoil might buy back shares as part of the total distribution of capital to the shareholders. In order to be able to buy back shares the board of directors will need an authorisation from the general assembly. Such authorisation must be renewed on an annual basis. At the annual general meeting on 11 May 2016, the board was authorised to acquire in the market, on behalf of the company, Statoil ASA shares with a nominal value of up to NOK 187,500,000. Within minimum and maximum prices of NOK 50 and NOK 500, respectively, the board was authorised to decide at what price and at what time such acquisition should take place. Own shares acquired pursuant to this authorisation could only be used for annulment through a reduction of the company's share capital, pursuant to the Public Limited Companies Act section 12-1. It was also a precondition for the repurchase and the annulment of own shares that the state's ownership interest in Statoil ASA was not changed. In order to achieve this, a proposal for the redemption of a proportion of the state's shares, so that the state's ownership interest in the company remains unchanged, would also be put forward at the later general meeting which was to decide the annulment of the repurchased shares. The authorisation remains valid until the next annual general meeting, but no longer than until 30 June 2017. As of 1 March 2017, the board has not used this authorisation to buy back own shares for subsequent annulment.

Purchase of own shares for use in the share savings programme

Since 2004, Statoil has had a share savings plan for its employees. The purpose of this plan is to strengthen the business culture and encourage loyalty through employees becoming part-owners of the company. The annual general meeting annually authorises the board to acquire Statoil shares in the market in order to continue implementation of the employees share savings plan. The authorisation remains valid until the next annual general meeting, but no longer than until 30 June the following year.

On 11 May 2016, the board was authorised on behalf of the company to acquire Statoil ASA shares for a total nominal value of up to NOK 42,000,000 for use in the share savings plan for own employees.

Deviations from the Code: None

3.4 EQUAL TREATMENT OF SHAREHOLDERS AND TRANSACTIONS WITH CLOSE ASSOCIATES

Equal treatment of all shareholders is a core governance principle in Statoil. Statoil has one class of shares, and each share confers one vote at the general meeting. The articles of association contain no restrictions on voting rights and all shares have equal rights. The nominal value of each share is NOK 2.50. The repurchase of own shares for use in the share savings programme for employees (or, if applicable, for subsequent cancellation) is carried out through the Oslo Børs.

The Norwegian State as majority owner

The Norwegian State is the majority shareholder of Statoil and also holds major investments in other Norwegian companies. As of 31 December 2016 the Norwegian State had an ownership interest in Statoil of 67% (excluding Folketrygdfondet's (Norwegian national insurance fund) ownership interest of 3.22%). This ownership structure means that Statoil participates in transactions with many parties that are under a common ownership structure and therefore meet the definition of a related party. All transactions are considered to be on an arm's length basis. The State's ownership interest in Statoil is managed by the Norwegian Ministry of Petroleum and Energy.

The Norwegian State's ownership policy is that the principles in the Norwegian Code of Practice for Corporate Governance will apply to state ownership and the Government has stated that it expects companies in which the State has ownership interests to adhere to the Code. The principles are presented in the State's annual ownership reports.

Contact between the State as owner and Statoil takes place in the same manner as for other institutional investors. In all matters in which the State acts in its capacity as shareholder, exchanges with the company are based on information that is available to all shareholders. We ensure that, in any interaction between the Norwegian State and Statoil, a distinction is drawn between the State's different roles.

The State has no appointed board members or members of the corporate assembly in Statoil. As majority shareholder, the State has appointed a member of Statoil's nomination committee.

Sale of the State's oil and gas
Pursuant to Statoil's articles of association, Statoil markets and sells the Norwegian State's share of oil and gas production from the Norwegian continental shelf together with its own production. The Norwegian State has a common ownership strategy aimed at maximising the total value of its ownership interests in Statoil and its own oil and gas interests. This is incorporated in the marketing instruction, which obliges Statoil, in its activities on the Norwegian continental shelf, to emphasise these overall interests in decisions that may be of significance to the implementation of the sales arrangements.

The state-owned oil company Petoro AS handles commercial matters relating to the Norwegian State's direct involvement in petroleum activities on the Norwegian continental shelf and pertaining activities.

Other transactions
In relation to its ordinary business operations such as pipeline transport, gas storage and processing of petroleum products, Statoil also has regular transactions with certain entities in which Statoil has ownership interests. Such transactions are carried out on an arm's length basis.

Requirements for board members and management
It follows from our Code of Conduct, which applies to both management, employees and board members, that individuals must behave impartially in all business dealings and not give other companies, organisations or individuals improper advantages. The importance of openness is underlined, and any situations that might lead to an actual or perceived conflict of interest should be discussed with the individual's leader. All external directorships or other material assignments held or carried out by Statoil employees must be approved by Statoil.

The board's rules of procedures state that members of the board and the chief executive officer may not participate in the discussion or decision of issues which are of special personal importance to them, or to any closely-related party, so that the individual must be regarded as having a major personal or special financial interest in the matter. Each board member and the chief executive officer are individually responsible for ensuring that they are not disqualified from discussing any particular matter. Members of the board are obliged to disclose any interests they themselves or their closely-related parties may have in the outcome of a particular issue. The board must approve any agreement between the company and a member of the board or the chief executive officer. The board must also approve any agreement between the company and a third party in which a member of the board or the chief executive officer may have a special interest. Each member of the board shall also continually assess whether there are circumstances which could undermine the general confidence in the board member's independence. It is incumbent on each board member to be especially vigilant when making such assessments in connection with the board's handling of transactions, investments and strategic decisions. The board member shall immediately notify the chair of the board if such circumstances are present or arise and the chair of the board will determine how the matter will be dealt with.

Deviations from the Code: None

3.5 FREELY NEGOTIABLE SHARES

Statoil's primary listing is on the Oslo Børs. Our American Depository Rights (ADRs) are traded on the New York Stock Exchange. Each Statoil ADR represents one underlying ordinary share.

Statoil's articles of association contain no form of restriction on the negotiability of its shares and the shares and ADRs are freely negotiable.

Deviations from the Code: None

3.6 GENERAL MEETING OF SHAREHOLDERS

The general meeting of shareholders is Statoil's supreme corporate body. It serves as a democratic and effective forum for interaction between the company's shareholders, board of directors and management.

The next annual general meeting (AGM) is scheduled for 11 May 2017 in Stavanger, Norway, with simultaneous transmission by webcast through our website. The AGM is conducted in Norwegian, with simultaneous English translation during the webcast. At Statoil's AGM on 11 May 2016, 76.79% of the share capital was represented either by advance voting, in person or by proxy.

The main framework for convening and holding Statoil's AGM is as follows:
Pursuant to Statoil's articles of association, the AGM must be held by the end of June each year. Notice of the meeting and documents relating to the AGM are published on Statoil's website and notice is sent to all shareholders with known addresses at least 21 days prior to the meeting. All shareholders who are registered in the Norwegian Central Securities Depository (VPS) will receive an invitation to the AGM. Other documents relating to Statoil's AGMs will be made available on Statoil's website. A shareholder may nevertheless request that documents that relate to matters to be dealt with at the AGM be sent to him/her.

Shareholders are entitled to have their proposals dealt with at the AGM if the proposal has been submitted in writing to the board of directors in sufficient time to enable it to be included in the notice of meeting, i.e. no later than 28 days before the meeting. Shareholders who are unable to attend may vote by proxy.

As described in the notice of the general meeting, shareholders may vote in writing, including through electronic communication, for a period before the general meeting.

The AGM is normally opened and chaired by the chair of the corporate assembly. If there is a dispute concerning individual matters and the chair of the corporate assembly belongs to one of the disputing parties, or is for some other reason not perceived as being impartial, another person will be appointed to chair the AGM. This is in order to ensure impartiality in relation to the matters to be considered. As Statoil has a large number of shareholders with a wide geographic distribution, Statoil offers shareholders the opportunity to follow the AGM by webcast.

The following matters are decided at the AGM:

- Approval of the board of directors' report, the financial statements and any dividend proposed by the board of directors and recommended by the corporate assembly
- Election of the shareholders' representatives to the corporate assembly and approval of the corporate assembly's fees
- Election of the nomination committee and approval of the nomination committee's fees
- Election of the external auditor and approval of the auditor's fee
- Any other matters listed in the notice convening the AGM

All shares carry an equal right to vote at general meetings. Resolutions at general meetings are normally passed by simple majority. However, Norwegian company law requires a qualified majority for certain resolutions, including resolutions to waive preferential rights in connection with any share issue, approval of a merger or demerger, amendment of the articles of association or authorisation to increase or reduce the share capital. Such matters require the approval of at least two-thirds of the aggregate number of votes cast as well as two-thirds of the share capital represented at the general meeting.

If shares are registered by a nominee in the Norwegian Central Securities Depositary (VPS), cf. section 4-10 of the Norwegian Public Limited Liability Companies Act, and the beneficial shareholder wants to vote for their shares, the beneficial shareholder must re-register the shares in a separate VPS account in their own name prior to the general meeting. If the holder can prove that such steps have been taken and that the holder has a de facto shareholder interest in the company, the company will allow the shareholder to vote for the shares. Decisions regarding voting rights for shareholders and proxy holders are made by the person opening the meeting, whose decisions may be reversed by the general meeting by simple majority vote.

The minutes of the AGM are made available on Statoil's website immediately after the AGM.

As regards to extraordinary general meetings (EGM), an EGM will be held in order to consider and decide a specific matter if demanded by the corporate assembly, the chair of the corporate assembly, the auditor or shareholders representing at least 5% of the share capital. The board must ensure that an EGM is held within a month of such demand being submitted.

In the following, certain types of resolutions by the general meeting of shareholders are outlined:

New share issues

If Statoil issues any new shares, including bonus shares, the articles of association must be amended. This requires the same majority as other amendments to the articles of association. In addition, under Norwegian law, the shareholders have a preferential right to subscribe for new shares issued by Statoil. The preferential right to subscribe for an issue may be waived by a resolution of a general meeting passed by the same percentage majority as required to approve amendments to the articles of association. The general meeting may, with a majority as described above, authorise the board of directors to issue new shares, and to waive the preferential rights of shareholders in connection with such share issues. Such authorisation may be effective for a maximum of two years, and the par value of the shares to be issued may not exceed 50% of the nominal share capital when the authorisation was granted.

The issuing of shares through the exercise of preferential rights to holders who are citizens or residents of the USA may require Statoil to file a registration statement in the USA under US securities laws. If Statoil decides not to file a registration statement, these holders may not be able to exercise their preferential rights.

Right of redemption and repurchase of shares

Statoil's articles of association do not authorise the redemption of shares. In the absence of authorisation, the redemption of shares may nonetheless be decided upon by a general meeting of shareholders by a two-thirds majority on certain conditions. However, such share redemption would, for all practical purposes, depend on the consent of all shareholders whose shares are redeemed.

A Norwegian company may purchase its own shares if authorisation to do so has been granted by a general meeting with the approval of at least two-thirds of the aggregate number of votes cast as well as two-thirds of the share capital represented at the general meeting. The aggregate par value of such treasury shares held by the company must not exceed 10% of the company's share capital, and treasury shares may only be acquired if, according to the most recently adopted balance sheet, the company's distributable equity exceeds the consideration to be paid for the shares. Pursuant to Norwegian law, authorisation by the general meeting cannot be granted for a period exceeding 18 months.

Distribution of assets on liquidation

Under Norwegian law, a company may be wound up by a resolution of the company's shareholders at a general meeting passed by both a two-thirds majority of the aggregate votes cast and a two-thirds majority of the aggregate share capital represented at the general meeting. The shares are ranked equally in the event of a return on capital by the company upon winding up or otherwise.

Deviations from the Code:

The Code recommends that the board of directors, the nomination committee and the company's auditor are present at the general meetings. Due to the nature of the discussions at general meetings, Statoil has not deemed it necessary to require the presence of all members of the board of directors and the nomination committee. The chair of the board, our external auditor, the chair of the nomination committee, as well as the chair of the corporate assembly, the CEO and other members of management, are, however, always present at general meetings.

3.7 NOMINATION COMMITTEE

Pursuant to Statoil's articles of association, the nomination committee shall consist of four members who are shareholders or representatives of shareholders. The duties of the nomination committee are set forth in the articles of association, and the instructions for the committee are adopted by the general meeting of shareholders.

The duties of the nomination committee are to submit recommendations to:

- the annual general meeting for the election of shareholder-elected members and deputy members of the corporate assembly, and the remuneration of members of the corporate assembly
- the annual general meeting for the election and remuneration of members of the nomination committee
- the corporate assembly for the election of shareholder-elected members of the board of directors and remuneration of the members of the board of directors and
- the corporate assembly for the election of the chair and deputy chair of the corporate assembly

The nomination committee would like to ensure that the shareholders' views are taken into consideration when candidates to the governing bodies of Statoil ASA are proposed. The nomination committee invites in writing Statoil's largest shareholders to propose shareholder-elected candidates of the corporate assembly and the board of directors, as well as members of the nomination committee. The shareholders are also invited to provide input to the nomination committee in respect of the composition and competence of Statoil's governing bodies in light of Statoil's strategies and challenges going forward. The deadline for providing input is normally set to early January in order to secure that the response is taken into account in the upcoming nominations. In addition, all shareholders have an opportunity to submit proposals through an electronic mailbox as described on Statoil's website. In the board nomination process, the board shares with the nomination committee the results from the annual, normally externally facilitated board evaluation with input from both management and the board. Separate meetings are held between the nomination committee and each board member, including employee-elected board members. The chair of the board and the chief executive officer are invited, without having the right to vote, to attend at least one meeting of the nomination committee before it makes its final recommendations. The committee regularly utilises external expertise in its work.

The members of the nomination committee are elected by the annual general meeting. The chair of the nomination committee and one other member are elected from among the shareholder-elected members of the corporate assembly. Members of the nomination committee are normally elected for a term of two years.

Personal deputy members for one or more of the nomination committee's members may be elected in accordance with the same criteria as described above. A deputy member normally only meets for the permanent member if the appointment of that member terminates before the term of office has expired.

Statoil's nomination committee consists of the following members as per 31 December 2016 and are elected for the period up to the annual general meeting in 2018:

- Tone Lunde Bakker (chair), Global head of cash management at Danske Bank (also chair of Statoil's corporate assembly)
- Tom Rathke, Group executive vice president Wealth Management at DnB
- Elisabeth Berge, Secretary general, Norwegian Ministry of Petroleum and Energy (personal deputy for Elisabeth Berge is Bjørn Ståle Haavik, Director at the Norwegian Ministry of Petroleum and Energy)
- Jarle Roth, CEO of Arendals Fossekompani ASA (also a member of Statoil's corporate assembly)

The board considers all members of the nomination committee to be independent of Statoil's management and board of directors. The general meeting decides the remuneration of the nomination committee.

The nomination committee held 15 ordinary meetings and four telephone meetings in 2016.

The instructions for the nomination committee are available at www.statoil.com/nominationcommittee.

Deviations from the Code: None

3.8 CORPORATE ASSEMBLY, BOARD OF DIRECTORS AND MANAGEMENT

Corporate assembly

Pursuant to the Norwegian Public Limited Liability Companies Act, companies with more than 200 employees must elect a corporate assembly unless otherwise agreed between the company and a majority of its employees.

In accordance with Statoil's articles of association, the corporate assembly normally consists of 18 members, 12 of whom (with four deputy members) are nominated by the nomination committee and elected by the annual general meeting. They represent a broad cross-section of the company's shareholders and stakeholders. Six members, with deputy members, and three observers are elected by and among our employees. Such employees are non-executive personnel. The corporate assembly elects its own chair and deputy chair from and among its members.

Members of the corporate assembly are normally elected for a term of two years. Members of the board of directors and management cannot be members of the corporate assembly, but they are entitled to attend and to speak at meetings of the corporate assembly unless the corporate assembly decides otherwise in individual cases. All members of the corporate assembly live in Norway. Members of the corporate assembly do not have service contracts with the company or its subsidiaries providing for benefits upon termination of office.

An overview of the members and observers of the corporate assembly as of 31 December 2016 follows below.

Name	Occupation	Place of residence	Year of birth	Position	Family relations to corporate executive committee, board or corporate assembly members	Share ownership for members as of 31.12.2016	Share ownership for members as of 08.03.2017	First time elected	Expiration date of current term
Tone Lunde Bakker	Global head of cash management at Danske Bank	Oslo	1962	Chair, Shareholder-elected	No	0	0	2014	2018
Nils Bastiansen	Executive director of equities in Folketrygdfondet	Oslo	1960	Deputy chair, Shareholder-elected	No	0	0	2016	2018
Jarle Roth	CEO, Arendals Fossekompani ASA	Bærum	1960	Shareholder-elected	No	43	43	2016	2018
Greger Mannsverk	Managing director, Kimek AS	Kirkenes	1961	Shareholder-elected	No	0	0	2002	2018
Steinar Olsen	CEO, Jemso A/S	Stavanger	1949	Shareholder-elected	No	0	0	2007	2018
Kathrine Næss	Plant manager at the aluminium smelter at Alcoa Mosjøen	Mosjøen	1979	Shareholder-elected	No	0	0	2016	2018
Ingvald Strømmen	Dean at Norwegian University of Science and Technology (NTNU)	Ranheim	1950	Shareholder-elected	No	0	0	2006	2018
Rune Bjerke	President and CEO, DNB ASA	Oslo	1960	Shareholder-elected	No	0	0	2007	2018
Birgitte Ringstad Vartdal	CEO of the dry bulk shipping company Golden Ocean Group Ltd	Oslo	1977	Shareholder-elected	No	0	0	2016	2018
Siri Kalvig	Associate professor, University of Stavanger	Stavanger	1970	Shareholder-elected	No	0	0	2010	2018
Terje Venold	Independent advisor with various directorships	Bærum	1950	Shareholder-elected	No	519	519	2014	2018
Kjersti Kleven	Co-owner of John Kleven AS	Ulsteinvik	1967	Shareholder-elected	No	0	0	2014	2018
Brit Gunn Ersland	Union representative, Tekna. Prosj leder Res Tek	Bergen	1960	Employee-elected	No	2072	2270	2011	2017
Steinar Kåre Dale	Union representative, NITO, SR Analyst	Mongstad	1961	Employee-elected	No	3033	1931	2013	2017
Per Martin Labråten	Union representative, Industri Energi. Production technician	Brevik	1961	Employee-elected	No	983	1151	2007	2017
Anne K.S. Horneland	Union representative, Industri Energi	Hafrsfjord	1956	Employee-elected	No	5216	5498	2006	2017
Jan-Eirik Feste	Union representative, YS	Lindås	1952	Employee-elected	No	1251	1437	2008	2017
Hilde Møllerstad	Union representative, Tekna/NITO	Oslo	1966	Employee-elected	No	3338	3642	2013	2017
Per Helge Ødegård	Union representative, Lederne. Discipl resp operation process	Porsgrunn	1963	Employee-elected, observer	No	1181	1361	1994	2017
Dag-Rune Dale	Union representative, Industri Energi, Safety officer	Kollsnes	1963	Employee-elected, observer	No	3334	3555	2013	2017
Sun Lehmann	Union representative, Tekna. Advisor Data Management	Trondheim	1972	Employee-elected, observer	No	3608	3924	2015	2017
Total						24,578	25,331		

An election of shareholder-elected members of the corporate assembly was held at Statoil's annual general meeting 11 May 2016. Effective as of 12 May 2016, Nils Bastiansen, Birgitte Ringstad Vartdal (former deputy member), Jarle Roth and Kathrine Næss were elected as new members of the corporate assembly, while Kjerstin Fyllingen, Håkon Volldal and Kari Skeidsvoll Moe were elected as new deputy members. Olaug Svarva (chair), Idar Kreutzer (deputy chair), Karin Aslaksen (member), Barbro Hætta (member), Arthur Sletteberg (deputy member) and Bassim Haj (deputy member) left the corporate assembly as of the same date. On 7 June 2016 the corporate assembly elected Tone Lunde Bakker as chair, and Nils Bastiansen as deputy chair, of the corporate assembly.

The duties of the corporate assembly are defined in section 6-37 of the Norwegian Public Limited Liability Companies Act. The corporate assembly elects the board of directors and the chair of the board and can vote separately on each nominated candidate. Its responsibilities also include overseeing the board and the CEO's management of the company, making decisions on investments of considerable magnitude in relation to the company's resources, and making decisions involving the rationalisation or reorganisation of operations that will entail major changes in or reallocation of the workforce.

Statoil's corporate assembly held four ordinary meetings in 2016, and visited Statoil's operation center for logistics and emergency response in Bergen in connection with one of the meetings. The chair of the board participated at four meetings, and the CEO at three meetings (with the CFO acting on his behalf at one meeting). Other members of management were also present at the meetings.

The procedure for the work of the corporate assembly, as well as an updated overview of its members, is available at www.statoil.com/corporateassembly.

Board of directors

Pursuant to Statoil's articles of association, the board of directors consists of between nine and 11 members elected by the corporate assembly. The chair of the board and the deputy chair of the board are also elected by the corporate assembly. At present, Statoil's board of directors consists of 10 members. As required by Norwegian company law, the company's employees are represented by three board members.

The employee-elected board members, but not the shareholder-elected board members, have four deputy members who attend board meetings in the event an employee-elected member of the board is unable to attend. The management is not represented on the board of directors. Members of the board are elected for a term of up to two years, normally for one year at a time. There are no board member service contracts that provide for benefits upon termination of office.

The board considers its composition to be diverse and competent with respect to the expertise, capacity and diversity appropriate to attend to the company's goals, main challenges, and the common interest of all shareholders. The board also deems its composition to be made up of individuals who are willing and able to work as a team, resulting in the board working effectively as a collegiate body. At least one board member qualifies as "audit committee financial expert", as defined in the US Securities and Exchange Commission requirements. Five board members are women and three board members are non-Norwegians resident outside of Norway.

Statoil's board of directors has determined that, in its judgment, all of the shareholder representatives on the board, except for Wenche Agerup, are considered independent. Under the NYSE rules, a director will not be considered independent if the director is, or was within the past three years, an executive officer of another company at which any of the listed company's current executive officers are, or were within the past three years, members of the compensation committee. Wenche Agerup was a member of Norsk Hydro ASA's management team while Irene Rummelhoff, Executive Vice President of New Energy Solutions in Statoil, was member of the board's compensation committee in Norsk Hydro. Agerup is therefore deemed as a non-independent board member until 31 December 2017.

The board held eight ordinary board meetings and two extraordinary meetings in 2016. Average attendance at these board meetings was 98,1%.

Further information about the members of the board and its sub-committees, including information about expertise, experience, other directorships, independence, share ownership and loans, is available below as well as on our website at www.statoil.com/board which is regularly updated.

Members of the board of directors as of 31 December 2016:

Øystein Løseth
Born: 1958
Position: Shareholder-elected chair of the board and chair of the board's compensation and executive committee.
Term of office: Member of the board of directors of Statoil ASA since 1 October 2014, and since 1 July 2015, also chair of the board and chair of the board's compensation and executive development committee. Up for election in 2017.
Independent: Yes
Other directorships: Chair of the board of Eidsiva Energi AS and Hunton Fiber AS.
Number of shares in Statoil ASA as of 31 December 2016: 1,040
Loans from Statoil: None
Experience: In the period 2010 - 2014, Løseth was the CEO, and before that First Senior Executive Vice President since 2009, of Vattenfall AB. In the period 2003 - 2009, Løseth worked for NUON, a Dutch energy company, first as Division Managing Director, then as a Managing Director and the CEO, from 2006 and 2008 respectively. From 2002 to 2003, Løseth was the Head of Production, Business Development and R&D of Statkraft. In addition,

he has other extensive management experience from Statkraft and Statoil, within strategy and business development among others.
Education: Løseth graduated as M.Sc. from the Norwegian University of Science and Technology and has a degree in Economics from BI Norwegian School of Management in Bergen.
Family relations: No family relations to other members of the board, members of the corporate executive committee or the corporate assembly.
Other matters: In 2016, Løseth participated in eight ordinary board meetings, two extraordinary board meetings, five meetings of the compensation and executive development committee and one meeting in the safety, sustainability and ethics committee. Løseth is a Norwegian citizen and resident in Norway.

Roy Franklin
Born: 1953
Position: Shareholder-elected deputy chair of the board, chair of the board's safety, sustainability and ethics committee and member of the board's audit committee.
Term of office: Board member and deputy chair of the board of Statoil ASA from 1 July 2015. Franklin was also previously a member of the board of StatoilHydro from October 2007 and Statoil from November 2009 until June 2013. Up for election in 2017.
Independent: Yes
Other directorships: Non-executive chair of the board of Cuadrilla Resources Holdings Limited, a privately held UK company focusing on unconventional energy sources. Board member of the Australian oil and gas company Santos Ltd, the private equity firm Kerogen Capital Ltd and the London-based international engineering company Amec Foster Wheeler.
Number of shares in Statoil ASA as of 31 December 2016: None
Loans from Statoil ASA: None
Experience: Franklin has broad experience from management positions in several countries, including positions with BP, Paladin Resources plc and Clyde Petroleum plc.
Education: Franklin has a Bachelor of Science in Geology from the University of Southampton, UK.
Family relations: No family relations to other members of the board, members of the corporate executive committee or the corporate assembly.
Other matters: In 2016, Franklin participated in eight ordinary board meetings, two extraordinary board meetings, five meetings of the audit committee and six meetings of the safety, sustainability and ethics committee. Franklin is a UK citizen and resident in UK.

Bjørn Tore Godal
Born: 1945
Position: Shareholder-elected member of the board, the board's compensation and executive development committee and the board's safety, sustainability and ethics committee.
Term of office: Member of the board of Statoil ASA from 1 September 2010. Up for election in 2017.
Independent: Yes
Other directorships: Vice chair of the board of the Fridtjof Nansen Institute (FNI).
Number of shares in Statoil ASA as of 31 December 2016: None
Loans from Statoil ASA: None
Experience: Godal was a member of the Norwegian parliament for 15 years during the period 1986-2001. At various times, he served as minister for trade and shipping, minister for defense, and minister of foreign affairs for a total of eight years between 1991 and 2001. From 2007-2010, Godal was special adviser for international energy and climate issues at the Norwegian Ministry of Foreign Affairs. From 2003-2007, Godal was Norway's ambassador to Germany and from 2002-2003 he was senior adviser at the department of political science at the University of Oslo. From 2014-2016, Godal lead a government-appointed committee responsible for the evaluation of the civil and military contribution from Norway in Afghanistan in the period 2001 - 2014.
Education: Godal has a bachelor of arts degree in political science, history and sociology from the University of Oslo.
Family relations: No family relations to other members of the board, members of the corporate executive committee or the corporate assembly.
Other matters: In 2016, Godal participated in eight ordinary board meetings, two extraordinary board meetings, five meetings of the compensation and executive development committee and three meetings of the safety, sustainability and ethics committee. Godal is a Norwegian citizen and resident in Norway.

Maria Johanna Oudeman
Born: 1958
Position: Shareholder-elected member of the board and member of the board's compensation and executive development committee.
Term of office: Member of the board of Statoil ASA since 15 September 2012. Up for election in 2017.
Independent: Yes
Other directorships: Oudeman is a member of the boards of Solvay SA, Het Concertgebouw, Rijksmuseum and SHV Holdings.
Number of shares in Statoil ASA as of 31 December 2016: None
Loans from Statoil: None
Experience: Oudeman is the President of Utrecht University in the Netherlands, one of Europe's leading universities. From 2010 to 2013, Oudeman was a member of the Executive Committee of Akzo Nobel, responsible for HR and Organisational Development. Akzo Nobel is the world's largest paint and coatings company and major producer of specialty chemicals, with operations in more than 80 countries. Before joining Akzo Nobel, she was Executive Director Strip Products Division at Corus Group, now Tata Steel Europe. Oudeman has extensive experience as a line manager in the steel industry and considerable international business experience.
Education: Oudeman has a law degree from Rijksuniversiteit Groningen in the Netherlands and an MBA in business administration from the University of Rochester, New York, USA and Erasmus University, Rotterdam, the Netherlands.
Family relations: No family relations to other members of the board, members of the corporate executive committee or the corporate assembly.
Other matters: In 2016, Oudeman participated in eight ordinary board meetings, two extraordinary board meetings and four meetings of the compensation and executive development committee. Oudeman is a Dutch citizen and resident in the Netherlands.

Rebekka Glasser Herlofsen
Born: 1970
Position: Shareholder-elected member of the board and the board's audit committee.
Term of office: Member of the board of Statoil ASA since 19 March 2015. Up for election in 2017.
Independent: Yes
Other directorships: Member of the board of directors of DNV Foundation, DNV Holding, DNV GL, and member of the committee for tax and capital in the Norwegian Shipowners' Association.
Number of shares in Statoil ASA as of 31 December 2016: None
Loans from Statoil: None
Experience: Since 2012, Herlofsen has been the Chief Financial Officer in the shipping company Torvald Klaveness. She will during the first half of 2017 take on a new position as Chief Financial Officer in WWL ASA, an international shipping company under establishment. She has broad financial and strategic experience from several corporations and board directorships. Herlofsen's professional career began in the Nordic Investment Bank, Enskilda Securities, where she worked with corporate finance from 1995 to 1999 in Oslo and London. During the next ten years Herlofsen worked in the Norwegian shipping company Bergesen d.y. ASA (later BW Group). During her period with Bergesen d.y. ASA/BW Group Herlofsen held leading positions within M&A, strategy and corporate planning and was part of the group management team.
Education: MSc in Economics and Business Administration (Siviløkonom) and Certified Financial Analyst Program (AFA), the Norwegian School of Economics (NHH). Breakthrough Program for Top Executives at IMD business school, Switzerland.
Family relations: No family relations to other members of the board, members of the corporate executive committee or the corporate assembly.
Other matters: In 2016, Herlofsen participated in eight ordinary board meetings, two extraordinary board meeting and six meetings of the audit committee. Herlofsen is a Norwegian citizen and resident in Norway.

Wenche Agerup
Born: 1964
Position: Shareholder-elected member of the board, the board's compensation and executive development committee and the board's safety, sustainability and ethics committee.
Term of office: Member of the board of Statoil ASA since 21 August 2015. Up for election in 2017.
Independent: No.
Under the NYSE rules, a director will not be considered independent under the NYSE rules if the director is, or was within the past three years, an executive officer of another company at which any of the listed company's current executive officers are, or were within the past three years, members of the compensation committee. Agerup was a member of Norsk Hydro ASA's management team while Irene Rummelhoff, Executive Vice President of New Energy Solutions in Statoil, was member of the board's compensation committee in Norsk Hydro. Agerup is therefore deemed as a non-independent board member in Statoil until 31 December 2017.
Other directorships: Agerup is a member of the board of the seismic company TGS ASA and a member of Det Norske Veritas Council.
Number of shares in Statoil ASA as of 31 December 2016: 2,522
Loans from Statoil: None
Experience: Agerup is an Executive Vice President (Corporate Affairs) and General Counsel in Telenor ASA. Agerup was the Executive Vice President for Corporate Staffs and the General Counsel of Norsk Hydro ASA from 2010 to 31 December 2014. She has held various executive roles in Hydro since 1997, including within the company's M&A-activities, the business area Alumina, Bauxite and Energy, as a plant manager at Hydro's metal plant in Årdal and as a project director for a Joint Venture in Australia where Hydro cooperated with the Australian listed company UMC.
Education: MA in Law from the University of Oslo, Norway (1989) and a Master of Business Administration from Babson College, USA (1991).
Family relations: No family relations to other members of the board, members of the corporate executive committee or the corporate assembly.
Other matters: In 2016, Agerup participated in seven ordinary board meetings, two extraordinary board meetings, five meetings of the compensation and executive development committee and five meetings of the safety, sustainability and ethics committee. Agerup is a Norwegian citizen and resident in Norway.

Jeroen van der Veer
Born: 1947
Position: Shareholder-elected member of the board and chair of the board's audit committee.
Term of office: Member of the board of Statoil ASA since 18 March 2016. Up for election in 2017.
Independent: Yes
Other directorships: Van der Veer is the chair of the supervisory boards of ING Bank NV and Royal Philips Electronics, chair of the supervisory council of Technical University of Delft and Platform Betatechniek, chair of the advisory board of the Rotterdam Climate Initiative as well as a board member in Boskalis Westminster Groep NV and Het Concertbebouw.
Number of shares in Statoil ASA as of 31 December 2016: None
Loans from Statoil: None
Experience: Van der Veer was the Chief Executive Officer in the international oil and gas company Royal Dutch Shell Plc (Shell) in the period 2004 to 2009 when he retired. Van der Veer thereafter continued as a non-executive director on the board of Shell until 2013. He started to work for Shell in 1971 and has experience within all sectors of the business and has significant competence within corporate governance.
Education: Van der Veer has a degree in Mechanical Engineering (MSc) from Delft University of Technology, Netherlands and a degree in Economics (MSc) from Erasmus University, Rotterdam, Netherlands. Since 2005 he holds an honorary doctorate from the University of Port Harcourt, Nigeria.
Family relations: No family relations to other members of the board, members of the corporate executive committee or the corporate assembly.
Other matters: In 2016, van der Veer participated in six ordinary board meetings, one extraordinary board meetings and three meetings of the audit committee. Van der Veer is a Dutch citizen and resident in Netherlands.

Lill-Heidi Bakkerud
Born: 1963
Position: Employee-elected member of the board and member of the board's safety, sustainability and ethics committee.
Term of office: Member of the board of Statoil ASA from 1998 to 2002, and again since 2004. Up for election in 2017.
Independent: No
Other directorships: Bakkerud is a member of the executive committee of the Industry Energy (IE) trade union and holds a number of offices as a result of this.
Number of shares in Statoil ASA as of 31 December 2016: 342
Loans from Statoil: None
Experience: Bakkerud has worked as a process technician at the petrochemical plant in Bamble and on the Gullfaks field in the North Sea. She is now a full-time employee representative as the leader of the union Industri Energi's Statoil branch.
Education: Bakkerud has a craft certificate as a process/chemistry worker.
Family relations: No family relations to other members of the board, members of the corporate executive committee or the corporate assembly.
Other matters: In 2016, Bakkerud participated in eight ordinary board meetings, two extraordinary board meetings and five meetings of the safety, sustainability and ethics committee. Bakkerud is a Norwegian citizen and resident in Norway.

Ingrid Elisabeth di Valerio
Born: 1964
Position: Employee-elected member of the board and member of the board's audit committee.
Term of office: Member of board of directors of Statoil ASA from 1 July 2013. Up for election in 2017.
Independent: No
Other directorships: Board member of Tekna's central nomination committee.
Number of shares held in Statoil ASA as of 31 December 2016: 3,670
Loans from Statoil: None
Experience: Di Valerio has been employed by Statoil since 2005, and works within materials discipline for Technology, Projects & Drilling. Di Valerio was the union Tekna's main representative in Statoil from 2008 to 2013. She also sat on Tekna's central committee from 2005 to 2013.
Education: Chartered engineer (mathematics and physics) from the Norwegian University of Science and Technology in Trondheim (NTNU).
Familiy relations: No family relationships to other board members, members of the corporate executive committee or the corporate assembly.
Other matters: In 2016, di Valerio participated in eight ordinary board meetings, two extraordinary board meetings and six meetings of the audit committee. Di Valerio is a Norwegian citizen and resident in Norway.

Stig Lægreid
Born: 1963
Position: Employee-elected member of the board and member of the board's safety, sustainability and ethics committee.
Term of office: Member of the board of directors of Statoil ASA from 1 July 2013. Up for election in 2017.
Independent: No
Other directorships: Member of The Norwegian society for Engineers and Technologists' (NITO) negotiation committee for private sector.
Number of shares held in Statoil ASA as of 31 December 2016: 1,881
Loans from Statoil: None
Experience: Employed in ÅSV and Norsk Hydro since 1985. Mainly occupied as project engineer and constructor for production of primary metals until 2005 and from 2005 as weight estimator for platform design. He is now a full-time employee representative as the leader of the union NITO, Statoil.
Education: Bachelor degree, mechanical construction from OIH.
Family relations: No family relationships to other board members, members of the corporate executive committee or the corporate assembly.
Other matters: In 2016, Lægreid participated in eight ordinary board meetings, two extraordinary board meetings and six meetings of the safety, sustainability and ethics committee. Lægreid is a Norwegian citizen and resident in Norway.

The most recent changes to the composition of the board of directors were the election of Jeroen van der Veer as a new shareholder-elected board member effective as of 18 March 2016, as well as the resignation of shareholder-elected board member Jakob Stausholm effective as of 30 September 2016. Van der Veer replaced Stausholm as chair of the board's audit committee as per 26 October 2016.

Management

The president and CEO has overall responsibility for day-to-day operations in Statoil and appoints the corporate executive committee (CEC). The president and CEO is responsible for developing Statoil's business strategy and presenting it to the board of directors for decision, for the execution of the business strategy and for cultivating a performance-driven, values-based culture.

Members of the CEC have a collective duty to safeguard and promote Statoil's corporate interests and to provide the president and CEO with the best possible basis for deciding the company's direction, making decisions and executing and following up business activities. In addition, each of the CEC members is head of a separate business area or staff function.

Members of Statoil's corporate executive committee as of 31 December 2016:

Eldar Sætre,
President and CEO

Eldar Sætre
Born: 1956
Position: President and chief executive officer of Statoil ASA since 15 October 2014.
External offices: Member of the board of Strømberg Gruppen AS and Trucknor AS.
Number of shares in Statoil ASA as of 31 December 2016: 47,882
Loans from Statoil: None
Experience: Sætre joined Statoil in 1980. Executive vice president and CFO from October 2003 until December 2010. Executive vice president for Marketing, Midstream and Processing (MMP) from 2011 until 2014.
Education: MA in business economics from the Norwegian School of Economics and Business Administration (NHH) in Bergen.
Family relations: No family relations to other members of the CEC, members of the board or the corporate assembly.
Other matters: Sætre is a Norwegian citizen and resident in Norway.

Hans Jakob Hegge,
Chief financial
officer (CFO)

Hans Jakob Hegge
Born: 1969
Position: Executive vice president and chief financial officer (CFO) of Statoil ASA since 1 August 2015.
External offices: None
Number of shares in Statoil ASA as of 31 December 2016: 28,190
Loans from Statoil: None
Experience: Hegge has held several managerial positions in Statoil, including senior vice president (SVP) for Operations North in Development and Production Norway (DPN) (2013-2015), SVP for Operations East (2011-2013) in DPN, SVP for Operational Development in DPN (2009-2011) and SVP for Global Business Services in Chief Financial Officer area (CFO) (2005-2009). From 1995 to 2004 he held various positions in DPN, Natural Gas business area and corporate functions in Statoil.
Education: Master of Science degree from the Norwegian School of Economics and Business Administration (NHH).
Family relations: No family relations to other members of the CEC, members of the board or the corporate assembly.
Other matters: Hegge is a Norwegian citizen and resident in Norway.

Jannicke Nilsson
Chief Operating Officer (COO)

Jannicke Nilsson
Born: 1965
Position: Executive vice president and chief operating officer (COO) of Statoil ASA since 1 December 2016.
External offices: Member of the board of Odfjell SE
Number of shares in Statoil ASA as of 31 December 2016: 35,049
Loans from Statoil: None
Experience: Jannicke Nilsson joined Statoil in 1999 and has held a number of central management positions within upstream operations Norway, including senior vice president for Technical Excellence in Technology, Projects & Drilling, senior vice president for Operations North Sea, vice president for modifications and project portfolio Bergen and platform manager at Oseberg South. In august 2013 she was appointed programme leader for Statoil technical efficiency

programme (STEP), responsible for a project portfolio targeting yearly efficiency gains of 2.5 billion USD from 2016.
Education: MSc in cybernetics and process automation and a BSc in automation from the Rogaland Regional College/University of Stavanger.
Family relations: No family relations to other members of the CEC, members of the board or the corporate assembly.
Other matters: Nilsson is a Norwegian citizen and resident in Norway.

Lars Christian Bacher,
Executive vice president Development and Production International (DPI)

Lars Christian Bacher
Born: 1964
Position: Executive vice president of Statoil ASA since 1 September 2012.
External offices: None
Number of shares in Statoil ASA as of 31 December 2016: 24,896
Loans from Statoil ASA: None
Experience: Bacher joined Statoil in 1991 and has held a number of leading positions in Statoil, including that of platform manager on the Norne and Statfjord fields on the Norwegian continental shelf. He was in charge of the merger process involving the offshore installations of Norsk Hydro and Statoil. Bacher has also been senior vice president for Gullfaks operations and subsequently for the Tampen area. His most recent position, which he held from September 2009, was as senior vice president for Statoil's Canadian operations in Development & Production International (DPI).
Education: Master of science in chemical engineering from the Norwegian Institute of Technology (NTH). He also holds a business degree in Finance from the Norwegian School of Economics and Business Administration (NHH).
Family relations: No family relations to other members of the corporate executive committee, the board of directors or the corporate assembly.
Other matters: Bacher is a Norwegian citizen and resident in Norway.

Torgrim Reitan,
Executive vice president Development and Production USA (DPUSA)

Torgrim Reitan
Born: 1969
Position: Executive vice president of Statoil ASA since 1 January 2011.
External offices: None
Number of shares in Statoil ASA as of 31 December 2016: 32,276
Loans from Statoil: None
Experience: From 1 January 2011 to 1 August 2015 Reitan held the position as executive vice president and chief financial officer of Statoil (CFO). He has held several managerial positions in Statoil, including senior vice president (SVP) in trading and operations in the Natural Gas business area (2009 - 2010), SVP in performance management and analysis (2007 - 2009) and SVP in performance management, tax and M&A (2005 - 2007). From 1995 to 2004, Reitan held various positions in the Natural Gas business area and corporate functions in Statoil.
Education: Master of science degree from the Norwegian School of Economics and Business Administration (Siviløkonom) (NHH).
Family relations: No family relations to other members of the CEC, members of the board or the corporate assembly.
Other matters: Reitan is a Norwegian citizen and resident in the United States.

John Knight,
Executive vice president
Global Strategy and Business Development (GSB)

John Knight
Born: 1958
Position: Executive vice president of Statoil ASA since 1 January 2011.
External offices: Member on the advisory board of the Columbia University Center on Global Energy Policy in New York, and member of the advisory board of Lloyd's Register. Chair of ONS18 Conference Committee in Stavanger, Norway.
Numbers of shares in Statoil ASA as of 31 December 2016: 103,808
Loans from Statoil ASA: None
Experience: Knight held several central managerial positions in International Operations in Statoil since 2002, mainly in business development. Between 1987 and 2002, Knight held various positions in energy investment banking. From 1977 to 1987, he

qualified and worked as a barrister/lawyer, and was employed by Shell Petroleum in London during the period 1985-1987.
Education: Knight has first and post-graduate degrees in law from Cambridge University and the Inns of Court School of Law in London.
Family relations: No family relations to other members of the CEC, members of the board or the corporate assembly.
Other matters: Knight is a British citizen and resident in England.

Tim Dodson.
Executive vice president, Exploration (EXP)

Tim Dodson
Born: 1959
Position: Executive vice president of Statoil ASA since 1 January 2011.
External offices: None
Number of shares in Statoil ASA as of 31 December 2016: 29,418
Loans from Statoil ASA: None
Experience: Dodson has worked in Statoil since 1985 and held central management positions in the company, including the positions of senior vice president for Global Exploration, Exploration & Production Norway and the Technology arena.
Education: Bachelor's degree of science in geology and geography from the University of Keele.
Family relations: No family relations to other members of the CEC, members of the board or the corporate assembly.
Other matters: Dodson is a British citizen and resident in Norway.

Margareth Øvrum.
Executive vice president Technology, Projects and Drilling (TPD)

Margareth Øvrum
Born: 1958
Position: Executive vice president of Statoil ASA since September 2004.
External offices: Member of the board of Atlas Copco AB (Sweden) (until 26 April 2017), Alfa Laval (Sweden) and FMC Corporation (US).
Number of shares in Statoil ASA as of 31 December 2016: 49,227
Loans from Statoil: None
Experience: Øvrum has worked for Statoil since 1982 and has held central management positions in the company, including the position of executive vice president for health, safety and the environment and executive vice president for Technology & Projects. Øvrum was the company's first female platform manager, on the Gullfaks field. She was senior vice president for operations for Veslefrikk and vice president of operations support for the Norwegian continental shelf.
Education: Master's degree in engineering (sivilingeniør) from the Norwegian Institute of Technology (NTH) in Trondheim, specialising in technical physics.
Family relations: No family relations to other members of the CEC, members of the board or the corporate assembly.
Other matters: Øvrum is a Norwegian citizen and resident in Norway.

Arne Sigve Nylund,
Executive vice president Development and production Norway (DPN)

Arne Sigve Nylund
Born: 1960
Position: Executive vice president of Statoil ASA since 1 January 2014.
External offices: Member of the board of directors of The Norwegian Oil & Gas Association (Norsk Olje & Gass).
Number of shares in Statoil ASA as of 31 December 2016: 11,312
Loans from Statoil: None
Experience: Employed by Mobil Exploration Inc. from 1983-1987. Since 1987, Nylund has held several central management positions in Statoil ASA.
Education: Mechanical engineer from Stavanger College of Engineering with further qualifications in operational technology from Rogaland Regional College/University of Stavanger (UiS). Business graduate of the Norwegian School of Business and Management (NHH).
Family relations: No family relations to other members of the CEC, members of the board or the corporate assembly.
Other matters: Nylund is a Norwegian citizen and is resident in Norway.

Jens Økland,
executive vice president Marketing,
Midstream and Processing (MMP)

Jens Økland
Born: 1969
Position: Executive vice president of Statoil ASA since 1 June 2015.
External offices: None
Number of shares in Statoil ASA as of 31 December 2016: 13,937
Loans from Statoil ASA: None
Experience: Økland joined Statoil in 1994 and has mainly worked in the mid and downstream areas. Before becoming executive vice president of MMP, Økland worked as vice president of operations for the Åsgard area in Development and Production Norway. Previously Økland was senior vice president of Statoil's natural gas portfolio and supply business in North America, marketing and developing infrastructure solutions for equity and non-equity production. Before heading up Statoil's downstream gas division in North America, he had senior marketing and business development positions within natural gas in Europe mainly focusing on Germany, Statoil's largest gas market.
Education: MSc in business from BI Norwegian Business School.
Family relations: No family relations to other members of the CEC, members of the board or the corporate assembly.
Other matters: Økland is a Norwegian citizen and resident in Norway.

Irene Rummelhoff,
executive vice president New Energy
Solutions (NES)

Irene Rummelhoff
Born: 1967
Position: Executive vice president of Statoil ASA since 1 June 2015.
External offices: Deputy chair of the board of directors of Norsk Hydro ASA.
Number of shares in Statoil ASA as of 31 December 2016: 21,556
Loans from Statoil ASA: None
Experience: Rummelhoff joined Statoil in 1991. She has held a number of management positions within international business development, exploration, and the downstream business in Statoil.
Education: Master's degree in petroleum geosciences from the Norwegian Institute of Technology (NTH).
Family relations: No family relations to other members of the CEC, members of the board or the corporate assembly.
Other matters: Rummehoff is a Norwegian citizen and resident in Norway.

Statoil has granted loans to the Statoil-employed spouse of certain of the Executive Vice Presidents as part of its general loan arrangement for Statoil employees. Employees in salary grade 12 or higher may take out a car loan from Statoil in accordance with standardised provisions set by the company. The standard maximum car loan is limited to the cost of the car, including registration fees, but not exceeding NOK 300,000. Employees outside the collective labour area are entitled to a car loan up to NOK 575,000 (vice presidents and senior vice presidents) or NOK 475,000 (other positions). The car loan is interest-free, but the tax value, "interest advantage", must be reported as salary. Permanent employees in Statoil ASA may also apply for a consumer loan up to NOK 300.000. The interest rate on consumer loans is corresponding to the standard rate in effect at any time for "reasonable loans" from employer as decided by the Norwegian Ministry of Finance, i.e. the lowest rate an employer may offer without triggering taxation of the advantage for the employee.

Deviations from the Code: None

3.9 THE WORK OF THE BOARD OF DIRECTORS

The board is responsible for managing the Statoil group and for monitoring day-to-day management and the group's business activities. This means that the board is responsible for establishing control systems and for ensuring that Statoil operates in compliance with laws and regulations, with our values as stated in The Statoil Book, the Code of Conduct, as well as in accordance with the owners' expectations of good corporate governance. The board emphasises the safeguarding of the interests of all shareholders, but also the interests of Statoil's other stakeholders.

The board handles matters of major importance, or of an extraordinary nature, and may in addition require the management to refer any matter to it. An important task for the board is to appoint the chief executive officer (CEO) and stipulate his/her job instructions and terms and conditions of employment.

The board has adopted a generic annual plan for its work which is revised with regular intervals. Recurrent items on the board's annual plan are: security, safety and sustainability, corporate strategy, business plans, quarterly and annual results, annual reporting, ethics, management's monthly performance reporting, management compensation issues, CEO and top management leadership assessment and succession planning, project status review, people and organisation strategy and priorities, an annual enterprise risk management review, two yearly discussions of main risks and risk issues and an annual review of the board's governing documentation. In the beginning of each board meeting, the CEO meets separately with the board to discuss key matters in the company. At the end of all board meetings, the board has a closed session with only board members attending the discussions and evaluating the meeting.

The work of the board is based on rules of procedure that describe the board's responsibilities, duties and administrative procedures, and determines which cases are to be handled by the board. The rules of procedure also determines the handling of matters in which individual board members or a closely related party have a major personal or financial interest. The rules of procedure further describe the duties of the CEO and his/her duties vis-à-vis the board of directors. The board's rules of procedure are available on our website at www.statoil.com/board. In addition to the board of directors, the CEO, the CFO, the COO, the senior vice president for communication, the general counsel and the company secretary attend all board meetings. Other members of the executive committee and senior management attend board meetings by invitation in connection with specific matters.

New members of the board are offered an induction program where meetings with key members of the management are arranged, an introduction to Statoil's business is given and relevant information about the company and the board's work is made available through the company's web based board portal.

The board carries out an annual board evaluation, with input from various sources and as a main rule with external facilitation. The evaluation report is discussed in a board meeting and is made available to the nomination committee as input to the committee's work.

The entire board, or part of it, regularly visits several Statoil locations in Norway and globally, and a longer board trip for all board members to an international location is made at least on a biennial basis. When visiting Statoil locations globally, the board emphasises the importance of improving its insight into, and knowledge about, safety and security in Statoil's operations, Statoil's technical and commercial activities as well as the company's local organisations. In 2016, whole or parts of the board visited Statoil's operations in Brazil, Tanzania, Russia and the United States.

Statoil's board has established three sub-committees: the audit committee; the compensation and executive development committee; and the safety, sustainability and ethics committee. The committees prepare items for consideration by the board and their authority is limited to making such recommendations. The committees consist entirely of board members and are answerable to the board alone for the performance of their duties. Minutes of the committee meetings are sent to the whole board, and the chair of each committee regularly informs the board at board meetings about the committee's work. The composition and work of the committees are further described below.

Audit committee

The board of directors elects at least three of its members to serve on the board of directors' audit committee and appoints one of them to act as chair. The employee-elected members of the board of directors may nominate one audit committee member.

At year-end 2016, the audit committee members were Jeroen van der Veer (chair), Roy Franklin, Rebekka Glasser Herlofsen and Ingrid di Valerio (employee-elected board member). Jakob Stausholm chaired the audit committee from September 2009 and until his resignation as board member 30 September 2016.

The audit committee is a sub-committee of the board of directors, and its objective is to act as a preparatory body in connection with the board's supervisory roles with respect to financial reporting and the effectiveness of the company's internal control system. It also attends to other tasks assigned to it in accordance with the instructions for the audit committee adopted by the board of directors. The audit committee is instructed to assist the board of directors in its supervising of matters such as:

- Approving the internal audit plan on behalf of the board of directors
- Monitoring the financial reporting process, including oil and gas reserves, fraudulent issues and reviewing the implementation of accounting principles and policies
- Monitoring the effectiveness of the company's internal control, internal audit and risk management systems
- Maintaining continuous contact with the external auditor regarding the annual and consolidated accounts
- Reviewing and monitoring the independence of the company's internal auditor and the independence of the external auditor, reference is made to the Norwegian Auditors Act chapter 4, and, in particular, whether services other than audits provided by the external auditor or the audit firm are a threat to the external auditor's independence

The audit committee supervises implementation of and compliance with the group's Code of Conduct in relation to financial reporting.

The internal audit function reports directly to the board of directors' audit committee and to the chief executive officer.

Under Norwegian law, the external auditor is appointed by the shareholders at the annual general meeting based on a proposal from the corporate assembly. The audit committee issues a statement to the annual general meeting relating to the proposal.

The audit committee meets at least five times a year and both the board and the board's audit committee hold meetings with the internal auditor and the external auditor on a regular basis without the company's management being present.

The audit committee is also charged with reviewing the scope of the audit and the nature of any non-audit services provided by external auditors.

The audit committee is tasked with ensuring that the company has procedures in place for receiving and dealing with complaints received by the company regarding accounting, internal control or auditing matters, and procedures for the confidential and anonymous submission, via the group's ethics helpline, by company employees of concerns regarding accounting or auditing matters, as well as other matters regarded as being in breach of the group's Code of Conduct, a material violation of an applicable US federal or state securities law, a material breach of fiduciary duties or a similar material violation of any other US or Norwegian statutory provision. The audit committee is designated as the company's qualified legal compliance committee for the purposes of Part 205 in Title 17 of the U.S. Code of Federal Regulations.

In the execution of its tasks, the audit committee may examine all activities and circumstances relating to the operations of the company. In this regard, the audit committee may request the chief executive officer or any other employee to grant it access to information, facilities and personnel and such assistance as it requests. The audit committee is authorised to carry out or instigate such investigations as it deems necessary in order to carry out its tasks and it may use the company's internal audit or investigation unit, the external auditor or other external advice and assistance. The costs of such work will be covered by the company.

The audit committee is only responsible to the board of directors for the execution of its tasks. The work of the audit committee in no way alters the responsibility of the board of directors and its individual members, and the board of directors retains full responsibility for the audit committee's tasks.

The audit committee held six meetings in 2016. There was 96% attendance at the committee's meetings.

The board of directors has decided that a member of the audit committee, Jeroen van der Veer, qualifies as an "audit committee financial expert", as defined in Item 16A of Form 20-F. The board of directors has also concluded that Jeroen van der Veer, Roy Franklin and Rebekka Glasser Herlofsen are independent within the meaning of Rule 10A-3 under the Securities Exchange Act.

The committee's mandate is available at www.statoil.com/auditcommittee.

Compensation and executive development committee

The compensation and executive development committee is a sub-committee of the board of directors that assists the board in matters relating to management compensation and leadership development. The main responsibilities of the compensation and executive development committee are:

(1) as a preparatory body for the board, to make recommendations to the board in all matters relating to principles and the framework for executive rewards, remuneration strategies and concepts, the CEO's contract and terms of employment, and leadership development, assessments and succession planning;

(2) to be informed about and advise the company's management in its work on Statoil's remuneration strategy for senior executive and in drawing up appropriate remuneration policies for senior executives; and

(3) to review Statoil's remuneration policies in order to safeguard the owners' long-term interests.

The committee consists of up to four board members. At year-end 2016, the committee members were Øystein Løseth (chair), Bjørn Tore Godal, Maria Johanna Oudeman and Wenche Agerup. All of the committee members are non-executive directors. All members, except for Wenche Agerup, are independent.

The committee held five meetings in 2016 and attendance was 95%.

For a more detailed description of the objective and duties of the compensation and executive development committee, please see the instructions for the committee available at www.statoil.com/compensationcommittee.

Safety, sustainability and ethics committee

The safety, sustainability and ethics committee is a sub-committee of the board of directors that assists the board in matters relating to safety, sustainability and ethics.

The safety, sustainability and ethics committee is chaired by Roy Franklin and the other members are Bjørn Tore Godal, Wenche Agerup, Stig Lægreid (employee-elected board member) and Lill-Heidi Bakkerud (employee-elected board member).

In its business activities, Statoil is committed to comply with applicable laws and regulations and to act in an ethical, environmental, safe and socially responsible manner. The committee has been established to support our commitment in this regard, and it assists the board of directors in its supervision of the company's safety, sustainability and ethics policies, systems and principles with the exception of aspects related to "financial matters".

Establishing and maintaining a committee dedicated to safety, sustainability and ethics is intended to ensure that the board of directors has a strong focus on and knowledge of these complex, important and constantly evolving areas. The committee acts as a preparatory body for the board of directors and, among other things, monitors and assesses the effectiveness, development and implementation of policies, systems and principles in the areas of safety, sustainability and ethics, with the exception of aspects related to "financial matters".

The committee held six meetings in 2016, and attendance was 83%.

For a more detailed description of the objective, duties and composition of the committee, please see the instructions for the committee available at www.statoil.com/ssecommittee.

Deviations from the Code: None

3.10 RISK MANAGEMENT AND INTERNAL CONTROL

Risk management

The board focuses on ensuring adequate control of the company's internal control and overall risk management. The board conducts an annual enterprise risk management review and two times pr. year the board is presented with and discusses the main risks and risk issues Statoil is facing. The board's audit committee assists the board and act as a preparatory body in connection with monitoring of the company's internal control, internal audit and risk management systems. The board's safety, sustainability and ethics committee monitors and assesses safety and sustainability risks which are relevant for Statoil's operations and both committees report regularly to the full board.

Statoil manages risk to make sure that our operations are safe and in compliance with our requirements. Our overall risk management approach includes continuously assessing and managing risks related to our value chain in order to support the achievement of our principal objectives, i.e. value creation and avoiding incidents.

The company has a separate Corporate Risk Committee chaired by the chief financial officer. The committee meets at least five times a year to give advice and make recommendations on Statoil's enterprise risk management. Further information about the company's risk management is presented in section 2.10 Risk review.

All risks are related to Statoil's value chain - from access, maturing, project execution and operations to market. In addition to the financial impact these risks could have on Statoil's cash flows, we have also implemented procedures and systems to reduce safety, security and integrity incidents (such as fraud and corruption), as well as any reputation impact resulting from human rights, labour standards and transparency issues. Most of the risks are managed by our principal business area line managers. Some operational risks are insured by our captive insurance company, which operates in the Norwegian and international insurance markets.

Controls and procedures

This section describes controls and procedures relating to our financial reporting.

Evaluation of disclosure controls and procedures

The management, with the participation of our chief executive officer and chief financial officer, has evaluated the effectiveness of the design and operation of our disclosure controls and procedures pursuant to Exchange Act Rule 13a-15(b) as of the end of the period covered by the Form 20-F. Based on that evaluation, the chief executive officer and chief financial officer have concluded that these disclosure controls and procedures are effective at a reasonable level of assurance.

In order to facilitate the evaluation, the disclosure committee reviews material disclosures made by Statoil for any errors, misstatements and omissions. The disclosure committee is chaired by the chief financial officer. It consists of the heads of investor relations, accounting and financial compliance, performance management and risk, tax and the general counsel and it may be supplemented by other internal and external personnel. The head of the internal audit is an observer at the committee's meetings.

In designing and evaluating our disclosure controls and procedures, our management, with the participation of the chief executive officer and chief financial officer, recognised that any controls and procedures, no matter how well designed and operated, can only provide reasonable assurance that the desired control objectives will be achieved, and that the management must necessarily exercise judgment when evaluating the cost-benefit aspects of possible controls and procedures. Because of the limitations inherent in all control systems, no evaluation of controls can provide absolute assurance that all control issues and any instances of fraud in the company have been detected.

The management's report on internal control over financial reporting

The management of Statoil ASA is responsible for establishing and maintaining adequate internal control over financial reporting. Our internal control over financial reporting is a process designed, under the supervision of the chief executive officer and chief financial officer, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of Statoil's financial statements for external reporting purposes in accordance with International Financial Reporting Standards (IFRS) as adopted by the European Union (EU). The accounting policies applied by the group also comply with IFRS as issued by the International Accounting Standards Board (IASB).

The management has assessed the effectiveness of internal control over financial reporting based on the Internal Control - Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Based on this assessment, the management has concluded that Statoil's internal control over financial reporting as of 31 December 2016 was effective.

Statoil's internal control over financial reporting includes policies and procedures that pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect transactions and dispositions of assets, provide reasonable assurance that transactions are recorded in the manner necessary to permit the preparation of financial statements in accordance with IFRS, and that receipts and expenditures are only carried out in accordance with the authorisation of the management and directors of Statoil; and provide reasonable assurance regarding the prevention or timely detection of any unauthorised acquisition, use or disposition of Statoil's assets that could have a material effect on our financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect all misstatements. Moreover, projections of any evaluation of the effectiveness of internal control to future periods are subject to a risk that controls may become inadequate because of changes in conditions and that the degree of compliance with the policies or procedures may deteriorate.

The effectiveness of internal control over financial reporting as of 31 December 2016 has been audited by KPMG AS, an independent registered public accounting firm that also audits the Consolidated financial statements included in this annual report. Their audit report on the internal control over financial reporting is included in section 4.1 Consolidated financial statements in this report.

No changes occurred in our internal control over financial reporting during the period that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

We continuously make improvement to our internal control environment.

Code of Conduct

Ethics - Statoil's approach

Statoil believes that responsible and ethical behaviour is a necessary condition for a sustainable business. Statoil's Code of Conduct (the Code) is based on its values and reflects Statoil's commitment to high ethical standards in all its activities.

Our Code of Conduct

The Code describes Statoil's code of business practice and the requirements to expected behaviour in areas such as anti-corruption, fair competition, human rights and non-discrimination working environments with equal opportunities. The Code applies to Statoil's board members, employees and hired personnel.

Statoil seeks to work with others who share its commitment to ethics and compliance, and Statoil manages its risks through in-depth knowledge of suppliers, business partners and markets. Statoil expects its suppliers and business partners to comply with applicable laws, respect internationally recognised human rights and adhere to ethical standards which are consistent with Statoil's ethical requirements when working for or together with Statoil. In joint ventures and entities where Statoil does not have control, Statoil makes good faith efforts to encourage the adoption of ethics and anti-corruption policies and procedures that are consistent with its standards. Anyone working for Statoil who does not comply with the Code faces disciplinary action, up to and including summery dismissal or termination of their contract.

Training and Certifying the Code
Code of Conduct training and comprehensive trainings on specific issues, including anti-corruption and anti-trust, is carried out to explain how the Code applies and to describe the tools that Statoil has made available to address risk.

All Statoil employees have to annually confirm electronically that they understand and will comply with the Code (Code certification). The Code certification reminds the individuals of their duty to comply with Statoil's values and ethical requirements and creates an environment with open dialog on ethical issues, both internally and externally.

Anti-corruption compliance programme
Statoil is against all forms of corruption including bribery, facilitation payments and trading in influence and has a company-wide anti-corruption compliance programme which implements its zero-tolerance policy. The programme includes mandatory procedures designed to comply with applicable laws and regulations and training on relevant issues such as gifts, hospitality and conflicts of interest. Compliance officers, who are responsible for ensuring that ethics and anti-corruption considerations are integrated into Statoil's business activities, constitute an important part of the programme.

In 2016, Statoil introduced and rolled out an updated and more user-friendly Code of Conduct, which included new information on international trade restrictions and money laundering. Statoil continued to develop its implementation of the Code including focus on supplier monitoring and follow-up and integrating risk assessments more deeply into the business. Statoil also introduced a holistic approach to discussing various compliance and sustainability issues, and the links between the two, through workshops for internal and external stakeholders.

Speak Up
Statoil is committed to maintain an open dialog on ethical issues. The Code requires those who have a question or suspect misconduct to raise their concern either through internal channels or through Statoil's external Ethics Helpline. Employees are encouraged to discuss their concerns with their supervisor. Statoil recognises that raising a concern is not always easy so there are several internal channels for taking concerns forward, including through human resources or the ethics and compliance function in the legal department. Concerns can also be expressed through the externally operated Ethics Helpline which is available 24/7, and allows for anonymous reporting and two-way communication through the use of a pin-code. Statoil has a non-retaliation policy for anyone who reports in good faith.

More information about Statoil's policies and requirements related to the Code of Conduct is available on www.statoil.com/ethics.

Deviations from the Code: None

3.11 REMUNERATION TO THE BOARD OF DIRECTORS AND CORPORATE ASSEMBLY

Remuneration to the board of directors

The remuneration of the board and its sub-committees is decided by the corporate assembly, based on a recommendation from the nomination committee. The members have an annual, fixed remuneration, except for deputy members (only elected for employee-elected board members) who receive remuneration per meeting attended. Separate rates are set for the board's chair, deputy chair and other members, respectively. Separate rates are also adopted for the board's sub-committees, with similar differentiation between the chair and the other members of each committee. The employee-elected members of the board receive the same remuneration as the shareholder-elected members.

The board receives its remuneration by cash payment. Board members from outside Scandinavia and outside Europe, respectively, receive separate travel allowances for each meeting attended. The remuneration is not linked to the board members' performance, option programmes or similar. None of the shareholder-elected board members have a pension scheme or agreement concerning pay after termination of their office with the company. If shareholder-elected members of the board and/or companies they are associated with should take on specific assignments for Statoil in addition to their board membership, this will be disclosed to the full board.

In 2016, the total remuneration to the board, including fees for the board's three sub-committees, was NOK 6,524,119 (USD 776,803).

Detailed information about the individual remuneration to the members of the board of directors in 2016 is provided in the table below.

Members of the board (figures in USD thousand except number of shares)	Total remuneration	Share ownership as of 31 December 2016
Øystein Løseth (chair of the board)	104	1,040
Roy Franklin (deputy chair of the board)	114	-
Jakob Stausholm[1)]	52	n.a.
Wenche Agerup	65	2,522
Bjørn Tore Godal	65	-
Rebekka Glasser Herlofsen	61	-
Maria Johanna Oudeman	81	-
Jeroen van der Veer[2)]	61	-
Lill-Heidi Bakkerud	55	342
Stig Lægreid	55	1,881
Ingrid Elisabeth di Valerio	61	3,670
Total	777	9,455

1) Member until 30 September 2016 (resigned).

2) Member from 18 March 2016.

Remuneration to the corporate assembly

The remuneration of the corporate assembly is decided by the general meeting, based on a recommendation from the nomination committee. The members have an annual, fixed remuneration, except for deputy members who receive remuneration per meeting attended. Separate rates are set for the corporate assembly's chair, deputy chair and other members, respectively. The employee-elected members of the corporate assembly receive the same remuneration as the shareholder-elected members. The corporate assembly receives its remuneration by cash payment.

In 2016, the total remuneration to the corporate assembly was NOK 1,065,682 (USD 126,875).
Deviations from the Code: None

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3.12 REMUNERATION TO THE CORPORATE EXECUTIVE COMMITTEE

In 2016, the aggregate remuneration to the corporate executive committee was NOK 71,414,699 (USD 8,503,083) (rounded figure). The board of directors' complete declaration on remuneration of executive personnel follows below.

Only the following portions of this Section 3.12 Remuneration to the corporate executive committee form part of Statoil's annual report on Form 20-F as filed with the SEC: the table summarizing the main elements of Statoil executive remuneration; the discussion regarding pension and insurance schemes, severance pay arrangements and other benefits; the discussion regarding Performance management and results essential for variable pay and the table summarising the main objectives and KPIs for each perspective; the table summarising remuneration paid to each member of the corporate executive committee; the discussion of the Company performance modifier; and the discussion regarding share ownership, including the summary table.

MESSAGE FROM CHAIR OF THE BOARD

Declaration on remuneration and other employment terms for Statoil's corporate executive committee

Statoil's remuneration policy and terms are aligned with the company's overall values, people policy and performance-oriented framework. Our rewards and recognition for executives are designed to attract and retain the right people; people who are committed to deliver on our business strategy and able to adapt to changing business environment. It remains a key role for the board to ensure that executive compensation is competitive, but not market leading, in the markets in which we operate. Executive compensation should also be seen as fair and aligned with overall compensation levels in the company, and with shareholders' interests. The board must strike this balance. It is our responsibility.

It is the board's belief that the remuneration systems and practices are good and transparent and in accordance with prevailing guidelines and good corporate governance.

Oslo 9 March 2017
Øystein Løseth

Pursuant to the Norwegian Public Limited Liability Companies Act, section 6-16 a, the board will present the following declaration regarding remuneration of Statoil's corporate executive committee to the 2017 annual general meeting.

Remuneration policy and concept for the accounting year 2017

Policy and principles

The company's established remuneration principles and concepts as described in previous year's declaration on remuneration and other employment terms for Statoil's corporate executive committee will be continued in the accounting year 2017.

The remuneration concept is an integrated part of our values based and commercial performance framework. It has been designed to:

- reflect our global competitive market strategy and local market conditions
- encourage a strong and sustainable performance culture
- equally reward and recognise "what" we deliver and "how" we deliver
- differentiate on the basis of responsibilities and performance
- be fair, transparent and non-discriminatory
- promote collaboration and teamwork
- reward both short- and long-term contributions and results
- reflect the company's performance and financial result
- strengthen the common interests of employees in the Statoil group and its shareholders

The remuneration concept for the corporate executive committee

Statoil's remuneration policy and guidelines for the corporate executive committee are translated into the following main elements;

- Fixed remuneration: base salary and as applicable cash compensation
- Variable pay: annual variable pay (AVP) and long-term incentive (LTI)
- Benefits: primarily pension, insurance and share savings plan
- Company performance modifier and threshold for variable pay

The table below illustrate how our reward policy and framework is translated into key remuneration elements.

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Main elements - Statoil executive remuneration

Remuneration element	Objective	Award level	Performance criteria
Base salary	Attract and retain the right individuals providing competitive but not market-leading terms.	We offer base salary levels which are aligned with and differentiated according to the individual's responsibility and performance. The level is competitive in the markets in which we operate.	The base salary is normally subject to annual review based on an evaluation of the individual's performance.; see "Annual Variable Pay" below
Cash compensation	The cash compensation is applied as a supplementing fixed remuneration element to be competitive in the market.	Reference is made to the remuneration table. Four of the executive vice presidents receive a cash compensation in lieu of pension accrual with reference to the section on pension and insurance scheme.	No performance criteria are linked to the cash compensation. The cash compensation is not included in the pensionable income.
Annual variable pay	Encourage a strong performance culture. Reward individuals for annual achievement of business objectives and goals relating to 'how' results are delivered.	Members of the corporate executive committee are entitled to annual variable pay ranging from 0 - 50% of their fixed remuneration. Target2 value is 25%. The threshold principles and the company modifier are applied.	Achievement of annual performance goals (how and what to deliver), in order to create long-term and sustainable shareholder value. Assessment of goals defined on the individual's performance contract including objectives related to selected KPI's on the balanced scorecard constitute the basis for annual variable pay.
Long-term incentive (LTI)	Strengthen the alignment of top management and shareholder's long term interests. Retention of key executives.	The LTI system is a monetary compensation calculated as a portion of the participant's base salary. On behalf of the participant, the company acquires shares equivalent to the net annual grant amount. The shares are subject to a three-year lock-in period and then released for the participant's disposal. The level of the annual LTI reward is in the range of 25-30%. The threshold principles are applied for the annual grant The company performance modifier is not applied for the LTI.in Statoil ASA	In Statoil ASA, LTI participation and grant level are reflective of the level and impact of the position and not directly linked to the incumbent's performance.
Threshold	Financial threshold for payment of variable remuneration and award of LTI grant.	The threshold is based on Statoil group's full-year adjusted earnings after tax [2], requiring that a minimum level of earnings must be achieved for any payments to be made. This minimum level is USD 2 billion. Earnings between USD 2 and 3.3 will result in bonus payments reduced by 50%. Above USD 3.3 billion the threshold is fully achieved and variable pay payments are not affected.	Adjusted earnings after tax. Application of the threshold is subject to a discretionary assessment of the company's overall performance.
Company performance modifier	Strengthen the alignment between variable remuneration and the company's performance.	The company performance modifier determines the proportion of the bonus that will be paid, ranging from 50% to 150% The company performance modifier is subject to approval by the annual general meeting.	Company performance is assessed against two equally weighted measures: relative total shareholder return (TSR) and relative return on average capital employed (RoACE). Application of the modifier is subject to discretionary assessment based on the company's overall performance.
Pension & insurance schemes	Provide competitive postemployment and other benefits.	The company offers a general occupational pension plan and insurance scheme aligned with local markets c.f. section on pension and insurance scheme	N/A
Employee share savings plan	Align and strengthen employee and shareholder's interests and remunerate for long term commitment and value creation.	The share savings plan is offered to all employees in the group, provided no restrictions due to local legislation or business requirements. Participants are offered to purchase Statoil shares in the market limited to 5% of annual base salary.	If shares are kept for two calendar years of continued employment, the participants will be allocated bonus shares proportionate to their purchase.

2 Target value reflects fully satisfactory goal achievement
[2] See calculation of Adjusted earnings after tax in section 5.2 Accounting standards and non-GAAP measures

Pension and insurance schemes
Members of the corporate executive committee in Statoil ASA are covered by the company's general occupational pension scheme which is a defined contribution scheme with a contribution level of 7% below 7,1 G and 22% above 7,1 G[3]. A defined benefit scheme is retained by a grandfathered group of employees. For new members of the corporate executive committee appointed after 13 February 2015, a cap on pension contribution at 12 G is applied. In lieu of pension accrual above 12 G a cash compensation is provided.

Members of the corporate executive committee appointed before 13 February 2015, will maintain their pension contribution above 12 G based on obligations in previously established agreements.

The chief executive officer and three executive vice presidents have individual early retirement pension agreement with the company.

The chief executive officer and one of the executive vice presidents have individual pension terms according to a previous standard arrangement implemented in October 2006. Subject to specific terms those executives are entitled to a pension amounting to 66 per cent of pensionable salary and a retirement age of 62. When calculating the number of years of membership in Statoil's general pension plan, these agreements grant the right to an extra contribution time corresponding to half a year of extra membership for each year the individual has served as executive vice president.

In addition, two members of the corporate executive committee have individually agreed retirement age of 65 and an early retirement pension level amounting to 66% of pensionable salary.

The individual pension terms for executive vice presidents outlined above are results of commitments according to previous established agreements.

Statoil has implemented a general cap on pensionable income at 12 G for all new hires into the company employed as of 1 September 2017.

In addition to the pension benefits outlined above, the executive vice presidents in the parent company are offered disability and dependents' benefits in accordance with Statoil's general pension plan/defined benefit plan. Members of the corporate executive committee are covered by the general insurance schemes applicable within Statoil.

Severance pay arrangements
The chief executive officer and the executive vice presidents are entitled to a severance payment equivalent to six months' salary, commencing at the time of expiry of a six months' notice period, when the resignation is at the request from the company. The same amount of severance payment is also payable if the parties agree that the employment should be discontinued and the executive vice president gives notice pursuant to a written agreement with the company. Any other payment earned by the executive vice president during the period of severance payment will be fully deducted. This relates to earnings from any employment or business activity where the executive vice president has active ownership.

The entitlement to severance payment is conditional on the chief executive officer or the executive vice president not being guilty of gross misconduct, gross negligence, disloyalty or other material breach of his/her duties.

As a general rule, the chief executive officer's/executive vice president's own notice will not instigate any severance payment.

Other benefits
The members of the corporate executive committee have benefits in kind such as company car and electronic communication. They are also eligible for participation in the share saving scheme as described above.

Performance management, assessment and results essential for variable pay

Individual salary and annual variable pay reviews are based on the performance evaluation in our performance management system.

Performance is evaluated in two dimensions; "What" we deliver and "How" we deliver. "What" we deliver (business delivery) is defined through the company's performance framework "Ambition to Action", which addresses strategic objectives, key performance Indicators (KPIs) and actions across the five perspectives; Safety, Security and Sustainability, People and Leadership, Operations, Market and Results. Generally, Statoil believes in setting ambitious targets to inspire and drive strong performance.

Goals on "How" we deliver are based on our core values and leadership principles and address the behaviour required and expected in order to achieve our delivery goals.

Performance evaluation is holistic, involving both measurement and assessment. Since KPIs are indicators only, sound judgement and hindsight insights are applied. Significant changes in assumptions are taken into account, as well as target ambition levels, sustainability of delivered results and strategic contribution.

This balanced approach, which involves a broad set of goals defined in relation to both "What" and "How" dimensions and an overall performance evaluation, is viewed to significantly reduce the likelihood that remuneration policies may stimulate excessive risk-taking or have other material adverse effects.

In the performance contracts of the chief executive officer and chief financial officer, one of several targets is related to the company's relative total shareholder return (TSR). The amount of the annual variable pay is decided based on an overall assessment of the performance of various targets including but not limited to the company's relative TSR.

[3] G = The basic amount of the Norwegian Social security system

In 2016, the main objectives and KPIs for each perspective were as outlined below. Each perspective was in addition supported by comprehensive plans and actions.

Strategic objectives		2016 assessment
Safety, security and sustainability	The strategic objectives and actions address safety, security and sustainability	Serious Incident Frequency (actual) of 0.29 was above target. Target on the number of oil and gas leakages was not met. CO_2 intensity for the upstream portfolio was in line with target.
People and organisation	The strategic objectives and actions address high performing leaders and teams, and global and cost-effective capabilities	Employee engagement was above target, increasing from 2015 during a period of extensive organizational efficiency programmes. People development was in line with 2015, with strong focus on building competence and upholding learning activity throughout 2016 yielding positive results.
Operations	The strategic objectives and actions address reliable and cost-efficient operations, and value-driven technology development	Production exceeded target, despite an extensive maintenance programme. Relative unit production cost remained the lowest among industry peers. Production efficiency was slightly below target.
Market	The strategic objectives and actions address stakeholder trust, value chain optimisation and portfolio and project management	Capex was below target and external guiding level, due to increased efficiency and stricter prioritization. Cost efficiency for projects under development was above target, exceeding the industry average. Reserve replacement ratio was below the target of >1. Value creation from exploration was below target, mainly due to lower-than-expected discovered volumes.
Results	The strategic objectives and actions address shareholder return, financial robustness, value creation from exploration and cost & capital discipline	Relative Shareholder Return (TSR) improved and ended 3rd in an industry peer group of 12. Relative ROACE for 2016 ended 9th in an industry peer group of 12, falling as a result of exposure to upstream margins. The cash flow improvement programme delivered above target.

Board assessment of the chief executive officer's performance

In its assessment of the chief executive officer's performance, and consequently his annual pay for 2016, the board has put emphasis on the solid delivery on production, efficiency, and prioritization. CAPEX was below target and guiding, and relative TSR is first quartile. The number of oil and gas leakages was above target, while CO_2 intensity for the upstream portfolio was in line with target. The actual SIF was above target (0.29 versus target of 0.18).

Key performance indicators for the chief executive officer for 2017

The delivery dimension for the CEO's variable remuneration and base salary merit increase as of 1 January 2018 will be based on assessment of results on the following KPIs:

Safety, Security and Sustainability

- Serious Incident Frequency (actual)
- CO_2 intensity for the upstream portfolio

Market

- Capex (capital expenditure)

Results

- Relative Total Shareholder Return
- Relative RoACE
- Cash flow improvement programme

Execution of the remuneration policy and principles in 2016

Introduction

- The remuneration policy and principles executed in 2016 were in accordance with the declaration given to the AGM 11 May 2016
- There was no general salary increase for members of the executive committee in 2016
- Subject to application of the threshold described in section on the remuneration concept for the corporate executive committee the LTI in Statoil ASA was reduced by 50% of the executive maximum levels

Threshold and company modifier for variable pay

The company modifier depends on the outcome of two metrics RoACE and TSR, both parameters measured relatively to a peer group of 11 other companies. The results for Statoil in 2016 were; relative ROACE number 9 and relative TSR number 3 in the peer group. This gives 3rd quartile result for RoACE and first quartile result for TSR, which gives a company modifier of 1,17 for 2016.

The threshold measure is the company's adjusted earnings after tax. In 2016 Statoil's adjusted earnings after tax were negative USD 208 million, strongly impacted by low oil and gas prices throughout the year. At the same time, the company has delivered strong operational results and the improvement programmes have given substantial cost reductions.

Even though the adjusted earnings for 2016 ended below the threshold limit, it has been decided based on a holistic assessment of total results that a threshold of 50% will be applied for the earning year 2016. Thus, the bonus payment and LTI award have been be reduced by 50%.

Executive Terms and conditions

The chief executive officer, Eldar Sætre's annual base salary is NOK 5,700,000. Furthermore, the chief executive officer is entitled to an additional fixed remuneration element of NOK 2,000,000 not included in the pensionable income. The remuneration package of the chief executive officer has been restructured. In order to be consistent with revised governmental guidelines the company's long term incentive scheme has been changed. The LTI grant will no longer be included in the basis for calculating annual variable pay. To mitigate the effect of reduced annual variable, pay for the CEO, his fixed remuneration element will be increased by NOK 373,000 from 1 January 2017

The chief executive officer will participate in an annual variable pay scheme with a target level of 25% (max 50%), and participation to the Company's 2017 LTI scheme with a value of 30% (gross) of base salary. The pension terms remain unchanged according to previously established pension agreement, as described in section on pension and insurance scheme.

Terms and conditions for Executive vice president employed in Statoil ASA, are described in section on the remuneration concept for the corporate executive committee.

Based on a mutual understanding, John Knight, employed by Statoil UK, will end his employment with the company as of 1 January 2019. To provide clarity and predictability of compensation and costs related to Knight's remaining employment it has been decided to adjust his remuneration package with effect from the earning year 2016.

The main changes to John Knights remuneration package are;

- The base salary is increased from GBP 599,908 to GBP 630,000 with effect from 1 January 2017
- The variable pay schemes (AVP and LTI), which provided for a maximum variable pay of 150% of base salary are discontinued
- In lieu of variable pay he will be awarded a cash allowance amounting to GBP 535,000 in 2017 and 2018 and GBP 600,000 in 2019

In lieu of pension contribution Knight receives an annual allowance of 20% of his base salary. His contract also includes a provision for severance payment of 12 months' base salary. John Knights taxable compensation in 2016 is USD 1,810,000, compared to USD 2,089,000 in 2015[4]. The adjusted remuneration package does not include variable pay elements and is thus not considered as a deviation from the governmental guidelines on variable compensation. Furthermore, and in line with the company's guidelines, the adjusted compensation package will remain competitive, but not market leading.

The decision-making process

The decision-making process for implementing or changing remuneration policies and concepts, and the determination of salaries and other remuneration for corporate executive committee, are in accordance with the provisions of the Norwegian public limited liability companies act sections 5-6 and 6-16 a and the board's rules of procedure. The board's rules of procedure are available at www.statoil.com/board.

The board of directors has appointed a designated compensation and executive development committee. The compensation and executive development committee is a preparatory body for the board. The committee's main objective is to assist the board of directors in its work relating to the terms of employment for Statoil's chief

4 Based on average currency rates for 2015: USD/NOK = 8,0739, USD/GBP = 1,5289.

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executive officer and the main principles and strategy for the remuneration and leadership development of our senior executives. The board of directors determines the chief executive officer's salary and other terms of employment.

The compensation and executive development committee answers to the board of Statoil ASA for the performance of its duties. The work of the committee in no way alters the responsibilities of the board of directors or the individual board members.

For further details about the roles and responsibilities of the compensation and executive development committee, please refer to the committee's instructions available at www.statoil.com/compensationcommittee.

Members of corporate executive committee (figures in USD thousand, except no. of shares)1), 2)	Fixed remuneration Fixed pay3)	Cash allowance4)	LTI 5)	Annual variable pay6)	Taxable benefits	2016 Taxable compensation	Non-taxable benefits in kind	Estimated pension cost7)	Estimated present value of pension obligation 8)	2015 Taxable compensation9)	Share ownership at 31 December 2016
Eldar Sætre13)	937	0	138	245	37	1,356	0	0	11,261	1,754	47,882
Margareth Øvrum	453	0	53	106	18	631	20	0	6,788	751	49,227
Timothy Dodson	440	0	51	67	15	573	39	141	4,746	673	29,418
Irene Rummelhoff	349	54	37	61	10	511	0	26	1,070	294	21,556
Jens Økland	347	58	40	53	12	509	0	22	785	329	13,937
Arne Sigve Nylund	398	0	49	80	18	546	0	112	4,047	690	11,312
Lars Christian Bacher	419	0	45	89	14	567	52	110	2,039	647	24,896
Hans Jakob Hegge	372	62	43	71	13	561	0	23	1,097	251	28,190
Jannicke Nilsson10)	32	5	2	0	0	40	0	3	1,032	NA	35,049
Anders Opedal11)	338	57	40	78	2	514	0	23	1,030	456	15,910
Torgrim Reitan12)	611	0	49	87	137	884	0	115	1,947	744	32,276
John Knight13)	1,679	0	0	0	131	1,810	0	0	0	2,089	103,808

1) All figures in the table are presented in USD based on average currency rates (2016: USD/NOK = 8.3987, USD/GBP = 1.3538. 2015: USD/NOK = 8,0739, USD/GBP = 1,5289). The figures are presented on accrual basis.
2) All CEC members receive their remuneration in Norwegian Kroner except John Knight who receives the remuneration in GBP.
3) Fixed pay consists of base salary, fixed remuneration element, holiday allowance and other administrative benefits.
4) Cash allowance in lieu of pension accrual above 12 G (the base amount in the national insurance scheme).
5) The fixed long-term incentive (LTI) element implies an obligation to invest the net amount in Statoil shares, including a lock-in period. The LTI element is presented the year it is granted for the members of the corporate executive committee employed by Statoil ASA.
6) Annual variable pay includes holiday allowance for corporate executive committee (CEC) members resident in Norway.
7) Estimated pension cost is calculated based on actuarial assumptions and pensionable salary (mainly base salary) at 31 December 2015 and is recognized as pension cost in the statement of income for 2016.
8) Estimated present value of pension obligation related to Eldar Sætre, Arne Sigve Nylund, Margareth Øvrum og Timothy Dodson are based on the estimated value of paid-up policies and rights letters from the Defined Benefit Pension Scheme. Estimated present value of pension obligation for the rest of the members of the corporate executive committee employed by Statoil ASA, is presented with value of paid-up policies and right letters from the Defined Benefit Pension Scheme and accrued pension assets from the Defined Contribution Pension Scheme.
9) Includes 2015 CEC members who are also CEC members in 2016.
10) Jannicke Nilsson was appointed executive vice president and chief operating officer (COO) from 1 December 2016.
11) Anders Opedal left the position as executive vice president and chief operating officer (COO) at 30 November 2016.
12) Compensation and benefit for Torgrim Reitan is according to Statoil's international assignment terms.
13) Fixed pay for Eldar Sætre includes a fixed remuneration element of USD 238 thousand not included in pensionable salary. John Knight's fixed pay includes a fixed remuneration element of USD 143 thousand that replaces his defined contribution pension plan and a fixed remuneration element of USD 724 thousand replacing his variable pay arrangements.

There are no loans from the company to members of the corporate executive committee.

Company performance modifier

Introduction

Based on approval by the annual general meeting in 2016 a company performance modifier has been introduced to be applied in calculation of variable pay. The intention is to continue with the performance modifier in 2017. The relative total shareholder return is recommended as one of the criteria in the modifier. Thus, the case is submitted to the annual general meeting for approval, pursuant to the provisions in the Public Limited Companies Act § 5-6 third paragraph last sentence ref. § 6-16 a, first paragraph third sentence number 3.

Background

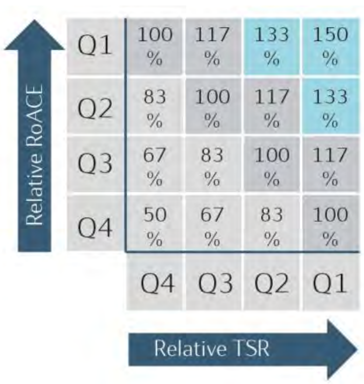
Statoil has implemented annual variable pay schemes (AVP) for members of the corporate executive committee. The schemes are described in section on remuneration concept for the corporate executive committee of this declaration. Other executives, managers and employees in defined professional positions are also eligible for individual variable pay according to the company's guidelines.

The company performance modifier is implemented to strengthen the link between the company's overall financial results and the individual variable pay. The governmental guidelines on executive remuneration also underline that "there shall be a clear connection between the variable salary and the performance of the company."

Proposal

Based on this, the performance modifier will be continued in 2017. The company performance will be assessed against two equally weighted measures: relative total shareholder return (TSR) and relative return on average capital employed (RoACE). TSR and RoACE are currently also applied as performance indicators in the corporate performance management system.

The results of these two performance measures are compared to our peers and our relative position determined. A position of Q1 means that Statoil is amongst the top scoring quartile of peer companies. A position of Q4 means Statoil is in the bottom performing quartile. In years with strong deliveries on relative TSR and RoACE, the matrix will result in the variable pay being modified with a factor higher than one and, correspondingly, lower than one in weak years. The combination of ratings for both measures, will act as a 'multiplier' according to the guideline in the matrix displayed below.



By applying relative numbers, the effect of fluctuating oil price will be reduced. Within the framework of 50 - 150%, the matrix is a guideline and the multiplier (percentages) may be adjusted if oil or gas price effects or other occurrences outside the control of the company are deemed to cause disproportionate results in a given year.

Subject to approval by the 2017 general meeting, the company performance modifier will be continued in calculations of annual variable pay for members of the corporate executive committee in the earning year 2017 with subsequent impact on annual variable pay in 2018. The modifier will also be applied in other variable pay schemes below the corporate executive level. Further application of the company performance modifier will also be assessed and decided if deemed appropriate.

The annual variable pay for members of the corporate executive committee will be within a framework of 50% of the fixed remuneration irrespective of the result of the modifier. Any deviations from this framework for members of the corporate executive committee will be explained in the board's annual declaration on remuneration and other employment terms for Statoil's corporate executive committee.

Share ownership

The number of Statoil shares owned by the members of the board of directors and the executive committee and/or owned by their close associates is shown below. Individually, each member of the board of directors and the corporate executive committee owned less than 1% of the outstanding Statoil shares.

Ownership of Statoil shares (including share ownership of «close associates»)	As of 31 December 2016	As of 8 March 2017
Members of the corporate executive committee		
Eldar Sætre	47,882	48,629
Hans Jakob Hegge	28,190	29,111
Jannicke Nilsson	35,049	35,972
Lars Christian Bacher	24,896	20,895
Torgrim Reitan	32,276	33,133
John Knight	103,808	105,593
Tim Dodson	29,418	30,349
Margareth Øvrum	49,227	50,499
Arne Sigve Nylund	11,312	11,312
Jens Økland	13,937	14,462
Irene Rummelhoff	21,556	22,082
Members of the board of directors		
Øystein Løseth	1,040	1,040
Roy Franklin	0	0
Bjørn Tore Godal	0	0
Jeroen van der Veer	0	0
Maria Johanna Oudeman	0	0
Rebekka Glasser Herlofsen	0	0
Wenche Agerup	2,522	2,522
Lill-Heidi Bakkerud	342	342
Ingrid Elisabeth di Valerio	3,670	3,949
Stig Lægreid	1,881	1,881

Individually, each member of the corporate assembly owned less than 1% of the outstanding Statoil shares as of 31 December 2016 and as of 8 March 2017. In aggregate, members of the corporate assembly owned a total of 24,578 shares as of 31 December 2016 and a total of 25,331 shares as of 8 March 2017. Information about the individual share ownership of the members of the corporate assembly is presented in the section 3.8 Corporate assembly, board of directors and management.

The voting rights of members of the board of directors, the corporate executive committee and the corporate assembly do not differ from those of ordinary shareholders.

Deviations from the Code: None

3.13 INFORMATION AND COMMUNICATIONS

The reporting is based on openness and it takes into account the requirement for equal treatment of all participants in the securities market. Statoil has established guidelines for the company's reporting of financial and other information and the purpose of these guidelines is to ensure that timely and correct information about the company is made available to our shareholders and society in general.

A financial calendar and shareholder information is published at www.statoil.com/calendar.

The investor relations corporate staff function is responsible for coordinating the company's communication with capital markets and for relations between Statoil and existing and potential investors. Investor relations is responsible for distributing and registering information in accordance with the legislation and regulations that apply where Statoil securities are listed. Investor relations reports directly to the chief financial officer.

The company's management holds regular presentations for investors and analysts. The company's quarterly presentations are broadcast live on our website. Investor relations communicate with present and potential shareholders through presentations, one-to-one meetings, conferences, web-site, financial media, telephone, mail and e-mail contact. The pertaining reports from these communication channels are made available together with other relevant information at www.statoil.com/investor.

All information distributed to the company's shareholders is published on the company's website at the same time as it is sent to the shareholders.

Deviations from the Code: None

3.14 TAKE-OVERS

The board of directors endorses the principles concerning equal treatment of all shareholders and Statoil's articles of association do not set limits on share acquisitions. Statoil has no defence mechanisms against take-over bids in its articles of association, nor has it implemented other measures that limit the opportunity to acquire shares in the company. The Norwegian State owns 67% of the shares, and the marketability of these shares is subject to parliamentary decree.

The board is obliged to act professionally and in accordance with the applicable principles for good corporate governance if a situation should arise in which this principle in the Code were put to the test.

Deviations from the Code:
The Code recommends that the board establish guiding principles for how it will act in the event of a take-over bid. The board has not established such guidelines, due to Statoil's ownership structure and for the reasons stated above. In the event of a bid as discussed in section 14 of the Code, the board of directors will, in addition to complying with relevant legislation and regulations, seek to comply with the recommendations in the Code. The board has no other explicit basic principles or written guidelines for procedures to be followed in the event of a take-over bid. The board of directors otherwise concurs with what is stated in the Code regarding this issue.

3.15 EXTERNAL AUDITOR

Our external registered public accounting firm (external auditor) is independent in relation to Statoil and is elected by the general meeting of shareholders. The external auditor's fee must be approved by the general meeting of shareholders.

Pursuant to the instructions for the board's audit committee approved by the board of directors, the audit committee is responsible for ensuring that the company is subject to an independent and effective external and internal audit. Every year, the external auditor presents a plan to the audit committee for the execution of the external auditor's work. The external auditor attends the meeting of the board of directors that deals with the preparation of the annual accounts.

The external auditor also participates in meetings of the audit committee. The audit committee considers all reports from the external auditor before they are considered by the board of directors. The audit committee meets at least five times a year and both the board and the board's audit committee hold meetings with the internal auditor and the external auditor on a regular basis without the company's management being present.

When evaluating the external auditor, emphasis is placed on the firm's qualifications, capacity, local and international availability and the size of the fee.

The audit committee evaluates and makes a recommendation to the board of directors, the corporate assembly and the general meeting of shareholders regarding the choice of external auditor. The committee is responsible for ensuring that the external auditor meets the requirements in Norway and in the countries where Statoil is listed. The external auditor is subject to the provisions of US securities legislation, which stipulates that a responsible partner may not lead the engagement for more than five consecutive years.

The audit committee's policies and procedures for pre-approval
In its instructions for the audit committee, the board of directors has delegated authority to the audit committee to pre-approve assignments to be performed by the external auditor. Within this pre-approval, the audit committee has issued further guidelines. The audit committee has issued guidelines for the management's pre-approval of assignments to be performed by the external auditor.

All audit-related and other services provided by the external auditor must be pre-approved by the audit committee. Provided that the types of services proposed are permissible under SEC guidelines, pre-approval is usually granted at a regular audit committee meeting. The chair of the audit committee has been authorised to pre-approve services that are in accordance with policies established by the audit committee that specify in detail the types of services that qualify. It is a condition that any services pre-approved in this manner are presented to the full audit committee at its next meeting. Some pre-approvals can therefore be granted by the chair of the audit committee if an urgent reply is deemed necessary.

Remuneration of the external auditor in 2014 - 2016
In the annual Consolidated financial statements and in the parent company's financial statements, the independent auditor's remuneration is split between the audit fee and the fee for audit-related and other services. The chair presents the breakdown between the audit fee and the fee for audit-related and other services to the annual general meeting of shareholders.

The following table sets out the aggregate fees related to professional services rendered by Statoil's principal accountant KPMG AS, for the fiscal year 2016, 2015 and 2014.

Auditor's remuneration

(in USD million, excluding VAT)	Full year 2016	2015	2014
Audit fee	6.5	6.1	7.1
Audit related fee	1.0	1.7	1.3
Tax fee	0.1	0.0	0.0
Other service fee	0.0	0.0	0.0
Total	7.5	7.9	8.4

All fees included in the table have been approved by the board's audit committee.

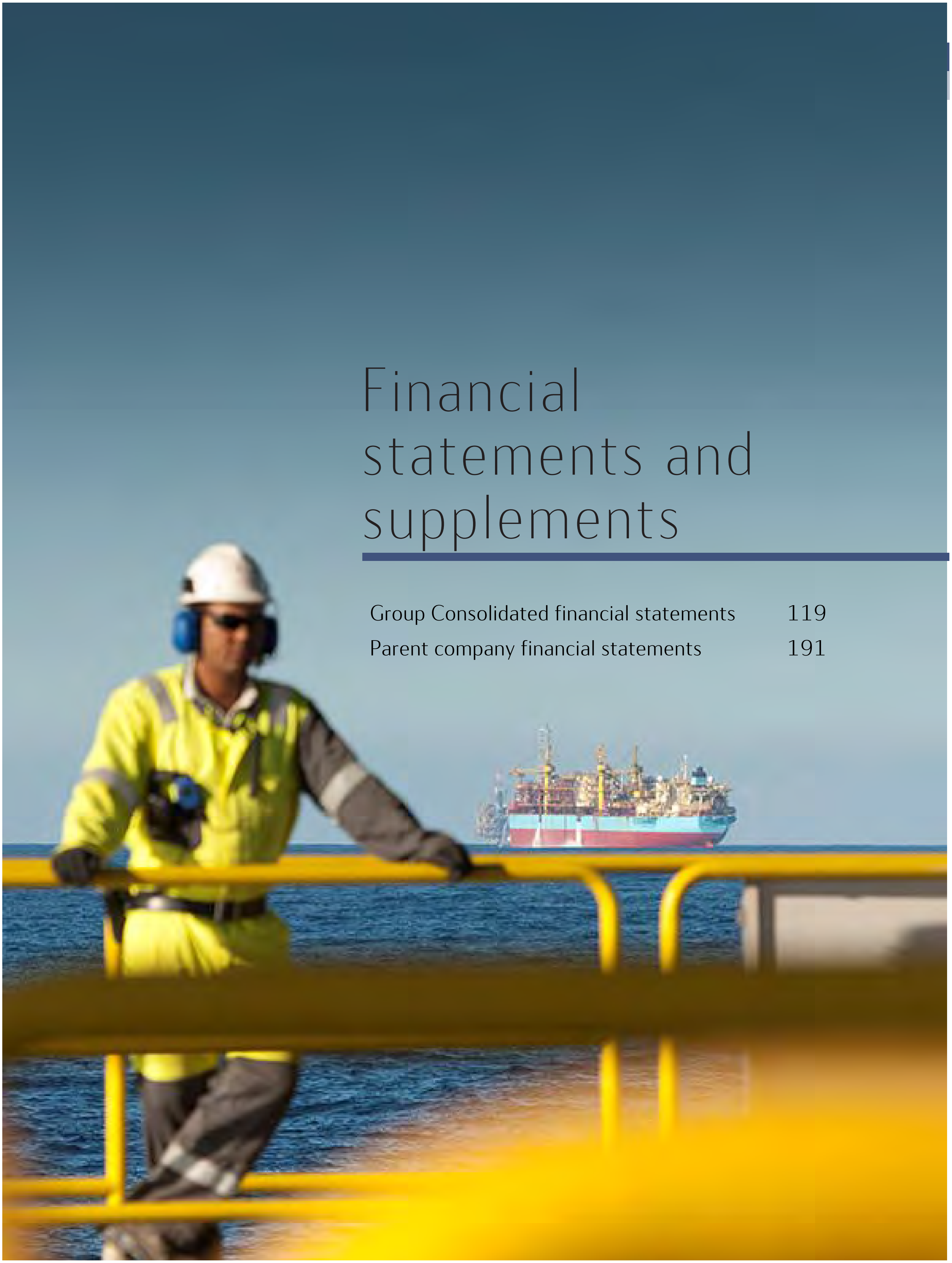
Audit fee is defined as the fee for standard audit work that must be performed every year in order to issue an opinion on Statoil's Consolidated financial statements, on Statoil's internal control over annual reporting and to issue reports on the statutory financial statements. It also includes other audit services, which are services that only the independent auditor can reasonably provide, such as the auditing of non-recurring transactions and the application of new accounting policies, audits of significant and newly implemented system controls and limited reviews of quarterly financial results.

Audit-related fees include other assurance and related services provided by auditors, but not limited to those that can only reasonably be provided by the external auditor who signs the audit report, that are reasonably related to the performance of the audit or review of the company's financial statements, such as acquisition due diligence, audits of pension and benefit plans, consultations concerning financial accounting and reporting standards.

Other services fees include services provided by the auditors within the framework of the Sarbanes-Oxley Act, i.e. certain agreed procedures.

In addition to the figures in the table above, the audit fees and audit-related fees relating to Statoil operated licences paid to KPMG for the years 2016, 2015 and 2014 amounted to USD 0.8 million, USD 0.9 million and USD 1.0 million, respectively.

Deviations from the Code: None



Financial statements and supplements

4.1 Statoil Consolidated financial statements

With effect from 1 January 2016 the financial statements are presented in US dollars (USD). Comparative data has been converted from Norwegian kroner (NOK) to USD accordingly. For more information concerning this see note 26 Change of presentation currency.

CONSOLIDATED STATEMENT OF INCOME

			Full year	
(in USD million)	Note	2016	2015	2014
Revenues		45,688	57,900	96,708
Net income from equity accounted investments		(119)	(29)	(34)
Other income	4	304	1,770	2,590
Total revenues and other income	3	45,873	59,642	99,264
Purchases [net of inventory variation]		(21,505)	(26,254)	(47,980)
Operating expenses		(9,025)	(10,512)	(11,657)
Selling, general and administrative expenses		(762)	(921)	(1,159)
Depreciation, amortisation and net impairment losses	10, 11	(11,550)	(16,715)	(15,925)
Exploration expenses	11	(2,952)	(3,872)	(4,666)
Net operating income	3	80	1,366	17,878
Net financial items	8	(258)	(1,311)	20
Income before tax		(178)	55	17,898
Income tax	9	(2,724)	(5,225)	(14,011)
Net income		(2,902)	(5,169)	3,887
Attributable to equity holders of the company		(2,922)	(5,192)	3,871
Attributable to non-controlling interests		20	22	16
Basic earnings per share (in USD)		(0.91)	(1.63)	1.22
Diluted earnings per share (in USD)		(0.91)	(1.63)	1.21
Weighted average number of ordinary shares outstanding (in millions)		3,195	3,179	3,180
Weighted average number of ordinary shares outstanding, diluted (in millions)		3,207	3,189	3,189

CONSOLIDATED STATEMENT OF COMPREHENSIVE INCOME

(in USD million)	Note	Full year 2016	2015	2014
Net income		(2,902)	(5,169)	3,887
Actuarial gains (losses) on defined benefit pension plans	19	(503)	1,599	636
Income tax effect on income and expenses recognised in OCI		129	(461)	(56)
Items that will not be reclassified to the Consolidated statement of income		(374)	1,138	580
Currency translation adjustments		17	(3,976)	(5,167)
Items that may be subsequently reclassified to the Consolidated statement of income		17	(3,976)	(5,167)
Other comprehensive income		(357)	(2,838)	(4,587)
Total comprehensive income		(3,259)	(8,007)	(701)
Attributable to the equity holders of the company		(3,279)	(8,030)	(717)
Attributable to non-controlling interests		20	22	16

CONSOLIDATED BALANCE SHEET

(in USD million)	Note	At 31 December 2016	2015	2014
ASSETS				
Property, plant and equipment	10	**59,556**	62,006	75,619
Intangible assets	11	**9,243**	9,452	11,458
Equity accounted investments	12	**2,245**	824	1,127
Deferred tax assets	9	**2,195**	2,022	1,732
Pension assets	19	**839**	1,284	1,072
Derivative financial instruments	25	**1,819**	2,697	4,023
Financial investments	13	**2,344**	2,336	2,634
Prepayments and financial receivables	13	**893**	967	766
Total non-current assets		**79,133**	81,588	98,430
Inventories	14	**3,227**	2,502	3,193
Trade and other receivables	15	**7,839**	6,671	11,212
Derivative financial instruments	25	**492**	542	717
Financial investments	13	**8,211**	9,817	7,968
Cash and cash equivalents	16	**5,090**	8,623	11,182
Total current assets		**24,859**	28,154	34,272
Assets classified as held for sale	4	**537**	0	0
Total assets		**104,530**	109,742	132,702
EQUITY AND LIABILITIES				
Shareholders' equity		**35,072**	40,271	51,225
Non-controlling interests		**27**	36	57
Total equity	17	**35,099**	40,307	51,282
Finance debt	18, 22	**27,999**	29,965	27,593
Deferred tax liabilities	9	**6,427**	7,421	9,613
Pension liabilities	19	**3,380**	2,979	3,752
Provisions	20	**13,406**	12,422	15,766
Derivative financial instruments	25	**1,420**	1,285	611
Total non-current liabilities		**52,633**	54,073	57,335
Trade, other payables and provisions	21	**9,666**	9,333	13,545
Current tax payable		**2,184**	2,740	5,321
Finance debt	18	**3,674**	2,326	3,561
Dividends payable	17	**712**	700	770
Derivative financial instruments	25	**508**	264	887
Total current liabilities		**16,744**	15,363	24,085
Liabilities directly associated with the assets classified as held for sale	4	**54**	0	0
Total liabilities		**69,431**	69,436	81,420
Total equity and liabilities		**104,530**	109,743	132,702

CONSOLIDATED STATEMENT OF CHANGES IN EQUITY

(in USD million)	Share capital	Additional paid-in capital	Retained earnings	Currency translation adjustments	Shareholders' equity	Non-controlling interests	Total equity
At 31 December 2013	1,139	5,741	47,690	3,863	58,432	81	58,513
Net income for the period			3,871		3,871	16	3,887
Other comprehensive income			580	(5,167)	(4,587)		(4,587)
Total comprehensive income							(701)
Dividends			(6,517)		(6,517)		(6,517)
Other equity transactions		(26)	54		27	(39)	(12)
At 31 December 2014	1,139	5,714	45,677	(1,305)	51,225	57	51,282
Net income for the period			(5,192)		(5,192)	22	(5,169)
Other comprehensive income			1,138	(3,976)	(2,838)		(2,838)
Total comprehensive income							(8,007)
Dividends			(2,930)		(2,930)		(2,930)
Other equity transactions		6	(0)		6	(43)	(38)
At 31 December 2015	1,139	5,720	38,693	(5,281)	40,271	36	40,307
Net income for the period			(2,922)		(2,922)	20	(2,902)
Other comprehensive income			(374)	17	(357)		(357)
Total comprehensive income							(3,259)
Dividends	17	887	(2,824)		(1,920)		(1,920)
Other equity transactions		1	0		2	(30)	(28)
At 31 December 2016	1,156	6,607	32,573	(5,264)[1)]	35,072	27	35,099

1) Balance of currency translation adjustments includes a loss of USD 321 million directly associated with assets classified as held for sale. See note 4 Acquisitions and disposals for information on transaction.

Refer to note 17 Shareholders' equity and dividends.

CONSOLIDATED STATEMENT OF CASH FLOWS

(in USD million)	Note	Full year 2016	2015	2014
Income before tax		(178)	55	17,898
Depreciation, amortisation and net impairment losses	10, 11	11,550	16,715	15,925
Exploration expenditures written off	11	1,800	2,164	2,097
(Gains) losses on foreign currency transactions and balances		(137)	1,166	883
(Gains) losses on sales of assets and businesses	4	(110)	(1,716)	(1,998)
(Increase) decrease in other items related to operating activities		1,076	558	(1,671)
(Increase) decrease in net derivative financial instruments	25	1,307	1,551	254
Interest received		280	363	341
Interest paid		(548)	(443)	(551)
Cash flows provided by operating activities before taxes paid and working capital items		15,040	20,414	33,178
Taxes paid		(4,386)	(8,078)	(15,308)
(Increase) decrease in working capital		(1,620)	1,292	2,335
Cash flows provided by operating activities		9,034	13,628	20,205
Additions through business combinations	4	0	(398)	0
Capital expenditures and investments		(12,191)	(15,518)	(19,497)
(Increase) decrease in financial investments		877	(2,813)	(1,919)
(Increase) decrease in other non-current items		107	(22)	128
Proceeds from sale of assets and businesses	4	761	4,249	3,514
Cash flows used in investing activities		(10,446)	(14,501)	(17,775)
New finance debt	18	1,322	4,272	3,010
Repayment of finance debt		(1,072)	(1,464)	(1,537)
Dividend paid	17	(1,876)	(2,836)	(5,499)
Net current finance debt and other		(333)	(701)	(2)
Cash flows provided by (used in) financing activities		(1,959)	(729)	(4,028)
Net increase (decrease) in cash and cash equivalents		(3,371)	(1,602)	(1,598)
Effect of exchange rate changes on cash and cash equivalents		(152)	(871)	(1,329)
Cash and cash equivalents at the beginning of the period (net of overdraft)	16	8,613	11,085	14,013
Cash and cash equivalents at the end of the period (net of overdraft)	16	5,090	8,613	11,085

Cash and cash equivalents include bank overdrafts of nil at 31 December 2016 (2015: USD 10 million; 2014: USD 97 million).

Interest paid in cash flows provided by operating activities is excluding capitalised interest of USD 355 million at 31 December 2016, USD 392 million at 31 December 2015 and USD 250 million at 31 December 2014. Capitalised interest is included in Capital expenditures and investments in cash flows used in investing activities.

Notes to the Consolidated financial statements

1 Organisation

Statoil ASA, originally Den Norske Stats Oljeselskap AS, was founded in 1972 and is incorporated and domiciled in Norway. The address of its registered office is Forusbeen 50, N-4035 Stavanger, Norway.

Statoil ASA is listed on the Oslo Børs (Norway) and the New York Stock Exchange (USA).

The Statoil group's business consists principally of the exploration, production, transportation, refining and marketing of petroleum and petroleum-derived products and other forms of energy.

All the Statoil group's oil and gas activities and net assets on the Norwegian continental shelf are owned by Statoil Petroleum AS, a 100% owned operating subsidiary. Statoil Petroleum AS is co-obligor or guarantor of certain debt obligations of Statoil ASA.

The Consolidated financial statements of Statoil for the full year 2016 were authorised for issue in accordance with a resolution of the board of directors on 9 March 2017.

2 Significant accounting policies

Statement of compliance
The Consolidated financial statements of Statoil ASA and its subsidiaries (Statoil) have been prepared in accordance with International Financial Reporting Standards (IFRSs) as adopted by the European Union (EU) and also comply with IFRSs as issued by the International Accounting Standards Board (IASB), effective at 31 December 2016.

Basis of preparation
The financial statements are prepared on the historical cost basis with some exceptions, as detailed in the accounting policies set out below. These policies have been applied consistently to all periods presented in these Consolidated financial statements. Certain amounts in the comparable years have been restated to conform to current year presentation. The subtotals and totals in some of the tables may not equal the sum of the amounts shown due to rounding.

Operating related expenses in the Consolidated statement of income are presented as a combination of function and nature in conformity with industry practice. Purchases [net of inventory variation] and Depreciation, amortisation and net impairment losses are presented in separate lines by their nature, while Operating expenses and Selling, general and administrative expenses as well as Exploration expenses are presented on a functional basis. Significant expenses such as salaries, pensions, etc. are presented by their nature in the notes to the Consolidated financial statements.

Standards and amendments to standards, issued but not yet adopted
At the date of these Consolidated financial statements, the following standards and amendments to standards applicable to Statoil have been issued, but were not yet effective:

IFRS 15 Revenue from Contracts with Customers
IFRS 15, effective from 1 January 2018, covers the recognition of revenue in the financial statements and related disclosure. IFRS 15 will replace IAS 18 Revenue.

IFRS 15 requires identification of the performance obligations for the transfer of goods and services in each contract with customers. Revenue will be recognised upon satisfaction of the performance obligations for the amounts that reflect the consideration to which Statoil expects to be entitled in exchange for those goods and services.

The impact of adopting IFRS 15 will principally impact the Marketing, Midstream and Processing segment (MMP), which accounts for the majority of Statoil's petroleum sales to customers, and which is responsible for the marketing and sale of the State's direct financial interest's (SDFI's) petroleum volumes.

IFRS 15 requires adoption either on a retrospective basis or on the basis of the cumulative effect on retained earnings. Statoil has not yet determined its implementation method for the standard, but at this stage in the evaluations, does not expect either implementation method to affect the Consolidated statement of income, balance sheet or statement of cash flows materially.

Statoil will adopt IFRS 15 on 1 January 2018.

The most significant accounting matters with regards to the implementation of IFRS 15 in Statoil, as well as their expected impact, can be summarised as follows.

Marketing and sale of the Norwegian State's share of crude oil and natural gas production from the Norwegian continental shelf (NCS) and related agent/principal evaluations; in evaluating these sales, Statoil has considered whether it acts as the principal in the transactions under IFRS 15, i.e. whether it controls the State's volumes prior to onwards sales to third party customers. Statoil's sales of the State's natural gas volumes are performed for the Norwegian State's account and risk, and although Statoil has been granted the ability to direct the use of the volumes, all the benefits from the sales of these volumes flow to the State. On that basis, Statoil is not considered the principal in the sale of the SDFI's natural gas volumes. In the sales of the State-originated crude oil, Statoil also directs the use of the volumes. However, although certain benefits from these sales subsequently flow to the State, Statoil purchases the crude oil volumes from the State and obtains substantially all the remaining benefits. Statoil therefore is considered the principal in the crude oil sales. The accounting for Statoil's sale of the SDFI's natural gas and crude oil under IFRS 15 will consequently not lead to material changes compared to the current practice under IAS 18, as separately described in this note disclosure.

Transport of goods sold; in certain sales of goods such as crude oil or natural gas, Statoil provides transport services after control of the good has been transferred to the customer. Following implementation of IFRS 15, in most such instances this transport will be considered a service that is completed over time and is distinct from the good sold, and therefore will be recognised separately. The impact on the Consolidated financial statements from the resulting timing differences in the reflection of revenues from contracts with customers is currently not expected to be material.

Accounting for taxes paid in kind under the terms of profit sharing agreements (PSAs); in certain countries, taxes are paid in kind and the volumes are subsequently sold according to the terms of the PSA and applicable tax regulations. As the sale of the volumes is not performed directly by Statoil, evaluation is still ongoing as to whether the sales proceeds qualify as revenue from contracts with customers under IFRS 15. Irrespective of the conclusion reached, the in-kind tax payments and related sales of volumes will continue to be accounted for gross in the Statement of income, classified as tax expense in accordance with IAS 12 Income taxes and as a form of revenue, respectively.

IFRS 9 Financial Instruments

IFRS 9, effective from 1 January 2018, will replace IAS 39 Financial Instruments: Recognition and Measurement. IFRS 9 introduces a new model for classification and measurement of financial assets and financial liabilities, a reformed approach to hedge accounting, and a more forward-looking impairment model.

IFRS 9 will principally impact Statoil's financing and liquidity management activities, as well as the MMP segment, which reflects the majority of Statoil's trade receivables and commodity-based financial instruments.

Portions of Statoil's cash equivalents and current financial investments tied to liquidity management, which under IAS 39 are classified as held for trading and reflected at fair value through profit and loss, will under IFRS 9 be classified and measured at amortised cost, based on an evaluation of the contractual terms and the business model applied. The investment portfolio of Statoil's captive insurance company will continue to be classified and measured at fair value through profit and loss under IFRS 9.

The impact on the Consolidated statement of income of commodity-based derivative financial instruments, which due to their connection with sales and revenue risk management currently are classified under revenues, is expected to be reflected in an appropriate section within total revenues and other income upon the implementation of IFRS 9. No decisions have yet been made related to whether, and if so, on which elements, hedge accounting will be applied.

IFRS 9's transition provisions partially require retrospective adoption, and partially prospective adoption. IFRS 9 implementation issues are currently not expected to have a material impact on the Consolidated balance sheet, statement of income and statement of cash flows.

Statoil will adopt IFRS 9 on 1 January, 2018.

IFRS 16 Leases

IFRS 16, effective from 1 January 2019, covers the recognition of leases and related disclosure in the financial statements, and will replace IAS 17 Leases. In the financial statement of lessees, the new standard requires recognition of all contracts that qualify under its definition of a lease as right-of-use assets and lease liabilities in the balance sheet, while lease payments are to be reflected as interest expense and reduction of lease liabilities. The right-of-use assets are to be depreciated in accordance with IAS 16 Property, Plant and Equipment over the shorter of each contract's term and the assets' useful life.

The standard consequently implies a significant change in lessees' accounting for leases currently defined as operating leases under IAS 17, both with regard to impact on the balance sheet and the statement of income. IFRS 16 defines a lease as a contract that conveys the right to control the use of an identified asset for a period of time in exchange for consideration. While this definition is not dissimilar to that of IAS 17, it would have required further evaluation of each contract to determine whether all leases included in Note 22 Leases of these financial statements, or contracts currently not defined as leases, would qualify as leases under the new standard.

The standard introduces new requirements both as regards establishing the term of a lease and the related discounted cash flows that determine the amount of a lease liability to be recognised. The standard requires adoption either on a full retrospective basis, or retrospectively with the cumulative effect of initially recognising the standard as an adjustment to retained earnings at the date of initial application, and if so with a number of practical expedients in transitioning existing leases at the time of initial application. Statoil is in the process of evaluating the impact of IFRS 16, and has not yet determined the expected impact of the standard on the Consolidated financial statements.

Implementation of IFRS 16 will affect all Statoil's segments.

Statoil will adopt IFRS 16 on 1 January 2019 and currently expects to apply the modified retrospective method in implementing the standard.

Other amendments to standards
The amendments to IFRS 10 Consolidated Financial Statements and IAS 28 Investments in Associates and Joint Ventures, effective from a future date to be determined by the IASB, establish requirements for the accounting for sales or contributions of assets between an investor and its associate or joint venture. Whether or not the assets are housed in a subsidiary, a full gain or loss will be recognised in the statement of income when the transaction involves assets that constitute a business, whereas a partial gain or loss will be recognised when the transaction involves assets that do not constitute a business. The amendments are to be applied prospectively. Statoil has not determined an adoption date for the amendments.

The disclosure initiative amendments to IAS 7 Statement of Cash Flows, effective from 1 January 2017, establish certain additional requirements for disclosure of changes in financing liabilities. Statoil has implemented the amendments on the effective date.

Other standards and amendments to standards, issued but not yet effective, are either not expected to impact Statoil's Consolidated financial statements materially, or are not expected to be relevant to Statoil's Consolidated financial statements upon adoption.

Change in the Statoil group's presentation currency
On 1 January 2016 Statoil changed its presentation currency from Norwegian kroner (NOK) to US dollars (USD), mainly in order to better reflect the underlying USD exposure of Statoil's business activities and to align with industry practice. As the change in presentation currency represents a policy change, comparative figures have been re-presented in USD to reflect the change. All currency translation adjustments have been set to zero as of 1 January 2006, which was the date of Statoil's transition to IFRS. Translation adjustments and cumulative translation adjustments have been presented as if Statoil had used USD as the presentation currency from that date. For further details and re-presented consolidated financial information for prior periods, reference is made to Note 26 Change of presentation currency in these Consolidated financial statements.

Basis of consolidation
The Consolidated financial statements include the accounts of Statoil ASA and its subsidiaries and include Statoil's interest in jointly controlled and equity accounted investments.

Subsidiaries
Entities are determined to be controlled by Statoil, and consolidated in Statoil's financial statements, when Statoil has power over the entity, ability to use that power to affect the entity's returns, and exposure to, or rights to, variable returns from its involvement with the entity.

All intercompany balances and transactions, including unrealised profits and losses arising from Statoil's internal transactions, have been eliminated in full.

Non-controlling interests are presented separately within equity in the balance sheet.

Joint operations and similar arrangements, joint ventures and associates
A joint arrangement is present where Statoil holds a long-term interest which is jointly controlled by Statoil and one or more other venturers under a contractual arrangement in which decisions about the relevant activities require the unanimous consent of the parties sharing control. Such joint arrangements are classified as either joint operations or joint ventures.

The parties to a joint operation have rights to the assets and obligations for the liabilities, relating to their respective share of the joint arrangement. In determining whether the terms of contractual arrangements and other facts and circumstances lead to a classification as joint operations, Statoil in particular considers the nature of products and markets of the arrangement and whether the substance of their agreements is that the parties involved have rights to substantially all the arrangement's assets. Statoil accounts for the assets, liabilities, revenues and expenses relating to its interests in joint operations in accordance with the principles applicable to those particular assets, liabilities, revenues and expenses. Normally this leads to accounting for the joint operation in a manner similar to the previous proportionate consolidation method.

Those of Statoil's exploration and production licence activities that are within the scope of IFRS 11 Joint Arrangements have been classified as joint operations. A considerable number of Statoil's unincorporated joint exploration and production activities are conducted through arrangements that are not jointly controlled, either because unanimous consent is not required among all parties involved, or no single group of parties has joint control over the activity. Licence activities where control can be achieved through agreement between more than one combination of involved parties are considered to be outside the scope of IFRS 11, and these activities are accounted for on a pro-rata basis using Statoil's ownership share. In determining whether each separate arrangement related to Statoil's unincorporated joint exploration and production licence activities is within or outside the scope of IFRS 11, Statoil considers the terms of relevant licence agreements, governmental concessions and other legal arrangements impacting how and by whom each arrangement is controlled. Subsequent changes in the ownership shares and number of licence participants, transactions involving licence shares, or changes in the terms of relevant agreements may lead to changes in Statoil's evaluation of control and impact a licence arrangement's classification in relation to IFRS 11 in Statoil's Consolidated financial statements. Currently there are no significant differences in Statoil's accounting for unincorporated licence arrangements whether in scope of IFRS 11 or not.

Joint ventures, in which Statoil has rights to the net assets, are accounted for using the equity method.

Investments in companies in which Statoil has neither control nor joint control, but has the ability to exercise significant influence over operating and financial policies, are classified as associates and are also accounted for using the equity method.

Under the equity method, the investment is carried on the balance sheet at cost plus post-acquisition changes in Statoil's share of net assets of the entity, less distribution received and less any impairment in value of the investment. Goodwill may arise as the surplus of the cost of investment over Statoil's share of the net fair value of the identifiable assets and liabilities of the joint venture or associate. Such goodwill is recorded within the corresponding investment. The Consolidated statement of income reflects Statoil's share of the results after tax of an equity-accounted entity, adjusted to account for depreciation, amortization and any impairment of the equity-accounted entity's assets based on their fair values at the date of acquisition. Where material differences in accounting policies arise, adjustments are made to the financial statements of equity-accounted entities in order to bring the accounting policies used into line with Statoil's. Material unrealised gains on transactions between Statoil and its equity-accounted entities are eliminated to the extent of Statoil's interest in each equity-accounted entity. Unrealised losses are also eliminated unless the transaction provides evidence of an impairment of the asset transferred. Statoil assesses investments in equity-accounted entities for impairment whenever events or changes in circumstances indicate that the carrying value may not be recoverable.

Statoil as operator of joint operations and similar arrangements
Indirect operating expenses such as personnel expenses are accumulated in cost pools. These costs are allocated on an hours incurred basis to operating segments and Statoil operated joint operations under IFRS 11 and to similar arrangements (licences) outside the scope of IFRS 11. Costs allocated to the other partners' share of operated joint operations and similar arrangements reduce the costs in the Consolidated statement of income. Only Statoil's share of the statement of income and balance sheet items related to Statoil operated joint operations and similar arrangements are reflected in the Consolidated statement of income and the Consolidated balance sheet.

Reportable segments
Statoil identifies its operating segments on the basis of those components of Statoil that are regularly reviewed by the chief operating decision maker, Statoil's corporate executive committee (CEC). Statoil combines operating segments when these satisfy relevant aggregation criteria.

Statoil's accounting policies as described in this note also apply to the specific financial information included in reportable segments related disclosure in these Consolidated financial statements.

Foreign currency translation
In preparing the financial statements of the individual entities, transactions in foreign currencies (those other than functional currency) are translated at the foreign exchange rate at the dates of the transactions. Monetary assets and liabilities denominated in foreign currencies are translated to the functional currency at the foreign exchange rate at the balance sheet date. Foreign exchange differences arising on translation are recognised in the Consolidated statement of income as foreign exchange gains or losses within net financial items. Foreign exchange differences arising from the translation of estimate-based provisions, however, generally are accounted for as part of the change in the underlying estimate and as such may be included within the relevant operating expense or income tax sections of the Consolidated statement of income depending on the nature of the provision. Non-monetary assets that are measured at historical cost in a foreign currency are translated using the exchange rate at the date of the transactions.

Presentation currency
For the purpose of the Consolidated financial statements, the statement of income, the balance sheet and the cash flows of each entity are translated from the functional currency into the presentation currency, USD. The assets and liabilities of entities whose functional currencies are other than USD, are translated into USD at the foreign exchange rate at the balance sheet date. The revenues and expenses of such entities are translated using the foreign exchange rates on the dates of the transactions. Foreign exchange differences arising on translation from functional currency to presentation currency are recognised separately in Other comprehensive income (OCI). The cumulative amount of such translation differences relating to an entity and previously recognised in OCI, is reclassified to the Consolidated statement of income and reflected as a part of the gain or loss on disposal of that entity.

Business combinations
Determining whether an acquisition meets the definition of a business combination requires judgement to be applied on a case by case basis. Acquisitions are assessed under the relevant IFRS criteria to establish whether the transaction represents a business combination or an asset purchase. Depending on the specific facts, acquisitions of exploration and evaluation licences for which a development decision has not yet been made, have largely been concluded to represent asset purchases.

Business combinations, except for transactions between entities under common control, are accounted for using the acquisition method of accounting. The acquired identifiable tangible and intangible assets, liabilities and contingent liabilities are measured at their fair values at the date of the acquisition. Acquisition costs incurred are expensed under Selling, general and administrative expenses.

Revenue recognition
Revenues associated with sale and transportation of crude oil, natural gas, petroleum products and other merchandise are recognised when risk passes to the customer, which is normally when title passes at the point of delivery of the goods, based on the contractual terms of the agreements.

Revenues from the production of oil and gas properties in which Statoil shares an interest with other companies are recognised on the basis of volumes lifted and sold to customers during the period (the sales method). Where Statoil has lifted and sold more than the ownership interest, an accrual is recognised for the cost of the overlift. Where Statoil has lifted and sold less than the ownership interest, costs are deferred for the underlift.

Revenue is presented net of customs, excise taxes and royalties paid in-kind on petroleum products. Revenue is presented gross of in-kind payments of amounts representing income tax.

Sales and purchases of physical commodities, which are not settled net, are presented on a gross basis as revenues and purchases [net of inventory variation] in the statement of income. Activities related to trading and commodity-based derivative instruments are reported on a net basis, with the margin included in revenues.

Transactions with the Norwegian State

Statoil markets and sells the Norwegian State's share of oil and gas production from the Norwegian continental shelf (NCS). The Norwegian State's participation in petroleum activities is organised through the SDFI. All purchases and sales of the SDFI's oil production are classified as purchases [net of inventory variation] and revenues, respectively. Statoil sells, in its own name, but for the Norwegian State's account and risk, the State's production of natural gas. These sales and related expenditures refunded by the Norwegian State are presented net in the Consolidated financial statements.

Employee benefits

Wages, salaries, bonuses, social security contributions, paid annual leave and sick leave are accrued in the period in which the associated services are rendered by employees of Statoil.

Research and development

Statoil undertakes research and development both on a funded basis for licence holders and on an unfunded basis for projects at its own risk. Statoil's own share of the licence holders' funding and the total costs of the unfunded projects are considered for capitalisation under the applicable IFRS requirements. Subsequent to initial recognition, any capitalised development costs are reported at cost less accumulated amortisation and accumulated impairment losses.

Income tax

Income tax in the Consolidated statement of income comprises current and deferred tax expense. Income tax is recognised in the Consolidated statement of income except when it relates to items recognised in OCI.

Current tax consists of the expected tax payable on the taxable income for the year and any adjustment to tax payable for previous years. Uncertain tax positions and potential tax exposures are analysed individually, and the best estimate of the probable amount for liabilities to be paid (unpaid potential tax exposure amounts, including penalties) and for assets to be received (disputed tax positions for which payment has already been made) in each case is recognised within current tax or deferred tax as appropriate. Interest income and interest expenses relating to tax issues are estimated and recognised in the period in which they are earned or incurred, and are presented within net financial items in the Consolidated statement of income. Uplift benefit on the NCS is recognised when the deduction is included in the current year tax return and impacts taxes payable.

Deferred tax assets and liabilities are recognised for the future tax consequences attributable to differences between the carrying amounts of existing assets and liabilities and their respective tax bases, subject to the initial recognition exemption. The amount of deferred tax is based on the expected manner of realisation or settlement of the carrying amount of assets and liabilities, using tax rates enacted or substantively enacted at the balance sheet date. A deferred tax asset is recognised only to the extent that it is probable that future taxable income will be available against which the asset can be utilised. In order for a deferred tax asset to be recognised based on future taxable income, convincing evidence is required, taking into account the existence of contracts, production of oil or gas in the near future based on volumes of proved reserves, observable prices in active markets, expected volatility of trading profits, expected currency rate movements and similar facts and circumstances.

Oil and gas exploration, evaluation and development expenditures

Statoil uses the successful efforts method of accounting for oil and gas exploration costs. Expenditures to acquire mineral interests in oil and gas properties and to drill and equip exploratory wells are capitalised as exploration and evaluation expenditures within intangible assets until the well is complete and the results have been evaluated, or there is any other indicator of a potential impairment. Exploration wells that discover potentially economic quantities of oil and natural gas remain capitalised as intangible assets during the evaluation phase of the find. This evaluation is normally finalised within one year after well completion. If, following the evaluation, the exploratory well has not found potentially commercial quantities of hydrocarbons, the previously capitalised costs are evaluated for derecognition or tested for impairment. Geological and geophysical costs and other exploration and evaluation expenditures are expensed as incurred.

Capitalised exploration and evaluation expenditures, including expenditures to acquire mineral interests in oil and gas properties, related to offshore wells that find proved reserves are transferred from exploration expenditures and acquisition costs - oil and gas prospects (intangible assets) to property, plant and equipment at the time of sanctioning of the development project. For onshore wells where no sanction is required, the transfer of acquisition cost - oil and gas prospects (intangible assets) to property, plant and equipment occurs at the time when a well is ready for production.

For exploration and evaluation asset acquisitions (farm-in arrangements) in which Statoil has made arrangements to fund a portion of the selling partner's (farmor's) exploration and/or future development expenditures (carried interests), these expenditures are reflected in the Consolidated financial statements as and when the exploration and development work progresses. Statoil reflects exploration and evaluation asset dispositions (farm-out arrangements) on a historical cost basis with no gain or loss recognition.

A gain or loss related to a post-tax based disposition of assets on the NCS includes the release of tax liabilities previously computed and recognised related to the assets in question. The resulting gross gain or loss is recognised in full in other income in the Consolidated statement of income.

Consideration from the sale of an undeveloped part of an onshore asset reduces the carrying amount of the asset. The part of the consideration that exceeds the carrying amount of the asset, if any, is reflected in the Consolidated statement of income under other income.

Exchanges (swaps) of exploration and evaluation assets are accounted for at the carrying amounts of the assets given up with no gain or loss recognition.

Property, plant and equipment
Property, plant and equipment is reflected at cost, less accumulated depreciation and accumulated impairment losses. The initial cost of an asset comprises its purchase price or construction cost, any costs directly attributable to bringing the asset into operation, the initial estimate of an asset retirement obligation, if any, exploration costs transferred from intangible assets and, for qualifying assets, borrowing costs. Property, plant and equipment include costs relating to expenditures incurred under the terms of PSAs in certain countries, and which qualify for recognition as assets of Statoil. State-owned entities in the respective countries, however, normally hold the legal title to such PSA-based property, plant and equipment.

Exchanges of assets are measured at the fair value of the asset given up, unless the fair value of neither the asset received nor the asset given up is measurable with sufficient reliability.

Expenditure on major maintenance refits or repairs comprises the cost of replacement assets or parts of assets, inspection costs and overhaul costs. Where an asset or part of an asset is replaced and it is probable that future economic benefits associated with the item will flow to Statoil, the expenditure is capitalised. Inspection and overhaul costs, associated with regularly scheduled major maintenance programs planned and carried out at recurring intervals exceeding one year, are capitalised and amortised over the period to the next scheduled inspection and overhaul. All other maintenance costs are expensed as incurred.

Capitalised exploration and evaluation expenditures, development expenditure on the construction, installation or completion of infrastructure facilities such as platforms, pipelines and the drilling of production wells, and field-dedicated transport systems for oil and gas are capitalised as producing oil and gas properties within property, plant and equipment. Such capitalised costs, when designed for significantly larger volumes than the reserves from already developed and producing wells, are depreciated using the unit of production method based on proved reserves expected to be recovered from the area during the concession or contract period. Depreciation of production wells uses the unit of production method based on proved developed reserves, and capitalised acquisition costs of proved properties are depreciated using the unit of production method based on total proved reserves. In the rare circumstances where the use of proved reserves fails to provide an appropriate basis reflecting the pattern in which the asset's future economic benefits are expected to be consumed, a more appropriate reserve estimate is used. Depreciation of other assets and transport systems used by several fields is calculated on the basis of their estimated useful lives, normally using the straight-line method. Each part of an item of property, plant and equipment with a cost that is significant in relation to the total cost of the item is depreciated separately. For exploration and production assets, Statoil has established separate depreciation categories which as a minimum distinguish between platforms, pipelines and wells.

The estimated useful lives of property, plant and equipment are reviewed on an annual basis, and changes in useful lives are accounted for prospectively. An item of property, plant and equipment is derecognised upon disposal or when no future economic benefits are expected to arise from the continued use of the asset. Any gain or loss arising on derecognition of the asset (calculated as the difference between the net disposal proceeds and the carrying amount of the item) is included in other income or operating expenses, respectively, in the period the item is derecognised.

Assets classified as held for sale
Non-current assets are classified separately as held for sale in the balance sheet when their carrying amount will be recovered through a sale transaction rather than through continuing use. This condition is met only when the sale is highly probable, the asset is available for immediate sale in its present condition, and management is committed to the sale, which should be expected to qualify for recognition as a completed sale within one year from the date of classification. Liabilities directly associated with the assets classified as held for sale, and expected to be included as part of the sale transaction, are correspondingly also classified separately. Once classified as held for sale, property, plant and equipment and intangible assets are not subject to depreciation or amortisation. The net assets and liabilities of a disposal group classified as held for sale are measured at the lower of their carrying amount and fair value less costs to sell.

Leases
Leases for which Statoil assumes substantially all the risks and rewards of ownership are reflected as finance leases. When an asset leased by a joint operation or similar arrangement to which Statoil is a party qualifies as a finance lease, Statoil reflects its proportionate share of the leased asset and related obligations. Finance leases are classified in the Consolidated balance sheet within property, plant and equipment and finance debt. All other leases are classified as operating leases, and the costs are charged to the relevant operating expense related caption on a straight line basis over the lease term, unless another basis is more representative of the benefits of the lease to Statoil.

Statoil distinguishes between lease and capacity contracts. Lease contracts provide the right to use a specific asset for a period of time, while capacity contracts confer on Statoil the right to and the obligation to pay for certain volume capacity availability related to transport, terminal use, storage, etc. Such capacity contracts that do not involve specified assets or that do not involve substantially all the capacity of an undivided interest in a specific asset are not considered by Statoil to qualify as leases for accounting purposes. Capacity payments are reflected as operating expenses in the Consolidated statement of income in the period for which the capacity contractually is available to Statoil.

Intangible assets including goodwill
Intangible assets are stated at cost, less accumulated amortisation and accumulated impairment losses. Intangible assets include acquisition cost for oil and gas prospects, expenditures on the exploration for and evaluation of oil and natural gas resources, goodwill and other intangible assets.

Intangible assets relating to expenditures on the exploration for and evaluation of oil and natural gas resources are not amortised. When the decision to develop a particular area is made, its intangible exploration and evaluation assets are reclassified to property, plant and equipment.

Goodwill is initially measured at the excess of the aggregate of the consideration transferred and the amount recognised for any non-controlling interest over the fair value of the identifiable assets acquired and liabilities assumed in a business combination at the acquisition date. Goodwill acquired is allocated to each cash generating unit, or group of units, expected to benefit from the combination's synergies. Following initial recognition, goodwill is measured at cost less any accumulated impairment losses.

Financial assets

Financial assets are initially recognised at fair value when Statoil becomes a party to the contractual provisions of the asset. For additional information on fair value methods, refer to the Measurement of fair values section below. The subsequent measurement of the financial assets depends on which category they have been classified into at inception.

At initial recognition, Statoil classifies its financial assets into the following three main categories: Financial investments at fair value through profit or loss, loans and receivables, and available-for-sale (AFS) financial assets. The first main category, financial investments at fair value through profit or loss, further consists of two sub-categories: Financial assets held for trading and financial assets that on initial recognition are designated as fair value through profit and loss. The latter approach may also be referred to as the fair value option.

Cash and cash equivalents include cash in hand, current balances with banks and similar institutions, and short-term highly liquid investments that are readily convertible to known amounts of cash, are subject to an insignificant risk of changes in fair value and have a maturity of three months or less from the acquisition date.

Trade receivables are carried at the original invoice amount less a provision for doubtful receivables which is made when there is objective evidence that Statoil will be unable to recover the balances in full.

A significant part of Statoil's investments in treasury bills, commercial papers, bonds and listed equity securities is managed together as an investment portfolio of Statoil's captive insurance company and is held in order to comply with specific regulations for capital retention. The investment portfolio is managed and evaluated on a fair value basis in accordance with an investment strategy and is accounted for using the fair value option with changes in fair value recognised through profit or loss.

Financial assets are presented as current if they contractually will expire or otherwise are expected to be recovered within 12 months after the balance sheet date, or if they are held for the purpose of being traded. Financial assets and financial liabilities are shown separately in the Consolidated balance sheet, unless Statoil has both a legal right and a demonstrable intention to net settle certain balances payable to and receivable from the same counterparty, in which case they are shown net in the balance sheet.

Inventories

Inventories are stated at the lower of cost and net realisable value. Cost is determined by the first-in first-out method and comprises direct purchase costs, cost of production, transportation and manufacturing expenses.

Impairment

Impairment of property, plant and equipment and intangible assets other than goodwill

Statoil assesses individual assets or groups of assets for impairment whenever events or changes in circumstances indicate that the carrying value of an asset may not be recoverable. Assets are grouped into cash generating units (CGUs) which are the smallest identifiable groups of assets that generate cash inflows that are largely independent of the cash inflows from other groups of assets. Normally, separate CGUs are individual oil and gas fields or plants. Each unconventional asset play is considered a single CGU when no cash inflows from parts of the play can be reliably identified as being largely independent of the cash inflows from other parts of the play. In impairment evaluations, the carrying amounts of CGUs are determined on a basis consistent with that of the recoverable amount. In Statoil's line of business, judgement is involved in determining what constitutes a CGU. Development in production, infrastructure solutions, markets, product pricing, management actions and other factors may over time lead to changes in CGUs such as the division of one original CGU into several.

In assessing whether a write-down of the carrying amount of a potentially impaired asset is required, the asset's carrying amount is compared to the recoverable amount. The recoverable amount of an asset is the higher of its fair value less cost of disposal and its value in use. Fair value less cost of disposal is determined based on comparable recent arm's length market transactions, or based on Statoil's estimate of the price that would be received for the asset in an orderly transaction between market participants. Value in use is determined using a discounted cash flow model. The estimated future cash flows applied are based on reasonable and supportable assumptions and represent management's best estimates of the range of economic conditions that will exist over the remaining useful life of the assets, as set down in Statoil's most recently approved long-term forecasts. Statoil uses an approach of regular updates of assumptions and economic conditions in establishing the long-term forecasts which are reviewed by corporate management and updated at least annually. For assets and CGUs with an expected useful life or timeline for production of expected reserves extending beyond 5 years, the forecasts reflect expected production volumes for oil and natural gas, and the related cash flows include project or asset specific estimates reflecting the relevant period. Such estimates are established on the basis of Statoil's principles and assumptions consistently applied.

In performing a value-in-use-based impairment test, the estimated future cash flows are adjusted for risks specific to the asset and discounted using a real post-tax discount rate which is based on Statoil's post-tax weighted average cost of capital (WACC). The use of post-tax discount rates in determining value in use does not result in a materially different determination of the need for, or the amount of, impairment that would be required if pre-tax discount rates had been used.

Unproved oil and gas properties are assessed for impairment when facts and circumstances suggest that the carrying amount of the asset may exceed its recoverable amount, and at least once a year. Exploratory wells that have found reserves, but where classification of those reserves as proved depends on whether major capital expenditure can be justified or where the economic viability of that major capital expenditure depends on the successful completion of further exploration work, will remain capitalised during the evaluation phase for the exploratory finds. Thereafter it will be considered a trigger for impairment evaluation of the well if no development decision is planned for the near future and there are no firm plans for future drilling in the licence.

An assessment is made at each reporting date as to whether there is any indication that previously recognised impairment losses may no longer be relevant or may have decreased. If such an indication exists, the recoverable amount is estimated. A previously recognised impairment loss is reversed only if there has been a change in the estimates used to determine the asset's recoverable amount since the last impairment loss was recognised. If that is the case, the carrying amount of the asset is increased to its recoverable amount. That increased amount cannot exceed the carrying amount that would have been determined, net of depreciation, had no impairment loss been recognised for the asset in prior years.

Impairment losses and reversals of impairment losses are presented in the Consolidated statement of income as Exploration expenses or Depreciation, amortisation and net impairment losses, on the basis of their nature as either exploration assets (intangible exploration assets) or development and producing assets (property, plant and equipment and other intangible assets), respectively.

Impairment of goodwill
Goodwill is reviewed for impairment annually or more frequently if events or changes in circumstances indicate that the carrying value may be impaired. Impairment is determined by assessing the recoverable amount of the CGU, or group of units, to which the goodwill relates. Where the recoverable amount of the CGU, or group of units, is less than the carrying amount, an impairment loss is recognised. Once recognised, impairments of goodwill are not reversed in future periods.

Financial liabilities
Financial liabilities are initially recognised at fair value when Statoil becomes a party to the contractual provisions of the liability. The subsequent measurement of financial liabilities depends on which category they have been classified into. The categories applicable for Statoil are either financial liabilities at fair value through profit or loss or financial liabilities measured at amortised cost using the effective interest method. The latter applies to Statoil's non-current bank loans and bonds.

Financial liabilities are presented as current if the liability is due to be settled within 12 months after the balance sheet date, or if they are held for the purpose of being traded. Financial liabilities are derecognised when the contractual obligations expire, are discharged or cancelled. Gains and losses arising on the repurchase, settlement or cancellation of liabilities are recognised either in interest income and other financial items or in interest and other finance expenses within net financial items.

Derivative financial instruments
Statoil uses derivative financial instruments to manage certain exposures to fluctuations in foreign currency exchange rates, interest rates and commodity prices. Such derivative financial instruments are initially recognised at fair value on the date on which a derivative contract is entered into and are subsequently re-measured at fair value through profit and loss. The impact of commodity-based derivative financial instruments is recognised in the Consolidated statement of income under revenues, as such derivative instruments are related to sales contracts or revenue-related risk management for all significant purposes. The impact of other financial instruments is reflected under net financial items.

Derivatives are carried as assets when the fair value is positive and as liabilities when the fair value is negative. Derivative assets or liabilities expected to be recovered, or with the legal right to be settled more than 12 months after the balance sheet date are classified as non-current, with the exception of derivative financial instruments held for the purpose of being traded.

Contracts to buy or sell a non-financial item that can be settled net in cash or another financial instrument, or by exchanging financial instruments, as if the contracts were financial instruments, are accounted for as financial instruments. However, contracts that are entered into and continue to be held for the purpose of the receipt or delivery of a non-financial item in accordance with Statoil's expected purchase, sale or usage requirements, also referred to as own-use, are not accounted for as financial instruments. This is applicable to a significant number of contracts for the purchase or sale of crude oil and natural gas, which are recognised upon delivery.

Derivatives embedded in other financial instruments or in non-financial host contracts are recognised as separate derivatives and are reflected at fair value with subsequent changes through profit and loss, when their risks and economic characteristics are not closely related to those of the host contracts, and the host contracts are not carried at fair value. Where there is an active market for a commodity or other non-financial item referenced in a purchase or sale contract, a pricing formula will, for instance, be considered to be closely related to the host purchase or sales contract if the price formula is based on the active market in question. A price formula with indexation to other markets or products will however result in the recognition of a separate derivative. Where there is no active market for the commodity or other non-financial item in question, Statoil assesses the characteristics of such a price related embedded derivative to be closely related to the host contract if the price formula is based on relevant indexations commonly used by other market participants. This applies to certain long-term natural gas sales agreements.

Pension liabilities

Statoil has pension plans for employees that either provide a defined pension benefit upon retirement or a pension dependent on defined contributions and related returns. A portion of the contributions are provided for as notional contributions, for which the liability increases with a promised notional return, set equal to the actual return of assets invested through the ordinary defined contribution plan. For defined benefit plans, the benefit to be received by employees generally depends on many factors including length of service, retirement date and future salary levels.

Statoil's proportionate share of multi-employer defined benefit plans are recognised as liabilities in the balance sheet to the extent that sufficient information is available and a reliable estimate of the obligation can be made.

Statoil's net obligation in respect of defined benefit pension plans is calculated separately for each plan by estimating the amount of future benefit that employees have earned in return for their services in the current and prior periods. That benefit is discounted to determine its present value, and the fair value of any plan assets is deducted. The discount rate is the yield at the balance sheet date, reflecting the maturity dates approximating the terms of Statoil's obligations. The discount rate for the main part of the pension obligations has been established on the basis of Norwegian mortgage covered bonds, which are considered high quality corporate bonds. The cost of pension benefit plans is expensed over the period that the employees render services and become eligible to receive benefits. The calculation is performed by an external actuary.

The net interest related to defined benefit plans is calculated by applying the discount rate to the opening present value of the benefit obligation and opening present value of the plan assets, adjusted for material changes during the year. The resulting net interest element is presented in the statement of income as part of net pension cost within net operating income. The difference between estimated interest income and actual return is recognised in the Consolidated statement of comprehensive income.

Past service cost is recognised when a plan amendment (the introduction or withdrawal of, or changes to, a defined benefit plan) or curtailment (a significant reduction by the entity in the number of employees covered by a plan) occurs, or when recognising related restructuring costs or termination benefits. The obligation and related plan assets are re-measured using current actuarial assumptions, and the gain or loss is recognised in the statement of income.

Actuarial gains and losses are recognised in full in the Consolidated statement of comprehensive income in the period in which they occur, while actuarial gains and losses related to provision for termination benefits are recognised in the Consolidated statement of income in the period in which they occur. Due to the parent company Statoil ASA's functional currency being USD, the significant part of Statoil's pension obligations will be payable in a foreign currency (i.e. NOK). As a consequence, actuarial gains and losses related to the parent company's pension obligation include the impact of exchange rate fluctuations.

Contributions to defined contribution schemes are recognised in the statement of income in the period in which the contribution amounts are earned by the employees.

Notional contribution plans, reported in the parent company Statoil ASA, are recognised as pension liabilities with the actual value of the notional contributions and promised return at reporting date. Notional contributions and changes in fair value of notional assets are recognised in the statement of income as periodic pension cost.

Periodic pension cost is accumulated in cost pools and allocated to operating segments and Statoil operated joint operations (licences) on an hours incurred basis and recognised in the statement of income based on the function of the cost.

Onerous contracts

Statoil recognises as provisions the net obligation under contracts defined as onerous. Contracts are deemed to be onerous if the unavoidable cost of meeting the obligations under the contract exceeds the economic benefits expected to be received in relation to the contract. A contract which forms an integral part of the operations of a CGU whose assets are dedicated to that contract, and for which the economic benefits cannot be reliably separated from those of the CGU, is included in impairment considerations for the applicable CGU.

Asset retirement obligations (ARO)

Provisions for ARO costs are recognised when Statoil has an obligation (legal or constructive) to dismantle and remove a facility or an item of property, plant and equipment and to restore the site on which it is located, and when a reliable estimate of that liability can be made. The amount recognised is the present value of the estimated future expenditures determined in accordance with local conditions and requirements. Cost is estimated based on current regulations and technology, considering relevant risks and uncertainties. The discount rate used in the calculation of the ARO is a risk-free rate based on the applicable currency and time horizon of the underlying cash flows, adjusted for a credit premium which reflects Statoil's own credit risk. Normally an obligation arises for a new facility, such as an oil and natural gas production or transportation facility, upon construction or installation. An obligation may also crystallise during the period of operation of a facility through a change in legislation or through a decision to terminate operations, or be based on commitments associated with Statoil's ongoing use of pipeline transport systems where removal obligations rest with the volume shippers. The provisions are classified under provisions in the Consolidated balance sheet. Some of the refining and process operations are deemed to have indefinite lives, and in consequence, no ARO has been recognised for their plants.

When a provision for ARO cost is recognised, a corresponding amount is recognised to increase the related property, plant and equipment and is subsequently depreciated as part of the costs of the facility or item of property, plant and equipment. Any change in the present value of the estimated expenditure is reflected as an adjustment to the provision and the corresponding property, plant and equipment. When a decrease in the ARO provision related to a producing asset exceeds the carrying amount of the asset, the excess is recognised as a reduction of depreciation, amortisation and net impairment losses in the Consolidated statement of income. When an asset has reached the end of its useful life, all subsequent changes to the ARO provision are recognised as they occur in operating expenses in the Consolidated statement of income. Removal provisions associated with Statoil's role as shipper of volumes through third party transport systems are expensed as incurred.

Measurement of fair values

Quoted prices in active markets represent the best evidence of fair value and are used by Statoil in determining the fair values of assets and liabilities to the extent possible. Financial instruments quoted in active markets will typically include commercial papers, bonds and equity instruments with quoted market prices obtained from the relevant exchanges or clearing houses. The fair values of quoted financial assets, financial liabilities and derivative instruments are determined by reference to mid-market prices, at the close of business on the balance sheet date.

Where there is no active market, fair value is determined using valuation techniques. These include using recent arm's-length market transactions, reference to other instruments that are substantially the same, discounted cash flow analysis, and pricing models and related internal assumptions. In the valuation techniques, Statoil also takes into consideration the counterparty and its own credit risk. This is either reflected in the discount rate used or through direct adjustments to the calculated cash flows. Consequently, where Statoil reflects elements of long-term physical delivery commodity contracts at fair value, such fair value estimates to the extent possible are based on quoted forward prices in the market and underlying indexes in the contracts, as well as assumptions of forward prices and margins where observable market prices are not available. Similarly, the fair values of interest and currency swaps are estimated based on relevant quotes from active markets, quotes of comparable instruments, and other appropriate valuation techniques.

Critical accounting judgements and key sources of estimation uncertainty

Critical judgements in applying accounting policies

The following are the critical judgements, apart from those involving estimations (see below), that Statoil has made in the process of applying the accounting policies and that have the most significant effect on the amounts recognised in the financial statements:

Revenue recognition - gross versus net presentation of traded SDFI volumes of oil and gas production

As described under Transactions with the Norwegian State above, Statoil markets and sells the Norwegian State's share of oil and gas production from the NCS. Statoil includes the costs of purchase and proceeds from the sale of the SDFI oil production in purchases [net of inventory variation] and revenues, respectively. In making the judgement, Statoil considered the detailed criteria for the recognition of revenue from the sale of goods and, in particular, concluded that the risk and reward of the ownership of the oil had been transferred from the SDFI to Statoil.

Statoil sells, in its own name, but for the Norwegian State's account and risk, the State's production of natural gas. These gas sales, and related expenditures refunded by the State, are shown net in Statoil's Consolidated financial statements. In making the judgement, Statoil considered the same criteria as for the oil production and concluded that the risk and reward of the ownership of the gas had not been transferred from the SDFI to Statoil.

Key sources of estimation uncertainty

The preparation of the Consolidated financial statements requires that management make estimates and assumptions that affect reported amounts of assets, liabilities, income and expenses. The estimates and associated assumptions are based on historical experience and various other factors that are believed to be reasonable under the circumstances, the result of which form the basis of making the judgements about carrying values of assets and liabilities that are not readily apparent from other sources. Actual results may differ from these estimates. The estimates and underlying assumptions are reviewed on an on-going basis considering the current and expected future market conditions.

Statoil is exposed to a number of underlying economic factors which affect the overall results, such as liquids prices, natural gas prices, refining margins, foreign exchange rates and interest rates as well as financial instruments with fair values derived from changes in these factors. In addition, Statoil's results are influenced by the level of production, which in the short term may be influenced by, for instance, maintenance programmes. In the long term, the results are impacted by the success of exploration and field development activities.

The matters described below are considered to be the most important in understanding the key sources of estimation uncertainty that are involved in preparing these Consolidated financial statements and the uncertainties that could most significantly impact the amounts reported on the results of operations, financial position and cash flows.

Proved oil and gas reserves

Proved oil and gas reserves may materially impact the Consolidated financial statements, as changes in the proved reserves, for instance as a result of changes in prices, will impact the unit of production rates used for depreciation and amortisation. Proved oil and gas reserves have been estimated by internal qualified professionals on the basis of industry standards and governed by criteria established by regulations of the U.S. Securities Exchange Commission (SEC), which require the use of a price based on a 12-month average for reserve estimation, and which are to be based on existing economic conditions and operating methods and with a high degree of confidence (at least 90% probability) that the quantities will be recovered. The Financial Accounting Standards Board (FASB) requirements for supplemental oil and gas disclosures align with the SEC regulations. Reserves estimates are based on subjective judgements involving geological and engineering assessments of in-place hydrocarbon volumes, the production, historical recovery and processing yield factors and installed plant operating capacity. For future development projects, proved reserves estimates are included only where there is a significant commitment to project funding and execution and when relevant governmental and regulatory approvals have been secured or are reasonably certain to be secured. The reliability of these estimates at any point in time depends on both the quality and quantity of the technical and economic data and the efficiency of extracting and processing the hydrocarbons. An independent third party has evaluated Statoil's proved reserves estimates, and the results of this evaluation do not differ materially from Statoil's estimates. Proved oil and gas reserves are those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward, from known reservoirs, and under existing economic conditions, operating methods and government regulations. Unless evidence indicates that renewal is reasonably certain, estimates of economically producible reserves only reflect the period before the contracts providing the right to operate expire. The project to extract the hydrocarbons must have commenced, or the operator must be reasonably certain that it will commence within a reasonable time.

Expected oil and gas reserves
Expected oil and gas reserves may materially impact the Consolidated financial statements, as changes in the expected reserves, for instance as a result of changes in prices, will impact asset retirement obligations and impairment testing of upstream assets, which in turn may lead to changes in impairment charges affecting operating income. Expected oil and gas reserves are the estimated remaining, commercially recoverable quantities, based on Statoil's judgement of future economic conditions, from projects in operation or justified for development. Recoverable oil and gas quantities are always uncertain, and the expected value is the weighted average, or statistical mean, of the possible outcomes. Expected reserves are therefore typically larger than proved reserves as defined by the SEC rules. Expected oil and gas reserves have been estimated by internal qualified professionals on the basis of industry standards and are used for impairment testing purposes and for calculation of asset retirement obligations. Reserves estimates are based on subjective judgements involving geological and engineering assessments of in-place hydrocarbon volumes, the production, historical recovery and processing yield factors, installed plant operating capacity and operating approval limits. The reliability of these estimates at any point in time depends on both the quality and quantity of the technical and economic data and the efficiency of extracting and processing the hydrocarbons.

Exploration and leasehold acquisition costs
Statoil capitalises the costs of drilling exploratory wells pending determination of whether the wells have found proved oil and gas reserves. Statoil also capitalises leasehold acquisition costs and signature bonuses paid to obtain access to undeveloped oil and gas acreage. Judgements as to whether these expenditures should remain capitalised or written down due to impairment losses in the period may materially affect the operating income for the period.

Impairment/reversal of impairment
Statoil has significant investments in property, plant and equipment and intangible assets. Changes in the circumstances or expectations of future performance of an individual asset may be an indicator that the asset is impaired, requiring the carrying amount to be written down to its recoverable amount. Impairments are reversed if conditions for impairment are no longer present. Evaluating whether an asset is impaired or if an impairment should be reversed requires a high degree of judgement and may to a large extent depend upon the selection of key assumptions about the future.

The key assumptions used will bear the risk of change based on the inherent volatile nature of macro-economic factors such as future commodity prices or discount rate and uncertainty in asset specific factors such as reserve estimates and operational decisions impacting the production profile or activity levels for our oil and natural gas properties. When estimating the recoverable amount, the single most likely future cash flows, the point estimate, is the primary method applied to reflect uncertainties in timing and amount inherent in the assumptions used in the estimated future cash flows. For assumptions in which the expected probability distributions or outcome are expected to be significantly skewed the use of decision trees or simulation is applied.

Unproved oil and gas properties are assessed for impairment when facts and circumstances suggest that the carrying amount of the asset may exceed its recoverable amount, and at least annually. If, following evaluation, an exploratory well has not found proved reserves, the previously capitalised costs are tested for impairment. Subsequent to the initial evaluation phase for a well, it will be considered a trigger for impairment testing of a well if no development decision is planned for the near future and there is no firm plan for future drilling in the licence. Impairment of unsuccessful wells is reversed, as applicable, to the extent that conditions for impairment are no longer present.

Estimating recoverable amounts involves complexity in estimating relevant future cash flows, based on assumptions about the future, discounted to their present value. Impairment testing requires long-term assumptions to be made concerning a number of economic factors such as future market prices, refinery margins, currency exchange rates and future output, discount rates and political and country risk among others, in order to establish relevant future cash flows. Long-term assumptions for major economic factors are made at a group level, and there is a high degree of reasoned judgement involved in establishing these assumptions, in determining other relevant factors such as forward price curves, in estimating production outputs and in determining the ultimate terminal value of an asset.

Employee retirement plans
When estimating the present value of defined benefit pension obligations that represent a long-term liability in the Consolidated balance sheet, and indirectly, the period's net pension expense in the Consolidated statement of income, management make a number of critical assumptions affecting these estimates. Most notably, assumptions made about the discount rate to be applied to future benefit payments and plan assets, the expected rate of pension increase and the annual rate of compensation increase, have a direct and potentially material impact on the amounts presented. Significant changes in these assumptions between periods can have a material effect on the Consolidated financial statements.

Asset retirement obligations
Statoil has significant obligations to decommission and remove offshore installations at the end of the production period. The costs of these decommissioning and removal activities require revisions due to changes in current regulations and technology while considering relevant risks and uncertainties. Most of the removal activities are many years into the future, and the removal technology and costs are constantly changing. The estimates include assumptions of the time required and the day rates for rigs, marine operations and heavy lift vessels that can vary considerably depending on the assumed removal complexity. As a result, the initial recognition of the liability and the capitalised cost associated with decommissioning and removal obligations, and the subsequent adjustment of these balance sheet items, involve the application of significant judgement.

Derivative financial instruments
When not directly observable in active markets, the fair value of derivative contracts must be computed internally based on internal assumptions as well as directly observable market information, including forward and yield curves for commodities, currencies and interest rates. Changes in internal assumptions, forward and yield curves could materially impact the internally computed fair value of derivative contracts, particularly long-term contracts, resulting in a corresponding impact on income or loss in the Consolidated statement of income.

Income tax
Every year Statoil incurs significant amounts of income taxes payable to various jurisdictions around the world and recognises significant changes to deferred tax assets and deferred tax liabilities, all of which are based on management's interpretations of applicable laws, regulations and relevant court decisions. The quality of these estimates is highly dependent upon proper application of at times very complex sets of rules, the recognition of changes in applicable rules and, in the case of deferred tax assets, management's ability to project future earnings from activities that may apply loss carry forward positions against future income taxes.

3 Segments

Statoil's operations are managed through the following operating segments: Development and Production Norway (DPN), Development and Production USA (DPUSA), Development and Production International (DPI), Marketing, Midstream and Processing (MMP), **New Energy Solutions (NES)** and Other.

The development and production operating segments are responsible for the commercial development of the oil and gas portfolios within their respective geographical areas: DPN on the Norwegian continental shelf, DPUSA including offshore and onshore activities in the USA and Mexico, and DPI worldwide outside of DPN and DPUSA.

Exploration activities are managed by a separate business unit, which has the global responsibility across the group for discovery and appraisal of new resources. Exploration activities are allocated to and presented in the respective development and production operating segments.

The MMP segment is responsible for marketing and trading of oil and gas commodities (crude, condensate, gas liquids, products, natural gas and liquefied natural gas), electricity and emission rights, as well as transportation, processing and manufacturing of the above mentioned commodities, operations of refineries, terminals, processing and power plants.

The NES segment is responsible for wind parks, carbon capture and storage as well as other renewable energy and low-carbon energy solutions.

Statoil reports its business through reporting segments which correspond to the operating segments, except for the operating segments DPI and DPUSA which have been aggregated into one reporting segment, Development and Production International. This aggregation has its basis in similar economic characteristics, the nature of products, services and production processes, the type and class of customers, the methods of distribution and regulatory environment. The operating segment NES is reported in the segment Other due to its immateriality.

The Other reporting segment includes activities within New Energy Solutions, Global Strategy and Business Development, Technology, Projects and Drilling and Corporate Staffs and Services.

The eliminations section includes the elimination of inter-segment sales and related unrealised profits, mainly from the sale of crude oil and products. Inter-segment revenues are based upon estimated market prices.

Segment data for the years ended 31 December 2016, 2015 and 2014 is presented below. The measurement basis of segment profit is *Net operating income*. In the tables below, deferred tax assets, pension assets and non-current financial assets are not allocated to the segments. Also, the line additions to PP&E, intangibles and equity accounted investments are excluding movements due to changes in asset retirement obligations.

(in USD million)	Development and Production Norway	Development and Production International	Marketing, Midstream and Processing	Other	Eliminations	Total
Full year 2016						
Revenues third party and other income	184	884	44,883	41	0	45,993
Revenues inter-segment	12,971	5,873	35	1	(18,880)	(0)
Net income (loss) from equity accounted investments	(78)	(100)	61	(3)	0	(119)
Total revenues and other income	13,077	6,657	44,979	39	(18,880)	45,873
Purchases [net of inventory variation]	1	(7)	(39,696)	(0)	18,198	(21,505)
Operating and SG&A expenses	(2,547)	(2,923)	(4,439)	(340)	463	(9,787)
Depreciation, amortisation and net impairment losses	(5,698)	(5,510)	(221)	(121)	0	(11,550)
Exploration expenses	(383)	(2,569)	0	0	0	(2,952)
Net operating income	4,451	(4,352)	623	(423)	(219)	80
Additions to PP&E, intangibles and equity accounted investments	6,785	6,397	492	451	0	14,125
Balance sheet information						
Equity accounted investments	1,133	365	129	618	0	2,245
Non-current segment assets	27,816	36,181	4,450	352	0	68,799
Non-current assets, not allocated to segments						8,090
Total non-current assets						79,133

(in USD million)	Development and Production Norway	Development and Production International	Marketing, Midstream and Processing	Other	Eliminations	Total
Full year 2015						
Revenues third party and other income	(123)	1,576	57,868	349	0	59,671
Revenues inter-segment	17,459	6,715	183	1	(24,357)	(0)
Net income (loss) from equity accounted investments	3	(91)	55	4	0	(29)
Total revenues and other income	17,339	8,200	58,106	354	(24,357)	59,642
Purchases [net of inventory variation]	(0)	(10)	(50,547)	(0)	24,303	(26,254)
Operating and SG&A expenses	(3,223)	(3,391)	(4,664)	(342)	187	(11,433)
Depreciation, amortisation and net impairment losses	(6,379)	(10,231)	37	(142)	(0)	(16,715)
Exploration expenses	(576)	(3,296)	(0)	0	0	(3,872)
Net operating income	7,161	(8,729)	2,931	(129)	133	1,366
Additions to PP&E, intangibles and equity accounted investments	6,293	8,119	900	273	0	15,584
Balance sheet information						
Equity accounted investments	5	333	214	272	0	824
Non-current segment assets	27,706	37,475	5,588	690	0	71,458
Non-current assets, not allocated to segments						9,305
Total non-current assets						81,588

(in USD million)	Development and Production Norway	Development and Production International	Marketing, Midstream and Processing	Other	Eliminations	Total
Full year 2014						
Revenues third party and other income	1,347	3,017	94,812	122	0	99,299
Revenues inter-segment	27,568	10,757	286	1	(38,612)	0
Net income (loss) from equity accounted investments	11	(113)	73	(5)	0	(34)
Total revenues and other income	28,926	13,661	95,171	118	(38,612)	99,264
Purchases [net of inventory variation]	(0)	(2)	(86,689)	0	38,711	(47,980)
Operating and SG&A expenses	(4,034)	(3,654)	(5,287)	(161)	321	(12,815)
Depreciation, amortisation and net impairment losses	(6,301)	(8,885)	(583)	(156)	0	(15,925)
Exploration expenses	(838)	(3,824)	(4)	0	0	(4,666)
Net operating income	17,753	(2,703)	2,608	(199)	420	17,878
Additions to PP&E, intangibles and equity accounted investments	8,817	9,750	1,225	132	0	19,924
Balance sheet information						
Equity accounted investments	32	640	434	20	0	1,127
Non-current segment assets	35,243	44,912	6,234	688	0	87,077
Non-current assets, not allocated to segments						10,226
Total non-current assets						98,430

See note 4 Acquisitions and dispositions for information on transactions that affect the different segments.

See note 10 Property, plant and equipment for information on impairment losses that affected the different segments.

See note 11 Intangible assets for information on impairment losses that affected the different segments.

See note 23 Other commitments, contingent liabilities and contingent assets for information on contingencies that have influenced the segments.

Revenues by geographical areas
Statoil has business operations in more than 30 countries. When attributing revenues third party and other income to the country of the legal entity executing the sale, Norway constitutes 78% and the USA constitutes 14%.

Non-current assets by country

(in USD million)	At 31 December 2016	2015	2014
Norway	31,484	31,487	38,966
USA	18,223	20,531	24,605
Brazil	5,308	3,474	3,974
Angola	3,884	5,350	6,903
UK	3,108	2,882	2,650
Canada	1,494	2,270	2,366
Algeria	1,344	1,435	1,593
Azerbaijan	1,326	1,416	3,181
Other countries	4,873	3,436	3,965
Total non-current assets[1)]	71,043	72,282	88,204

1) Excluding deferred tax assets, pension assets and non-current financial assets.

Revenues by product type

(in USD million)	2016	2015	2014
Crude oil	24,307	27,806	51,803
Natural gas	9,202	12,390	15,732
Refined products	8,142	10,761	16,782
Natural gas liquids	4,036	5,482	9,506
Other	1	1,461	2,885
Total revenues	45,688	57,900	96,708

4 Acquisitions and disposals

2016

Acquisition of shares in Lundin Petroleum AB (Lundin) and sale of interests in the Edvard Grieg field

In January 2016 Statoil acquired 11.93% of the issued share capital and votes in Lundin Petroleum AB for a total purchase price of SEK 4.6 billion (USD 541 million). The shares were accounted for as a non-current financial investment at fair value with changes in fair value presented in the line item net gains (losses) from available for sale financial assets in the Consolidated statement of comprehensive income up until the transaction in June 2016.

In June 2016 Statoil closed an agreement with Lundin to divest its entire 15% interest in the Edvard Grieg field, a 9% interest in the Edvard Grieg Oil pipeline and a 6% interest in the Utsira High Gas pipeline for an increased ownership share in Lundin. In addition to the divested interests, a cash consideration of SEK 544 million (USD 64 million) was paid to Lundin. Following the completion of the transaction Statoil owns 68.4 million shares of Lundin, corresponding to 20.1% of the outstanding shares and votes. Statoil recognised a total net gain of USD 120 million related to the divestment presented in the line item other income in the Consolidated statement of income. In the segment reporting, the gain was recognised in the Development and Production Norway (DPN) segment (USD 114 million) and in the Marketing, Midstream and Processing (MMP) segment (USD 5 million). The transaction was tax exempt under the Norwegian petroleum tax legislation.

Following the increase in ownership interest on 30 June 2016, Statoil obtained significant influence over Lundin, and accounted for the investment as an associate under the equity method. Statoil performed a purchase price allocation to determine the net identifiable assets and liabilities of Lundin. Excess values were allocated mainly to Lundin`s exploration and production licences on the Norwegian continental shelf. The investment in Lundin was included in the Consolidated balance sheet within line item equity accounted investments with a book value of USD 1,199 million as per 30 June 2016. The Lundin investment is reported as part of the DPN segment. For summarized financial information relating investment in Lundin Petroleum AB, see note 12 Associated Companies.

Following the change in accounting classification, Statoil recognised a gain of USD 127 million representing the cumulative gain on its initial 11.93% shareholding being reclassified from the line item net gains (losses) from available for sale financial assets in the Consolidated statement of comprehensive income, to the net financial items line item in the Consolidated statement of income.

Sale of interest in Marcellus operated onshore play
In July 2016 Statoil closed an agreement to divest its operated properties in the US state of West Virginia to EQT Corporation for USD 407 million in cash. The transaction was reported as part of Development and Production International (DPI) segment and had an immaterial effect on the Consolidated statement of income recognized in the third quarter of 2016.

Acquisition of operated interest in Brazil
In November 2016 Statoil closed an agreement with Petróleo Brasileiro S.A. ("Petrobras") to acquire a 66% operated interest in the Brazilian offshore licence BM-S-8 in the Santos basin for the maximum cash consideration of USD 2,500 million. A cash consideration of USD 1,250 million was paid on the closing date. The payment of the remaining consideration is subject to certain conditions being met, and was reflected at fair value at the transaction date. The value of the acquired exploration assets has been recognised in the DPI segment, resulting in an increase in intangible assets of USD 2,271 million.

Sale of interest Kai Kos Dehseh
In December 2016 Statoil signed an agreement with Athabasca Oil Corporation to divest the 100% owned Kai Kos Dehseh (KKD) oil sands projects covering the producing Leismer plant and the undeveloped Corner project, along with a number of midstream contracts associated with Leismer's production. The total consideration consists of a cash consideration of CAD 435 million (USD 323 million), 100 million common shares in Athabasca Oil Corporation (slightly under 20% ownership share) and a series of contingent payments, capped at CAD 250 million (USD 186 million), based on development of oil price and production over the next four years. Both the shares and the contingent consideration will be measured at fair value on the closing date. As of 31 December 2016 the KKD related assets and associated liabilities were presented as held for sale in the Consolidated balance sheet. Upon entering into the agreement, Statoil impaired the assets by USD 412 million. This impairment is partly reflected as depreciation, amortisation and net impairment losses and partly as exploration expense in the Consolidated statement of income. In addition, as a consequence of the transaction, a separate onerous contract provision of USD 50 million, mainly related to vacant office spaces, has been recognised as selling, general and administration expenses. Accumulated foreign exchange losses, currently recognised in other comprehensive income, will be reflected in the Consolidated Statement of Income at the closing date. The transaction was closed 31 January 2017, and will be reflected in the DPI segment in the first quarter 2017.

2015

Sale of interests in the Marcellus onshore play
In January 2015 Statoil reduced its average working interest in the non-operated southern Marcellus onshore play from 29% to 23% through a divestment to Southwestern Energy. Proceeds from the sale were USD 365 million, recognized in the DPI segment with no gain.

Sale of interests in the Shah Deniz project and the South Caucasus Pipeline
In April 2015 Statoil sold its remaining 15.5% interest in the Shah Deniz project and the South Caucasus Pipeline to Petronas with a total gain of USD 1,182 million, recognised in the DPI and the MMP segments. Total proceeds from the sale were USD 2,688 million.

Sale of buildings
In 2015 Statoil sold the shares in Forusbeen 50 AS, Strandveien 4 AS and Arkitekt Ebbelsvei 10 AS with a gain of USD 211 million, recognised in the Other segment. Proceeds from the sale were USD 486 million. At the same time Statoil entered into 15 year operating lease agreements for the buildings.

Sale of interests in the Trans Adriatic Pipeline AG
In December 2015 Statoil sold its 20% interest in Trans Adriatic Pipeline AG to Snam SpA, with a gain of USD 139 million, recognised in the MMP segment. Total proceeds from the sale were USD 227 million.

Sale of interests in the Gudrun field and acquisition of interests in Eagle Ford
In December 2015 Statoil sold a 15% interest in the Gudrun field on the Norwegian continental shelf (NCS) to Repsol, recognizing a total gain of USD 142 million in the DPN segment. Proceeds from the sale were USD 216 million. Simultaneously Statoil acquired an additional 13% interest in the Eagle Ford formation with the same party. The acquisition was accounted for as a business combination using the acquisition method in the DPI and MMP segments with the fair value of net identifiable assets of USD 277 million and USD 121 million, respectively as of 30 December 2015. No goodwill was recognised.

2014

Sale of interests in the Shah Deniz project and the South Caucasus Pipeline
In March 2014 and May 2014 Statoil sold a 3.33% and a 6.67% working interests, in the Shah Deniz project and the South Caucasus Pipeline, to BP and SOCAR respectively, with a total gain of USD 942 million, presented in the DPI and the MMP segments. Proceeds from the sale were USD 1,383 million.

Kai Kos Dehseh oil sands swap agreement
In May 2014 Statoil and its partner PTTEP swapped the two parties' respective interests in the Kai Kos Dehseh oil sands project in Alberta, Canada. Subsequent to the closing, Statoil continues as 100% owner of the Leismer and Corner projects. The transaction has been recognised in the DPI segment resulting in an increase in property, plant and equipment of USD 769 million, including a transfer from intangible assets of USD 301 million, and with no impact on the Consolidated statement of income.

Sale of interests in licences on the Norwegian continental shelf
In December 2014 Statoil sold certain ownership interests in licences on the NCS to Wintershall with a gain of USD 861 million, recognised in the DPN segment. Proceeds from the sale were USD 1,250 million.

5 Financial risk management

General information relevant to financial risks
Statoil's business activities naturally expose Statoil to financial risk. Statoil's approach to risk management includes assessing and managing risk in all activities using a holistic risk approach. Statoil utilises correlations between the most important market risks, such as oil and natural gas prices, refined oil product prices, currencies, and interest rates, to calculate the overall market risk and thereby take into account the natural hedges inherent in Statoil's portfolio. Adding the different market risks without considering these correlations would overestimate Statoil's total market risk. This approach allows Statoil to reduce the number of risk management transactions and thereby reduce transaction costs and avoid sub-optimisation.

An important element in risk management is the use of centralised trading mandates. All major strategic transactions are required to be coordinated through Statoil's corporate risk committee. Mandates delegated to the trading organisations within crude oil, refined products, natural gas and electricity are relatively small compared to the total market risk of Statoil.

The corporate risk committee, which is headed by the chief financial officer and includes representatives from the principal business segments, is responsible for defining, developing and reviewing Statoil's risk policies. The chief financial officer, assisted by the committee, is also responsible for overseeing and developing Statoil's Enterprise Risk Management and proposing appropriate measures to adjust risk at the corporate level.

Financial risks
Statoil's activities expose Statoil to the following financial risks:
- Market risk (including commodity price risk, currency risk and interest rate risk)
- Liquidity risk
- Credit risk

Market risk
Statoil operates in the worldwide crude oil, refined products, natural gas, and electricity markets and is exposed to market risks including fluctuations in hydrocarbon prices, foreign currency rates, interest rates, and electricity prices that can affect the revenues and costs of operating, investing and financing. These risks are managed primarily on a short-term basis with a focus on achieving the highest risk-adjusted returns for Statoil within the given mandate. Long-term exposures are managed at the corporate level, while short-term exposures are managed according to trading strategies and mandates approved by Statoil's corporate risk committee.

For more information on sensitivity analysis of market risk see note 25 Financial instruments: fair value measurement and sensitivity analysis of market risk.

Commodity price risk
Statoil's most important long term commodity risk (oil and natural gas) is related to future market prices as Statoil's risk policy is to be exposed to both upside and downside price movements. To manage short-term commodity risk, Statoil enters into commodity- based derivative contracts, including futures, options, over-the-counter (OTC) forward contracts, market swaps and contracts for differences related to crude oil, petroleum products, natural gas and electricity. Statoil's bilateral gas sales portfolio is exposed to various price indices and uses derivatives to manage the net gas sales exposure towards a diversified combination of long and short dated gas price markers.

The term of crude oil and refined oil products derivatives are usually less than one year, and they are traded mainly on the Inter Continental Exchange (ICE) in London, the New York Mercantile Exchange (NYMEX), the OTC Brent market, and crude and refined products swap markets. The term of natural gas and electricity derivatives is usually three years or less, and they are mainly OTC physical forwards and options, NASDAQ OMX Oslo forwards and futures traded on the NYMEX and ICE.

Currency risk
Statoil's cash flows from operating activities deriving from oil and gas sales, operating expenses and capital expenditures are mainly in USD, but taxes, dividends to shareholders on the Oslo Børs, a share of our operating expenses and capital expenditures are in NOK. Accordingly, Statoil's currency management is primarily linked to mitigate currency risk related to payments in NOK. This means that Statoil regularly purchases NOK, primarily spot, but also on a forward basis using conventional derivative instruments.

Interest rate risk
Bonds are normally issued at fixed rates in a variety of local currencies (among others USD, EUR and GBP). Bonds are normally converted to floating USD bonds by using interest rate and currency swaps. Statoil manages its interest rates exposure on its bond debt based on risk and reward considerations from an enterprise risk management perspective. This means that the fixed/floating mix on interest rate exposure may vary from time to time. For more detailed information about Statoil's long-term debt portfolio see note 18 Finance debt.

Liquidity risk
Liquidity risk is the risk that Statoil will not be able to meet obligations of financial liabilities when they become due. The purpose of liquidity management is to ensure that Statoil has sufficient funds available at all times to cover its financial obligations.

The main cash outflows are the quarterly dividend payments and Norwegian petroleum tax payments paid six times per year. If the cash flow forecasts indicate that the liquid assets will fall below target levels, new long-term funding will be considered.

Short-term funding needs will normally be covered by the USD 5.0 billion US Commercial Papers Programme (CP) which is backed by a revolving credit facility of USD 5.0 billion, supported by 21 core banks, maturing in 2021. The facility supports secure access to funding, supported by the best available short-term rating. As at 31 December 2016 it has not been drawn.

Statoil raises debt in all major capital markets (USA, Europe and Asia) for long-term funding purposes. The policy is to have a smooth maturity profile with repayments not exceeding five percent of capital employed in any year for the nearest five years. Statoil's non-current financial liabilities have a weighted average maturity of approximately nine years.

For more information about Statoil's non-current financial liabilities see note 18 Finance debt.

The table below shows a maturity profile, based on undiscounted contractual cash flows, for Statoil's financial liabilities.

(in USD million)	At 31 December 2016	2015
Due within 1 year	12,766	11,909
Due between 1 and 2 years	4,913	8,361
Due between 3 and 4 years	9,891	9,861
Due between 5 and 10 years	10,884	10,645
Due after 10 years	13,278	13,113
Total specified	51,732	53,889

Credit risk

Credit risk is the risk that Statoil's customers or counterparties will cause Statoil financial loss by failing to honour their obligations. Credit risk arises from credit exposures with customer accounts receivables as well as from financial investments, derivative financial instruments and deposits with financial institutions.

Prior to entering into transactions with new counterparties, Statoil's credit policy requires all counterparties to be formally identified and assigned internal credit ratings as well as exposure limits. The internal credit ratings reflect Statoil's assessment of the counterparties' credit risk and are based on a quantitative and qualitative analysis of recent financial statements and other relevant business information including general market and industry information. All counterparties are re-assessed regularly.

Statoil uses risk mitigation tools to reduce or control credit risk both on a counterparty and portfolio level. The main tools include bank and parental guarantees, prepayments and cash collateral.

Statoil has pre-defined limits for the absolute credit risk level allowed at any given time on Statoil's portfolio as well as maximum credit exposures for individual counterparties. Statoil monitors the portfolio on a regular basis and individual exposures against limits on a daily basis. The total credit exposure portfolio of Statoil is geographically diversified among a number of counterparties within the oil and energy sector, as well as larger oil and gas consumers and financial counterparties. The majority of Statoil's credit exposure is with investment grade counterparties.

The following table contains the carrying amount of Statoil's financial receivables and derivative financial instruments split by Statoil's assessment of the counterparty's credit risk. Trade and other receivables include 4% overdue receivables for 30 days and more. The overdue receivables are mainly joint venture receivables pending the settlement of disputed working interest items payable from Statoil's working interest partners within its US unconventional activities. Provisions have been made for expected losses. Only non-exchange traded instruments are included in derivative financial instruments.

(in USD million)	Non-current financial receivables	Trade and other receivables	Non-current derivative financial instruments	Current derivative financial instruments
At 31 December 2016				
Investment grade, rated A or above	234	1,682	754	412
Other investment grade	264	4,090	1,064	75
Non-investment grade or not rated	210	1,302	0	4
Total financial asset	707	7,074	1,819	491
At 31 December 2015				
Investment grade, rated A or above	0	1,653	1,346	230
Other investment grade	377	3,126	1,350	278
Non-investment grade or not rated	277	1,055	0	34
Total financial asset	655	5,834	2,697	542

At 31 December 2016, USD 571 million of cash was held as collateral to mitigate a portion of Statoil's credit exposure. At 31 December 2015, USD 1,161 million was held as collateral. The collateral cash is received as a security to mitigate credit exposure related to positive fair values on interest rate swaps, cross currency swaps and foreign exchange swaps. Cash is called as collateral in accordance with the master agreements with the different counterparties when the positive fair values for the different swap agreements are above an agreed threshold.

Under the terms of various master netting agreements for derivative financial instruments as of 31 December 2016, USD 817 million presented as liabilities do not meet the criteria for offsetting. At 31 December 2015, USD 794 million was not offset. The collateral received and the amounts not offset from derivative financial instrument liabilities, reduce the credit exposure in the derivative financial instruments presented in the table above as they will offset each other in a potential default situation for the counterparty. Trade and other receivables subject to similar master netting agreements USD 364 million have been offset as of 31 December 2016, and respectively USD 341 million as of 31 December 2015.

6 Remuneration

(in USD million, except average number of employees)	2016	Full year 2015	2014
Salaries[1)]	2,576	2,791	3,698
Pension costs	650	846	544
Payroll tax	394	419	548
Other compensations and social costs	276	312	376
Total payroll costs	3,895	4,369	5,166
Average number of employees[2)]	21,300	22,300	23,300

1) Salaries include bonuses, severance packages and expatriate costs in addition to base pay.
2) Part time employees amount to 3%, 3% and 2% for the years 2016, 2015 and 2014 respectively.

Total payroll expenses are accumulated in cost-pools and partly charged to partners of Statoil operated licences on an hours incurred basis.

Compensation to the board of directors (BoD) and the corporate executive committee (CEC)
Remuneration to members of the BoD and the CEC during the year was as follows:

(in USD thousand)[1]	2016	Full year 2015	2014
Current employee benefits	9,270	11,436	11,624
Post-employment benefits	574	799	2,064
Other non-current benefits	19	15	0
Share-based payment benefits	102	167	175
Total	9,966	12,418	13,863

1) All figures in the table are presented on accrual basis.

At 31 December 2016, 2015 and 2014 there are no loans to the members of the BoD or the CEC.

Share-based compensation
Statoil's share saving plan provides employees with the opportunity to purchase Statoil shares through monthly salary deductions and a contribution by Statoil. If the shares are kept for two full calendar years of continued employment following the year of purchase, the employees will be allocated one bonus share for each one they have purchased.

Estimated compensation expense including the contribution by Statoil for purchased shares, amounts vested for bonus shares granted and related social security tax was USD 61 million, USD 77 million and USD 94 million related to the 2016, 2015 and 2014 programs, respectively. For the 2017 program (granted in 2016) the estimated compensation expense is USD 62 million. At 31 December 2016 the amount of compensation cost yet to be expensed throughout the vesting period is USD 138 million.

7 Other expenses

Auditor's remuneration

(in USD million, excluding VAT)	2016	Full year 2015	2014
Audit fee	6.5	6.1	7.1
Audit related fee	1.0	1.7	1.3
Tax fee	0.1	0.0	0.0
Other service fee	0.0	0.0	0.0
Total	7.5	7.9	8.4

In addition to the figures in the table above, the audit fees and audit related fees related to Statoil operated licences amount to USD 0.8 million, USD 0.9 million and USD 1.0 million for 2016, 2015 and 2014, respectively.

Research and development expenditures
Research and development (R&D) expenditures were USD 298 million, USD 344 million and USD 476 million in 2016, 2015 and 2014, respectively. R&D expenditures are partly financed by partners of Statoil operated licenses. Statoil's share of the expenditures has been recognised as expense in the Consolidated statement of income.

8 Financial items

(in USD million)	Full year 2016	2015	2014
Foreign exchange gains (losses) derivative financial instruments	353	548	(198)
Other foreign exchange gains (losses)	(473)	(793)	(109)
Net foreign exchange gains (losses)	(120)	(245)	(307)
Dividends received	46	42	42
Gains (losses) financial investments	(0)	47	176
Interest income financial investments	63	76	111
Interest income non-current financial receivables	22	23	19
Interest income current financial assets and other financial items	305	208	281
Interest income and other financial items	436	396	628
Gains (losses) derivative financial instruments	470	(491)	904
Interest expense bonds and bank loans and net interest on related derivatives	(830)	(707)	(684)
Interest expense finance lease liabilities	(26)	(27)	(47)
Capitalised borrowing costs	355	392	250
Accretion expense asset retirement obligations	(420)	(481)	(597)
Interest expense current financial liabilities and other finance expense	(122)	(147)	(127)
Interest and other finance expenses	(1,043)	(971)	(1,205)
Net financial items	(258)	(1,311)	20

Statoil's main financial items relate to assets and liabilities categorised in the held for trading category and the amortised cost category. For more information about financial instruments by category see note 25 Financial instruments: fair value measurement and sensitivity analysis of market risk.

The line item interest expense bonds and bank loans and net interest on related derivatives primarily includes interest expenses of USD 1,018 million, USD 1,041 million and USD 1,079 million from the financial liabilities at amortised cost category. This was partly offset by net interest on related derivatives from the held for trading category, USD 188 million, USD 334 million and USD 395 million for 2016, 2015 and 2014, respectively.

The line item gains (losses) derivative financial instruments primarily includes fair value gain from the held for trading category of USD 454 million, a loss of USD 492 million and a gain of USD 897 million for 2016, 2015 and 2014, respectively.

Foreign exchange gains (losses) derivative financial instruments include fair value changes of currency derivatives related to liquidity and currency risk. The line item foreign exchange gains (losses) includes a net foreign exchange loss of USD 205 million, a loss of USD 1,208 million and a loss of USD 2,120 million from the held for trading category for 2016, 2015 and 2014, respectively.

9 Income taxes

Significant components of income tax expense

(in USD million)	Full year 2016	2015	2014
Current income tax expense in respect of current year	(3,869)	(6,488)	(14,299)
Prior period adjustments	(158)	(91)	307
Current income tax expense	(4,027)	(6,579)	(13,993)
Origination and reversal of temporary differences	1,372	1,519	29
Change in tax regulations	(50)	(90)	(19)
Prior period adjustments	(20)	(74)	(29)
Deferred tax expense	1,302	1,355	(19)
Income tax expense	(2,724)	(5,225)	(14,011)

During the normal course of its business, Statoil files tax returns in many different tax regimes. There may be differing interpretation of applicable tax laws and regulations regarding some of the matters in the tax returns. In certain cases it may take several years to complete the discussions with the relevant tax authorities or to reach a resolution of the tax positions through litigations. Statoil has provided for probable income tax related assets and liabilities based on best estimates reflecting consistent interpretations of the applicable laws and regulations.

Reconciliation of statutory tax rate to effective tax rate

(in USD million)	Full year 2016	2015	2014
Income before tax	(178)	55	17,898
Calculated income tax at statutory rate[1)]	676	1,078	(5,139)
Calculated Norwegian Petroleum tax[2)]	(2,250)	(4,145)	(9,960)
Tax effect uplift[2)]	812	847	980
Tax effect of permanent differences regarding divestments	153	468	911
Tax effect of permanent differences caused by functional currency different from tax currency	(356)	719	762
Tax effect of other permanent differences	(48)	(2)	(298)
Change in unrecognised deferred tax assets	(1,625)	(3,557)	(1,299)
Change in tax regulations	(50)	(90)	(19)
Prior period adjustments	(177)	(165)	278
Other items including currency effects	141	(376)	(228)
Income tax expense	(2,724)	(5,225)	(14,011)
Effective tax rate	>(100%)	>100%	78.3%

1) The weighted average of statutory tax rates was positive 379.8% in 2016, negative 1,950.2% in 2015 and positive 28.7% in 2014. The high tax rate in 2016, the negative rate in 2015 and the change in average statutory tax rates from 2015 to 2016 is mainly caused by earnings composition between tax regimes with lower statutory tax rates and tax regimes with higher statutory tax rates. In both years there are positive income in tax regimes with relatively lower tax rates and losses, including impairments and provisions, in tax regimes with relatively higher tax rates. The decrease from 2014 to 2015 was mainly caused by losses, impairments and provisions in entities with higher than average statutory tax rates.

2) When computing the petroleum tax of 53% (54% from 2017) on income from the Norwegian continental shelf, an additional tax-free allowance, or uplift, is granted at a rate of 5.5% per year (5.4% per year from 2017 for new investments) on the basis of the original capitalised cost of offshore production installations. For investments made prior to 5 May 2013, the rate is 7.5% per year. Transitional rules apply to investments from 5 May 2013 covered by among others Plans for development and operation (PDOs) or Plans for installation and operation (PIOs) submitted to the Ministry of Oil and Energy prior to 5 May 2013. The uplift may be deducted from taxable income for a period of four years, starting in the year in which the capital expenditure is incurred. Unused uplift may be carried forward indefinitely. At year end 2016 and 2015, unrecognised uplift credits amounted to USD 2,121 million and USD 2,333 million, respectively.

Deferred tax assets and liabilities comprise

(in USD million)	Tax losses carried forward	Property, plant and equipment and Intangible assets	Asset removal obligation	Pensions	Derivatives	Other	Total
Deferred tax at 31 December 2016							
Deferred tax assets	4,283	233	7,078	743	138	849	13,323
Deferred tax liabilities	0	(16,797)	0	0	(270)	(488)	(17,555)
Net asset (liability) at 31 December 2016	4,283	(16,564)	7,078	743	(132)	361	(4,231)
Deferred tax at 31 December 2015							
Deferred tax assets	4,743	185	6,980	578	7	797	13,291
Deferred tax liabilities	(0)	(16,731)	0	(0)	(928)	(1,032)	(18,691)
Net asset (liability) at 31 December 2015	4,743	(16,545)	6,980	578	(920)	(235)	(5,399)

Changes in net deferred tax liability during the year were as follows:

(in USD million)	2016	2015	2014
Net deferred tax liability at 1 January	5,399	7,881	10,317
Charged (credited) to the Consolidated statement of income	(1,302)	(1,355)	19
Other comprehensive income	(129)	461	56
Translation differences and other	264	(1,588)	(2,510)
Net deferred tax liability at 31 December	4,231	5,399	7,881

Deferred tax assets and liabilities are offset to the extent that the deferred taxes relate to the same fiscal authority, and there is a legally enforceable right to offset current tax assets against current tax liabilities. After netting deferred tax assets and liabilities by fiscal entity, deferred taxes are presented on the balance sheet as follows:

(in USD million)	At 31 December 2016	2015
Deferred tax assets	2,195	2,022
Deferred tax liabilities	6,427	7,421

Deferred tax assets are recognised based on the expectation that sufficient taxable income will be available through reversal of taxable temporary differences or future taxable income. At year end 2016 and 2015 the deferred tax assets of USD 2,195 million and USD 2,022 million, respectively, were primarily recognised in Norway, Angola, Brasil and the UK.

Unrecognised deferred tax assets

	At 31 December			
	2016		2015	
(in USD million)	Basis	Tax	Basis	Tax
Deductible temporary differences	3,431	1,360	2,448	1,010
Tax losses carried forward	17,440	6,557	14,329	5,297
Total	20,871	7,917	16,776	6,307

Approximately 9% of the unrecognised carry forward tax losses can be carried forward indefinitely. The majority of the remaining part of the unrecognised tax losses expire after 2027. The unrecognised deductible temporary differences do not expire under the current tax legislation. Deferred tax assets have not been recognised in respect of these items because currently there is insufficient evidence to support that future taxable profits will be available to secure utilisation of the benefits.

At year end 2016 unrecognised deferred tax assets in the US and Angola represents USD 5,655 million and USD 800 million of the total unrecognised deferred tax assets of USD 7,917 million. Similar amounts for 2015 were USD 4,461 million in the US and USD 643 million in Angola of a total of USD 6,307 million.

10 Property, plant and equipment

(in USD million)	Machinery, equipment and transportation equipment, including vessels	Production plants and oil and gas assets	Refining and manufacturing plants	Buildings and land	Assets under development	Total
Cost at 31 December 2015	3,466	133,269	7,459	928	20,284	165,406
Additions and transfers	62	11,960	776	70	(2,148)	10,720
Disposals at cost[1)]	(98)	(1,857)	(48)	(130)	(445)	(2,577)
Assets reclassified to held for sale (HFS)	(7)	(2,169)	0	(12)	(51)	(2,239)
Effect of changes in foreign exchange	(30)	1,546	75	2	(325)	1,268
Cost at 31 December 2016	3,394	142,750	8,262	859	17,315	172,579
Accumulated depreciation and impairment losses at 31 December 2015	(2,826)	(90,762)	(5,386)	(468)	(3,958)	(103,400)
Depreciation	(137)	(9,657)	(411)	(31)	0	(10,235)
Impairment losses	(0)	(1,672)	(240)	(12)	(969)	(2,893)
Reversal of impairment losses	0	1,186	371	0	35	1,592
Transfers	71	(2,013)	(79)	(0)	1,789	(232)
Accumulated depreciation and impairment disposed assets[1)]	91	1,231	44	57	14	1,437
Accumulated depreciation and impairment assets classified as HFS	6	1,757	0	8	22	1,794
Effect of changes in foreign exchange	28	(1,042)	(71)	1	(1)	(1,086)
Accumulated depreciation and impairment losses at 31 December 2016	(2,767)	(100,971)	(5,772)	(446)	(3,068)	(113,023)
Carrying amount at 31 December 2016	626	41,779	2,490	413	14,247	59,556
Estimated useful lives (years)	3-20	UoP[2)]	15 - 20	20 - 33		

(in USD million)	Machinery, equipment and transportation equipment, including vessels	Production plants and oil and gas assets	Refining and manufacturing plants	Buildings and land	Assets under development	Total
Cost at 31 December 2014	3,508	139,578	8,691	1,358	22,162	175,297
Additions and transfers	52	9,895	598	78	1,292	11,914
Disposals at cost	(20)	(1,657)	(1,052)	(437)	(1,197)	(4,362)
Effect of changes in foreign exchange	(74)	(14,547)	(779)	(70)	(1,973)	(17,443)
Cost at 31 December 2015	3,466	133,269	7,459	928	20,284	165,406
Accumulated depreciation and impairment losses at 31 December 2014	(2,708)	(88,344)	(6,490)	(641)	(1,494)	(99,677)
Depreciation	(173)	(10,162)	(266)	(48)	0	(10,650)
Impairment losses and transfers	0	(3,419)	(67)	0	(2,661)	(6,147)
Reversal of impairment losses	0	108	483	6	22	620
Accumulated depreciation and impairment disposed assets	2	830	324	190	(0)	1,347
Effect of changes in foreign exchange	53	10,224	629	25	175	11,107
Accumulated depreciation and impairment losses at 31 December 2015	(2,826)	(90,762)	(5,386)	(468)	(3,958)	(103,400)
Carrying amount at 31 December 2015	641	42,507	2,073	460	16,326	62,006
Estimated useful lives (years)	3-20	UoP [2]	15 - 20	20 - 33		

1) Includes USD 445 million related to change in the classification of Statoil's investment in joint operation (pro-rata line by line consolidation)/full consolidation to joint venture (equity method), mainly related to Dudgeon Offshore Wind Ltd (USD 341 million).
2) Depreciation according to unit of production method (UoP), see note 2 Significant accounting policies.

The carrying amount of assets transferred to Property, plant and equipment from Intangible assets in 2016 and 2015 amounted to USD 692 million and USD 332 million, respectively.

Impairments

(in USD million)	Property, plant and equipment	Intangible assets[3]	Total
At 31 December 2016			
Producing and development assets[1]	1,301	590	1,890
Acquisition costs related to oil and gas prospects[2]	0	403	403
Total net impairment losses recognised	1,301	992	2,293
At 31 December 2015			
Producing and development assets[1]	5,526	1,263	6,788
Goodwill[1]	0	539	539
Acquisition costs related to oil and gas prospects[2]	0	688	688
Total net impairment losses recognised	5,526	2,490	8,015

1) Producing and development assets and goodwill are subject to impairment assessment under IAS 36. The total net impairment losses recognised under IAS 36 in 2016 and 2015 amount to USD 1,890 million and USD 7,327 million, respectively, including impairment of acquisition costs - oil and gas prospects (intangible assets).
2) Acquisition costs related to exploration activities, subject to impairment assessment under the successful efforts method (IFRS 6).
3) See note 11 Intangible assets.

In assessing the need for impairment of the carrying amount of a potentially impaired asset, the asset's carrying amount is compared to its recoverable amount. The recoverable amount is the higher of fair value less cost of disposal (FVLCOD) and estimated value in use (VIU).

The base discount rate for VIU calculations is 6.0% real after tax (2015: 6.5%). The discount rate is derived from Statoil's weighted average cost of capital. A derived pre-tax discount rate would generally be in the range of 8-12%, depending on asset specific characteristics, such as specific tax treatments, cash flow profiles and economic life. For certain assets a pre-tax discount rate could be outside this range, mainly due to special tax elements (for example permanent differences) affecting the pre-tax equivalent. See note 2 Significant accounting policies for further information regarding impairment on property, plant and equipment.

		2016		2015	
(in USD million)	Impairment method	Carrying amount after impairment 1)	Net impairment loss	Carrying amount after impairment 1)	Net impairment loss
At 31 December					
Development and Production Norway	VIU	3,115	760	1,427	454
	FVLCOD	1,401	69	2,010	620
North America - unconventional	VIU	3,887	945	5,733	3,119
	FVLCOD	483	412	1,240	539
North America Conventional offshore Gulf of Mexico	VIU	4,459	141	3,699	2,210
	FVLCOD	0	0	0	0
North Africa	VIU	0	104	490	130
	FVLCOD	0	0	0	0
Sub - Saharan Africa	VIU	772	(137)	903	169
	FVLCOD	0	0	0	0
Europe and Asia	VIU	1,124	(330)	1,018	511
	FVLCOD	0	0	0	0
Marketing, Midstream and Processing	VIU	1,046	(74)	1,005	(425)
	FVLCOD	0	0	0	0
Total		16,286	1,890	17,525	7,327

1) Carrying amount relates to assets impaired/reversed.

During 2016 net impairment losses of USD 1,890 million were recognised on producing and development assets mainly due to downward revision of long-term commodity price assumptions. For 2015 the net impairment losses recognised were USD 7,327 million primarily due to declining commodity prices.

Development and Production Norway (DPN)
In the DPN segment net impairment losses of USD 829 million were recognised in 2016, which were mainly related to conventional offshore assets in the development phase. The net impairment losses were triggered by reduction in commodity price assumptions. In 2015 impairment losses of USD 1,074 million were recognised.

Development and Production International (DPI)
In the DPI segment net impairment losses of USD 1,130 million were recognised in 2016 of which USD 1,357 million, including a reversal of USD 571 million, related to unconventional onshore assets in North America. The loss includes impairment of Kai Kos Dehseh, classified as held for sale as of 31 December 2016. In addition, impairment reversals of USD 780 million and impairment losses of USD 553 million were recognised in relation to conventional assets. Net impairment losses of USD 541 million were recognised as Depreciation, amortisation and net impairment losses and net impairment losses of USD 590 million related to signature bonuses and acquisition costs recognised as Exploration expenses. In 2015 impairment losses of USD 6,678 million were recognised.

The net impairment losses were mainly a result from reduced long term commodity price assumptions partly offset by increased short term prices, operational performance improvements and cost reductions.

Marketing, Midstream and Processing (MMP)
The MMP segment recognised a net impairment reversal of USD 74 million mainly related to a refinery. The reversal of impairment was triggered by increased refinery margins and operational and commercial improvements. In 2015 net reversal of USD 425 million were recognised.

The recoverable amount of assets tested for impairment was mainly based on Value in Use (VIU) estimates on the basis of internal forecasts on costs, production profiles and commodity prices. In fourth quarter, the downward revision of the long term price forecast constituted the most important impairment indicator. Business plan updates including improved production profiles, more efficient operations and lower costs in addition to increased short term commodity prices partially offsets the effect of lower long term prices. Short term commodity prices (2017 - 2019) are forecasted by using observable forward prices for 2017 and a linear projection towards the 2020 internal forecast. In 2015 the observable forward prices were used for the first three years.

Recoverable amount for assets measured at Fair Value Less Cost of Disposal (FVLCOD) have partially been established through comparisons with observed market transactions and bids, and partially through internally prepared net present value estimates using assumed market participant assumptions.

The price assumptions used for impairment calculations were as follows (prices used in 2015 impairment calculations for the respective years are indicated in brackets):

Year (Prices in real terms)	2017		2020		2025		2030	
Brent Blend - USD/bbl	55	(45)	75	(83)	78	(92)	80	(100)
NBP - USD/mmbtu	6.0	(4.9)	6.0	(8.0)	8.0	(9.0)	8.0	(9.2)
Henry Hub - USD/mmbtu	3.4	(2.7)	4.0	(4.2)	4.0	(4.4)	4.0	(4.6)

Sensitivities
Commodity prices have historically been volatile. Significant further downward adjustments of Statoil's commodity price assumptions would result in impairment losses on certain producing and development assets in Statoil's portfolio. If a further decline in commodity price forecasts over the lifetime of the assets were 20%, considered to represent a reasonably likely change, the impairment amount to be recognised could illustratively be in the region of USD 8 billion before tax effects. This illustrative impairment sensitivity assumes no changes to input factors other than prices; however, a price reduction of 20% is likely to result in changes in business plans as well as other factors used when estimating an asset's recoverable amount. Changes in such input factors would likely significantly reduce the actual impairment amount compared to the illustrative sensitivity above. Changes that could be expected would include a reduction in the cost level in the oil and gas industry as well as offsetting currency effects, both of which have historically occurred following significant changes in commodity prices. The illustrative sensitivity is therefore not considered to represent a best estimate of an expected impairment impact, nor an estimated impact on revenues or operating income in such a scenario. A significant and prolonged reduction in oil and gas prices would also result in mitigating actions by Statoil and its license partners, as a reduction of oil and gas prices would impact drilling plans and production profiles for new and existing assets. Quantifying such impacts is considered impracticable, as it requires detailed technical, geological and economical evaluations based on hypothetical scenarios and not based on existing business or development plans.

11 Intangible assets

(in USD million)	Exploration expenses	Acquisition costs - oil and gas prospects	Goodwill	Other	Total
Cost at 31 December 2015	3,701	5,207	1,565	402	10,875
Additions	246	2,477	0	(8)	2,715
Disposals at cost	(0)	(311)	0	(42)	(353)
Transfers	(298)	(392)	0	(2)	(692)
Assets reclassified to held for sale	(19)	(78)	0	0	(97)
Expensed exploration expenditures previously capitalised	(808)	(992)	0	0	(1,800)
Effect of changes in foreign exchange	33	(3)	5	(4)	31
Cost at 31 December 2016	2,856	5,907	1,570	346	10,679
Accumulated depreciation and impairment losses at 31 December 2015			(1,242)	(182)	(1,423)
Amortisation and impairments for the year			0	(13)	(13)
Amortisation and impairment losses disposed intangible assets			0	(2)	(2)
Effect of changes in foreign exchange			0	2	2
Accumulated depreciation and impairment losses at 31 December 2016			(1,242)	(195)	(1,437)
Carrying amount at 31 December 2016	2,856	5,907	328	151	9,243

(in USD million)	Exploration expenses	Acquisition costs - oil and gas prospects	Goodwill	Other	Total
Cost at 31 December 2014	3,075	7,183	1,632	454	12,345
Additions	1,188	546	0	(18)	1,716
Disposals at cost	(61)	(293)	(9)	(24)	(387)
Transfers	(82)	(250)	0	(0)	(332)
Expensed exploration expenditures previously capitalised	(213)	(1,951)	0	0	(2,164)
Effect of changes in foreign exchange	(206)	(29)	(58)	(9)	(303)
Cost at 31 December 2015	3,701	5,207	1,565	402	10,875
Accumulated depreciation and impairment losses at 31 December 2014			(702)	(183)	(885)
Amortisation and impairments for the year			(539)	(2)	(541)
Effect of changes in foreign exchange			0	2	2
Accumulated depreciation and impairment losses at 31 December 2015			(1,242)	(182)	(1,423)
Carrying amount at 31 December 2015	3,701	5,207	323	220	9,452

The useful lives of intangible assets are assessed to be either finite or indefinite. Intangible assets with finite useful lives are amortised systematically over their estimated economic lives, ranging between 10-20 years.

During 2016, intangible assets were impacted by impairments of acquisition costs related to exploration activities of USD 403 million primarily as a result from dry wells and uncommercial discoveries in Gulf of Mexico, South America and Angola. Additionally, Statoil recognised impairments of signature bonuses and acquisition costs totalling USD 590 million.

Impairment losses and reversals of impairment losses are presented as Exploration expenses and Depreciation, amortisation and net impairment losses on the basis of their nature as exploration assets (intangible assets) and other intangible assets, respectively. The impairment losses and reversal of impairment losses are based on recoverable amount estimates triggered by changes in reserve estimates, cost estimates and market conditions. See note 10 Property, plant and equipment for more information on the basis for impairment assessments.

The table below shows the aging of capitalised exploration expenditures.

(in USD million)	2016	2015
Less than one year	311	1,448
Between one and five years	2,216	1,923
More than five years	329	331
Total	2,856	3,701

The table below shows the components of the exploration expenses.

(in USD million)	2016	Full year 2015	2014
Exploration expenditures	1,437	2,860	3,730
Expensed exploration expenditures previously capitalised	1,800	2,164	2,097
Capitalised exploration	(285)	(1,151)	(1,161)
Exploration expenses	2,952	3,872	4,666

12 Equity accounted investments

		(in USD million)			
		2016		2015	
	Ownership	Book value	Profit share	Book value	Profit share
Lundin Petroleum AB	20.1%	1,121	(78)	-	-
Other equity accounted investments		1,124	(41)	824	(29)
Total		2,245	(119)	824	(29)

Voting rights corresponds to ownership.

Summary financial information of equity accounted investments

The following table provides summarised financial information relating to Lundin Petroleum AB. This information is presented on a 20.1% basis and also reflects adjustments made by Statoil to Lundin Petroleum AB's own results in applying the equity method of accounting. Statoil adjusts Lundin Petroleum AB's results for depreciation of excess values determined in the purchase price allocation at the date of acquisition. Where there are significant differences in accounting policies, adjustments are made to bring the accounting policies applied in line with Statoil's. These adjustments have decreased the reported net income for 2016, as shown in the table below, compared with the equivalent amount reported by Lundin Petroleum AB.

	Lundin Petroleum AB
(in USD million)	2016
At 31 December	
Current assets	69
Non-Current assets	3,069
Current liabilities	(70)
Non-Current liabilities	(1,947)
Net assets	1,121
Year ended 31 December	
Gross revenues[1)]	135
Income before tax[1)]	(83)
Net income[1)]	(78)
Capital expenditures[1)]	589

1) For the period 30 June to 31 December 2016.

Statoil has not received dividends from Lundin Petroleum AB for 2016.

Statoil's quoted market value as per 31.12.2016 was USD 1.496 billion.

13 Financial investments and non-current prepayments

Non-current financial investments

(in USD million)	At 31 December 2016	2015
Bonds	1,362	1,412
Listed equity securities	731	715
Non-listed equity securities	251	209
Financial investments	2,344	2,336

Bonds and listed equity securities relate to investment portfolios which are held by Statoil's captive insurance company and accounted for using the fair value option.

Non-current prepayments and financial receivables

(in USD million)	At 31 December 2016	2015
Financial receivables interest bearing	707	764
Prepayments and other non-interest bearing receivables	185	203
Prepayments and financial receivables	893	967

Financial receivables interest bearing primarily relate to project financing of equity accounted companies and loans to employees.

Current financial investments

(in USD million)	At 31 December 2016	2015
Time deposits	3,242	2,166
Interest bearing securities	4,995	7,650
Financial investments	8,211	9,817

At 31 December 2016 current financial investments include USD 818.3 million investment portfolios which are held by Statoil's captive insurance company and accounted for using the fair value option. The corresponding balance at 31 December 2015 was USD 677.2 million.

For information about financial instruments by category, see note 25 Financial instruments: fair value measurement and sensitivity analysis of market risk.

14 Inventories

(in USD million)	At 31 December 2016	2015
Crude oil	1,966	1,210
Petroleum products	744	580
Natural gas	160	294
Other	358	419
Inventories	3,227	2,502

Higher inventory level of crude oil at 31 December is mainly related to higher prices and in-transit volumes. Other inventory consists of spare parts and operational materials, including drilling and well equipment.

The write-down of inventories from cost to net realisable value amounted to an expense of USD 74 million and USD 439 million in 2016 and 2015, respectively.

15 Trade and other receivables

(in USD million)	At 31 December 2016	2015
Trade receivables	5,504	4,464
Current financial receivables	862	736
Joint venture receivables	592	574
Equity accounted investments and other related party receivables	116	60
Total financial trade and other receivables	7,074	5,834
Non-financial trade and other receivables	765	837
Trade and other receivables	7,839	6,671

For more information about the credit quality of Statoil's counterparties, see note 5 Financial risk management. For currency sensitivities, see note 25 Financial instruments: fair value measurement and sensitivity analysis of market risk.

16 Cash and cash equivalents

(in USD million)	At 31 December 2016	2015
Cash at bank available	596	1,047
Time deposits	1,660	1,494
Money market funds	65	450
Interest bearing securities	2,234	5,091
Restricted cash, including margin deposits	535	540
Cash and cash equivalents	5,090	8,623

Restricted cash at 31 December 2016 and 2015 includes collateral deposits related to trading activities of USD 398 million and USD 411 million, respectively. Collateral deposits are related to certain requirements set out by exchanges where Statoil is participating. The terms and conditions related to these requirements are determined by the respective exchanges.

17 Shareholders' equity and dividends

At 31 December 2016, Statoil's share capital of NOK 8,112,623,527.50 (USD 1,155,993,270) comprised 3,245,049,411 shares at a nominal value of NOK 2.50. Share capital at 31 December 2015 was NOK 7,971,617,757.50 (USD 1,138,981,520) comprised 3,188,647,103 shares at a nominal value of NOK 2.50.

Statoil ASA has only one class of shares and all shares have voting rights. The holders of shares are entitled to receive dividends as and when declared and are entitled to one vote per share at general meetings of the company.

Dividends declared per share were USD 0.2201 for the first three quarters of 2016. The board of directors will propose to the annual general meeting to maintain a dividend of USD 0.2201 per ordinary share for the fourth quarter, and continue the scrip programme giving shareholders the option to receive the dividend for the fourth quarter in cash or newly issued shares in Statoil at 5% discount.

As part of Statoil's scrip dividend program, approved by Statoil's general assembly in May 2016, eligible shareholders can elect to receive their dividend in the form of new ordinary Statoil shares or in cash. For ADR (American Depository Receipts) holders, dividend can be received in the form of ADSs (American Depository Shares) or in cash. The subscription price for the dividend shares will have a discount compared to the volume-weighted average price on OSE of the last two trading days of the subscription period for each quarter. For the fourth quarter of 2015 and for the first, second and third quarter of 2016 the discount has been set at 5%.

During 2016 dividend for the third and for the fourth quarter of 2015 and dividend for the first and second quarter of 2016 were settled. Dividend declared but not yet settled, is presented as dividends payable in the Consolidated balance sheet, regardless of whether the dividend is expected to be paid in cash or by issuance of new shares. The Consolidated statement of changes in equity shows declared dividend in the period (retained earnings), offset by scrip dividend settled during the period (share capital and additional paid-in-capital). Dividend declared in 2016 relate to the fourth quarter of 2015 and to the first three quarters of 2016.

(in USD million)	At 31 December 2016	2015
Dividends declared	2,824	2,930
US dollar per share or ADS	0.8804	0.9173 1)
Dividends paid in cash	1,876	2,836
US dollar per share or ADS	0.8804	0.9034
Norwegian kroner per share	7.3364	7.2000
Scrip dividends	904	-
Number of shares issued (millions)	56.4	-
Sum dividends settled	2,780	2,836

1) Dividend for the fourth quarter 2014 and for the first quarter 2015 declared in NOK and translated to USD at currency rate on declaration date.

During 2016 a total of 4,011,860 treasury shares were purchased for USD 62 million and 3,882,153 treasury shares were allocated to employees participating in the share saving plan. In 2015 a total of 4,057,902 treasury shares were purchased for USD 69 million and 3,203,968 treasury shares were allocated to employees participating in the share saving plan. At 31 December 2016 Statoil had 11,138,890 treasury shares and at 31 December 2015 11,009,183 treasury shares, all of which are related to Statoil's share saving plan. For further information, see note 6 Remuneration.

18 Finance debt

Capital management

The main objectives of Statoil's capital management policy are to maintain a strong financial position and to ensure sufficient financial flexibility. One of the key ratios in the assessment of Statoil's financial robustness is net interest-bearing debt adjusted (ND) to capital employed adjusted (CE).

(in USD million)	At 31 December 2016	2015
Net interest-bearing debt adjusted (ND)	19,389	14,748
Capital employed adjusted (CE)	54,490	55,055
Net debt to capital employed adjusted (ND/CE)	35.6%	26.8%

ND is defined as Statoil's interest bearing financial liabilities less cash and cash equivalents and current financial investments, adjusted for collateral deposits and balances held by Statoil's captive insurance company (amounting to USD 1,216 million and USD 1,111 million for 2016 and 2015, respectively) and balances related to the SDFI (amounting to USD 199 million and USD 214 million for 2016 and 2015, respectively) CE is defined as Statoil's total equity (including non-controlling interests) and ND.

Non-current finance debt

Finance debt measured at amortised cost

	Weighted average interest rates in %[1]		Carrying amount in USD millions at 31 December		Fair value in USD millions at 31 December[2]	
	2016	2015	2016	2015	2016	2015
Unsecured bonds						
United States Dollar (USD)	3.54	3.51	19,712	20,768	20,681	21,630
Euro (EUR)	2.10	2.28	8,211	7,201	8,884	7,495
Great Britain Pound (GBP)	6.08	6.08	1,693	2,040	2,475	2,698
Norwegian kroner (NOK)	4.18	4.18	348	341	386	378
Total			29,964	30,350	32,427	32,201
Unsecured loans						
Japanese yen (JPY)	4.30	4.30	85	83	88	89
Secured bank loans						
Norwegian kroner (NOK)	-	3.11	-	52	-	52
Finance lease liabilities			507	580	526	575
Total			592	715	614	716
Total finance debt			30,556	31,065	33,041	32,918
Less current portion			2,557	1,100	2,584	1,100
Non-current finance debt			27,999	29,965	30,457	31,818

1) Weighted average interest rates are calculated based on the contractual rates on the loans per currency at 31 December and do not include the effect of swap agreements.
2) The fair value of the non-current financial liabilities is determined using a discounted cash flow model and is classified at level 2 in the fair value hierarchy. Interest rates used in the model are derived from the LIBOR and EURIBOR forward curves and will vary based on the time to maturity for the non-current financial liabilities. The credit premium used is based on indicative pricing from external financial institutions.

Unsecured bonds amounting to USD 19,712 million are denominated in USD and unsecured bonds amounting to USD 7,420 million are swapped into USD. Four bonds denominated in EUR amounting to USD 2,832 million are not swapped. The table does not include the effects of agreements entered into to swap the various currencies into USD. For further information see note 25 Financial instruments: fair value measurement and sensitivity analysis of market risk.

Substantially all unsecured bond and unsecured bank loan agreements contain provisions restricting future pledging of assets to secure borrowings without granting a similar secured status to the existing bondholders and lenders.

In 2016 Statoil issued the following bonds:

Issuance date	Amount in EUR billion	Interest rate in %	Maturity date
9 November 2016	0.60	0.750	November 2026
9 November 2016	0.60	1.625	November 2036

Out of Statoil's total outstanding unsecured bond portfolio, 47 bond agreements contain provisions allowing Statoil to call the debt prior to its final redemption at par or at certain specified premiums if there are changes to the Norwegian tax laws. The carrying amount of these agreements is USD 29,616 million at the 31 December 2016 closing exchange rate.

For more information about the revolving credit facility, maturity profile for undiscounted cash flows and interest rate risk management, see note 5 Financial risk management.

Non-current finance debt maturity profile

(in USD million)	At 31 December 2016	2015
Year 2 and 3	6,478	6,234
Year 4 and 5	3,798	4,881
After 5 years	17,723	18,850
Total repayment of non-current finance debt	27,999	29,965
Weighted average maturity (years)	9	9
Weighted average annual interest rate (%)	3.41	3.39

More information regarding finance lease liabilities is provided in note 22 Leases.

Current finance debt

(in USD million)	At 31 December 2016	2015
Collateral liabilities	571	1,161
Non-current finance debt due within one year	2,557	1,100
Other including bank overdraft	545	66
Total current finance debt	3,674	2,326
Weighted average interest rate (%)	1.61	1.90

Collateral liabilities and other current liabilities relate mainly to cash received as security for a portion of Statoil's credit exposure and outstanding amounts on US Commercial paper (CP) programme. At 31 December USD 500 million were issued on the CP programme. Corresponding at 31 December 2015 there were no outstanding amounts.

19 Pensions

The main pension plans for Statoil ASA and its most significant subsidiaries are defined contribution plans, in which the pension costs are recognised in the Consolidated statement of income in line with payments of annual pension premiums. The pension contribution plans in Statoil ASA also includes certain unfunded elements (notional contribution plans), for which the annual notional contributions are recognised as pension liabilities. These notional pension liabilities are regulated equal to the return on asset within the main contribution plan. See note 2 Significant accounting policies for more information about the accounting treatment of the notional contribution plans reported in Statoil ASA.

In addition, Statoil ASA has a closed defined benefit plan for employees which in 2015 had less than 15 years of future service before their regular retirement age, and for employees in certain subsidiaries. Statoil's defined benefit plans are generally based on a minimum of 30 years of service and 66% of the final salary level, including an assumed benefit from the Norwegian National Insurance Scheme. The Norwegian companies in the group are subject to, and complies with, the requirements of the Norwegian Mandatory Company Pensions Act.

The defined benefit plans in Norway are managed and financed through Statoil Pensjon (Statoil's pension fund - hereafter "Statoil Pension"). Statoil Pension is an independent pension fund that covers the employees in Statoil's Norwegian companies. The pension fund's assets are kept separate from the company's and group companies' assets. Statoil Pension is supervised by the Financial Supervisory Authority of Norway ("Finanstilsynet") and is licensed to operate as a pension fund.

Statoil is a member of a Norwegian national agreement-based early retirement plan ("AFP"), and the premium is calculated on the basis of the employees' income between 1 and 7.1 G. The premium is payable for all employees until age 62. Pension from the AFP scheme will be paid from the AFP plan administrator to employees for their full lifetime. Statoil has determined that its obligations under this multi-employer defined benefit plan can be estimated with sufficient reliability for recognition purposes. Accordingly, the estimated proportionate share of the AFP plan is recognised as a defined benefit obligation.

The present values of the defined benefit obligation, except for the notional contribution plan, and the related current service cost and past service cost are measured using the projected unit credit method. The assumptions for salary increases, increases in pension payments and social security base amount are based on agreed regulation in the plans, historical observations, future expectations of the assumptions and the relationship between these assumptions. At 31 December 2016 the discount rate for the defined benefit plans in Norway was established on the basis of seven years' mortgage covered bonds interest rate extrapolated on a yield curve which matches the duration of Statoil's payment portfolio for earned benefits, which was calculated to be 17.4 years at the end of 2016. Social security tax is calculated based on a pension plan's net funded status and is included in the defined benefit obligation.

Statoil has more than one defined benefit plan, but the disclosure is made in total since the plans are not subject to materially different risks. Pension plans outside Norway are not material and as such not disclosed separately. The pension costs in Statoil ASA are partly re-charged to license partners.

Net pension cost

(in USD million)	2016	2015	2014
Current service cost	238	378	751
Interest cost	192	191	496
Interest (income) on plan asset	(148)	(145)	(409)
Past service cost	2	-	(1)
Losses (gains) from curtailment, settlement or plan amendment	109	250	(298)
Actuarial (gains) losses related to termination benefits	59	(1)	(27)
Notional contributions	50	36	-
Defined benefit plans	503	709	512
Defined contribution plans	148	135	32
Total net pension cost	650	844	544

New entrants for the early retirement plans have been included as a settlement cost. The total impact in 2016 was USD 123 million and USD 173 million in 2015.

(in USD million)	2016	2015
Defined benefit obligations (DBO)		
Defined benefit obligations at 1 January	6,822	8,745
Current service cost	239	378
Interest cost	192	191
Actuarial (gains) losses - Financial assumptions	879	(703)
Actuarial (gains) losses - Experience	(282)	(369)
Benefits paid	(235)	(233)
Losses (gains) from curtailment, settlement or plan amendment[1)]	171	253
Paid-up policies	(131)	(143)
Foreign currency translation	87	(1,332)
Changes in notional contribution liability	50	34
Defined benefit obligations at 31 December	7,791	6,822
Fair value of plan assets		
Fair value of plan assets at 1 January	5,127	6,066
Interest income	148	145
Return on plan assets (excluding interest income)	76	69
Company contributions	22	35
Benefits paid	(80)	(70)
Paid-up policies and personal insurance	(92)	(208)
Foreign currency translation	50	(911)
Fair value of plan assets at 31 December	5,250	5,127
Net pension liability at 31 December	(2,541)	(1,695)
Represented by:		
Asset recognised as non-current pension assets (funded plan)	839	1,284
Liability recognised as non-current pension liabilities (unfunded plans)	(3,380)	(2,979)
DBO specified by funded and unfunded pension plans	7,791	6,822
Funded	4,423	3,849
Unfunded	3,368	2,974
Actual return on assets	131	207

The actuarial losses from changes in financial assumptions mainly relate to increased pension liabilities due to reduced interest rates and a higher expected rate of pension increase. For 2015 Statoil recognised a gain from an opposite movement of these assumptions.

Actuarial losses and gains recognised directly in Other comprehensive income (OCI)

(in USD million)	2016	2015	2014
Net actuarial (losses) gains recognised in OCI during the year	(482)	1,139	24
Actuarial (losses) gains related to currency effects on net obligation and foreign exchange translation	(21)	460	611
Tax effects of actuarial (losses) gains recognised in OCI	129	(461)	(56)
Recognised directly in OCI during the year net of tax	(374)	1,138	580
Cumulative actuarial (losses) gains recognised directly in OCI net of tax	(1,188)	(814)	(1,952)

Actuarial assumptions

	Assumptions used to determine benefit costs in %		Assumptions used to determine benefit obligations in %	
	2016	2015	2016	2015
Discount rate	2.75	2.50	2.50	2.75
Rate of compensation increase	2.25	2.25	2.25	2.25
Expected rate of pension increase	1.00	1.50	1.75	1.00
Expected increase of social security base amount (G-amount)	2.25	2.25	2.25	2.25
Weighted-average duration of the defined benefit obligation			17.4	17.1

The assumptions presented are for the Norwegian companies in Statoil which are members of Statoil's pension fund. The defined benefit plans of other subsidiaries are immaterial to the consolidated pension assets and liabilities.

Expected attrition at 31 December 2016 and 2015 was 0.4% and 0.1% for employees between 50-59 years and 60-67 years, respectively.

For population in Norway, the mortality table K2013, issued by The Financial Supervisory Authority of Norway, is used as the best mortality estimate.

Disability tables for plans in Norway developed by the actuary were implemented in 2013 and represent the best estimate to use for plans in Norway.

Sensitivity analysis

The table below presents an estimate of the potential effects of changes in the key assumptions for the defined benefit plans. The following estimates are based on facts and circumstances as of 31 December 2016.

	Discount rate		Expected rate of compensation increase		Expected rate of pension increase		Mortality assumption	
(in USD million)	0.50%	-0.50%	0.50%	-0.50%	0.50%	-0.50%	+ 1 year	- 1 year
Changes in:								
Defined benefit obligation at 31 December 2016	(605)	689	129	(121)	599	(542)	371	(384)
Service cost 2017	(24)	28	6	(6)	24	(22)	9	(10)

The sensitivity of the financial results to each of the key assumptions has been estimated based on the assumption that all other factors would remain unchanged. The estimated effects on the financial result would differ from those that would actually appear in the Consolidated financial statements because the Consolidated financial statements would also reflect the relationship between these assumptions.

Pension assets
The plan assets related to the defined benefit plans were measured at fair value. Statoil Pension invests in both financial assets and real estate.

Real estate properties owned by Statoil Pension amounted to USD 402 million and USD 386 million of total pension assets at 31 December 2016 and 2015, respectively, and are rented to Statoil companies.

The table below presents the portfolio weighting as approved by the board of Statoil Pension for 2016. The portfolio weight during a year will depend on the risk capacity.

(in %)	Pension assets on investments classes 2016	2015	Target portfolio weight
Equity securities	39.0	38.3	31 - 43
Bonds	41.1	40.3	36 - 48
Money market instruments	13.9	14.9	0 - 29
Real estate	5.4	5.0	5 - 10
Other assets	0.6	1.5	
Total	100.0	100.0	

In 2016 98% of the equity securities, 30% of bonds and 71% of money market instruments had quoted market prices in an active market (level 1). In 2015 100% of the equity securities, 38% of bonds and 100% of money market instruments had quoted market prices in an active market. For definition of the various levels, see note 25 *Financial instruments: fair value measurement and sensitivity analysis of market risk*.

No company contribution is expected to be paid to Statoil Pension in 2017.

20 Provisions

(in USD million)	Asset retirement obligations	Claims and litigations	Other provisions	Total
Non-current portion at 31 December 2015	10,632	1,116	675	12,422
Long term interest bearing provisions at 31 December 2015 reported as finance debt	-	-	27	27
Current portion at 31 December 2015 reported as trade and other payables	150	1,009	388	1,547
Provisions at 31 December 2015	10,782	2,124	1,090	13,997
New or increased provisions	660	256	2,046	2,962
Decrease in the estimates	(1,168)	(21)	(583)	(1,772)
Amounts charged against provisions	(221)	(3)	(195)	(420)
Effects of change in the discount rate	426	-	28	455
Reduction due to divestments	(41)	-	(0)	(41)
Accretion expenses	398	-	-	398
Reclassification and transfer	(44)	-	(0)	(45)
Currency translation	107	(0)	24	131
Provisions at 31 December 2016	10,899	2,356	2,409	15,664
Current portion at 31 December 2016 reported as trade and other payables	188	1,147	922	2,258
Non-current portion at 31 December 2016	10,711	1,209	1,487	13,406

Expected timing of cash outflows

(in USD million)	Asset retirement obligations	Other provisions, including claims and litigations	Total
2017 - 2021	1,233	4,340	5,574
2022 - 2026	1,849	78	1,927
2027 - 2031	1,760	27	1,788
2032 - 2036	3,306	21	3,328
Thereafter	2,751	298	3,048
At 31 December 2016	10,899	4,765	15,664

The claims and litigations category mainly relates to expected payments on unresolved claims. The timing and amounts of potential settlements in respect of these are uncertain and dependent on various factors that are outside management's control.

See also comments on provisions in note 23 Other commitments, contingent liabilities and contingent assets.

The other provisions category relates to expected payments on onerous contracts, cancellation fees and other. In 2016 Statoil recognised a provision amounting to USD 1 billion of which USD 0.3 billion is current portion for a contingent consideration related to the BM-S-8 acquisition in Brazil. For further information, see note 4 Acquisitions and dispositions.

For further information of methods applied and estimates required, see note 2 Significant accounting policies.

21 Trade, other payables and provisions

(in USD million)	At 31 December 2016	2015
Trade payables	2,358	2,052
Non-trade payables and accrued expenses	1,623	2,323
Joint venture payables	2,632	2,590
Equity accounted investments and other related party payables	620	622
Total financial trade and other payables	7,233	7,587
Current portion of provisions and other non-financial payables	2,433	1,746
Trade, other payables and provisions	9,666	9,333

Included in current portion of provisions and other non-financial payables are certain provisions that are further described in note 20 Provisions and in note 23 Other commitments, contingent liabilities and contingent assets. For information regarding currency sensitivities, see note 25 Financial instruments: fair value measurement and sensitivity analysis of market risk. For further information on payables to equity accounted investments and other related parties, see note 24 Related parties.

22 Leases

Statoil leases certain assets, notably drilling rigs, vessels and office buildings.

In 2016, net rental expenditures were USD 2,569 million (USD 3,439 million in 2015 and USD 3,637 million in 2014) consisting of minimum lease payments of USD 3,113 million (USD 4,046 million in 2015 and USD 4,505 million in 2014) reduced with sublease payments received of USD 558 million (USD 608 million in 2015 and USD 870 million in 2014). Net rental expenditures in 2016 include rig cancellation payments of USD 115 million. No material contingent rent payments have been expensed in 2016, 2015 or 2014.

The information in the table below shows future minimum lease payments due and receivable under non-cancellable operating leases at 31 December 2016:

	Operating leases						
(in USD million)	Rigs	Vessels	Land and buildings	Other	Total	Sublease	Net total
2017	1,099	592	143	158	1,993	(135)	1,857
2018	807	462	132	114	1,514	(100)	1,414
2019	624	336	126	94	1,179	(99)	1,080
2020	459	281	124	70	934	(97)	837
2021	324	223	123	52	723	(66)	657
2022-2026	572	396	591	91	1,650	(76)	1,574
2027-2031	-	105	408	29	542	-	542
Thereafter	-	-	100	15	114	-	114
Total future minimum lease payments	3,885	2,395	1,746	624	8,649	(573)	8,076

Statoil had certain operating lease contracts for drilling rigs at 31 December 2016. The remaining significant contracts' terms range from one month to eight years. Rig lease agreements are for the most part based on fixed day rates. Certain rigs have been subleased in whole or for part of the lease term mainly to Statoil operated licenses on the Norwegian continental shelf. These leases are shown gross as operating leases in the table above.

Statoil has a long-term time charter agreement with Teekay for offshore loading and transportation in the North Sea. The contract covers the lifetime of applicable producing fields and at year end 2016 includes three crude tankers. The contract's estimated nominal amount was approximately USD 650 million at year end 2016, and it is included in the category vessels in the table above.

The category land and buildings includes future minimum lease payments to related parties of USD 474 million regarding the lease of one office building located in Bergen and owned by Statoil`s pension fund ("Statoil Pension"). These operating lease commitments extend to the year 2034. USD 367 million of the total is payable after 2020.

Statoil had finance lease liabilities of USD 507 million at 31 December 2016. The nominal minimum lease payments related to these finance leases amount to USD 667 million. Property, plant and equipment includes USD 484 million for finance leases that have been capitalised at year end (USD 768 million in 2015), mainly presented in the category machinery, equipment and transportation equipment, including vessels in note 11 Property, plant and equipment.

Certain contracts contain renewal options. The execution of such options will depend on future market development and business needs at the time when such options are to be exercised.

23 Other commitments, contingent liabilities and contingent assets

Contractual commitments
Statoil had contractual commitments of USD 6,889 million at 31 December 2016. The contractual commitments reflect Statoil's share and mainly comprise construction and acquisition of property, plant and equipment as well as committed investments in equity accounted entities.

As a condition for being awarded oil and gas exploration and production licenses, participants may be committed to drill a certain number of wells. At the end of 2016, Statoil was committed to participate in 42 wells, with an average ownership interest of approximately 39%. Statoil's share of estimated expenditures to drill these wells amounts to USD 777 million. Additional wells that Statoil may become committed to participating in depending on future discoveries in certain licenses are not included in these numbers.

Other long-term commitments

Statoil has entered into various long-term agreements for pipeline transportation as well as terminal use, processing, storage and entry/exit capacity commitments and commitments related to specific purchase agreements. The agreements ensure the rights to the capacity or volumes in question, but also impose on Statoil the obligation to pay for the agreed-upon service or commodity, irrespective of actual use. The contracts' terms vary, with durations of up to 30 years.

Take-or-pay contracts for the purchase of commodity quantities are only included in the table below if their contractually agreed pricing is of a nature that will or may deviate from the obtainable market prices for the commodity at the time of delivery.

Obligations payable by Statoil to entities accounted for using the equity method are included gross in the table below. For assets (for example pipelines) that Statoil accounts for by recognising its share of assets, liabilities, income and expenses (capacity costs) on a line-by-line basis in the Consolidated financial statements, the amounts in the table include the net commitment payable by Statoil (i.e. gross commitment less Statoil's ownership share).

Nominal minimum other long-term commitments at 31 December 2016:

(in USD million)	
2017	1,483
2018	1,395
2019	1,262
2020	1,179
2021	1,021
Thereafter	5,513
Total	11,853

Long term commitments related to contracts in the process of being terminated, and for which the termination fee has been provided for in the accounts, are not included in the above table.

Guarantees

Statoil has guaranteed for its proportionate portion of an associate's long term bank debt, amounting to USD 160 million. The book value of the guarantee is immaterial.

Contingent liabilities and contingent assets

During the annual audits of Statoil's participation in Block 4, Block 15, Block 17 and Block 31 offshore Angola, the Angolan Ministry of Finance has assessed additional profit oil and taxes due on the basis of activities that currently include the years 2002 up to and including 2014. Statoil disputes the assessments and is pursuing these matters in accordance with relevant Angolan legal and administrative procedures. On the basis of the assessments and continued activity on the four blocks up to and including 2016, the exposure for Statoil at year end 2016 is estimated to USD 1,808 million, the most significant part of which relates to profit oil elements. Statoil has provided in the Consolidated financial statements for its best estimate related to the assessments, reflected in the Consolidated statement of income mainly as a revenue reduction, with additional amounts reflected as interest expenses and tax expenses, respectively.

Through its ownership in OML 128 in Nigeria, Statoil is party to an ownership interest redetermination process for the Agbami field. In October 2015, Statoil received the Expert's final ruling which implies a reduction of 5.17 percentage points in Statoil's equity interest in the field. Statoil had previously initiated arbitration proceedings to set aside interim decisions made by the Expert, but this was declined by the arbitration tribunal in its November 2015 judgment. Statoil has initiated proceedings before the Federal High Court in Lagos to set aside the arbitration award. In October 2016 Statoil also initiated a new arbitration to set aside the Expert's final ruling. Currently Statoil has two distinct, but connected, legal processes ongoing related to the Agbami redetermination. As of 31 December 2016, Statoil has recognised a provision of USD 1,104 million net of tax, which reflects a reduction of 5.17 percentage points in Statoil's equity interest in the Agbami field. The provision is reflected within Provisions in the Consolidated balance sheet.

Some long term gas sales agreements contain price review clauses. Certain counterparties have requested arbitration in connection with price review claims. The related exposure for Statoil has been estimated to an amount equivalent to approximately USD 374 million for gas delivered prior to year end 2016. Statoil has provided for its best estimate related to these contractual gas price disputes in the Consolidated financial statements, with the impact to the Consolidated statement of income reflected as revenue adjustments.

There is a dispute between the Nigerian National Petroleum Corporation (NNPC) and the partners (Contractor) in Oil Mining Lease (OML) 128 of the unitised Agbami field concerning interpretation of the terms of the OML 128 Production Sharing Contract (PSC). The dispute relates to the allocation between NNPC and Contractor of cost oil, tax oil and profit oil volumes. The Contractor initiated arbitration in the matter in accordance with the terms of the PSC. In 2015 the Arbitral Tribunal ruled in favour of Contractor's interpretation of the PSC on the main points. The Contractor is currently proceeding to enforce the favourable decision by the means available in the Nigerian legal system, while NNPC on its hand has initiated litigation concerning certain objections to the arbitration award. The Nigerian Federal Inland Revenue Service is also contesting the legality of the arbitration process as far as resolving tax related disputes goes, and in March 2017 the arbitration award was set aside by the Nigerian Federal High Court (FHC) based on the dispute having a tax nature and therefore being non-arbitrable. The Contractor will challenge this ruling in the Court of Appeal. The FHC's ruling will not impact Statoil's

2016 financial statements, as Statoil's stake in the dispute at year end mainly relates to oil volumes previously lifted by NNPC contrary to the PSC terms. NNPC has continued overlifting contrary to the arbitration award.

Brazilian tax authorities have issued an updated tax assessment for 2011 for Statoil's Brazilian subsidiary which was party to Statoil's divestment of 40% of the Peregrino field to Sinochem at that time. The assessment disputes Statoil's allocation of the sale proceeds between entities and assets involved, resulting in a significantly higher assessed taxable gain and related taxes payable in Brazil. Statoil disagrees with the assessment, and has provided an initial response to this effect. The process of formal communication with the Brazilian tax authorities, as well as any subsequent litigation that may become necessary, may take several years. No taxes will become payable until the matter has been finally settled. Statoil is of the view that all applicable tax regulations have been applied in the case and that the group has a strong position. No amounts have consequently been provided for in the accounts.

On 26 September 2016, the Norwegian Ministry of Finance (MoF) denied Statoil's appeal related to a 2014 order from the Financial Supervisory Authority of Norway to change the timing of a Cove Point related onerous contract provision to a financial period prior to the first quarter of 2013, in which Statoil originally reflected the provision. Statoil has decided not to pursue the matter further, as it does not impact any comparative financial periods presented in the annual Consolidated financial statements of 2016. Further reference is made to Note 23 Other commitments, contingent liabilities and contingent assets of Statoil's 2015 Financial Statements.

On 6 July 2016, the Norwegian tax authorities issued a deviation notice for the years 2012 to 2014 related to the internal pricing on certain transactions between Statoil Coordination Centre (SCC) in Belgium and Norwegian entities in the Statoil group. The main issue relates to SCC`s capital structure and its compliance with the arm's length principle. Statoil is of the view that arm's length pricing has been applied in these cases and that the group has a strong position, and no amounts have consequently been provided for in the accounts.

During the normal course of its business, Statoil is involved in legal proceedings, and several other unresolved claims are currently outstanding. The ultimate liability or asset, in respect of such litigation and claims cannot be determined at this time. Statoil has provided in its Consolidated financial statements for probable liabilities related to litigation and claims based on its best estimate. Statoil does not expect that its financial position, results of operations or cash flows will be materially affected by the resolution of these legal proceedings. Statoil is actively pursuing the above disputes through the contractual and legal means available in each case, but the timing of the ultimate resolutions and related cash flows, if any, cannot at present be determined with sufficient reliability.

Provisions related to claims are reflected within note 20 Provisions.

24 Related parties

Transactions with the Norwegian State
The Norwegian State is the majority shareholder of Statoil and also holds major investments in other Norwegian companies. As of 31 December 2016 the Norwegian State had an ownership interest in Statoil of 67.0% (excluding Folketrygdfondet, the Norwegian national insurance fund, of 3.2%). This ownership structure means that Statoil participates in transactions with many parties that are under a common ownership structure and therefore meet the definition of a related party. All transactions are considered to be on an arm's length basis.

Total purchases of oil and natural gas liquids from the Norwegian State amounted to USD 5,848 million, USD 7,431 million and USD 13,718 million in 2016, 2015 and 2014, respectively. Total purchases of natural gas regarding the Tjeldbergodden methanol plant from the Norwegian State amounted to USD 44 million, USD 68 million and USD 73 million in 2016, 2015 and 2014, respectively. These purchases of oil and natural gas are recorded in Statoil ASA. In addition, Statoil ASA sells in its own name, but for the Norwegian State's account and risk, the Norwegian State's gas production. These transactions are presented net. For further information please see note 2 Significant accounting policies. The most significant items included in the line item equity accounted investments and other related party payables in note 21 Trade and other payables, are amounts payable to the Norwegian State for these purchases.

Other transactions
In relation to its ordinary business operations Statoil enters into contracts such as pipeline transport, gas storage and processing of petroleum products, with companies in which Statoil has ownership interests. Such transactions are carried out on an arm's length basis and are included within the applicable captions in the Consolidated statement of income. Gassled and certain other infrastructure assets are operated by Gassco AS, which is an entity under common control by the Norwegian Ministry of Petroleum and Energy. Gassco's activities are performed on behalf of and for the risk and reward of pipeline and terminal owners, and capacity payments flow through Gassco to the respective owners. Statoil payments that flowed through Gassco in this respect amounted to USD 1,167 million, USD 1,105 million and USD 1,476 million in 2016, 2015 and 2014, respectively. These payments are recorded in Statoil ASA. In addition, Statoil ASA process in its own name, but for the Norwegian State's account and risk, the Norwegian State's share of the Gassco costs. These transactions are presented net.

On 30 June 2016, Statoil increased its ownership interest in Lundin Petroleum AB (Lundin) to 20.1% of the outstanding shares and votes. Since 30 June, total purchase of oil and related products from Lundin amounted to USD 155 million. The purchase of oil and related products is recorded in Statoil ASA. For more information concerning the Lundin acquisition, see note 4 Acquisitions and disposals.

For information concerning certain lease arrangements with Statoil Pension, see note 22 Leases.

Related party transactions with management are presented in note 6 Remuneration. Management remuneration for 2016 is presented in note 4 Remuneration in the financial statements of the parent company, Statoil ASA.

25 Financial instruments: fair value measurement and sensitivity analysis of market risk

Financial instruments by category

The following tables present Statoil's classes of financial instruments and their carrying amounts by the categories as they are defined in IAS 39 Financial Instruments: Recognition and Measurement. All financial instruments' carrying amounts are measured at fair value or their carrying amounts reasonably approximate fair value except non-current financial liabilities. See note 18 Finance debt for fair value information of non-current bonds, bank loans and finance lease liabilities.

See note 2 Significant accounting policies for further information regarding measurement of fair values.

				Fair value through profit or loss			
(in USD million)	Note	Loans and receivables	Available for sale	Held for trading	Fair value option	Non-financial assets	Total carrying amount
At 31 December 2016							
Assets							
Non-current derivative financial instruments		-	-	1,819	-	-	1,819
Non-current financial investments	13	-	207	-	2,137	-	2,344
Prepayments and financial receivables	13	707	-	-	-	185	893
Trade and other receivables	15	7,074	-	-	-	765	7,839
Current derivative financial instruments		-	-	492	-	-	492
Current financial investments	13	3,217	-	4,176	818	-	8,211
Cash and cash equivalents	16	2,791	-	2,299	-	-	5,090
Total		13,789	207	8,785	2,955	950	26,687

				Fair value through profit or loss			
(in USD million)	Note	Loans and receivables	Available for sale	Held for trading	Fair value option	Non-financial assets	Total carrying amount
At 31 December 2015							
Assets							
Non-current derivative financial instruments		-	-	2,697	-	-	2,697
Non-current financial investments	13	-	209	-	2,127	-	2,336
Prepayments and financial receivables	13	655	-	-	-	313	967
Trade and other receivables	15	5,834	-	-	-	837	6,671
Current derivative financial instruments		-	-	542	-	-	542
Current financial investments	13	2,166	1	6,973	677	-	9,817
Cash and cash equivalents	16	3,081	-	5,541	-	-	8,623
Total		11,736	210	15,753	2,804	1,150	31,652

(in USD million)	Note	Amortised cost	Fair value through profit or loss	Non-financial liabilities	Total carrying amount
At 31 December 2016					
Liabilities					
Non-current finance debt	18	27,999	-	-	27,999
Non-current derivative financial instruments		-	1,420	-	1,420
Trade and other payables	21	7,233	-	2,433	9,666
Current finance debt	18	3,674	-	-	3,674
Dividend payable		712	-	-	712
Current derivative financial instruments		-	508	-	508
Total		39,618	1,928	2,433	43,979

(in USD million)	Note	Amortised cost	Fair value through profit or loss	Non-financial liabilities	Total carrying amount
At 31 December 2015					
Liabilities					
Non-current finance debt	18	29,965	-	-	29,965
Non-current derivative financial instruments		-	1,285	-	1,285
Trade and other payables	21	7,587	-	1,746	9,333
Current finance debt	18	2,326	-	-	2,326
Dividend payable		700	-	-	700
Current derivative financial instruments		-	264	-	264
Total		40,578	1,549	1,746	43,873

Fair value hierarchy

The following table summarises each class of financial instruments which are recognised in the Consolidated balance sheet at fair value, split by Statoil's basis for fair value measurement.

(in USD million)	Non-current financial investments	Non-current derivative financial instruments - assets	Current financial investments	Current derivative financial instruments - assets	Cash equivalents	Non-current derivative financial instruments - liabilities	Current derivative financial instruments - liabilities	Net fair value
At 31 December 2016								
Level 1	1,095	-	516	-	-	-	-	1,611
Level 2	1,042	970	4,479	426	2,299	(1,414)	(503)	7,299
Level 3	207	848	-	66	-	(6)	(4)	1,110
Total fair value	2,344	1,819	4,994	492	2,299	(1,420)	(508)	10,019
At 31 December 2015								
Level 1	1,194	-	542	-	-	-	-	1,737
Level 2	932	1,756	7,109	491	5,541	(1,226)	(264)	14,340
Level 3	209	941	-	50	-	(59)	-	1,141
Total fair value	2,336	2,697	7,651	542	5,541	(1,285)	(264)	17,218

Level 1, fair value based on prices quoted in an active market for identical assets or liabilities, includes financial instruments actively traded and for which the values recognised in the Consolidated balance sheet are determined based on observable prices on identical instruments. For Statoil this category will, in most cases, only be relevant for investments in listed equity securities and government bonds.

Level 2, fair value based on inputs other than quoted prices included within level 1, which are derived from observable market transactions, includes Statoil's non-standardised contracts for which fair values are determined on the basis of price inputs from observable market transactions. This will typically be when Statoil uses forward prices on crude oil, natural gas, interest rates and foreign exchange rates as inputs to the valuation models to determining the fair value of its derivative financial instruments.

Level 3, fair value based on unobservable inputs, includes financial instruments for which fair values are determined on the basis of input and assumptions that are not from observable market transactions. The fair values presented in this category are mainly based on internal assumptions. The internal assumptions are only used in the absence of quoted prices from an active market or other observable price inputs for the financial instruments subject to the valuation.

The fair value of certain earn-out agreements and embedded derivative contracts are determined by the use of valuation techniques with price inputs from observable market transactions as well as internally generated price assumptions and volume profiles. The discount rate used in the valuation is a risk-free rate based on the applicable currency and time horizon of the underlying cash flows adjusted for a credit premium to reflect either Statoil's credit premium, if the value is a liability, or an estimated counterparty credit premium if the value is an asset. In addition a risk premium for risk elements not adjusted for in the cash flow may be included when applicable. The fair values of these derivative financial instruments have been classified in their entirety in the third category within current derivative financial instruments and non-current derivative financial instruments. Another reasonable assumption, that could have been applied when determining the fair value of these contracts, would be to extrapolate the last observed forward prices with inflation. If Statoil had applied this assumption, the fair value of the contracts included would have decreased by approximately USD 97 million at end of 2016 and decreased by USD 526 million at end of 2015 and impacted the Consolidated statement of income with corresponding amounts.

The reconciliation of the changes in fair value during 2016 and 2015 for financial instruments classified in the third level in the hierarchy are presented in the following table.

(in USD million)	Non-current financial investments	Non-current derivative financial instruments - assets	Current derivative financial instruments - assets	Non-current derivative financial instruments liabilities	Current derivative financial instruments - liabilities	Total amount
Full year 2016						
Opening balance	209	941	50	(59)	-	1,141
Total gains and losses recognised in statement of income	-	(98)	66	49	-	17
Purchases	2	-	-	-	-	2
Settlement	(5)	(17)	(53)	-	-	(75)
Transfer to current portion	-	(1)	1	4	(4)	-
Foreign currency translation differences	1	23	1	-	-	25
Closing balance	207	848	66	(6)	(4)	1,110
Full year 2015						
Opening balance	189	1,707	87	-	-	1,983
Total gains and losses recognised in statement of income	(2)	(442)	54	(59)	-	(449)
Purchases	28	-	-	-	-	28
Settlement	-	(110)	(79)	-	-	(190)
Foreign currency translation differences	(5)	(214)	(11)	-	-	(231)
Closing balance	209	941	50	(59)	-	1,141

During 2016 the financial instruments within level 3 have had a net decrease in the fair value of USD 31 million. The USD 44 million recognised in the Consolidated statement of income during 2016 are impacted by a reduction of USD 13 million related to changes in fair value of certain earn-out agreements. Related to the same earn-out agreements, USD 69 million included in the opening balance for 2016 has been fully realised as the underlying volumes have been delivered during 2016 and the amount is presented as settled in the above table.

Substantially all gains and losses recognised in the Consolidated statement of income during 2016 are related to assets held at the end of 2016.

Sensitivity analysis of market risk

Commodity price risk

The table below contains the commodity price risk sensitivities of Statoil's commodity based derivatives contracts. For further information related to the type of commodity risks and how Statoil manages these risks, see note 5 Financial risk management.

Statoil's assets and liabilities resulting from commodity based derivatives contracts consist of both exchange traded and non-exchange traded instruments, including embedded derivatives that have been bifurcated and recognised at fair value in the Consolidated balance sheet.

Price risk sensitivities at the end of 2016 and 2015 at 30% are assumed to represent a reasonably likely change based on the duration of the derivatives.

Since none of the derivative financial instruments included in the table below are part of hedging relationships, any changes in the fair value would be recognised in the Consolidated statement of income.

Commodity price sensitivity (in USD million)	2016 - 30%	2016 + 30%	2015 - 30%	2015 + 30%
At 31 December				
Crude oil and refined products net gains (losses)	395	(390)	110	(66)
Natural gas and electricity net gains (losses)	810	(809)	249	(248)

Currency risk

The following currency risk sensitivity has been calculated by assuming an 12% reasonably possible change in the main foreign exchange rates that Statoil is exposed to. At the end of 2015 a change of 11% in the foreign exchange rates were viewed as reasonably possible changes. An increase in the foreign exchange rates means that the transaction currency has strengthened in value. The estimated gains and the estimated losses following from a change in the foreign exchange rates would impact the Consolidated statement of income. For further information related to the currency risk and how Statoil manages these risks, see note 5 Financial risk management.

Currency risk sensitivity (in million)	2016 - 12%	2016 + 12%	2015 - 11%	2015 + 11%
At 31 December				
USD net gains (losses)	79	(79)	247	(247)
NOK net gains (losses)	31	(31)	(185)	185

Interest rate risk

The following interest rate risk sensitivity has been calculated by assuming a change of 0.8 percentage points as reasonably possible changes in the interest rates at the end of 2016. At the end of 2015 a change of 0.9 percentage points in the interest rates was viewed as reasonably possible changes. The estimated gains following from a decrease in the interest rates and the estimated losses following from an interest rate increase would impact the Consolidated statement of income. For further information related to the interest risks and how Statoil manages these risks, see note 5 Financial risk management.

Interest risk sensitivity (in USD million)	2016 - 0.8 percentage points	2016 + 0.8 percentage points	2015 - 0.9 percentage points	2015 + 0.9 percentage points
At 31 December				
Interest rate net gains (losses)	897	(897)	1,217	(1,217)

26 Change of presentation currency

On 1 January 2016 Statoil changed its presentation currency from Norwegian kroner (NOK) to US dollars (USD). The change was made mainly in order to better reflect the underlying USD exposure of Statoil's business activities and to align with industry practice.

The change in presentation currency has been accounted for as a policy change, and comparative figures have been re-presented to USD, to reflect the change in presentation currency. There are no policy changes other than the change in presentation currency.

The different components of assets and liabilities in USD correspond to the amount published in NOK translated at the USD/NOK closing rate applicable at the end of each reporting period. The same relates to the equity as a whole. As such, the change in presentation currency will not impact the valuation of assets, liabilities, equity or any ratios between these components, such as debt to equity ratios. Income statements are translated at quarterly average rate.

All currency translation adjustments have been set to zero as of 1 January 2006, which was the date of Statoil's transition to IFRS. Translation adjustments and cumulative translation adjustments have been presented as if Statoil had used USD as the presentation currency from that date.

The recalculation of currency translation adjustments in USD has an impact on the distribution of shareholders' equity for comparable periods, between currency translation adjustments and other components of equity. Together with changes in net income arising from the change in presentation currency, these effects are presented as re-presentations in the table below.

EFFECT OF CHANGES IN REPORTED EQUITY

31 December 2015	Historical Consolidated financial statements in NOK billion	Historical Consolidated financial statements in USD million[1]	Re-presentation in USD million	Consolidated financial statements in USD million
Share capital	8.0	905	234	1,139
Additional paid-in capital	40.1	4,552	1,168	5,720
Retained earnings	215.1	24,417	14,276	38,693
Currency translation adjustments	91.6	10,398	(15,679)	(5,281)
Non-controlling interests	0.3	34	2	36
Total equity	355.1	40,307	0	40,307

1) Translated at exchange rate USD/NOK 8,8090 as of 31 December 2015.

31 December 2014	Historical Consolidated financial statements in NOK billion	Historical Consolidated financial statements in USD million[1]	Re-presentation in USD million	Consolidated financial statements in USD million
Share capital	8.0	1,072	67	1,139
Additional paid-in capital	40.2	5,408	306	5,714
Retained earnings	268.4	36,097	9,580	45,677
Currency translation adjustments	64.3	8,650	(9,955)	(1,305)
Non-controlling interests	0.4	54	3	57
Total equity	381.2	51,282	0	51,282

1) Translated at exchange rate USD/NOK 7,4332 as of 31 December 2014.

The Consolidated statement of income, Consolidated statement of other comprehensive income, Consolidated statement of changes in equity and Consolidated statement of cash flows have been re-presented to reflect the currency rates of transactions in foreign currencies at the date of the transactions.

Upon disposal of a foreign operation accumulated currency translation adjustments arising from currency movements between the Group's presentation currency and the functional currency of the foreign operation are reclassified from equity to profit or loss and included as part of the gain or loss from the disposal, presented as other income. When changing the Group's presentation currency from NOK to USD, the gains or losses from such disposals have been changed to reflect accumulated currency gains or losses being calculated based on USD being the presentation currency rather than NOK. These effects are presented as re-presentations in the table below, and represent the only re-measurements following the change in presentation currency to USD.

EFFECT OF CHANGES IN REPORTED NET INCOME

Net income	Historical Consolidated financial statements in NOK billion	Historical Consolidated financial statements in USD million[1)]	Re-presentation in USD million	Consolidated financial statements in USD million
Full year 2015	(37)	(4,684)	(485)	(5,169)
Full year 2014	22	3,831	56	3,887

1) Translated at average exchange rates for the quarters.

The disposal with most significant effect on the net income of the Group is the disposal of Statoil's interests in Shah Deniz, presented within the DPI segment in the second quarter 2015, for which the gain presented in NOK included NOK 3.2 billion arising from reclassification of accumulated translation differences. As the disposed foreign operation had USD as functional currency, there are no accumulated translation differences when presented in USD for this transaction.

The Statement of cash flow has been re-presented to reflect the changes described above and based on the currency rates applicable at the transaction dates of relevant transactions. The re-presentation impacts the classification between the different lines in the statement of cash flow, between currency translation adjustments and other components of cash flow.

27 Supplementary oil and gas information (unaudited)

In accordance with Financial Accounting Standards Board Accounting Standards Codification "Extractive Activities - Oil and Gas" (Topic 932), Statoil is reporting certain supplemental disclosures about oil and gas exploration and production operations. While this information is developed with reasonable care and disclosed in good faith, it is emphasised that some of the data is necessarily imprecise and represents only approximate amounts because of the subjective judgement involved in developing such information. Accordingly, this information may not necessarily represent the present financial condition of Statoil or its expected future results.

For further information regarding the reserves estimation requirement, see note 2 Significant accounting policies - Critical accounting judgements and key sources of estimation uncertainty - Proved oil and gas reserves.

No new events have occurred since 31 December 2016 that would result in a significant change in the estimated proved reserves or other figures reported as of that date.

The disputed equity determination at Agbami will potentially alter Statoil's equity share in this field. The effect on the proved reserves will be included once the redetermination is finalised and the effect is known.The effect of the farm out of the oil sands projects will be included in 2017, after the closing date of the transaction, and will reduce the proved reserves at year end 2017 by an immaterial volume related to the Leismer field.

Oil and gas reserve quantities
Statoil's oil and gas reserves have been estimated by its qualified professionals in accordance with industry standards under the requirements of the U.S. Securities and Exchange Commission (SEC), Rule 4-10 of Regulation S-X. Statements of reserves are forward-looking statements.

The determination of these reserves is part of an ongoing process subject to continual revision as additional information becomes available. Estimates of proved reserve quantities are imprecise and change over time as new information becomes available. Moreover, identified reserves and contingent resources that may become proved in the future are excluded from the calculations.

Statoil's proved reserves are recognised under various forms of contractual agreements, including production sharing agreements (PSAs) where Statoil's share of reserves can vary due to commodity prices or other factors. Reserves from agreements such as PSAs and buy back agreements are based on the volumes to which Statoil has access (cost oil and profit oil), limited to available market access. At 31 December 2016, 7% of total proved reserves were related to such agreements (13% of total oil, condensate and natural gas liquids (NGL) reserves and 2% of total gas reserves). This compares with 9% and 12% of total proved reserves for 2015 and 2014, respectively. Net entitlement oil and gas production from fields with such agreements was 96 million boe during 2016 (104 million boe for 2015 and 95 million boe for 2014). Statoil participates in such agreements in Algeria, Angola, Azerbaijan, Libya, Nigeria and Russia.

Statoil is recording, as proved reserves, volumes equivalent to our tax liabilities under negotiated fiscal arrangements (PSAs) where the tax is paid on behalf of Statoil. Reserves are net of royalty oil paid in kind and quantities consumed during production.

Rule 4-10 of Regulation S-X requires that the appraisal of reserves is based on existing economic conditions, including a 12-month average price prior to the end of the reporting period, unless prices are defined by contractual arrangements. The proved reserves at year end 2016 have been determined based on a Brent blend price equivalent of USD 42.82/bbl, compared to USD 54.17/bbl and USD 101.27/bbl for 2015 and 2014 respectively. The volume weighted average gas price for proved reserves at year end 2016 was USD 4.50MMBtu. The comparable gas price used to determine gas reserves at year end 2015 and 2014 was USD 5.76MMBtu and USD 8.01MMBtu. The volume weighted average NGL price for proved reserves at year end 2016 was USD 24.85/boe. The corresponding NGL price used to determine NGL reserves at year end 2015 and 2014 was USD 30.56/boe and USD 57.03/boe. The decrease in commodity prices affects the profitable reserves to be recovered from accumulations resulting in reduced reserves marginally. The negative revisions due to price are in general a result of earlier economic cut-off. For fields with a production-sharing type of agreement this is to some degree offset by higher entitlement to the reserves. These changes are all included in the revision category in the tables below, giving a net reduction of Statoil's proved reserves at year end.

From the Norwegian continental shelf (NCS), Statoil is responsible for managing, transporting and selling the Norwegian State's oil and gas on behalf of the Norwegian State's direct financial interest (SDFI). These reserves are sold in conjunction with the Statoil reserves. As part of this arrangement, Statoil delivers and sells gas to customers in accordance with various types of sales contracts on behalf of the SDFI. In order to fulfil the commitments, Statoil utilizes a field supply schedule which provides the highest possible total value for the joint portfolio of oil and gas between Statoil and the SDFI.

Statoil and the SDFI receive income from the joint natural gas sales portfolio based upon their respective share in the supplied volumes. For sales of the SDFI natural gas, to Statoil and to third parties, the payment to the Norwegian State is based on achieved prices, a net back formula calculated price or market value. All of the Norwegian State's oil and NGL is acquired by Statoil. The price Statoil pays to the SDFI for the crude oil is based on market reflective prices. The prices for NGL are either based on achieved prices, market value or market reflective prices.

The regulations of the owner's instruction, as described above, may be changed or withdrawn by the Statoil ASA's general meeting. Due to this uncertainty and the Norwegian State's estimate of proved reserves not being available to Statoil, it is not possible to determine the total quantities to be purchased by Statoil under the owner's instruction.

Topic 932 requires the presentation of reserves and certain other supplemental oil and gas disclosures by geographical area, defined as country or continent containing 15% or more of total proved reserves. Norway contains 76% of total proved reserves at 31 December 2016 and no other country contains reserves approaching 15% of total proved reserves. Accordingly, management has determined that the most meaningful presentation of geographical areas would be Norway and the continents of Eurasia (excluding Norway), Africa and Americas.

The following tables reflect the estimated proved reserves of oil and gas at 31 December 2013 through 2016, and the changes therein.

The reason for the most significant changes to our proved reserves at year end 2016 were:

- Positive revisions due to better performance of producing fields, maturing of improved recovery projects, and reduced uncertainty due to further drilling and production experience. This added a total of 409 million boe in 2016. A significant part of these positive revisions are related to large, producing fields offshore Norway where production is declining less than previously assumed for the proved reserves due to continuous improvement activities.
- Proved reserves from new discoveries have also been added through the sanctioning of new field development projects in 2016, Svale Nord Trestakk and Utgard in Norway and Julia in US. The new projects added a total of 66 million boe. New discoveries with proved reserves booked in 2016 are all expected to start production within a period of five years.
- Further drilling in the Bakken, Marcellus and Eagle Ford onshore plays in the US increased the proved reserves in 2016, and some of these additions are presented as extensions. Extension of proved area on existing field added a total of 112 million boe of new proved reserves in 2016. Together with proved reserves from new fields this adds a total of 179 million boe of proved reserves from Extensions and discoveries.
- The net effect of purchase and sale increased the reserves by 39 million boe in 2016.
- Production during 2016 reduced proved reserves by 673 million boe.

Changes to the proved reserves in 2016 are also described in some detail in section 2.8 Operating and financial performance by each geographical area. Development of the proved reserves are described in section 2.8 Operating and financial performance, Development of reserve*s.*

	Consolidated companies					Equity accounted				Total
	Norway	Eurasia excluding Norway	Africa	Americas	Subtotal	Norway	Eurasia excluding Norway	Americas	Subtotal	Total
Net proved oil and condensate reserves in million barrels oil equivalent										
At 31 December 2013	918	227	271	399	1,815	-	-	63	63	1,877
Revisions and improved recovery	143	10	85	(4)	235	-	-	(3)	(3)	232
Extensions and discoveries	3	-	5	145	153	-	-	-	-	153
Purchase of reserves-in-place	-	-	-	20	20	-	-	-	-	20
Sales of reserves-in-place	(5)	(27)	(2)	-	(34)	-	-	-	-	(34)
Production	(173)	(14)	(64)	(51)	(301)	-	-	(4)	(4)	(306)
At 31 December 2014	886	196	296	508	1,887	-	-	55	55	1,942
Revisions and improved recovery	71	(68)	57	(54)	5	-	-	(5)	(5)	0
Extensions and discoveries	437	-	-	74	511	-	-	-	-	511
Purchase of reserves-in-place	-	-	-	4	4	-	-	-	-	4
Sales of reserves-in-place	(4)	(38)	-	(1)	(43)	-	-	-	-	(43)
Production	(174)	(13)	(75)	(57)	(319)	-	-	(4)	(4)	(324)
At 31 December 2015	1,216	76	278	474	2,045	-	-	46	46	2,091
Revisions and improved recovery	111	6	16	17	149	-	-	(12)	(12)	137
Extensions and discoveries	29	-	-	49	78	-	-	-	-	78
Purchase of reserves-in-place	-	-	-	-	-	60	0	-	60	60
Sales of reserves-in-place	(14)	-	-	-	(14)	-	-	-	-	(14)
Production	(169)	(12)	(72)	(60)	(313)	(2)	(0)	(4)	(6)	(320)
At 31 December 2016	1,174	71	221	480	1,945	58	-	30	88	2,033

Proved reserves of bitumen in Americas, representing less than 2% of Statoil's proved reserves, is included as oil in the table above.

	Consolidated companies					Equity accounted				Total
	Norway	Eurasia excluding Norway	Africa	Americas	Subtotal	Norway	Eurasia excluding Norway	Americas	Subtotal	Total
Net proved NGL reserves in million barrels oil equivalent										
At 31 December 2013	368	-	16	56	441	-	-	-	-	441
Revisions and improved recovery	(2)	-	1	5	4	-	-	-	-	4
Extensions and discoveries	3	-	-	18	21	-	-	-	-	21
Purchase of reserves-in-place	-	-	-	-	-	-	-	-	-	-
Sales of reserves-in-place	(10)	-	-	(2)	(12)	-	-	-	-	(12)
Production	(42)	-	(2)	(7)	(51)	-	-	-	-	(51)
At 31 December 2014	318	-	15	69	403	-	-	-	-	403
Revisions and improved recovery	7	-	3	(20)	(10)	-	-	-	-	(10)
Extensions and discoveries	11	-	-	16	27	-	-	-	-	27
Purchase of reserves-in-place	-	-	-	4	4	-	-	-	-	4
Sales of reserves-in-place	(1)	-	-	(5)	(5)	-	-	-	-	(5)
Production	(44)	-	(3)	(7)	(54)	-	-	-	-	(54)
At 31 December 2015	291	-	15	57	364	-	-	-	-	364
Revisions and improved recovery	37	-	3	6	46	-	-	-	-	46
Extensions and discoveries	5	-	-	13	18	-	-	-	-	18
Purchase of reserves-in-place	-	-	-	-	-	2	-	-	2	2
Sales of reserves-in-place	(0)	-	-	-	(0)	-	-	-	-	(0)
Production	(46)	-	(2)	(9)	(58)	(0)	-	-	(0)	(58)
At 31 December 2016	287	-	16	67	370	2	-	-	2	372

	Consolidated companies					Equity accounted				Total
	Norway	Eurasia excluding Norway	Africa	Americas	Subtotal	Norway	Eurasia excluding Norway	Americas	Subtotal	Total
Net proved gas reserves in billion standard cubic feet										
At 31 December 2013	14,761	1,923	328	1,404	18,416	-	-	-	-	18,416
Revisions and improved recovery	439	32	8	197	676	-	-	-	-	676
Extensions and discoveries	79	-	-	364	443	-	-	-	-	443
Purchase of reserves-in-place	-	-	-	-	-	-	-	-	-	-
Sales of reserves-in-place	(355)	(681)	-	(15)	(1,051)	-	-	-	-	(1,051)
Production	(1,229)	(56)	(38)	(242)	(1,565)	-	-	-	-	(1,565)
At 31 December 2014	13,694	1,218	299	1,708	16,919	-	-	-	-	16,919
Revisions and improved recovery	385	(18)	129	(676)	(180)	-	-	-	-	(180)
Extensions and discoveries	179	-	-	318	497	-	-	-	-	497
Purchase of reserves-in-place	-	-	-	31	31	-	-	-	-	31
Sales of reserves-in-place	(10)	(991)	-	(42)	(1,043)	-	-	-	-	(1,043)
Production	(1,306)	(16)	(63)	(215)	(1,600)	-	-	-	-	(1,600)
At 31 December 2015	12,942	193	366	1,123	14,624	-	-	-	-	14,624
Revisions and improved recovery	1,160	29	(25)	102	1,265	-	-	-	-	1,265
Extensions and discoveries	78	-	-	384	462	-	-	-	-	462
Purchase of reserves-in-place	-	-	-	-	-	16	0	-	16	16
Sales of reserves-in-place	(5)	-	-	(65)	(70)	-	-	-	-	(70)
Production	(1,338)	(34)	(60)	(227)	(1,659)	(1)	(0)	-	(2)	(1,661)
At 31 December 2016	12,836	188	280	1,318	14,623	15	-	-	15	14,637

	Consolidated companies					Equity accounted				Total
	Norway	Eurasia excluding Norway	Africa	Americas	Subtotal	Norway	Eurasia excluding Norway	Americas	Subtotal	Total
Net proved reserves in million barrels oil equivalent										
At 31 December 2013	3,916	569	346	705	5,537	-	-	63	63	5,600
Revisions and improved recovery	219	16	87	36	359	-	-	(3)	(3)	356
Extensions and discoveries	20	-	5	227	253	-	-	-	-	253
Purchase of reserves-in-place	-	-	-	20	20	-	-	-	-	20
Sales of reserves-in-place	(78)	(148)	(2)	(5)	(233)	-	-	-	-	(233)
Production	(434)	(24)	(72)	(102)	(631)	-	-	(4)	(4)	(635)
At 31 December 2014	3,644	413	364	882	5,304	-	-	55	55	5,359
Revisions and improved recovery	146	(72)	83	(194)	(37)	-	-	(5)	(5)	(42)
Extensions and discoveries	480	-	-	146	627	-	-	-	-	627
Purchase of reserves-in-place	-	-	-	13	13	-	-	-	-	13
Sales of reserves-in-place	(6)	(215)	-	(13)	(235)	-	-	-	-	(235)
Production	(450)	(16)	(88)	(103)	(658)	-	-	(4)	(4)	(662)
At 31 December 2015	3,814	111	358	731	5,014	-	-	46	46	5,060
Revisions and improved recovery	355	11	14	41	421	-	-	(12)	(12)	409
Extensions and discoveries	48	-	-	130	179	-	-	-	-	179
Purchase of reserves-in-place	-	-	-	-	-	65	0	-	65	65
Sales of reserves-in-place	(15)	-	-	(11)	(27)	-	-	-	-	(27)
Production	(454)	(18)	(85)	(110)	(666)	(3)	(0)	(4)	(7)	(673)
At 31 December 2016	3,748	104	287	782	4,921	62	-	30	92	5,013

Proved reserves of bitumen in Americas, representing less than 2% of Statoil's proved reserves, is included as oil in the table above.

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	Consolidated companies					Equity accounted				Total
	Norway	Eurasia excluding Norway	Africa	Americas	Subtotal	Norway	Eurasia excluding Norway	Americas	Subtotal	Total
Net proved oil and condensate reserves in million barrels oil equivalent										
At 31 December 2013										
Developed	548	63	197	212	1,020	-	-	32	32	1,052
Undeveloped	370	164	74	187	795	-	-	30	30	826
At 31 December 2014										
Developed	559	63	243	267	1,133	-	-	24	24	1,156
Undeveloped	327	133	52	242	754	-	-	32	32	786
At 31 December 2015										
Developed	505	48	248	282	1,083	-	-	21	21	1,104
Undeveloped	711	29	30	192	962	-	-	25	25	987
At 31 December 2016										
Developed	536	43	200	303	1,082	7	-	16	23	1,105
Undeveloped	638	28	22	176	863	51	-	13	65	928
Net proved NGL reserves in million barrels oil equivalent										
At 31 December 2013										
Developed	287	-	10	34	330	-	-	-	-	330
Undeveloped	82	-	7	22	111	-	-	-	-	111
At 31 December 2014										
Developed	258	-	9	42	310	-	-	-	-	310
Undeveloped	60	-	6	27	93	-	-	-	-	93
At 31 December 2015										
Developed	235	-	9	45	290	-	-	-	-	290
Undeveloped	56	-	6	12	74	-	-	-	-	74
At 31 December 2016										
Developed	213	-	10	53	276	1	-	-	1	277
Undeveloped	74	-	6	14	94	1	-	-	1	95
Net proved gas reserves in billion standard cubic feet										
At 31 December 2013										
Developed	11,580	467	209	817	13,073	-	-	-	-	13,073
Undeveloped	3,181	1,455	120	586	5,343	-	-	-	-	5,343
At 31 December 2014										
Developed	11,227	312	191	946	12,677	-	-	-	-	12,677
Undeveloped	2,467	906	108	762	4,242	-	-	-	-	4,242
At 31 December 2015										
Developed	10,664	32	206	999	11,901	-	-	-	-	11,901
Undeveloped	2,278	161	160	124	2,723	-	-	-	-	2,723
At 31 December 2016										
Developed	9,219	188	171	1,002	10,580	4	-	-	4	10,584
Undeveloped	3,617	-	110	316	4,043	11	-	-	11	4,054
Net proved oil, condensate, NGL and gas reserves in million barrels oil equivalent										
At 31 December 2013										
Developed	2,898	146	244	392	3,679	-	-	32	32	3,711
Undeveloped	1,018	423	103	314	1,858	-	-	30	30	1,888
At 31 December 2014										
Developed	2,818	119	287	477	3,701	-	-	24	24	3,725
Undeveloped	826	295	78	405	1,603	-	-	32	32	1,635
At 31 December 2015										
Developed	2,641	53	294	505	3,494	-	-	21	21	3,515
Undeveloped	1,173	57	64	226	1,521	-	-	25	25	1,546
At 31 December 2016										
Developed	2,392	76	240	535	3,244	8	-	16	24	3,268
Undeveloped	1,357	28	47	246	1,678	54	-	13	68	1,746

The conversion rates used are 1 standard cubic meter = 35.3 standard cubic feet, 1 standard cubic meter oil equivalent = 6.29 barrels of oil equivalent (boe) and 1,000 standard cubic meter gas = 1 standard cubic meter oil equivalent.

Capitalised cost related to oil and gas producing activities

Consolidated companies

(in USD million)	2016	2015	At 31 December 2014
Unproved properties	13,563	13,341	13,121
Proved properties, wells, plants and other equipment	159,284	150,653	158,586
Total capitalised cost	172,847	163,994	171,707
Accumulated depreciation, impairment and amortisation	(109,160)	(99,118)	(92,451)
Net capitalised cost	63,687	64,876	79,256

Net capitalised cost related to equity accounted investments as of 31 December 2016 was USD 2,000 million, USD 1,000 million in 2015 and USD 1,147 million in 2014. The increase is mainly related to the investment in Lundin Petroleum AB as described in note 12. The reported figures are based on capitalised costs within the upstream segments in Statoil, in line with the description below for result of operations for oil and gas producing activities.

Expenditures incurred in oil and gas property acquisition, exploration and development activities

These expenditures include both amounts capitalised and expensed.

Consolidated companies

(in USD million)	Norway	Eurasia excluding Norway	Africa	Americas	Total
Full year 2016					
Exploration expenditures	495	155	197	590	1,437
Development costs	5,245	661	780	2,118	8,804
Acquired proved properties	6	0	0	3	9
Acquired unproved properties	57	58	0	2,362	2,477
Total	5,803	874	977	5,073	12,727
Full year 2015					
Exploration expenditures	796	213	381	1,469	2,859
Development costs	5,863	1,420	1,315	3,600	12,198
Acquired proved properties	0	0	0	79	79
Acquired unproved properties	6	77	88	375	546
Total	6,665	1,710	1,784	5,523	15,682
Full year 2014					
Exploration expenditures	1,117	291	1,244	1,075	3,727
Development costs	8,354	2,140	2,107	3,389	15,990
Acquired proved properties	0	0	0	778	778
Acquired unproved properties	0	3	(3)	355	355
Total	9,471	2,434	3,348	5,596	20,849

Expenditures incurred in development activities related to equity accounted investments was USD 1,370 million in 2016, USD 46 million in 2015 and USD 255 million in 2014. The increase is mainly related to the investment in Lundin Petroleum AB, USD 1,199 million, as described in note 12.

Results of operation for oil and gas producing activities
As required by Topic 932, the revenues and expenses included in the following table reflect only those relating to the oil and gas producing operations of Statoil.

The result of operations for oil and gas producing activities contains the two upstream reporting segments Development and Production Norway (DPN) and Development and Production International (DPI) as presented in note 3 *Segments*. Production cost is based on operating expenses related to production of oil and gas. From the operating expenses certain expenses such as; transportation costs, accruals for over/underlift position, royalty payments and diluent costs are excluded. These expenses and mainly upstream business administration are included as other expenses in the tables below. Other revenues mainly consist of gains and losses from sales of oil and gas interests and gains and losses from commodity based derivatives within the upstream segments.

Income tax expense is calculated on the basis of statutory tax rates adjusted for uplift and tax credits. No deductions are made for interest or other elements not included in the table below.

Consolidated companies

(in USD million)	Norway	Eurasia excluding Norway	Africa	Americas	Total
Full year 2016					
Sales	57	161	305	226	749
Transfers	12,962	494	2,803	2,466	18,725
Other revenues	136	30	6	266	438
Total revenues	13,155	685	3,114	2,958	19,912
Exploration expenses	(383)	(274)	(284)	(2,011)	(2,952)
Production costs	(2,129)	(148)	(629)	(663)	(3,569)
Depreciation, amortisation and net impairment losses	(5,698)	(130)	(2,181)	(3,199)	(11,208)
Other expenses	(417)	(81)	(89)	(1,321)	(1,908)
Total costs	(8,627)	(633)	(3,183)	(7,194)	(19,637)
Results of operations before tax	4,528	52	(69)	(4,236)	275
Tax expense	(2,760)	272	(123)	(25)	(2,636)
Results of operations	1,768	324	(192)	(4,261)	(2,361)
Net income from equity accounted investments	(78)	(86)	0	(14)	(178)

Consolidated companies

(in USD million)	Norway	Eurasia excluding Norway	Africa	Americas	Total
Full year 2015					
Sales	50	257	(41)	198	464
Transfers	17,429	480	3,454	2,764	24,127
Other revenues	(143)	1,169	3	7	1,036
Total revenues	17,336	1,906	3,416	2,969	25,627
Exploration expenses	(576)	(190)	(630)	(2,476)	(3,872)
Production costs	(2,629)	(160)	(671)	(794)	(4,254)
Depreciation, amortisation and net impairment losses	(6,379)	(799)	(2,487)	(6,946)	(16,611)
Other expenses	(594)	(165)	(237)	(1,374)	(2,370)
Total costs	(10,178)	(1,314)	(4,025)	(11,590)	(27,107)
Results of operations before tax	7,157	593	(609)	(8,622)	(1,481)
Tax expense	(4,824)	238	(717)	(21)	(5,324)
Results of operations	2,333	831	(1,326)	(8,643)	(6,805)
Net income from equity accounted investments	3	32	0	(123)	(88)

Consolidated companies

(in USD million)	Norway	Eurasia excluding Norway	Africa	Americas	Total
Full year 2014					
Sales	286	688	818	615	2,407
Transfers	27,478	978	5,214	4,564	38,234
Other revenues	1,151	932	117	(152)	2,048
Total revenues	28,915	2,598	6,149	5,027	42,689
Exploration expenses	(838)	(397)	(1,349)	(2,078)	(4,662)
Production costs	(3,555)	(225)	(719)	(856)	(5,355)
Depreciation, amortisation and net impairment losses	(6,301)	(744)	(2,221)	(5,921)	(15,187)
Other expenses	(479)	(170)	33	(1,718)	(2,334)
Total costs	(11,173)	(1,536)	(4,256)	(10,573)	(27,538)
Results of operations before tax	17,742	1,062	1,893	(5,546)	15,151
Tax expense	(11,512)	(70)	(1,278)	(64)	(12,924)
Results of operations	6,230	992	615	(5,610)	2,227
Net income from equity accounted investments	11	132	0	(246)	(103)

Average production cost in USD per boe based on entitlement volumes (consolidated)	Norway	Eurasia excluding Norway	Africa	Americas	Total
2016	5	8	7	6	5
2015	6	10	8	8	6
2014	8	10	10	8	8

Production cost per boe is calculated as the production costs in the result of operations table, divided by the produced entitlement volumes (mboe) for the corresponding period.

Standardised measure of discounted future net cash flows relating to proved oil and gas reserves

The table below shows the standardised measure of future net cash flows relating to proved reserves. The analysis is computed in accordance with Topic 932, by applying average market prices as defined by the SEC, year end costs, year end statutory tax rates and a discount factor of 10% to year end quantities of net proved reserves. The standardised measure of discounted future net cash flows is a forward-looking statement.

Future price changes are limited to those provided by existing contractual arrangements at the end of each reporting year. Future development and production costs are those estimated future expenditures necessary to develop and produce year-end estimated proved reserves based on year-end cost indices, assuming continuation of year-end economic conditions. Pre-tax future net cash flow is net of decommissioning and removal costs. Estimated future income taxes are calculated by applying the appropriate year-end statutory tax rates. These rates reflect allowable deductions and tax credits and are applied to estimated future pretax net cash flows, less the tax basis of related assets. Discounted future net cash flows are calculated using a discount rate of 10% per year. Discounting requires a year-by-year estimate of when future expenditures will be incurred and when reserves will be produced. The standardised measure of discounted future net cash flows prescribed under Topic 932 requires assumptions as to the timing and amount of future development and production costs and income from the production of proved reserves. The information does not represent management's estimate or Statoil's expected future cash flows or the value of its proved reserves and therefore should not be relied upon as an indication of Statoil's future cash flow or value of its proved reserves.

(in USD million)	Norway	Eurasia excluding Norway	Africa	Americas	Total
At 31 December 2016					
Consolidated companies					
Future net cash inflows	120,355	4,032	10,644	20,034	155,065
Future development costs	(14,572)	(927)	(733)	(3,559)	(19,791)
Future production costs	(45,357)	(2,101)	(4,909)	(11,701)	(64,069)
Future income tax expenses	(36,268)	(127)	(1,492)	(1,355)	(39,243)
Future net cash flows	24,158	876	3,510	3,418	31,962
10% annual discount for estimated timing of cash flows	(8,729)	(241)	(646)	(1,255)	(10,870)
Standardised measure of discounted future net cash flows	15,429	635	2,864	2,164	21,092
Equity accounted investments					
Standardised measure of discounted future net cash flows	279	-	-	127	406
Total standardised measure of discounted future net cash flows including equity accounted investments	15,708	635	2,864	2,290	21,498

(in USD million)	Norway	Eurasia excluding Norway	Africa	Americas	Total
At 31 December 2015					
Consolidated companies					
Future net cash inflows	160,277	5,455	17,073	23,595	206,399
Future development costs	(19,409)	(1,345)	(1,330)	(5,157)	(27,242)
Future production costs	(54,911)	(2,765)	(6,832)	(12,762)	(77,271)
Future income tax expenses	(56,680)	(118)	(3,149)	(800)	(60,747)
Future net cash flows	29,276	1,226	5,762	4,875	41,139
10% annual discount for estimated timing of cash flows	(12,011)	(406)	(1,386)	(1,969)	(15,773)
Standardised measure of discounted future net cash flows	17,264	820	4,375	2,906	25,366
Equity accounted investments					
Standardised measure of discounted future net cash flows	-	-	-	140	140
Total standardised measure of discounted future net cash flows including equity accounted investments	17,264	820	4,375	3,047	25,506

(in USD million)	Norway	Eurasia excluding Norway	Africa	Americas	Total
At 31 December 2014					
Consolidated companies					
Future net cash inflows	234,404	32,474	34,114	51,585	352,577
Future development costs	(26,643)	(9,571)	(1,961)	(8,262)	(46,437)
Future production costs	(70,229)	(14,622)	(9,310)	(22,785)	(116,946)
Future income tax expenses	(96,896)	(1,287)	(7,764)	(5,432)	(111,378)
Future net cash flows	40,636	6,995	15,079	15,107	77,816
10% annual discount for estimated timing of cash flows	(15,925)	(4,438)	(4,494)	(6,688)	(31,546)
Standardised measure of discounted future net cash flows	24,711	2,556	10,584	8,419	46,270
Equity accounted investments					
Standardised measure of discounted future net cash flows	-	-	-	806	806
Total standardised measure of discounted future net cash flows including equity accounted investments	24,711	2,556	10,584	9,225	47,076

Changes in the standardised measure of discounted future net cash flows from proved reserves

(in USD million)	2016	2015	2014
Consolidated companies			
Standardised measure at beginning of year	25,366	46,270	47,448
Net change in sales and transfer prices and in production (lifting) costs related to future production	(21,148)	(71,817)	(20,157)
Changes in estimated future development costs	(16)	6,739	(3,838)
Sales and transfers of oil and gas produced during the period, net of production cost	(16,824)	(20,803)	(36,904)
Net change due to extensions, discoveries, and improved recovery	1,099	3,745	3,685
Net change due to purchases and sales of minerals in place	(566)	(1,026)	(4,181)
Net change due to revisions in quantity estimates	8,163	7,491	19,340
Previously estimated development costs incurred during the period	7,998	10,474	15,811
Accretion of discount	5,949	11,335	12,691
Net change in income taxes	11,070	32,958	12,374
Total change in the standardised measure during the year	(4,274)	(20,904)	(1,178)
Standardised measure at end of year	21,092	25,366	46,270
Equity accounted investments			
Standardised measure at end of year	406	140	806
Standardised measure at end of year including equity accounted investments	21,498	25,506	47,076

In the table above, each line item presents the sources of changes in the standardised measure value on a discounted basis, with the accretion of discount line item reflecting the increase in the net discounted value of the proved oil and gas reserves due to the fact that the future cash flows are now one year closer in time.

The standardized measure at the beginning of the year represents the discounted net present value after deductions of both future development costs, production costs and taxes. The 'Net change in sales and transfer prices and in production (lifting) costs related to future production' is, on the other hand, related to the future net cash flows at 31 December 2015. The proved reserves at 31 December 2015 were multiplied by the actual change in price, and change in unit of production costs, to arrive at the net effect of changes in price and production costs. Development costs and taxes are reflected in the line items 'Change in estimated future development costs' and 'Net change in income taxes' and are not included in the 'Net change in sales and transfer prices and in production (lifting) costs related to future production'.

28 Subsequent events

See note 17 Equity and dividend for proposed dividend for the fourth quarter 2016.

29 Condensed consolidated financial information related to guaranteed debt securities

Statoil Petroleum AS, a 100% owned subsidiary of Statoil ASA, is the co-obligor of certain existing debt securities of Statoil ASA that are registered under the US Securities Act of 1933 ("US registered debt securities"). As co-obligor, Statoil Petroleum AS fully, unconditionally and irrevocably assumes and agrees to perform, jointly and severally with Statoil ASA, the payment and covenant obligations for these US registered debt securities. In addition, Statoil ASA is also the co-obligor of a US registered debt security of Statoil Petroleum AS. As co-obligor, Statoil ASA fully, unconditionally and irrevocably assumes and agrees to perform, jointly and severally with Statoil Petroleum AS, the payment and covenant obligations of that security. In the future, Statoil ASA may from time to time issue future US registered debt securities for which Statoil Petroleum AS will be the co-obligor or guarantor.

The following financial information on a condensed consolidated basis provides financial information about Statoil ASA, as issuer and co-obligor, Statoil Petroleum AS, as co-obligor and guarantor, and all other subsidiaries as required by SEC Rule 3-10 of Regulation S-X. The condensed consolidated information is prepared in accordance with Statoil's IFRS accounting policies as described in note 2 *Significant accounting policies*, except that investments in subsidiaries and jointly controlled entities are accounted for using the equity method as required by Rule 3-10.

The following is condensed consolidated financial information for the full year 2016, 2015 and 2014, and as of 31 December 2016 and 2015.

CONDENSED CONSOLIDATED STATEMENT OF INCOME AND OTHER COMPREHENSIVE INCOME

Full year 2016 (in USD million)	Statoil ASA	Statoil Petroleum AS	Non-guarantor subsidiaries	Consolidation adjustments	The Statoil group
Revenues and other income	31,580	15,405	15,472	(16,464)	45,993
Net income from equity accounted companies	(2,726)	(3,987)	26	6,567	(119)
Total revenues and other income	28,854	11,418	15,498	(9,898)	45,873
Total operating expenses	(31,784)	(10,989)	(19,364)	16,344	(45,793)
Net operating income	(2,930)	429	(3,865)	6,446	80
Net financial items	728	(560)	(115)	(311)	(258)
Income before tax	(2,202)	(131)	(3,980)	6,135	(178)
Income tax	(407)	(2,392)	97	(23)	(2,724)
Net income	(2,608)	(2,523)	(3,884)	6,113	(2,902)
Other comprehensive income	(671)	153	(280)	441	(357)
Total comprehensive income	(3,279)	(2,370)	(4,163)	6,553	(3,259)

CONDENSED CONSOLIDATED STATEMENT OF INCOME AND OTHER COMPREHENSIVE INCOME

Full year 2015 (in USD million)	Statoil ASA	Statoil Petroleum AS	Non-guarantor subsidiaries	Consolidation adjustments	The Statoil group
Revenues and other income	39,289	20,583	20,248	(20,448)	59,671
Net income from equity accounted companies	(4,686)	(8,350)	(42)	13,050	(29)
Total revenues and other income	34,603	12,232	20,205	(7,399)	59,642
Total operating expenses	(39,372)	(12,561)	(26,907)	20,566	(58,276)
Net operating income	(4,769)	(329)	(6,702)	13,167	1,366
Net financial items	(2,771)	(106)	139	1,427	(1,311)
Income before tax	(7,541)	(435)	(6,563)	14,594	55
Income tax	925	(5,301)	(840)	(9)	(5,225)
Net income	(6,616)	(5,736)	(7,402)	14,585	(5,169)
Other comprehensive income	(1,414)	(1,771)	(1,405)	1,751	(2,838)
Total comprehensive income	(8,030)	(7,507)	(8,807)	16,336	(8,007)

CONDENSED CONSOLIDATED STATEMENT OF INCOME AND OTHER COMPREHENSIVE INCOME

Full year 2014 (in USD million)	Statoil ASA	Statoil Petroleum AS	Non-guarantor subsidiaries	Consolidation adjustments	The Statoil group
Revenues and other income	65,647	33,454	34,189	(33,991)	99,299
Net income from equity accounted companies	3,812	(4,794)	(41)	989	(34)
Total revenues and other income	69,458	28,660	34,148	(33,002)	99,264
Total operating expenses	(66,668)	(14,120)	(35,114)	34,516	(81,386)
Net operating income	2,791	14,540	(966)	1,514	17,878
Net financial items	(1,841)	(28)	(51)	1,940	20
Income before tax	950	14,512	(1,017)	3,453	17,898
Income tax	981	(13,007)	(1,802)	(184)	(14,011)
Net income	1,931	1,505	(2,819)	3,269	3,887
Other comprehensive income	(2,648)	(2,384)	(1,385)	1,829	(4,587)
Total comprehensive income	(717)	(879)	(4,204)	5,099	(701)

CONDENSED CONSOLIDATED BALANCE SHEET

At 31 December 2016 (in USD million)	Statoil ASA	Statoil Petroleum AS	Non-guarantor subsidiaries	Consolidation adjustments	The Statoil group
ASSETS					
Property, plant, equipment and intangible assets	576	29,944	38,310	(31)	68,799
Equity accounted companies	40,294	18,089	1,013	(57,151)	2,245
Other non-current assets	3,212	945	3,933	0	8,090
Non-current receivables from subsidiaries	23,644	(0)	26	(23,670)	0
Total non-current assets	67,725	48,979	43,281	(80,852)	79,133
Current receivables from subsidiaries	4,305	2,141	12,879	(19,325)	0
Other current assets	14,716	924	4,769	(639)	19,769
Cash and cash equivalents	4,274	46	770	0	5,090
Total current assets	23,295	3,111	18,418	(19,964)	24,859
Assets classified as held for sale	0	0	537	0	537
Total assets	91,021	52,089	62,236	(100,816)	104,530
EQUITY AND LIABILITIES					
Total equity	35,072	17,974	39,510	(57,457)	35,099
Non-current liabilities to subsidiaries	17	12,848	10,806	(23,670)	0
Other non-current liabilities	33,065	13,812	5,953	(198)	52,633
Total non-current liabilities	33,082	26,660	16,759	(23,868)	52,633
Other current liabilities	7,757	4,419	4,735	(166)	16,744
Current liabilities to subsidiaries	15,109	3,037	1,179	(19,325)	0
Total current liabilities	22,866	7,456	5,913	(19,492)	16,744
Liabilities directly associated with the assets classified as held for sale	0	0	54	0	54
Total liabilities	55,948	34,116	22,727	(43,359)	69,431
Total equity and liabilities	91,021	52,089	62,236	(100,816)	104,530

CONDENSED CONSOLIDATED BALANCE SHEET

At 31 December 2015 (in USD million)	Statoil ASA	Statoil Petroleum AS	Non-guarantor subsidiaries	Consolidation adjustments	The Statoil group
ASSETS					
Property, plant, equipment and intangible assets	636	29,653	41,205	(36)	71,458
Equity accounted companies	53,643	20,547	434	(73,800)	824
Other non-current assets	4,357	1,014	3,937	(3)	9,305
Non-current receivables from subsidiaries	13,976	(0)	24	(13,999)	0
Total non-current assets	72,612	51,214	45,600	(87,839)	81,588
Current receivables from subsidiaries	1,239	2,319	13,631	(17,189)	(0)
Other current assets	14,847	1,006	4,118	(440)	19,532
Cash and cash equivalents	7,471	87	1,066	0	8,623
Total current assets	23,557	3,412	18,815	(17,629)	28,154
Total assets	96,169	54,626	64,415	(105,468)	109,742
EQUITY AND LIABILITIES					
Total equity	40,271	20,895	52,607	(73,466)	40,307
Non-current liabilities to subsidiaries	15	13,726	259	(13,999)	0
Other non-current liabilities	34,415	14,363	5,432	(138)	54,073
Total non-current liabilities	34,430	28,089	5,691	(14,137)	54,073
Other current liabilities	5,954	4,377	5,707	(675)	15,363
Current liabilities to subsidiaries	15,514	1,265	410	(17,189)	0
Total current liabilities	21,468	5,643	6,117	(17,865)	15,363
Total liabilities	55,899	33,731	11,808	(32,002)	69,436
Total equity and liabilities	96,169	54,626	64,415	(105,468)	109,743

CONDENSED CONSOLIDATED CASH FLOW STATEMENT

Full year 2016 (in USD million)	Statoil ASA	Statoil Petroleum AS	Non-guarantor subsidiaries	Consolidation adjustments	The Statoil group
Cash flows provided by (used in) operating activities	3,330	7,262	1,561	(3,119)	9,034
Cash flows provided by (used in) investing activities	(3,138)	(6,785)	(5,393)	4,869	(10,447)
Cash flows provided by (used in) financing activities	(3,308)	(516)	3,616	(1,750)	(1,958)
Net increase (decrease) in cash and cash equivalents	(3,116)	(39)	(216)	0	(3,371)
Effect of exchange rate changes on cash and cash equivalents	(81)	(2)	(69)	0	(152)
Cash and cash equivalents at the beginning of the period (net of overdraft)	7,471	87	1,056	0	8,614
Cash and cash equivalents at the end of the period (net of overdraft)	4,274	46	770	0	5,090

Full year 2015 (in USD million)	Statoil ASA	Statoil Petroleum AS	Non-guarantor subsidiaries	Consolidation adjustments	The Statoil group
Cash flows provided by (used in) operating activities	2,883	8,348	4,567	(2,170)	13,628
Cash flows provided by (used in) investing activities	(5,694)	(17,219)	(5,630)	14,042	(14,501)
Cash flows provided by (used in) financing activities	1,333	8,986	824	(11,872)	(729)
Net increase (decrease) in cash and cash equivalents	(1,478)	115	(239)	0	(1,602)
Effect of exchange rate changes on cash and cash equivalents	(677)	(106)	(88)	0	(871)
Cash and cash equivalents at the beginning of the period (net of overdraft)	9,625	78	1,382	0	11,085
Cash and cash equivalents at the end of the period (net of overdraft)	7,470	87	1,055	0	8,612

Full year 2014 (in USD million)	Statoil ASA	Statoil Petroleum AS	Non-guarantor subsidiaries	Consolidation adjustments	The Statoil group
Cash flows provided by (used in) operating activities	2,666	11,966	8,927	(3,354)	20,205
Cash flows provided by (used in) investing activities	(2,528)	(9,872)	(8,500)	3,125	(17,775)
Cash flows provided by (used in) financing activities	(1,852)	(2,015)	(390)	229	(4,028)
Net increase (decrease) in cash and cash equivalents	(1,714)	79	37	0	(1,598)
Effect of exchange rate changes on cash and cash equivalents	(1,309)	(1)	(19)	0	(1,329)
Cash and cash equivalents at the beginning of the period (net of overdraft)	12,648	(2)	1,367	0	14,013
Cash and cash equivalents at the end of the period (net of overdraft)	9,625	76	1,385	0	11,086

The reports set out below are provided in accordance with standards of the Public Company Accounting Oversight Board (United States). KPMG AS has also issued a report in accordance with law, regulations, and auditing standards and practices generally accepted in Norway, including International Standards on Auditing (ISAs), which includes opinions on the consolidated financial statements and the parent company financial statements of Statoil ASA, and on other required matters. That report is set out on pages 226 to 230.

Report of Independent Registered Public Accounting Firm

To the board of directors and shareholders of Statoil ASA

We have audited the accompanying Consolidated balance sheets of Statoil ASA and subsidiaries as of 31 December 2016 and 2015, and the related Consolidated statements of income, comprehensive income, changes in equity, and cash flows for each of the years in the three-year period ended 31 December 2016. These Consolidated financial statements are the responsibility of the Statoil ASA's management. Our responsibility is to express an opinion on these Consolidated financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the Consolidated financial statements referred to above present fairly, in all material respects, the financial position of Statoil ASA and subsidiaries as of 31 December 2016 and 2015, and the results of their operations and their cash flows for each of the years in the three-year period ended 31 December 2016, in conformity with International Financial Reporting Standards as issued by the International Accounting Standards Board and International Financial Reporting Standards as adopted by the European Union.

As discussed in Note 26 to the Consolidated financial statements, Statoil ASA has elected to change its presentation currency from Norwegian Kroner to US Dollar. In addition to the information included in Note 26, Statoil ASA has also included a US Dollar Consolidated balance sheet as of 31 December 2014.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), Statoil ASA's internal control over financial reporting as of 31 December 2016, based on criteria established in Internal Control - Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO), and our report dated 9 March 2017 expressed an unqualified opinion on the effectiveness of the Statoil ASA's internal control over financial reporting.

/s/ KPMG AS

Oslo, Norway
9 March 2017

Report of KPMG on Statoil's internal control over financial reporting

Report of Independent Registered Public Accounting Firm

To the board of directors and shareholders of Statoil ASA

We have audited Statoil ASA's internal control over financial reporting as of 31 December 2016, based on criteria established in *Internal Control – Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Statoil ASA's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying *The management's report on internal control over financial reporting*. Our responsibility is to express an opinion on Statoil ASA's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audit also included performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, Statoil ASA maintained, in all material respects, effective internal control over financial reporting as of 31 December 2016, based on criteria established in Internal Control – Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Consolidated balance sheets of Statoil ASA and subsidiaries as of 31 December 2016 and 2015, and the related Consolidated statements of income, comprehensive income, changes in equity, and cash flows for each of the years in the three-year period ended 31 December 2016, and our report dated 9 March 2017 expressed an unqualified opinion on those Consolidated financial statements.

/s/ KPMG AS

Oslo, Norway
9 March 2017

4.2 Parent company financial statements

With effect from 1 January 2016 Statoil ASA changed the accounting principles from NGAAP to simplified IFRS and changed the presentation currency from Norwegian Kroner (NOK) to US dollars (USD). Comparative data has been converted from NGAAP to simplified IFRS and from NOK to USD accordingly. For more information concerning this, see note 24 Transition to Simplified IFRS and USD presentation currency.

STATEMENT OF INCOME STATOIL ASA

		Full year	
(in USD million)	Note	2016	2015
Revenues	3	31,554	39,059
Net income from subsidiaries and other equity accounted companies	10	(2,726)	(4,686)
Other income	10	26	229
Total revenues and other income		28,854	34,603
Purchases [net of inventory variation]		(29,463)	(36,457)
Operating expenses		(1,913)	(2,462)
Selling, general and administrative expenses		(216)	(244)
Depreciation, amortisation and net impairment losses	9	(97)	(103)
Exploration expenses		(95)	(107)
Net operating income		(2,930)	(4,769)
Net financial items	7	728	(2,771)
Income before tax		(2,202)	(7,541)
Income tax	8	(407)	925
Net income		(2,608)	(6,616)

STATEMENT OF COMPREHENSIVE INCOME

(in USD million)	Note	Full year 2016	2015
Net income		(2,608)	(6,616)
Actuarial gains (losses) on defined benefit pension plans	17	(503)	1,599
Income tax effect on income and expense recognised in OCI		129	(461)
Items that will not be reclassified to the Statement of income		(374)	1,138
Currency translation adjustments		(304)	(2,498)
Items that may be subsequently reclassified to the Statement of income		(304)	(2,498)
Other comprehensive income		(677)	(1,360)
Total comprehensive income		(3,286)	(7,975)
Attributable to the equity holders of the company		(3,286)	(7,975)
Attributable to non-controlling interests		0	0

BALANCE SHEET STATOIL ASA

(in USD million)	Note	At 31 December 2016	2015
ASSETS			
Property, plant and equipment	9	571	631
Intangible assets		5	5
Investments in subsidiaries and other equity accounted companies	10	39,886	51,330
Deferred tax assets	8	846	1,183
Pension assets	17	787	1,241
Derivative financial instruments	2	994	1,775
Prepayments and financial receivables		585	64
Receivables from subsidiaries and other equity accounted companies	11	23,644	13,976
Total non-current assets		67,318	70,206
Inventories	12	2,150	1,394
Trade and other receivables	13	4,760	3,828
Receivables from subsidiaries and other equity accounted companies	11	4,305	3,161
Derivative financial instruments	2	413	487
Financial investments	11	7,393	9,139
Cash and cash equivalents	14	4,274	7,471
Total current assets		23,295	25,479
Total assets		90,613	95,684

BALANCE SHEET STATOIL ASA

(in USD million)	Note	At 31 December 2016	2015
EQUITY AND LIABILITIES			
Share capital		1,156	1,139
Additional paid-in capital		3,363	2,476
Reserves for valuation variances		631	4,612
Reserves for unrealised gains		779	1,113
Retained earnings		28,130	29,937
Total equity	15	34,059	39,277
Finance debt	16	27,883	29,764
Liabilities to subsidiaries and other equity accounted companies		17	15
Pension liabilities	17	3,366	2,965
Provisions	18	289	294
Derivative financial instruments	2	1,420	1,285
Total non-current liabilities		32,974	34,323
Trade, other payables and provisions	19	2,893	2,713
Current tax payable	8	(0)	(22)
Finance debt	16	3,661	2,243
Dividends payable	16	1,426	1,400
Liabilities to subsidiaries and other equity accounted companies	11	15,109	15,524
Derivative financial instruments	2	491	228
Total current liabilities		23,580	22,085
Total liabilities		56,554	56,407
Total equity and liabilities		90,613	95,684

STATEMENT OF CASH FLOWS STATOIL ASA

(in USD million)	Note	Full year 2016	2015
Income before tax		(2,202)	(7,541)
Depreciation, amortisation and net impairment losses	9	97	103
(Gains) losses on foreign currency transactions and balances		(471)	1,778
(Gains) losses on sales of assets and businesses		(1)	(1)
(Increase) decrease in other items related to operating activities		5,932	8,314
(Increase) decrease in net derivative financial instruments	2	417	836
Interest received		865	443
Interest paid		(964)	(868)
Taxes paid		5	(1)
(Increase) decrease in working capital		(976)	(180)
Cash flows provided by operating activities		2,703	2,883
Capital expenditures and investments	9	(1,513)	(2,018)
(Increase) decrease in financial investments		987	(2,912)
(Increase) decrease in other non-current items		(11,785)	(6,156)
Proceeds from sale of assets and businesses and capital contribution received		9,800	5,393
Cash flows used in investing activities		(2,511)	(5,694)
New finance debt		1,322	4,262
Repayment of finance debt		(1,065)	(1,442)
Dividend paid	15	(1,876)	(2,836)
Net current finance debt and other		(268)	(624)
Increase (decrease) in financial receivables and payables to/from subsidiaries		(1,422)	1,973
Cash flows provided by (used in) financing activities		(3,308)	1,333
Net increase (decrease) in cash and cash equivalents		(3,116)	(1,478)
Effect of exchange rate changes on cash and cash equivalents		(81)	(677)
Cash and cash equivalents at the beginning of the period	14	7,471	9,625
Cash and cash equivalents at the end of the period	14	4,274	7,471

Notes to the Financial statements Statoil ASA

1 Significant accounting policies and basis of presentation

Statoil ASA is the parent company of the Statoil Group (Statoil), consisting of Statoil ASA and its subsidiaries. Statoil ASA's main activities includes shareholding in group companies, group management, corporate functions and group financing. Statoil ASA also carries out activities related to external sales of oil and gas products, purchased externally or from group companies, including related refinery and transportation activities. Reference is made to disclosure note 1 Organisation and basis of presentation in Statoil's Consolidated financial statements.

The financial statements of Statoil ASA ("the company") are prepared in accordance with simplified IFRS pursuant to the Norwegian Accounting Act §3-9 and regulations regarding simplified application of IFRS issued by the Norwegian Ministry of Finance on 3 November 2014. The use of simplified IFRS represents a change from previous years' financial statements, in which Statoil ASA used Norwegian Generally Accepted Accounting Principles (NGAAP). At the same time Statoil has changed the presentation currency for the parent company's accounts from Norwegian kroner (NOK) to United States dollars (USD). The basis for the changes in accounting framework and presentation currency is to seek consistency with the group financial statements and with the company's functional currency, which is USD. For a description of the transition effects when changing from NGAAP to simplified IFRS and from NOK to USD, see note 24 Transition to simplified IFRS and USD presentation currency.

These parent company financial statements should be read in connection with the Consolidated financial statements of Statoil, published together with these financial statements. With the exceptions described below, Statoil ASA applies the accounting policies of the group, as described in Statoil's disclosure note 2 Significant Accounting Policies, and reference is made to the Statoil note for further details. Insofar that the company applies policies that are not described in the Statoil note due to group level materiality considerations, such policies are included below if necessary for a sufficient understanding of Statoil ASA's accounts.

Subsidiaries, associated companies and joint ventures

Shareholdings and interests in subsidiaries, associated companies (companies in which the company does not have control, or joint control, but has the ability to exercise significant influence over operating and financial policies, generally when the ownership share is between 20% and 50%) and joint ventures are accounted for using the equity method. The company applies the equity method on the basis of the respective entities' financial reporting prepared in compliance with the Statoil group's IFRS accounting principles. Reserves for valuation variances included within the company's equity are established based on the sum of contributions from each individual equity accounted investment, with the limitation that the net amount cannot be negative. Goodwill included in the balance sheets of subsidiaries and associated companies is tested for impairment as part of the related investment in the subsidiary or associated company. Any related impairment expense is included in the company's statement of income under Net income from subsidiaries and other equity accounted companies.

Expenses related to the Statoil group as operator of joint operations and similar arrangements (licences)

Indirect operating expenses incurred by the company, such as personnel expenses, are accumulated in cost pools. Such expenses are allocated in part on an hours incurred cost basis to Statoil Petroleum AS, to other group companies, and to licences where Statoil Petroleum AS or other group companies are operators. Costs allocated in this manner reduce the expenses in the company's statement of income.

Asset transfers between the company and its subsidiaries

Transfers of assets and liabilities between the company and the entities that it directly or indirectly controls are accounted for at the carrying amounts (continuity) of the assets and liabilities transferred, when the transfer is part of a reorganisation within the Statoil group.

Dividends payable and group contributions

Dividends are reflected as Dividends payable within current liabilities. Group contributions for the year to other entities within Statoil's Norwegian tax group are reflected in the balance sheet as current liabilities within Liabilities to group companies. Under simplified IFRS the presentation of dividends payable and payable group contributions differs from the presentation under IFRS, as it also includes dividends and group contributions payable which at the date of the balance sheet is subject to a future general assembly approval before distribution.

Reserves for unrealised gains

Reserves for unrealised gains included within the Company's equity consists of accumulated unrealised gains on non-exchange traded financial instruments and the fair value of embedded derivatives, with the limitation that the net amount cannot be negative.

2 Financial risk management and measurement of financial instruments

General information relevant to financial risks

Statoil ASA's activities expose the company to market risk, liquidity risk and credit risk, and the management of such risks do not substantially differ from the Group's. See note 5 Financial risk management in the Consolidated financial statements.

Measurement of financial instruments by categories

The following tables present Statoil ASA's classes of financial instruments and their carrying amounts by the categories as they are defined in IAS 39 Financial Instruments: Recognition and Measurement. All financial instruments' carrying amounts are measured at fair value or their carrying amounts reasonably approximate fair value except non-current financial liabilities. See note 18 Finance debt for fair value information of non-current bonds, bank loans and finance lease liabilities and note 25 Financial instruments fair value measurement and sensitivity analysis of market risk in the Consolidated financial statements where fair value measurement is explained in detail.

See note 2 Significant accounting policies in the Consolidated financial statements for further information regarding measurement of fair values.

			Fair value through profit or loss		
(in USD million)	Note	Loans and receivables	Held for trading	Non-financial assets	Total carrying amount
At 31 December 2016					
Assets					
Non-current derivative financial instruments		-	994	-	994
Prepayments and financial receivables	-	384	-	201	585
Receivables from subsidiaries and other equity accounted companies	11	23,644	-	-	23,644
Trade and other receivables	13	4,614	-	146	4,760
Receivables from subsidiaries and other equity accounted companies	11	4,305	-	-	4,305
Current derivative financial instruments		-	413	-	413
Current financial investments	11	3,217	4,176	-	7,393
Cash and cash equivalents	14	1,989	2,285	-	4,274
Total		38,153	7,868	347	46,368

			Fair value through profit or loss		
(in USD million)	Note	Loans and receivables	Held for trading	Non-financial assets	Total carrying amount
At 31 December 2015					
Assets					
Non-current derivative financial instruments		-	1,775	-	1,775
Prepayments and financial receivables	-	-	-	64	64
Receivables from subsidiaries and other equity accounted companies	11	13,976	-	-	13,976
Trade and other receivables	13	3,665	-	163	3,828
Receivables from subsidiaries and other equity accounted companies	11	3,161	-	-	3,161
Current derivative financial instruments		-	487	-	487
Current financial investments	11	2,166	6,973	-	9,139
Cash and cash equivalents	14	1,943	5,527	-	7,471
Total		24,911	14,762	227	39,899

(in USD million)	Note	Amortised cost	Fair value through profit or loss	Non-financial liabilities	Total carrying amount
At 31 December 2016					
Liabilities					
Non-current finance debt	16	27,883	-	-	27,883
Liabilities to subsidiaries and other equity accounted companies		17	-	-	17
Non-current derivative financial instruments		-	1,420	-	1,420
Trade and other payables	19	2,790	-	103	2,893
Current finance debt	16	3,661	-	-	3,661
Dividend payable		1,426	-	-	1,426
Liabilities to subsidiaries and other equity accounted companies	11	15,109	-	-	15,109
Current derivative financial instruments		-	491	-	491
Total		50,886	1,911	103	52,900

(in USD million)	Note	Amortised cost	Fair value through profit or loss	Non-financial liabilities	Total carrying amount
At 31 December 2015					
Liabilities					
Non-current finance debt	16	29,764	-	-	29,764
Liabilities to subsidiaries and other equity accounted companies		15	-	-	15
Non-current derivative financial instruments		-	1,285	-	1,285
Trade and other payables	19	2,646	-	67	2,713
Current finance debt	16	2,243	-	-	2,243
Dividend payable		1,400	-	-	1,400
Liabilities to subsidiaries and other equity accounted companies	11	15,524	-	-	15,524
Current derivative financial instruments		-	228	-	228
Total		51,591	1,513	67	53,171

Financial instruments from tables above which are recognised in the balance sheet at a net fair value of USD 5,957 million in 2016 and USD 13,250 million in 2015, are mainly determined by Level 2 category in the Fair Value hierarchy.

The following table contains the estimated fair values of Statoil ASA's derivative financial instruments split by type.

(in USD million)	Fair value of assets	Fair value of liabilities	Net fair value
At 31 December 2016			
Foreign currency instruments	365	(28)	337
Interest rate instruments	987	(1,417)	(430)
Crude oil and refined products	13	(39)	(26)
Natural gas and electricity	41	(426)	(385)
Total	1,407	(1,911)	(504)
At 31 December 2015			
Foreign currency instruments	142	(143)	(0)
Interest rate instruments	1,772	(1,226)	546
Crude oil and refined products	40	(43)	(4)
Natural gas and electricity	308	(101)	207
Total	2,261	(1,513)	748

Sensitivity analysis of market risk

Commodity price risk
Statoil ASA's assets and liabilities resulting from commodity based derivatives contracts consist of both exchange traded and non-exchange traded instruments mainly in crude oil and refined products.

Price risk sensitivities at the end of 2016 and 2015 at 30% are assumed to represent a reasonably likely change based on the duration of the derivatives.

	2016		2015	
(in USD million)	- 30% sensitivity	30% sensitivity	- 30% sensitivity	30% sensitivity
At 31 December				
Crude oil and refined products net gains (losses)	650	(644)	336	(335)

Currency risk
The estimated gains and the estimated losses following from a change in the foreign exchange rates would impact the company's statement of income.

Currency risk sensitivity for Statoil ASA mainly differ from currency risk sensitivity in Group due to interesting bearing receivables from subsidiaries. For more detailed information about these receivables see note 11 Financial assets and liabilities.

+	2016		2015	
(in USD million)	- 12% sensitivity	12% sensitivity	- 11% sensitivity	11% sensitivity
At 31 December				
NOK net gains (losses)	(1,691)	1,691	(1,774)	1,774

Interest rate risk
The estimated gains following from a decrease in the interest rates and the estimated losses following from an interest rate increase would impact the company's statement of income.

	2016		2015	
(in USD million)	- 0.8 percentage points sensitivity	0.8 percentage points sensitivity	- 0.9 percentage points sensitivity	0.9 percentage points sensitivity
At 31 December				
Interest rate net gains (losses)	817	(817)	1,176	(1,176)

3 Revenues

	Full year	
(in USD million)	2016	2015
Revenues third party	28,333	34,776
Intercompany revenues	3,221	4,283
Revenues	31,554	39,059

4 Remuneration

Statoil ASA remuneration in 2016

(in USD million, except average number of employees)	Full year 2016	2015
Salaries[1)]	2,163	2,270
Pension cost	631	806
Social security tax	336	354
Other compensations	240	268
Total	3,370	3,698
Average number of employees[2)]	18,800	19,600

1) Salaries include bonuses, severance packages and expatriate costs in addition to base pay.
2) Part time employees amount to 3% for 2016 and 3% for 2015.

Total payroll expenses are accumulated in cost-pools and charged to partners of Statoil operated licences and group companies on an hours incurred basis. For further information see note 22 Related parties.

Compensation to and share ownership of the corporate assembly, the board of directors (BoD) and the corporate executive committee (CEC)
Compensation to the corporate assembly was USD 126,875 and the total share ownership of the members of the corporate assembly was 24,578 shares. Remuneration to members of the BoD and the CEC during the year and share ownership at the end of the year were as follows:

Members of the board (figures in USD thousand except number of shares)	Total remuneration	Share ownership as of 31 December 2016
Øystein Løseth (chair of the board)	104	1,040
Roy Franklin (deputy chair of the board)	114	-
Jakob Stausholm[1)]	52	n.a.
Wenche Agerup	65	2,522
Bjørn Tore Godal	65	-
Rebekka Glasser Herlofsen	61	-
Maria Johanna Oudeman	81	-
Jeroen van der Veer[2)]	61	-
Lill-Heidi Bakkerud	55	342
Stig Lægreid	55	1,881
Ingrid Elisabeth di Valerio	61	3,670
Total	777	9,455

1) Member until 30 September 2016 (resigned).

2) Member from 18 March 2016.

	Fixed remuneration										
Members of corporate executive committee (figures in USD thousand, except no. of shares)1), 2)	Fixed pay3)	Cash allowance4)	LTI 5)	Annual variable pay6)	Taxable benefits	2016 Taxable compensation	Non-taxable benefits in kind	Estimated pension cost7)	Estimated present value of pension obligation 8)	2015 Taxable compensation9)	Share ownership at 31 December 2016
Eldar Sætre13)	937	0	138	245	37	1,356	0	0	11,261	1,754	47,882
Margareth Øvrum	453	0	53	106	18	631	20	0	6,788	751	49,227
Timothy Dodson	440	0	51	67	15	573	39	141	4,746	673	29,418
Irene Rummelhoff	349	54	37	61	10	511	0	26	1,070	294	21,556
Jens Økland	347	58	40	53	12	509	0	22	785	329	13,937
Arne Sigve Nylund	398	0	49	80	18	546	0	112	4,047	690	11,312
Lars Christian Bacher	419	0	45	89	14	567	52	110	2,039	647	24,896
Hans Jakob Hegge	372	62	43	71	13	561	0	23	1,097	251	28,190
Jannicke Nilsson10)	32	5	2	0	0	40	0	3	1,032	NA	35,049
Anders Opedal11)	338	57	40	78	2	514	0	23	1,030	456	15,910
Torgrim Reitan12)	611	0	49	87	137	884	0	115	1,947	744	32,276
John Knight13)	1,679	0	0	0	131	1,810	0	0	0	2,089	103,808

1) All figures in the table are presented in USD based on average currency rates (2016: USD/NOK = 8.3987, USD/GBP = 1.3538. 2015: USD/NOK = 8,0739, USD/GBP = 1,5289). The figures are presented on accrual basis.
2) All CEC members receive their remuneration in Norwegian Kroner except John Knight who receives the remuneration in GBP.
3) Fixed pay consists of base salary, fixed remuneration element, holiday allowance and other administrative benefits.
4) Cash allowance in lieu of pension accrual above 12 G (the base amount in the national insurance scheme).
5) The fixed long-term incentive (LTI) element implies an obligation to invest the net amount in Statoil shares, including a lock-in period. The LTI element is presented the year it is granted for the members of the corporate executive committee employed by Statoil ASA.
6) Annual variable pay includes holiday allowance for corporate executive committee (CEC) members resident in Norway.
7) Estimated pension cost is calculated based on actuarial assumptions and pensionable salary (mainly base salary) at 31 December 2015 and is recognized as pension cost in the statement of income for 2016.
8) Estimated present value of pension obligation related to Eldar Sætre, Arne Sigve Nylund, Margareth Øvrum og Timothy Dodson are based on the estimated value of paid-up policies and rights letters from the Defined Benefit Pension Scheme. Estimated present value of pension obligation for the rest of the members of the corporate executive committee employed by Statoil ASA, is presented with value of paid-up policies and right letters from the Defined Benefit Pension Scheme and accrued pension assets from the Defined Contribution Pension Scheme.
9) Includes 2015 CEC members who are also CEC members in 2016.
10) Jannicke Nilsson was appointed executive vice president and chief operating officer (COO) from 1 December 2016.
11) Anders Opedal left the position as executive vice president and chief operating officer (COO) at 30 November 2016.
12) Compensation and benefit for Torgrim Reitan is according to Statoil's international assignment terms.
13) Fixed pay for Eldar Sætre includes a fixed remuneration element of USD 238 thousand not included in pensionable salary. John Knight's fixed pay includes a fixed remuneration element of USD 143 thousand that replaces his defined contribution pension plan and a fixed remuneration element of USD 724 thousand replacing his variable pay arrangements.

There are no loans from the company to members of the corporate executive committee.

Remuneration policy and concept

Reference is made to the section on «Declaration on remuneration and other employment terms for Statoil's Corporate Executive committee" for a detailed description of the remuneration and remuneration policy for executive management applicable for the years 2016 and 2017. The main elements of Statoil's executive remuneration are described in chapter 3 Governance, section 3.12 Remuneration to the corporate executive committee in this report.

5 Share-based compensation

Statoil's share saving plan provides employees with the opportunity to purchase Statoil shares through monthly salary deductions. If the shares are kept for two full calendar years of continued employment, following the year of purchase, the employees will be allocated one bonus share for each one they have purchased.

Estimated compensation expense including the contribution by Statoil ASA for purchased shares, amounts vested for bonus shares granted and related social security tax was USD 54 million in 2016 and USD 70 million in 2015. For the 2017 program (granted in 2016) the estimated compensation expense is USD 55 million. At 31 December 2016 the amount of compensation cost yet to be expensed throughout the vesting period is USD 122 million.

6 Auditor's remuneration

	Full year	
(in USD million, excluding VAT)	2016	2015
Audit fee	1.3	1.1
Audit related fee	0.3	1.1
Other service fee	0.0	0.0
Total	1.7	2.1

There are no fees incurred related to tax services.

7 Financial items

	Full year	
(in USD million)	2016	2015
Foreign exchange gains (losses) derivative financial instruments	353	548
Other foreign exchange gains (losses)	(59)	(2,367)
Net foreign exchange gains (losses)	294	(1,819)
Interest income from group companies	682	273
Interest income current financial assets and other financial items	298	140
Interest income and other financial items	981	413
Gains (losses) derivative financial instruments	470	(491)
Interest expense to group companies	(163)	(126)
Interest expense non-current finance debt	(850)	(725)
Interest expense current financial liabilities and other finance expense	(3)	(23)
Interest and other finance expenses	(1,016)	(874)
Net financial items	728	(2,771)

Statoil's main financial items relate to assets and liabilities categorised in the held for trading category and the amortised cost category. For more information about financial instruments by category see note 25 Financial instruments: fair value measurement and sensitivity analysis of market risk in the Consolidated financial statements.

The line item interest expense non-current finance debt primarily includes interest expenses of USD 1,039 million and USD 1,059 million from the financial liabilities at amortised cost category. This was partly offset by net interest on related derivatives from the held for trading category, USD 188 million and USD 334 million for 2016 and 2015, respectively.

The line item gains (losses) derivative financial instruments primarily includes fair value gain from the held for trading category of USD 454 million and a loss of USD 507 million for 2016 and 2015, respectively.

Foreign exchange gains (losses) derivative financial instruments include fair value changes of currency derivatives related to liquidity and currency risk. The line item foreign exchange gains (losses) includes a net foreign exchange loss of USD 289 million and a loss of USD 1,089 million from the held for trading category for 2016 and 2015, respectively.

8 Income taxes

Income tax

(in USD million)	Full year 2016	2015
Current taxes	92	75
Change in deferred tax	(499)	850
Income tax	(407)	925

Reconciliation of Norwegian statutory tax rate to effective tax rate

(in USD million)	Full year 2016	2015
Income(loss) before tax	(2,202)	(7,541)
Nominal tax rate in 2016 (25%) and in 2015 (27%)	550	2,036
Tax effect of:		
Permanent differences caused by NOK being the tax currency	(198)	(491)
Permanent differences caused by loans in USD	(0)	1,172
Tax effect of permanent differences related to equity accounted companies	(671)	(1,464)
Other permanent differences	(81)	57
Income tax prior years	(21)	(69)
Change in tax regulations	10	(132)
Other	4	(183)
Total	(407)	925
Effective tax rate	(18.5%)	12.3%

Change in tax regulations refers to change in deferred taxes caused by a reduction in Norwegian statutory tax rate from 25% to 24% effective from 2017.

Significant components of deferred tax assets and liabilities were as follows:

(in USD million)	At 31 December 2016	2015
Deferred tax - assets		
Inventory	0	52
Tax losses carry forward	22	422
Pensions	627	438
Long term provisions	105	64
Derivatives and long term debt	160	0
Other non-current items	2	280
Total deferred tax assets	917	1,256
Deferred tax - liabilities		
Inventory	6	0
Property, plant and equipment	65	54
Derivatives and long term debt	0	19
Total deferred tax liabilities	71	73
Net deferred tax assets	846	1,183

At 31 December 2016, Statoil ASA had recognised net deferred tax assets of USD 846 million, as it is considered probable that taxable profit will be available to utilise the deferred tax assets.

The movement in deferred tax

(in USD million)	2016	2015
Deferred tax assets at 1 January	1,183	1,676
Charged to the income statement	(499)	850
Actuarial losses pension	126	(435)
Group Contribution	32	(909)
Other	4	1
Deferred tax assets at 31 December	846	1,183

9 Property, plant and equipment

(in USD million)	Machinery, equipment and transportation equipment	Buildings and land	Vessels	Other	Total
Cost at 31 December 2015	567	276	662	160	1,666
Additions and transfers	30	7	0	0	37
Disposals at cost	(1)	(10)	(15)	0	(27)
Cost at 31 December 2016	596	273	647	160	1,677
Accumulated depreciation and impairment losses at 31 December 2015	(471)	(101)	(317)	(146)	(1,035)
Depreciation	(47)	(15)	(34)	(1)	(97)
Accumulated depreciation and impairment disposed assets	1	9	15	0	26
Accumulated depreciation and impairment losses at 31 December 2016	(516)	(107)	(335)	(147)	(1,106)
Carrying amount at 31 December 2016	80	166	312	13	571
Estimated useful lives (years)	3 - 10	20 - 33	15 - 20		

10 Investments in subsidiaries and other equity accounted companies

(in USD million)	2016	2015
Investments at 1 January	51,330	64,270
Net income from subsidiaries and other equity accounted companies	(2,726)	(4,686)
Increase (decrease) in paid-in capital	(8,462)	(2,794)
Acquisitions	1,199	0
Distributions	(1,194)	(2,984)
Translation adjustments	(260)	(2,498)
Other	(1)	22
Investments at 31 December	39,886	51,330

The closing balance of investments at 31 December of USD 39,886 million consists of investments in subsidiaries amounting to USD 38,660 million and investments in other equity accounted companies amounting to USD 1,226 million. In 2015, the amounts were USD 51,229 million and USD 101 million respectively.

The foreign currency translation adjustments relate to currency translation effects from subsidiaries with functional currencies other than USD.

In 2016 net income from subsidiaries and other equity accounted companies was impacted by net impairment losses related to property, plant and equipment and exploration assets of USD 1,678 million after tax, primarily resulting from reduced long term commodity price assumptions. For more information see the Consolidated financial statements of Statoil note 10 Property, plant and equipment. In 2015 net income from subsidiaries and other equity accounted companies was impacted by net impairment losses related to property, plant and equipment and exploration assets of USD 6,655 million after tax, primarily resulting from reduced short term commodity price assumptions.

No impairment of goodwill has been recognised in 2016 (2015: USD 539 million).

Increase (decrease) in paid-in capital in 2016 mainly consist of repayment of capital from Statoil Coordination Centre of USD 8,500 million.

Distributions during 2016 mainly consist of dividends and group contributions related to 2015 from group companies of USD 1,194 million. In 2015 distributions mainly consisted of dividends and group contributions related to 2014 from group companies of USD 1,312 million and group contribution from Statoil Petroleum AS of USD 358 million after tax and from other group companies of USD 1,094 million after tax.

In January 2016 Statoil ASA acquired 11.93% of the issued share capital and votes in Lundin Petroleum AB for a total purchase price of SEK 4.6 billion (USD 541 million). In June 2016 Statoil ASA increased ownership share in Lundin Petroleum AB till 68.4 million shares of Lundin, corresponding to 20.1% of the outstanding shares and votes. The consideration for these additional shares consisted of SEK 544 million (USD 64 million) in cash and the conversion of a previous receivable for the amount of USD 496 million.

Up until the transaction on 30 June 2016, the shares were accounted for as a non-current financial investment at fair value with changes in fair value presented in the line item net gains (losses) from available for sale financial assets in the Statoil ASA statement of comprehensive income. Statoil recognised gain of USD 153 million in the line net financial items in the Statoil ASA statement of income.

In 2015 Statoil sold the shares in Forusbeen 50 AS, Strandveien 4 AS and Arkitekt Ebbelsvei 10 AS with a gain of USD 211 million. Proceeds from the sale were USD 486 million. At the same time Statoil entered into a 15 year operating lease agreement for the buildings.

For further information, see in the Consolidated Financial Statements of Statoil Group note disclosure 4 Acquisitions and Dispositions.

The acquisition cost for investments in subsidiaries and other equity accounted companies are USD 39,254 million in 2016 and USD 46,717 million in 2015.

For a list of ownership in certain subsidiaries and other equity accounted companies, please see Significant and properties in section 2.7 Corporate.

11 Financial assets and liabilities

Non-current receivables from subsidiaries and other equity accounted companies

(in USD million)	At 31 December 2016	2015
Interest bearing receivables from subsidiaries and other equity accounted companies	23,520	13,879
Non-interest bearing receivables from subsidiaries	124	96
Receivables from subsidiaries and other equity accounted companies	23,644	13,976

Interest bearing receivables from subsidiaries and other equity accounted companies are mainly related to Statoil Petroleum AS. The total amount of credit facility given to Statoil Petroleum AS is NOK 135 billion at 31 December 2016 and NOK 135 billion at 31 December 2015, under which USD 14,501 million (NOK 125 billion) and USD 13,622 million (NOK 120 billion) is drawn in 2016 and 2015, respectively. Of the total USD amount drawn at 31 December 2016, USD 1,740 million (NOK 15 billion) is due within the next twelve months, and reclassified to current. The remaining amount on financial receivables interest bearing primarily relate to long term funding of other subsidiaries.

Of the total interest bearing non-current receivables at 31 December 2016, USD 580 million (NOK 5 billion) is due within the next five years. Remaining amounts fall due beyond five years.

Of the non-interest bearing receivables from subsidiaries at 31 December 2016, USD 79 million relates to pension, see also note 19 Pensions in the Consolidated financial statements. Correspondingly, USD 96 million related to pension at 31 December 2015.

Current receivables from subsidiaries and other equity accounted companies include current portion of credit facility given to Statoil Petroleum AS of USD 1,740 million and positive internal bank balances of USD 787 million at 31 December 2016.

Current receivables at 31 December 2015 include group contribution of USD 0.5 billion from Statoil Petroleum AS.

Current financial investments

(in USD million)	At 31 December 2016	2015
Time deposits	3,217	2,166
Interest bearing securities	4,176	6,973
Financial investments	7,393	9,139

Current Financial investments
The cost price for current financial investments was USD 6.0 billion at 31 December 2016 and USD 9.2 billion at 31 December 2015.

For more information about financial instruments by category, see note 25 Financial instruments: fair value measurement and sensitivity analysis of market risk in the Consolidated financial statements.

Current liabilities to subsidiaries and other equity accounted companies
Liabilities to subsidiaries and other equity accounted companies include current liabilities to Statoil Petroleum AS of USD 2.3 billion and liabilities related to Statoil groups' internal bank arrangements of USD 8.5 billion at 31 December 2016. The corresponding amounts were USD 2.2 billion and USD 7.0 billion at 31 December 2015.

12 Inventories

(in USD million)	At 31 December 2016	2015
Crude oil	1,504	749
Petroleum products	478	355
Natural gas	133	266
Other	36	24
Inventories	2,150	1,394

Higher inventory level of crude oil at 31 December is mainly related to higher prices and in-transit volumes. The write-down of inventories from cost to net realisable value amounts to an expense of USD 11 million and USD 277 million in 2016 and 2015, respectively.

13 Trade and other receivables

(in USD million)	At 31 December 2016	2015
Trade receivables	3,755	3,077
Other receivables	1,004	751
Trade and other receivables	4,760	3,828

14 Cash and cash equivalents

(in USD million)	At 31 December 2016	2015
Cash at bank available	128	243
Time deposits	1,658	1,494
Money market funds	65	450
Interest bearing securities	2,220	5,077
Margin deposits	203	206
Cash and cash equivalents	4,274	7,471

Restricted cash at 31 December 2016 and 2015 consists of margin deposits including both cash and exchange traded derivative products with daily settlement of USD 203 million and USD 206 million, respectively.

15 Equity and shareholders

Change in equity

(in USD million)	At 31 December 2016	2015
Shareholders' equity at 1 January	39,277	50,108
Net income	(2,608)	(6,616)
Actuarial gain (loss) defined benefit pension plans	(374)	1,138
Foreign currency translation adjustments	(304)	(2,498)
Ordinary dividend	(2,838)	(2,860)
Scrip dividend	904	0
Value of stock compensation plan	(26)	(4)
Treasury shares purchased	27	10
Total equity at 31 December	34,059	39,277

The accumulated foreign currency translation effect as of 31 December 2016 decreased total equity by USD 1,338 million. At 31 December 2015 the corresponding effect was a decrease in total equity of USD 1,034 million. The foreign currency translation adjustments relate to currency translation effects from the subsidiaries.

Common stock

	Number of shares	NOK per value	At 31 December Common stock
Authorised and issued	3,245,049,411	2.50	8,112,623,527.50
Treasury shares	11,138,890	2.50	27,847,225.00
Total outstanding shares	3,233,910,521	2.50	8,084,776,302.50

There is only one class of shares and all the shares have the same voting rights.

During 2016 a total of 4,011,860 treasury shares were purchased for USD 62 million and 3,882,153 treasury shares were allocated to employees participating in the share saving plan. In 2015 a total of 4,057,902 treasury shares were purchased for USD 69 million and 3,203,968 treasury shares were allocated to employees participating in the share saving plan. At 31 December 2016 Statoil had 11,138,890 treasury shares and at 31 December 2015 11,009,183 treasury shares, all of which are related to Statoil's share saving plan. For further information, see note 5 Share-based compensation.

Statoil's general assembly has authorised the company to acquire Statoil shares in the market. The authorisation may be used to acquire Statoil shares with an overall nominal value of up to NOK 42.0 million. Such shares acquired in accordance with the authorisation may only be used for sale and transfer to employees of the Statoil group as part of the group's share saving plan approved by the board. The minimum and maximum amount that may be paid per share will be NOK 50 and NOK 500, respectively. The authorisation is valid until the next ordinary general meeting. For further details, please see note 17 Shareholder's equity of the Consolidated financial statements.

For information regarding the 20 largest shareholders in Statoil ASA, please see Major Shareholders in section 5.1 Shareholder information.

16 Finance debt

Non-current finance debt

	At 31 December	
(in USD million)	2016	2015
Unsecured bonds	29,964	30,350
Unsecured loans	85	83
Finance lease liabilities	382	416
Total finance debt	30,432	30,849
Less current portion	2,549	1,084
Non-current finance debt	27,883	29,764
Weighted average interest rate (%)	3.30	3.33

Statoil ASA uses currency swaps to manage foreign exchange risk on its non-current financial liabilities. For information about the Statoil Group and Statoil ASA´s interest rate risk management, see note 5 Financial risk management in the Consolidated financial statement and note 2 Financial risk management and measurement of financial instruments in the Statoil ASA financial statement.

In 2016 Statoil ASA issued the following bonds:

Issuance date	Amount in EUR billion	Interest rate in %	Maturity date
9 November 2016	0.60	0.75	November 2026
9 November 2016	0.60	1.625	November 2036

Substantially all unsecured bond and unsecured bank loan agreements contain provisions restricting future pledging of assets to secure borrowings without granting a similar secured status to the existing bond holders and lenders.

Out of Statoil ASA total outstanding unsecured bond portfolio, 47 bond agreements contain provisions allowing Statoil to call the debt prior to its final redemption at par or at certain specified premiums if there are changes to the Norwegian tax laws. The carrying amount of these agreements is USD 29.6 billion at the 31 December 2016 closing exchange rate.

Statoil ASA has a revolving credit facility of USD 5.0 billion, supported by 21 core banks, maturing in 2021. The facility supports secure access to funding, supported by the best available short-term rating. As at 31 December 2016 and 2015 it has not been drawn.

Non-current finance debt repayment profile

(in USD million)	
2018	3,645
2019	2,822
2020	1,986
2021	1,803
Thereafter	17,627
Total	27,883

More information regarding finance lease liabilities is provided in note 20 Leases.

Current finance debt

(in USD million)	At 31 December 2016	2015
Collateral liabilities and other current financial liabilities	1,112	1,158
Non-current finance debt due within one year	2,549	1,084
Current finance debt	3,661	2,243
Weighted average interest rate (%)	1.62	1.93

Collateral liabilities and other current financial liabilities relate mainly to cash received as security for a portion of Statoil ASA's credit exposure and outstanding amounts on US Commercial paper (CP) programme. At 31 December USD 500 million were issued on the CP programme. Corresponding at 31 December 2015 there were no outstanding amounts.

17 Pensions

Statoil ASA is subject to the Mandatory Company Pensions Act, and the company's pension scheme follows the requirements of the Act. Reference is made to the Annual notes in the Financial statement for Statoil Group, for a description of the pension scheme in Statoil ASA.

Net pension cost

(in USD million)	2016	2015
Current service cost	234	368
Interest cost	182	180
Interest (income) on plan asset	(137)	(134)
Losses (gains) from curtailment, settlement or plan amendment	123	251
Actuarial (gains) losses related to termination benefits	59	(1)
Notional contributions	50	36
Defined benefit plans	512	700
Defined contribution plans	119	105
Total net pension cost	631	806

(in USD million)	2016	2015
Defined benefit obligations (DBO)		
Defined benefit obligation at 1 January	6,425	8,252
Current service cost	234	368
Interest cost	182	180
Actuarial (gains) losses - Financial assumptions	792	(692)
Actuarial (gains) losses - Experience	(274)	(358)
Benefits paid	(228)	(227)
Losses (gains) from curtailment, settlement or plan amendment	182	254
Paid-up policies	(131)	(151)
Change in receivable from subsidiary related to termination benefits	26	54
Foreign currency translation	130	(1,291)
Changes in notional contribution liability	50	36
Defined benefit obligation at 31 December	7,387	6,425
Fair value of plan assets		
Fair value of plan assets at 1 January	4,803	5,754
Interest income	137	134
Return on plan assets (excluding interest income)	11	80
Benefits paid	(74)	(65)
Paid-up policies and personal insurance	(92)	(199)
Foreign currency translation	104	(901)
Fair value of plan assets at 31 December	4,889	4,803
Net pension liability at 31 December	(2,498)	(1,621)
Represented by:		
Asset recognised as non-current pension assets (funded plan)	787	1,241
Asset recognised as non-current receivables from subsidiary	79	96
Liability recognised as non-current pension liabilities (unfunded plans)	(3,364)	(2,959)
DBO specified by funded and unfunded pension plans	7,387	6,425
Funded	4,102	3,562
Unfunded	3,285	2,863
Actual return on assets	56	206

Actuarial losses and gains recognised directly in retained earnings

(in USD million)	2016	2015
Net actuarial (losses) gains recognised in retained earnings during the year	(472)	1,184
Actuarial (losses) gains related to currency effects on net obligation and foreign exchange translation	(30)	415
Tax effects of actuarial (losses) gains recognised in retained earnings	129	(461)
Recognised directly in retained earnings during the year net of tax	(374)	1,138
Cumulative actuarial (losses) gains recognised directly in retained earnings net of tax	(1,188)	(814)

Actuarial assumptions and sensitivity analysis

Actuarial assumptions, sensitivity analysis, portfolio weighting and information about pension assets in Statoil Pension are presented in the Pension note in the Financial statement for Statoil Group. The number of employees, including pensioners related to the main benefit plan in Statoil ASA are 9,410. In addition, all employees are members of the AFP plan and different groups of employees are members of other unfunded plans.

18 Provisions

(in USD million)	Provisions
Non-current portion at 31 December 2015	294
Current portion at 31 December 2015	67
Provisions at 31 December 2015	360
New or increased provisions	100
Decrease in estimate	(31)
Amounts charged against provisions	(84)
Currency translation	2
Provisions at 31 December 2016	348
Current portion at 31 December 2016	59
Non-current portion at 31 December 2016	289

See also comments on provisions in note 21 Other commitments, contingent liabilities and contingent assets.

19 Trade, other payables and provisions

	At 31 December	
(in USD million)	2016	2015
Trade payables	1,388	977
Non-trade payables, accrued expenses and provisions	890	1,137
Equity accounted investments and other related party payables	615	599
Trade, other payables and provisions	2,893	2,713

20 Leases

Statoil ASA leases certain assets, notably vessels and office buildings.

In 2016, net rental expenditures were USD 464 million (USD 427 million in 2015) consisting of minimum lease payments of USD 533 million (USD 501 million in 2015) reduced with sublease payments received of USD 70 million in 2016 (USD 75 million in 2015). Contingent rents expensed were immaterial both years.

The information in the table below shows future minimum lease payments under non-cancellable leases at 31 December 2016. Amounts related to finance leases include future minimum lease payments for assets recognised in the financial statements at year end 2016.

			Finance leases		
(in USD million)	Operating leases	Operating sublease	Minimum lease payments	Discount element	Net present value minimum lease payments
2017	441	(25)	53	(2)	50
2018	335	(24)	53	(4)	48
2019	287	(23)	53	(7)	46
2020	251	(22)	53	(8)	44
2021	227	(21)	53	(10)	42
2022-2026	686	(76)	210	(59)	151
2027-2031	372	0	0	0	0
Thereafter	73	0	0	0	0
Total future minimum lease payments	2,671	(191)	473	(91)	382

More information related to the operating leases of vessels and office buildings is found in the Statoil group financial statements.

Statoil ASA leases three LNG vessels on behalf of Statoil and the State's direct financial interest (SDFI). Statoil ASA accounts for the combined Statoil and SDFI share of these agreements as finance leases in the balance sheet, and further accounts for the SDFI related portion as operating sublease. The finance leases included in the balance sheet reflect the original lease term of 20 years from 2006.

Property, plant and equipment includes USD 312 million for leases that have been capitalised at year end 2016 (USD 345 million in 2015), also presented in the category vessels in note 9 Property, plant and equipment.

21 Other commitments, contingent liabilities and contingent assets

Contractual commitments
Statoil ASA had contractual commitments of USD 960 million at 31 December 2016. The contractual commitments reflect the Statoil ASA share and comprise financing commitments related to exploration activities.

Other long-term commitments
Statoil ASA has entered into various long-term agreements for pipeline transportation as well as terminal use, processing, storage and entry/exit capacity commitments and commitments related to specific purchase agreements. The agreements ensure the rights to the capacity or volumes in question, but also impose on the company the obligation to pay for the agreed-upon service or commodity, irrespective of actual use. The contracts' terms vary, with duration of up to 30 years.

Take-or-pay contracts for the purchase of commodity quantities are only included in the table below if their contractually agreed pricing is of a nature that will or may deviate from the obtainable market prices for the commodity at the time of delivery.

Obligations payable by Statoil ASA to entities accounted for as associates and joint ventures are included gross in the table below. Obligations payable by Statoil ASA to entities accounted for as joint operations (for example pipelines) are included net (i.e. gross commitment less Statoil ASA's ownership share).

Nominal minimum commitments at 31 December 2016:

(in USD million)	
2017	1,106
2018	1,047
2019	1,031
2020	975
2021	822
Thereafter	4,084
Total	9,065

Guarantees
Statoil ASA has provided parent company guarantees covering liabilities of subsidiaries with operations in Algeria, Angola, Australia, Azerbaijan, Brazil, Colombia, Denmark, Germany, Greenland, India, Ireland, Libya, New Zealand, Nicaragua, Nigeria, Norway, Russia, Sweden, United Kingdom, the United States of America, Uruguay and Venezuela. The company has also counter-guaranteed certain bank guarantees covering liabilities of subsidiaries in Algeria, Angola, Australia, Brazil, Canada, Colombia, Denmark, the Faroes, Indonesia, Mexico, Myanmar, the Netherlands, Nicaragua, Norway, South Africa, Sweden, United Kingdom, the United States of America and Uruguay.

Statoil ASA has guaranteed for its proportionate portion of an associate's long term bank debt, amounting to USD 160 million. The book value of the guarantee is immaterial.

Contingencies
Statoil ASA is the participant in certain entities ("DAs") in which the company has unlimited responsibility for its proportionate share of such entities' liabilities, if any, and also participates in certain companies ("ANSs") in which the participants in addition have joint and several liability. For further details, refer to note 10 Investments in subsidiaries and other equity accounted investments.

A number of Statoil ASA's long-term gas sales agreements contain price review clauses. Certain counterparties have requested arbitration in connection with price review claims. The related exposure for Statoil ASA has been estimated to an amount equivalent to approximately USD 374 million for gas delivered prior to year end 2016. Statoil ASA has provided for its best estimate related to these contractual gas price disputes in the financial statements, with the impact to the statement of income reflected as revenue adjustments.

On 26 September 2016, the Norwegian Ministry of Finance (MoF) denied Statoil's appeal related to a 2014 order from the Financial Supervisory Authority of Norway to change the timing of a Cove Point related onerous contract provision to a financial period prior to the first quarter of 2013, in which Statoil originally reflected the provision. Statoil has decided not to pursue the matter further, as it does not impact any comparative financial periods presented in the annual Consolidated financial statements of 2016. Further reference is made to Note 23 Other commitments, contingent liabilities and contingent assets of Statoil's 2015 Consolidated financial statements.

On 6 July 2016, the Norwegian tax authorities issued a deviation notice for the years 2012 to 2014 related to the internal pricing on certain transactions between Statoil Coordination Centre (SCC) in Belgium and Statoil ASA. The main issue relates to SCC's capital structure and its compliance with the arm's length principle. Statoil ASA is of the view that arm's length pricing has been applied in these cases and that the group has a strong position, and no amounts have consequently been provided for in the accounts.

During the normal course of its business Statoil ASA is involved in legal proceedings, and several other unresolved claims are currently outstanding. The ultimate liability or asset in respect of such litigation and claims cannot be determined at this time. Statoil ASA has provided in its financial statements for probable liabilities related to litigation and claims based on the company's best judgment. Statoil ASA does not expect that its financial position, results of operations or cash flows will be materially affected by the resolution of these legal proceedings.

Provisions related to claims and disputes are reflected within note 18 Provisions.

22 Related parties

Reference is made to note 24 Related parties in Statoil's Consolidated financial statement for information regarding Statoil ASAs related parties. This include information regarding related parties as a result of Statoil ASA's ownership structure and also information regarding transactions with the Norwegian State.

Transactions with internally owned companies
Revenue transactions with related parties are presented in note 3 Revenues. Total intercompany revenues amounted to USD 3,221 million and USD 4,283 million in 2016 and 2015, respectively. The major part of intercompany revenues is attributed to sales of crude oil and sales of refined products to Statoil Refining Denmark AS and Statoil Marketing.

Statoil ASA sells natural gas and pipeline transport on a back-to-back basis to Statoil Petroleum AS. Similarly, Statoil ASA enters into certain financial contracts, also on a back-to-back basis with Statoil Petroleum AS. All of the risks related to these transactions are carried by Statoil Petroleum AS and the transactions are therefore not reflected in Statoil ASA's financial statements.

Statoil ASA buys volumes from its subsidiaries and sells them into the market. Total purchases of goods from subsidiaries amounted to USD 12,511 million and USD 15,296 million in 2016 and 2015, respectively. The major part of intercompany purchases of goods is attributed to Statoil Petroleum AS, USD 8,163 million and USD 10,282 million in 2016 and 2015, respectively.

In relation to its ordinary business operations, Statoil ASA has regular transactions with group companies in which Statoil has ownership interests. Statoil ASA makes purchases from group companies amounting to USD 490 million and USD 999 million in 2016 and 2015, respectively.

Expenses incurred by the company, such as personnel expenses, are accumulated in cost pools. Such expenses are allocated in part on an hours incurred cost basis to Statoil Petroleum AS, to other group companies, and to licences where Statoil Petroleum AS or other group companies are operators. Cost allocated in this manner is not reflected in Statoil ASA's financial statements. Expenses allocated to group companies amounted to USD 4,214 million and USD 4,758 million in 2016 and 2015, respectively. The major part of the allocation is related to Statoil Petroleum AS, USD 3,302 million and USD 3,980 million in 2016 and 2015, respectively.

Other transactions
Reference is made to note 24 Related parties in Statoil's Consolidated financial statement for information regarding Statoil ASAs transactions with related parties based on ordinary business operations.

Current receivables and current liabilities from subsidiaries and other equity accounted companies are included in note 11 Financial assets and liabilities.

Related party transactions with management and management remunerations for 2016 are presented in note 4 Remuneration.

23 Subsequent events

See note 17 Equity and dividend in Statoil's consolidated financial statements for proposed dividend for the fourth quarter 2016.

24 Transition to simplified IFRS and USD presentation currency

Change to simplified IFRS and change of presentation currency – re-presentation of comparative

With effect from 1 January 2016 Statoil ASA changed the accounting principles from NGAAP to simplified IFRS pursuant to the Norwegian Accounting Act § 3-9 and regulations regarding simplified application of IFRS issued by the Ministry of Finance on 3 November 2014. With effect from 1 January 2016 Statoil ASA also changed its presentation currency from Norwegian kroner (NOK) to US dollars (USD). The effects of the changes are described in this disclosure. The effects on the comparative figures for 2014 and 2015 are presented in the tables below.

Simplified IFRS Transition

The accounting policies set out in note 2 have been applied in preparing the financial statements for the year ended 31 December 2016, the comparative information presented in these financial statements for the year ended 31 December 2014 and 31 December 2015, and the preparation of an opening balance sheet in accordance with simplified IFRS at 1 January 2015.

Opening balance sheet

The financial statements have been retrospectively re-stated with effect from 1 January 2015. In preparing its opening simplified IFRS balance sheet as at 1 January 2015, Statoil ASA has adjusted amounts reported previously in financial statements prepared in accordance with its old basis of accounting, NGAAP. An explanation of how the transition from NGAAP to simplified IFRS has affected Statoil ASAs statement of income, balance sheet and statement of cash flows is set out below.

IFRS 1 Exemptions and elections applied, IAS 1 presentation and simplified IFRS exemptions

In making the transition to simplified IFRS Statoil ASA has applied IFRS 1, First-time Adoption of International Financial Reporting Standards and the simplified IFRS pursuant to the Norwegian Accounting Act § 3-9 and regulations regarding simplified application of IFRS issued by the Ministry of Finance on 3 November 2014. IFRS 1 requires that all IFRS standards and interpretations are applied consistently and retrospectively for all fiscal years presented. However, this standard provides exemptions and exceptions to this general requirement in specific cases. Simplified IFRS provides some exemptions from IFRS 1 and IAS 1. Statoil ASA has chosen to apply the following exemptions under IFRS 1 and the simplified IFRS regulation:

Business Combinations

IFRS 1 allows for Business combinations occurred before transition to IFRS not to be restated according to IFRS 3. Statoil has applied this exemption. Business combinations that occurred before 1 January 2015, has not been restated retrospectively. Within the limits imposed by IFRS 1, the carrying amounts of assets acquired and liabilities assumed as part of past business combinations that arose from such transactions as they were determined under NGAAP, are considered their deemed cost under simplified IFRS at the date of transition. The carrying amount of goodwill in the opening simplified IFRS statement of financial position is its carrying amount in accordance with NGAAP at the date of transition.

Cumulative currency translation differences

According to IFRS 1 the cumulative foreign translations for all foreign operations could be set to zero at the date of transition to IFRS. When IFRS was implemented in the Statoil group 1 January 2006, the currency translation adjustments were set to zero. The currency translation adjustments calculated from 1 January 2006 is regarded as the best approximation of the historical translation adjustment and is the starting point of the translation adjustments in the statutory accounts of Statoil ASA.

GAAP differences between IFRS and simplified IFRS

The IFRS principles applied by the Statoil Group have been applied in Statoil ASA with the following exemptions in accordance with the simplified IFRS regulations:

Dividends and group contributions

Statoil ASA has applied the exemptions from IAS 10, no 12 and 13, IAS 18 no. 30 and IFRIC 17 no 10 and recognize proposed dividend and group contributions at the end of the year.

Statement of changes in equity

Statoil ASA has applied the exemption from providing a statement of changes in equity. The specification of changes in equity is presented in disclosure 15.

Primary changes in accounting policies

The changes in accounting policies are primarily related to derivatives and goodwill.
See note 2 Significant accounting policies in the Consolidated financial statements for further information.

Change in presentation currency

The change in presentation currency effective from 1 January 2016 was made mainly in order to better reflect the underlying USD exposure of Statoil's business activities and to align with industry practice. The change in presentation currency has been accounted for as a policy change, and comparative figures have been re-presented to USD retrospectively from 1 January 2015 to reflect the change in presentation currency.

The different components of assets and liabilities in USD correspond to the amount published in NOK translated at the USD/NOK closing rate applicable at 31. December 2014. The same relates to the equity as a whole. As such, the change in presentation currency will not impact the valuation of assets, liabilities, equity or any ratios between these components, such as debt to equity ratios.

All currency translation adjustments have been calculated from 1 January 2006, which was the date of Statoil group's transition to IFRS. Cumulative translation adjustments have been presented as if Statoil ASA had used USD as the presentation currency from that date.

The recalculation of currency translation adjustments in USD has an impact on the distribution of shareholders' equity for comparable periods, between currency translation adjustments and other components of equity. Together with changes in net income arising from the change in presentation currency, these effects have been presented as re-presentations in the table below.

EFFECT OF CHANGES IN REPORTED EQUITY

	NGAAP NOK as reported (billion)	Simplified IFRS adjustments NOK (billion)	Simplified IFRS in NOK (billion)	Simplified IFRS in USD (million)[1)]	USD reclassifications (million)	Simplified IFRS in USD (million)
Share capital	8.0		8.0	1,073	66	1,139
Additional paid-in capital	17.3		17.3	2,331	145	2,476
Reserves for valuation variances	109.0	3.1	112.1	15,084	0	15,084
Reserves for unrealised gains	0.0	11.2	11.2	1,506	(0)	1,506
Retained earnings	223.8	0.0	223.8	30,113	(211)	29,903
Total equity 31.12.2014	358.2	14.3	372.5	50,108	0	50,108

1) Translated at exchange rate USD/NOK 7.433 as of 31 December 2014.

	NGAAP NOK as reported (billion)	Simplified IFRS adjustments NOK (billion)	Simplified IFRS in NOK (billion)	Simplified IFRS in USD (million)[1)]	USD reclassifications (million)	Simplified IFRS in USD (million)
Share capital	8.0		8.0	905	234	1,139
Additional paid-in capital	17.3		17.3	1,967	509	2,476
Reserves for valuation variances	38.1	2.5	40.6	4,612	(0)	4,612
Reserves for unrealised gains	0.0	9.8	9.8	1,113	(0)	1,113
Retained earnings	270.3	0.0	270.3	30,679	(743)	29,937
Total equity 31.12.2015	333.7	12.3	346.0	39,277	(0)	39,277

1) Translated at exchange rate USD/NOK 8.809 as of 31 December 2015.

IFRS adjustments relates to fair value adjustments on commodity and financial derivatives. In 2015 the adjustment also included depreciation of goodwill. Paid in capital have been recognized at the USD/NOK exchange rate of 6.998 at the time of the conversion of Statoil ASA from NOK to USD, 31 December 2008.

The Statement of income, Statement of financial position and Statement of cash flows have been re-presented to reflect the currency rates of transactions in foreign currencies at the date of the transactions.

Upon disposal of a foreign operation accumulated currency translation adjustments arising from currency movements between the Statoil ASA's presentation currency and the operational currency of the foreign operation are reclassified from equity to profit or loss and included as part of the gain or loss from the disposal, presented as other income. When changing Statoil ASA's presentation currency from NOK to USD, the gains or losses from such disposals have been changed to reflect accumulated currency gains or losses being calculated based on USD being the presentation currency rather than NOK. These effects are presented as re-presentations in the table below, and represent the only re-measurements following the change in presentation currency to USD.

EFFECT OF CHANGES IN REPORTED NET INCOME

	Full year ended 31 December 2015
Net income under NGAAP NOK as reported (billion)	(46.8)
Simplified IFRS adjustments	
Goodwill[1)]	0.3
Merger timing effects [2)]	0.7
Commodity derivatives[3)]	(0.9)
Financial derivatives[3)]	(2.3)
Total simplified IFRS translation adjustments NOK (billion)	(2.3)
Simplified IFRS in NOK (billion)	(49.1)
Simplified IFRS in USD (million) - Translated at average exchange rates for the quarters	(6,131)
Translation to USD re-presentation effects[4)]	(485)
Net income under simplified IFRS in USD (million)	(6,616)

Impacts in reported net income

1) Goodwill
According to NGAAP goodwill has been depreciated linear over 10 years. Goodwill depreciation according to NGAAP in 2015 has been reversed. The goodwill is recognized at amortized cost at 1 January 2015.

2) Merger effects
The entities within the Statholding group merged with Statholding AS in 2015. The transaction date for the merger was 1 January 2015 under NGAAP. Under simplified IFRS the transaction date was 15 December 2015. The Statholding AS has USD functional currency. Entities with NOK functional currency included in the merger changed the function currency from NOK to USD effective from 1 January 2015 under NGAAP and at 15 December 2015 under simplified IFRS.

3) Commodity and financial derivatives
Under simplified IFRS all non-exchange traded commodity derivatives and embedded derivatives have been booked at fair value. Under NGAAP all non-exchange traded commodity derivatives have been booked at the lowest of cost and fair value. Embedded derivatives have not been recognized under NGAAP. All interest derivatives (OTC) are booked at fair value under simplified IFRS while under NGAAP all interest derivatives were booked at the lowest of cost and fair value

4) Change in presentation currency
The disposal with most significant effect on the net income in Statoil ASA in 2015 is the disposal of Statoil's interests in the subsidiary Shah Deniz, for which the gain presented in NOK included NOK 3.2 billion arising from reclassification of accumulated translation differences. As the disposed foreign operation had USD as functional currency, there are no accumulated translation differences when presented in USD for this transaction.

Impact on cash flow

Simplified IFRS adjustments
There are no changes between cash flows from operating activities, investing activities, and financing activities. The transition to simplified IFRS has only effect between line items within cash flow provided by operating activity. The effect on net income related to the merger effect and commodity derivatives is offset in the line item (increase) decrease in other items related to operating activities. The effect on net income related to the financial derivatives is offset in the line item derivatives. No adjustments have been made to cash and cash equivalents, and no other adjustments have been made to the statements of cash flows on conversion.

Change in presentation currency
The Statement of cash flow has been re-presented to reflect the changes described above and based on the currency rates applicable at the transaction dates of relevant transactions. The re-presentation impacts the classification between the different lines in the statement of cash flow, between currency translation adjustments and other components of cash flow.

RESTATEMENT OF STATEMENT OF INCOME FOR 2015 - FROM NGAAP TO SIMPLIFIED IFRS

	NGAAP NOK as reported (billion)	Simplified IFRS adjustments NOK (billion)	Simplified IFRS in NOK (billion)	Simplified IFRS in USD (million) 1)
	For the year ended 31 December			
	2015			2015
Revenues	313.7	(0.0)	313.7	39,059
Net income from subsidiaries and other equity accounted companies	(33.7)	0.1	(33.7)	(4,686)
Other income	2.3		2.3	229
Total revenues and other income	282.3	0.0	282.3	34,603
Purchases [net of inventory variation]	(292.9)		(292.9)	(36,457)
Operating expenses	(19.9)		(19.9)	(2,462)
Selling, general and administrative expenses	(2.0)		(2.0)	(244)
Depreciation, amortisation and net impairment losses	(0.8)		(0.8)	(103)
Exploration expenses	(0.9)		(0.9)	(107)
Net operating income	(34.2)	0.0	(34.1)	(4,769)
Net financial items	(19.4)	(3.1)	(22.5)	(2,771)
Income before tax	(53.6)	(3.1)	(56.6)	(7,541)
Income tax	6.8	0.8	7.5	925
Net income	(46.8)	(2.3)	(49.1)	(6,616)

1) Translated at average exchange rates for the quarters.

RESTATEMENT OF BALANCE SHEET AS OF 1 JANUARY 2015 - FROM NGAAP TO SIMPLIFIED IFRS

1 January 2015	NGAAP NOK as reported (billion)	Simplified IFRS adjustments NOK (billion)	Simplified IFRS NOK (billion)	Simplified IFRS in USD (million)[1]
ASSETS				
Property, plant and equipment	5.7		5.7	771
Intangible assets	0.2		0.2	29
Investments in subsidiaries and other equity accounted companies[2]	474.6	3.1	477.7	64,270
Deferred tax assets[3]	16.7	(4.2)	12.5	1,676
Pension assets	7.9		7.9	1,061
Derivative financial instruments[3]	0.2	17.5	17.7	2,380
Prepayments and financial receivables	0.5		0.5	72
Receivables from subsidiaries and other equity accounted companies	68.6		68.6	9,225
Total non-current assets	574.4	16.4	590.8	79,483
Inventories	15.3		15.3	2,057
Trade and other receivables	43.6		43.6	5,868
Receivables from subsidiaries and other equity accounted companies[3]	21.0	0.1	21.1	2,844
Derivative financial instruments[3]	1.3	3.3	4.6	618
Financial investments	53.2		53.2	7,160
Cash and cash equivalents	71.5		71.5	9,625
Total current assets	206.0	3.4	209.4	28,173
Total assets	780.4	19.8	800.2	107,656

1) Translated at exchange rate USD/NOK 7.4332 as of 31 December 2014.

2) Commodity derivatives in Statoil Petroleum AS.

3) Financial derivatives and commodity derivatives in Statoil ASA.

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RESTATEMENT OF BALANCE SHEET AS OF 1 JANUARY 2015 - FROM NGAAP TO SIMPLIFIED IFRS

1 January 2015	NGAAP NOK as reported (billion)	Simplified IFRS adjustments NOK (billion)	Simplified IFRS NOK (billion)	Simplified IFRS in USD (million)[1]
EQUITY AND LIABILITIES				
Share capital	8.0		8.0	1,139
Additional paid-in capital	17.3		17.3	2,476
Reserves for valuation variances	109.0	3.1	112.1	15,084
Reserves for unrealised gains	0.0	11.2	11.2	1,506
Retained earnings	223.8	0.0	223.8	29,903
Total equity	358.2	14.3	372.5	50,108
Finance debt[3]	201.3	1.5	202.8	27,287
Liabilities to subsidiaries and other equity accounted companies	0.1		0.1	16
Pension liabilities	27.7		27.7	3,731
Provisions[3]	2.1	0.1	2.2	295
Derivative financial instruments[3]	5.2	(0.7)	4.5	611
Total non-current liabilities	236.4	1.0	237.4	31,939
Trade and other payables[3]	29.1	2.0	31.1	4,188
Current tax payable	0.6		0.6	75
Finance debt	24.7		24.7	3,328
Dividends payable	11.4		11.4	1,540
Liabilities to subsidiaries and other equity accounted companies[3]	114.7	1.9	116.5	15,676
Derivative financial instruments[3]	5.4	0.6	6.0	802
Total current liabilities	185.9	4.5	190.4	25,609
Total liabilities	422.3	5.5	427.8	57,548
Total equity and liabilities	780.4	19.8	800.2	107,656

1) Translated at exchange rate USD/NOK 7.4332 as of 31 December 2014.

RESTATEMENT OF BALANCE SHEET AS OF 31 DECEMBER 2015 - FROM NGAAP TO SIMPLIFIED IFRS

31 December 2015	NGAAP NOK as reported (billion)	Simplified IFRS adjustments NOK (billion)	Simplified IFRS NOK (billion)	Simplified IFRS in USD (million)[1]
ASSETS				
Property, plant and equipment	5.6		5.6	631
Intangible assets	0.0		0.0	5
Investments in subsidiaries and other equity accounted companies[2]	449.7	2.5	452.2	51,330
Deferred tax assets[3]	14.6	(4.1)	10.4	1,183
Pension assets	10.9		10.9	1,241
Derivative financial instruments[3]	0.0	15.6	15.6	1,775
Prepayments and financial receivables	0.6		0.6	64
Receivables from subsidiaries and other equity accounted companies	123.1		123.1	13,976
Total non-current assets	604.4	14.0	618.4	70,206
Inventories	12.3		12.3	1,394
Trade and other receivables	33.7		33.7	3,828
Receivables from subsidiaries and other equity accounted companies[3]	27.2	0.6	27.8	3,161
Derivative financial instruments[3]	1.6	2.7	4.3	487
Financial investments	80.5		80.5	9,139
Cash and cash equivalents	65.8		65.8	7,471
Total current assets	221.1	3.3	224.4	25,479
Total assets	825.6	17.3	842.9	95,684

1) Translated at exchange rate USD/NOK 8.809 as of 31 December 2015.
2) Commodity derivatives in Statoil Petroleum AS and depreciation of goodwill.
3) Financial derivatives and commodity derivatives in Statoil ASA.

RESTATEMENT OF BALANCE SHEET AS OF 31 DECEMBER 2015 - FROM NGAAP TO SIMPLIFIED IFRS

31 December 2015	NGAAP NOK as reported (billion)	Simplified IFRS adjustments NOK (billion)	Simplified IFRS NOK (billion)	Simplified IFRS in USD (million) 1)[1]
EQUITY AND LIABILITIES				
Share capital	8.0		8.0	1,139
Additional paid-in capital	17.3		17.3	2,476
Reserves for valuation variances	38.1	2.5	40.6	4,612
Reserves for unrealised gains	0.0	9.8	9.8	1,113
Retained earnings	270.3	0.0	270.3	29,937
Total equity	333.7	12.3	346.0	39,277
Finance debt[3)]	260.5	1.7	262.2	29,764
Liabilities to subsidiaries and other equity accounted companies	0.1		0.1	15
Pension liabilities	26.1		26.1	2,965
Provisions[3)]	2.5	0.1	2.6	294
Derivative financial instruments[3)]	12.1	(0.8)	11.3	1,285
Total non-current liabilities	301.4	1.0	302.3	34,323
Trade and other payables[3)]	21.8	2.1	23.9	2,713
Current tax payable	(0.2)		(0.2)	(22)
Finance debt	19.8		19.8	2,243
Dividends payable	12.3		12.3	1,400
Liabilities to subsidiaries and other equity accounted companies[3)]	135.2	1.5	136.7	15,524
Derivative financial instruments[3)]	1.7	0.4	2.0	228
Total current liabilities	190.5	4.0	194.5	22,085
Total liabilities	491.9	5.0	496.9	56,407
Total equity and liabilities	825.6	17.3	842.9	95,684

1) Translated at exchange rate USD/NOK 8.809 as of 31 December 2015.

Oslo, 9 March 2017

THE BOARD OF DIRECTORS OF STATOIL ASA

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ELDAR SÆTRE
PRESIDENT AND CEO

The report set out below is provided in accordance with law, regulations, and auditing standards and practices generally accepted in Norway, including International Standards on Auditing (ISAs). KPMG AS has also issued reports in accordance with standards of the Public Company Accounting Oversight Board in the US, which include opinions on the consolidated financial statements of Statoil ASA and on the effectiveness of internal control over financial reporting as at 31 December 2016. Those reports are set out on pages 189 and 190.

Independent auditor's report

To the annual shareholders' meeting of Statoil ASA

Report on the audit of the financial statements

Opinion

We have audited the financial statements of Statoil ASA (the Company) for the year ended 31 December 2016.

The financial statements comprise:
- the Consolidated financial statements of Statoil ASA and its subsidiaries (the Group), which comprise the Consolidated balance sheet as at 31 December 2016, the Consolidated statements of income, comprehensive income, changes in equity and cash flows for the year then ended, and a summary of significant accounting policies and other explanatory information
- the parent company financial statements of Statoil ASA, which comprise the company balance sheet as at 31 December 2016, and the company's statements of income, comprehensive income and cash flows for the year then ended, and a summary of significant accounting policies and other explanatory information

In our opinion:
- the financial statements are prepared in accordance with relevant Norwegian law and regulations
- the Consolidated financial statements give a true and fair view of the financial position of Statoil ASA and its subsidiaries as at 31 December 2016, of its financial performance and its cash flows for the year then ended in accordance with International Financial Reporting Standards as adopted by the EU
- the parent company financial statements give a true and fair view of the financial position of Statoil ASA as at 31 December 2016, of its financial performance and its cash flows for the year then ended in accordance with simplified application of international accounting standards according to section 3-9 of the Norwegian Accounting Act

Basis for opinion

We conducted our audit in accordance with law, regulations, and auditing standards and practices generally accepted in Norway, including International Standards on Auditing (ISAs). Our responsibilities under those standards are further described in the 'Auditor's Responsibilities for the Audit of the Financial Statements' section of our report. We are independent of the Company and the Group as required by law and regulations, and we have fulfilled our ethical responsibilities in accordance with these requirements.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our opinion.

Key audit matters

Key audit matters are those matters that, in our professional judgment, were of most significance in our audit of the financial statements for the year ended 31 December 2016. These matters were addressed in the context of our audit of the financial statements as a whole, and in forming our opinion thereon, and we do not express any discrete opinion on these matters.

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Key audit matter	*Our response*
Valuation of upstream assets including assets under development, capitalised exploration expenses and acquisition costs for oil and gas prospects The Group owns significant upstream assets including assets under development, capitalised exploration expenses and acquisition costs for oil and gas prospects. The recoverability of these assets is dependent on management's estimates of the future cash flows that these assets are expected to produce. The carrying value of these assets are therefore particularly sensitive to changes in management's long term commodity price forecasts. Changes in short term commodity price forecasts, which management derives from observed forward oil and gas price curves over a one year period, can also have a significant impact for shorter-lived assets. In the fourth quarter of 2016, management reduced the Company's long term commodity price forecasts. Further, management reduced the discount rate used to calculate the value in use of these assets from 6.5% to 6.0%. The reduction in commodity price assumptions resulted in a large number of assets being triggered for impairment. Management also included business plan updates and capital expenditure forecasts and reserves updates that, in combination with the reduction of the discount rate and improved short term commodity price outlook, partially offset the effect of the reduction in the long term commodity price forecasts. Capitalised exploration expenses and the capitalised acquisition cost of oil and gas prospects are assessed for impairment when facts and circumstances suggest that the carrying amount of the asset may exceed its recoverable amount. Strategic decisions made by management, notably in the Gulf of Mexico and Brazil led to impairment of capitalized exploration expenses in 2016. Refer to note 10 *Property, plant and equipment* and note 11 *Intangible assets* to the Consolidated financial statements.	We evaluated and tested management's controls over the process it uses to identify triggers that would require impairment testing of specific assets. We also assessed the appropriateness of management's identification of cash generating units in light of our knowledge of the business. In addition, we undertook our own analysis to assess whether all material assets requiring impairment testing had been identified by management. We did not identify any assets where impairment testing was required that had not been identified by management. For those assets where management identified an impairment trigger, we evaluated and tested management's controls over the impairment calculations performed, including the assumptions applied. We assessed management's macroeconomic assumptions including short and long term commodity price, foreign currency rate and inflation rate forecasts and discount rates. We compared the short term price forecasts to observable market forward curves that we sourced independently. We compared management's long term assumptions to views published by brokers, economists, consultancies and respected industry bodies that we sourced independently, which provided a range of relevant third-party data points, and to our own views. We also assessed by reference to market data the inputs to and calculation of the discount rate used by management to assess whether the discount rate being applied was too low. The key inputs included the risk-free rate, market risk premium and industry financing structures (gearing and cost of debt and equity). In testing these assumptions we made use of KPMG valuation experts. For those assets where management identified an impairment trigger, we assessed the valuation method, estimates of future cash flows and challenged whether these were appropriate in light of: • management's commodity price, foreign currency rate and inflation rate forecasts • production and reserve estimates • capital and operating budgets and historical performance; and • previous estimates We assessed the mathematical accuracy of the valuation models and the accuracy of the impairment (reversal) recognised in the financial statements. Based on our procedures we consider the impairment charges/reversals to be appropriate. We considered whether the sensitivity analysis included in note 10 *Property, plant and equipment* appropriately described the Group's exposure to further impairments should future commodity prices deviate from management's forecasts. We evaluated and tested management's controls over the process it uses to evaluate whether the carrying value of capitalised exploration expenses and acquisition cost for oil and gas prospects is no longer sustainable. Based on our procedures on the exploration portfolio we consider the write-offs and the remaining carrying value to be appropriate.

Taxation The Group has operations in multiple countries, each with its own taxation regime. Management makes judgements and estimates in relation to uncertain tax positions. The Group has significant deferred tax assets and unrecognised tax losses, most notably in the US. The period over which such assets are expected to be recovered can be extensive and management applies significant judgement in assessing whether deferred tax assets should be recognised and to determine the recoverability of those balances. In addition, management applies significant judgement in estimating the provision relating to uncertain tax positions and/or related disclosure. These usually arise in countries where the fiscal contribution of the oil and gas industry to the country's budget is very significant and where the tax regime and administration are immature and/or developing. The most notable significant uncertain tax positions are the dispute with the Angolan Ministry of Finance regarding the Group's participation in Block 4, Block 15, Block 17 and Block 31 offshore Angola with regards to profit oil and taxes on activities between 2002 and 2012. Further, the Norwegian tax authorities have issued a deviation notice regarding transactions between Statoil Coordination Centre (SSC) in Belgium and Norwegian entities within the Group. The issue relates to SCC's capital structure and compliance with the arm's length principle. In addition, the Brazilian tax authorities have issued a tax assessment for 2011 disputing the allocation of sale proceeds between entities and assets involved, with regard to a divestment of 40% interest in the Peregrino field to Sinochem at the time. Refer to note 9 *Income taxes* and note 23 *Other commitments, contingent liabilities and contingent assets* to the Consolidated financial statements.	We evaluated and tested management's controls over the process it uses to recognise deferred tax assets, to determine unrecognised tax losses and to determine provisions for uncertain tax positions and/or related disclosure. In determining the extent to which deferred tax assets should be recognised, management applied long term commodity price forecasts and foreign currency assumptions as described in the key audit matter relating to valuation of upstream assets including assets under development, capitalised exploration expenses and acquisition costs for oil and gas prospects. We challenged the key assumptions made by management and confirmed that these were consistent with the long term business plans used by management to manage and monitor the development of the business. We performed detailed testing over the tax position in each significant jurisdiction in which the Group operates using our global and local tax experts as appropriate. We examined and assessed correspondence with tax authorities and the Group's tax advisers and papers relating to tax investigations/cases as appropriate. The calculations used by management to determine the provisions for uncertain tax positions were assessed, based on our understanding of the position of the Group and the position of the tax authorities. We consider that the provisions for uncertain tax positions and related disclosure are appropriate. We highlighted the high level of inherent uncertainty in some of the positions.
Estimate of asset retirement obligation Given the nature of its operations, the Group incurs obligations to dismantle and remove facilities and to restore the site on which it is located. Management applies significant judgement to estimate the asset retirement obligation due to inherent complexity in estimating future costs and the limited historical experience against which to benchmark estimates of future costs. Key assumptions include future abandonment costs, foreign currency assumptions and inflation rates. Refer to note 20 *Provisions* to the Consolidated financial statements.	We challenged the key assumptions in management's annual review process for determining the asset retirement obligation. Our testing was focused on those assumptions having the most significant impact on the asset retirement obligation selected based on our sensitivity analysis. To validate the appropriateness of the expected future abandonment costs we tested whether technical inputs including the number of wells, weight of the structure and length of pipelines applied in the calculation are consistent with technical assessments of the relevant fields. Further, we assessed the reasonableness of rig rates using external market data and historic rig contracts. Our procedures over foreign currency assumptions and inflation rates were an integral part of our assessment of assumptions as applied in impairment testing. We refer to our response as described in the key audit matter over the valuation of upstream including assets under development, capitalised exploration expenses and acquisition costs for oil and gas prospects. Based on our procedures, we consider management's estimate of the asset retirement obligation as at 31 December 2016 to be appropriate.

Other information

Management is responsible for the other information. The other information comprises the chapters introduction, strategic report, governance and additional information included in the annual report, but does not include the financial statements and our auditor's report thereon.

Our opinion on the financial statements does not cover the other information and note 27 Supplementary oil and gas information to the Consolidated financial statements, and we do not express any form of assurance conclusion thereon.

In connection with our audit of the financial statements, our responsibility is to read the other information and, in doing so, consider whether the other information is materially inconsistent with the financial statements or our knowledge obtained in the audit or otherwise appears to be materially misstated.

If, based on the work we have performed, we conclude that there is a material misstatement of this other information, we are required to report that fact. We have nothing to report in this regard.

Responsibilities of management and board of directors for the financial statements

Management is responsible for the preparation and fair presentation of the financial statements of the parent company in accordance with simplified application of international accounting standards according to the Norwegian Accounting Act section 3-9, and for the preparation and fair presentation of the Consolidated financial statements of the Group in accordance with International Financial Reporting Standards as adopted by the EU, and for such internal control as management determines is necessary to enable the preparation of financial statements that are free from material misstatement, whether due to fraud or error.

In preparing the financial statements, management is responsible for assessing the Company's ability to continue as a going concern, disclosing, as applicable, matters related to going concern and using the going concern basis of accounting unless management either intends to liquidate the Group or to cease operations, or has no realistic alternative but to do so.

Auditor's responsibilities for the audit of the financial statements

Our objectives are to obtain reasonable assurance about whether the financial statements as a whole are free from material misstatement, whether due to fraud or error, and to issue an auditor's report that includes our opinion. Reasonable assurance is a high level of assurance, but is not a guarantee that an audit conducted in accordance with law, regulations, and auditing standards and practices generally accepted in Norway, including ISAs will always detect a material misstatement when it exists. Misstatements can arise from fraud or error and are considered material if, individually or in the aggregate, they could reasonably be expected to influence the economic decisions of users taken on the basis of these financial statements (see further explanation below).

As part of an audit in accordance with law, regulations, and auditing standards and practices generally accepted in Norway, including ISAs, we exercise professional judgment and maintain professional scepticism throughout the audit. We also:

- identify and assess the risks of material misstatement of the financial statements, whether due to fraud or error, design and perform audit procedures responsive to those risks, and obtain audit evidence that is sufficient and appropriate to provide a basis for our opinion. The risk of not detecting a material misstatement resulting from fraud is higher than for one resulting from error, as fraud may involve collusion, forgery, intentional omissions, misrepresentations, or the override of internal control
- obtain an understanding of internal control relevant to the audit in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's or the Group's internal control
- evaluate the appropriateness of accounting policies used and the reasonableness of accounting estimates and related disclosures made by management
- conclude on the appropriateness of management's use of the going concern basis of accounting and, based on the audit evidence obtained, whether a material uncertainty exists related to events or conditions that may cast significant doubt on the Company's and the Group's ability to continue as a going concern. If we conclude that a material uncertainty exists, we are required to draw attention in our auditor's report to the related disclosures in the financial statements or, if such disclosures are inadequate, to modify our opinion. Our conclusions are based on the audit evidence obtained up to the date of our auditor's report. However, future events or conditions may cause the Company to cease to continue as a going concern
- evaluate the overall presentation, structure and content of the financial statements, including the disclosures, and whether the financial statements represent the underlying transactions and events in a manner that achieves fair presentation
- obtain sufficient appropriate audit evidence regarding the financial information of the entities or business activities within the Group to express an opinion on the Consolidated financial statements. We are responsible for the direction, supervision and performance of the Group audit. We remain solely responsible for our audit opinion

We communicate with the board of directors regarding, among other matters, the planned scope and timing of the audit and significant audit findings, including any significant deficiencies in internal control that we identify during our audit.

We also provide the board of directors with a statement that we have complied with relevant ethical requirements regarding independence, and to communicate with them all relationships and other matters that may reasonably be thought to bear on our independence, and where applicable, related safeguards.

From the matters communicated with the board of directors, we determine those matters that were of most significance in the audit of the financial statements of the current period and are therefore the key audit matters. We describe these matters in our auditor's report unless law or regulation precludes public disclosure about the matter or when, in extremely rare circumstances, we determine that a matter should not be communicated in our report because the adverse consequences of doing so would reasonably be expected to outweigh the public interest benefits of such communication.

Report on other legal and regulatory requirements

Opinion on the board of directors' report and the statements on corporate governance and corporate social responsibility

Based on our audit of the financial statements as described above, it is our opinion that the information presented in the board of directors' report and in the statements on corporate governance and corporate social responsibility concerning the financial statements and the going concern assumption, and the proposal for the coverage of the loss is consistent with the financial statements and complies with relevant law and regulations.

Opinion on registration and documentation

Based on our audit of the financial statements as described above, and procedures we considered necessary in accordance with the International Standard on Assurance Engagements (ISAE) 3000, «Assurance Engagements Other than Audits or Reviews of Historical Financial Information», it is our opinion that management has fulfilled its duty to produce a proper and clearly set out registration and documentation of the Company's accounting information in accordance with relevant law and bookkeeping standards and practices generally accepted in Norway.

Oslo, 9 March 2017
KPMG AS

Mona Irene Larsen
State authorised public accountant 5

Jimmy Daboo

[Translation has been made for information purposes only]

5 Appointed as the responsible auditor by KPMG AS according to the Auditing and Auditors Act section 2-2

Additional information

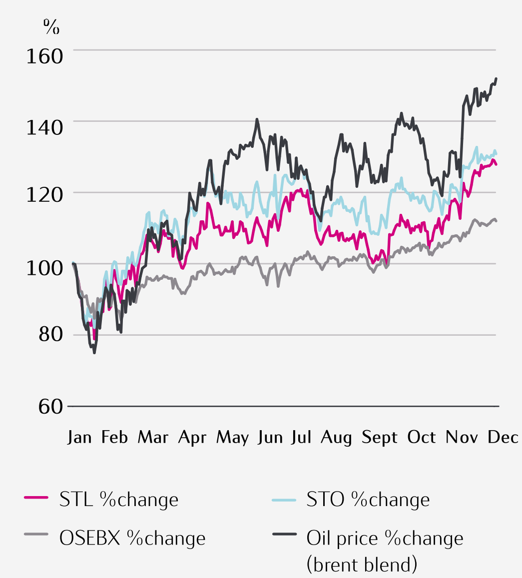
5.1 SHAREHOLDER INFORMATION

Statoil is the largest company listed on the Oslo Børs where it trades under the ticker code STL. Statoil is also listed on the New York Stock Exchange under the ticker code STO, trading in the form of American Depositary Shares (ADS).

Statoil's shares have been listed on the Oslo Børs since our initial public offering on 18 June 2001. The ADSs traded on the New York Stock Exchange are evidenced by American Depositary Receipts (ADR), and each ADS represents one ordinary share.

Statoil Share	2016	2015	2014	2013	2012
Shareprice STL (low) (NOK)	97.90	116.30	120.00	123.00	133.80
Shareprice STL (average) (NOK)	133.50	137.59	166.41	136.72	146.97
Shareprice STL (high) (NOK)	159.80	160.80	194.80	147.70	162.40
Shareprice STL (year-end) (NOK)	158.40	123.70	131.20	147.00	139.00
Shareprice STO (low) (USD)	11.38	13.42	15.82	20.14	22.15
Shareprice STO (average) (USD)	15.92	17.11	26.52	23.32	25.29
Shareprice STO (high) (USD)	18.51	21.31	31.91	27.00	28.92
Shareprice STO (year-end) (USD)	18.24	13.96	17.61	24.13	25.04
STL Market value year-end (NOK billion)	514	394	418	469	443
STL Daily turnover (million shares)	4.7	5.1	3.7	3.0	4.3
Ordinary shares outstanding, year-end	3,245,049,411	3,188,647,103	3,188,647,103	3,188,647,103	3,188,647,103

Statoil share price 2016



As of 31 December 2016, Statoil represented 23.24% of the total value of all companies registered on the Oslo Børs, with a market value of NOK 514 billion. Total shareholder return (dividend reinvested) for 2016 is 35.4%.

The graph shows the development of the Statoil share price compared to the oil price and the Oslo Børs Benchmark Index (OSEBX). The turnover of shares is a measure of traded volumes. On average, 4.62 million Statoil shares were traded on the Oslo Børs every day in 2016 compared to 5.1 million shares in 2015. In 2016, Statoil shares accounted for 15% of the total market value traded throughout the year which is equal to 2015.

Statoil ASA has one class of shares, and each share confers one vote at the general meeting. Statoil ASA had 3,245,049,411 ordinary shares outstanding at year end. As of 31 December 2016, Statoil had 91,128 shareholders registered in the Norwegian Central Securities Depository (VPS), down from 91,774 shareholders at 31 December 2015.

Share prices

These are the reported high and low quotations at market closing for the ordinary shares on the Oslo Børs and New York Stock Exchange for the periods indicated. They are derived from the Oslo Børs Daily Official List, and the highest and lowest sales prices of the ADSs as reported on the New York Stock Exchange composite tape.

Share price	NOK per ordinary share High	NOK per ordinary share Low	USD per ADS High	USD per ADS Low
Year ended 31 December				
2012	162.40	133.80	28.92	22.15
2013	147.70	123.00	27.00	20.14
2014	194.80	120.00	31.91	15.82
2015	160.80	116.30	21.31	13.42
2016	159.80	97.90	18.51	11.38
Quarter ended				
Monday, March 31, 2015	149.80	125.80	19.62	16.25
Monday, June 30, 2015	160.80	140.10	21.31	17.59
Wednesday, September 30, 2015	141.40	116.30	17.56	13.85
Thursday, December 31, 2015	145.60	118.70	17.74	13.42
Thursday, March 31, 2016	135.50	97.90	16.01	11.38
Thursday, June 30, 2016	144.80	122.40	17.68	14.66
Friday, September 30, 2016	149.80	124.00	17.74	15.07
Friday, December 30, 2016	159.80	129.30	18.51	15.86
Up until March 8, 2017	162.90	97.90	19.21	11.38
Month of				
September 2016	135.00	124.00	16.80	15.07
October 2016	140.70	133.90	17.30	16.24
November 2016	146.40	129.30	17.40	15.86
December 2016	159.80	147.30	18.51	18.51
January 2017	162.90	153.40	19.21	18.47
February 2017	156.50	147.10	18.81	17.41
Up until March 8, 2017	162.90	122.40	19.21	14.66

Dividend policy and dividends

It is Statoil's ambition to grow the annual cash dividend measured in USD per share in line with long-term underlying earnings.

Statoil's board approves first, second and third quarter interim dividends, based on an authorisation from the annual general meeting (AGM), while the AGM approves the fourth quarter dividend and implicitly the total annual dividend based on a proposal from the board. It is Statoil's intention to pay quarterly dividends, although when deciding the interim dividends and recommending the total annual dividend level, the board will take into consideration expected cash flow, capital expenditure plans, financing requirements and appropriate financial flexibility.

In addition to cash dividend, Statoil might buy back shares as part of total distribution of capital to the shareholders. The shareholders at the AGM may vote to reduce, but may not increase, the fourth quarter dividend proposed by the board of directors. Statoil announces dividend payments in connection with quarterly results.

Payment of quarterly dividends is expected to take place within six months after the announcement of each quarterly dividend.

The board of directors proposes to the AGM a dividend of USD 0.2201 per share for the fourth quarter 2016 and to continue with the two-year scrip dividend programme which started from fourth quarter 2015. The scrip programme will give shareholders the option to receive quarterly dividends in cash or in newly issued shares in Statoil at a 5% discount for the fourth quarter 2016. On 11 May 2016, Statoil and the Norwegian state entered into a two-year agreement whereby the Norwegian state shall use the part of its quarterly dividend to subscribe for the number of shares that is required to maintain its ownership of 67%. Any part of the Dividend not used as settlement for dividend shares by the Norwegian state shall be paid in cash. For further information about dividends and our scrip dividend programme see Statoil.com.

The following table shows the cash dividend amounts to all shareholders since 2011 on a per share basis and in aggregate.

ADDITIONAL INFORMATION

	Ordinary dividend per share									Ordinary dividend per share
Fiscal year	Curr.	Q1	Curr.	Q2	Curr.	Q3	Curr.	Q4	Curr.	
2012									NOK	6.7500
2013									NOK	7.0000
2014	NOK	1.8000	NOK	1.8000	NOK	1.8000	NOK	1.8000	NOK	7.2000
2015	NOK	1.8000	NOK	0.0000	NOK	0.0000	NOK	0.0000	NOK	1.8000
2015	USD	0.0000	USD	0.2201	USD	0.2201	USD	0.2201	USD	0.6603
2016	USD	0.2201	USD	0.2201	USD	0.2201	USD	0.2201	USD	0.8804

The proposed fourth quarter 2016 dividend will be considered at the annual general meeting 11 May 2017. The Statoil share will be traded ex dividend 12 May 2017 and the dividend will be disbursed around late June 2017. For US ADR holders, the ex-dividend date will be 11 May 2017 and expected payment and allocation of new dividend shares for ADR holders will be in June 2017.

Dividends in NOK per share will be calculated and communicated four business days after record date for shareholders at Oslo Børs. The NOK dividend will be based on average USD/NOK fixing rates from Norges Bank in the period plus/minus three business days from record date, in total seven business dates.

Share repurchase
For the period 2013-2016, the board of directors was authorised by the annual general meeting of Statoil to repurchase Statoil shares in the market for subsequent annulment. Statoil has not undertaken any share repurchase based on this authorisation.

It is Statoil's intention to renew this authorisation at the annual general meeting in May 2017.

SHARES PURCHASED BY ISSUER

Shares are acquired in the market for transfer to employees under the share savings scheme in accordance with the limits set by the board of directors. No shares were repurchased in the market for the purpose of subsequent annulment in 2016.

Statoil's share savings plan

Since 2004, Statoil has had a share savings plan for employees of the company. The purpose of this plan is to strengthen the business culture and encourage loyalty through employees becoming part-owners of the company.

Through regular salary deductions, employees can invest up to 5% of their base salary in Statoil shares. In addition, the company contributes 20% of the total share investment made by employees in Norway, up to a maximum of NOK 1,500 per year (approximately USD 170). This company contribution is a tax-free employee benefit under current Norwegian tax legislation. After a lock-in period of two calendar years, one extra share will be awarded for each share purchased. Under current Norwegian tax legislation, the share award is a taxable employee benefit, with a value equal to the value of the shares and taxed at the time of the award.

The board of directors is authorized to acquire Statoil shares in the market on behalf of the company. The authorization is valid until the next annual general meeting, but not beyond 30 June 2017. This authorisation replaces the previous authorisation to acquire Statoil's own shares for implementation of the share savings plan granted by the annual general meeting 19 May 2015. It is Statoil's intention to renew this authorisation at the annual general meeting. Statoil intends to use share buybacks more actively going forward, based on balance sheet strength considerations.

Period in which shares were repurchased	Number of shares repurchased	Average price per share in NOK	Total number of shares purchased as part of programme	Maximum number of shares that may yet be purchased under the programme authorisation
Jan-16	878,834	102.6997	5,821,999	8,178,001
Feb-16	745,858	117.5826	6,567,857	7,432,143
Mar-16	700,095	127.9825	7,267,952	6,732,048
Apr-16	682,975	130.5009	7,950,927	6,049,073
May-16	657,216	135.2827	8,608,143	5,391,857
Jun-16	665,179	133.1370	665,179	13,334,821
Jul-16	589,151	149.4623	1,254,330	12,745,670
Aug-16	653,493	134.1070	1,907,823	12,092,177
Sep-16	703,884	124.1965	2,611,707	11,388,293
Oct-16	627,062	138.7885	3,238,769	10,761,231
Nov-16	631,197	137.8332	3,869,966	10,130,034
Dec-16	567,259	153.3690	4,437,225	9,562,775
Jan-17	520,716	162,6375	4,957,941	9,042,059
Feb-17	577,674	147.8341	5,535,615	8,464,385
TOTAL	9,200,593 [1)]	144.3980 [2)]		

1) All shares repurchased have been purchased in the open market and pursuant to the authorisation mentioned above.

2) Weighted average price per share.

Statoil ADR programme fees

Fees and charges payable by a holder of ADSs.
As depositary from 31 January 2013, Deutsche Bank Trust Company Americas collects its fees for the delivery and surrender of ADSs directly from investors depositing shares or surrendering ADSs for the purpose of withdrawal, or from intermediaries acting for them.

The depositary collects fees from investors by deducting the fees from the amounts distributed or by selling a portion of distributable property to pay the fees. The depositary may refuse to provide fee-attracting services until its fees for those services are paid.

The charges of the depositary payable by investors are as follows:

Persons depositing or withdrawing shares must pay:	For:
USD 5.00 (or less) per 100 ADSs (or portion of 100 ADSs)	· Issuance of ADSs, including issuances resulting from a distribution of shares or rights or other property · Cancellation of ADSs for the purpose of withdrawal, including if the deposit agreement terminates
USD 0.02(or less) per ADS, subject to the company's consent	· Any cash distribution to ADS registered holders
USD 0.05 (or less) per ADS, subject to the company's consent	· For the operation and maintenance costs in administering the ADR programme
A fee equivalent to the fee that would be payable if securities distributed to you had been shares and the shares had been deposited for issuance of ADSs	· Distribution of securities distributed to holders of deposited securities which are distributed by the Depositary to ADS registered holders
Registration or transfer fees	· Transfer and registration of shares on our share register to or from the name of the Depositary or its agent when you deposit or withdraw shares
Expenses of the Depositary	· Cable, telex and facsimile transmissions (as provided in the deposit agreement) · Converting foreign currency to USD
Taxes and other governmental charges the Depositary or the custodian have to pay on any ADS or share underlying an ADS, for example, stock transfer taxes, stamp duty or withholding taxes	· As necessary
Any charges incurred by the Depositary or its agents for servicing the deposited securities	· As necessary

Reimbursements and payments made and fee waivers granted by the depositary
The depositary has agreed to reimburse certain company expenses related to the company's ADR programme and incurred by the company in connection with the programme. In the year ended 31 December 2016, the depositary reimbursed approximately USD 1.29 million to the company in relation to certain expenses including investor relations expenses, expenses related to the maintenance of the ADR programme, legal counsel fees, printing and ADR certificates.

The depositary has also agreed to waive fees for costs associated with the administration of the ADR programme, and it has paid certain expenses directly to third parties on behalf of the company. The expenses paid to third parties include expenses relating to reporting services, access charges to its online platform, re-registration costs borne by the custodian and costs in relation to printing and mailing AGM materials. For the year ended 31 December 2016, the depositary paid expenses of approximately USD 214,814 directly to third parties.

TAXATION

This section describes the material Norwegian tax consequences that apply to shareholders resident in Norway and to non-resident shareholders in connection with the acquisition, ownership and disposal of shares and American Depositary Shares (ADS). The term "shareholder" refers to both holders of shares and holders of ADSs, unless otherwise explicitly stated.

Norwegian tax matters

The outline does not provide a complete description of all tax regulations that might be relevant (i.e. for investors to whom special regulations may be applicable), and is based on current law and practice. Shareholders should consult their professional tax adviser for advice about individual tax consequences.

Taxation of dividends

Corporate shareholders (i.e. limited liability companies and similar entities) residing in Norway for tax purposes are generally subject to tax in Norway on dividends received from Norwegian companies. The basis for taxation is 3% of the dividends received, which is subject to the standard income tax rate. The standard income tax rate has been reduced from 25% in 2016 to 24% in 2017.

Individual shareholders resident in Norway for tax purposes are subject to the standard income tax rate (reduced from 25% in 2016 to 24% in 2017) in Norway for dividend income exceeding a basic tax free allowance. However, in 2017 dividend income exceeding the basic tax free allowance is grossed up with a factor of 1.24 before included in the ordinary taxable income, resulting in an effective tax rate of 29.76% (24% x 1.24). The tax free allowance is computed for each individual share or ADS and corresponds as a rule to the cost price of that share or ADS multiplied by an annual risk-free interest rate. Any part of the calculated allowance for one year that exceeds the dividend distributed for the share or ADS ("unused allowance") may be carried forward and set off against future dividends received for (or gains upon the realisation of, see below) the same share or ADS. Any unused allowance will also be added to the basis for computation of the allowance for the same share or ADS the following year.

Non-resident shareholders are as a rule subject to withholding tax at a rate of 25% on dividends distributed by Norwegian companies. It is the responsibility of the distributing company to deduct the withholding tax when dividends are paid to non-resident shareholders. This withholding tax does not apply to corporate shareholders in the EEA area that document that they are genuinely established and carry on genuine economic business activity within the EEA area, provided that Norway is entitled to receive information from the state of residence pursuant to a tax treaty or other international treaty. If no such treaty exists with the state of residence, the shareholder may instead present confirmation issued by the tax authorities of the state of residence verifying the documentation. Individual shareholders resident for tax purposes in the EEA area may apply to the Norwegian tax authorities for a refund if the tax withheld by the distributing company exceeds the tax that would have been levied on individual shareholders resident in Norway.

The withholding rate of 25% is often reduced in tax treaties between Norway and other countries. The reduced withholding rate will generally only apply to dividends paid on shares held by shareholders who are able to properly demonstrate that they are the beneficial owner and entitled to the benefits of the tax treaty.

For holders of shares and ADSs deposited with Deutsche Bank Trust Company Americas (Deutsche Bank), documentation establishing that the holder is eligible for the benefits under the tax treaty with Norway, may be provided to Deutsche Bank. Deutsche Bank has been granted permission by the Norwegian tax authorities to receive dividends from us for redistribution to a beneficial owner of shares and ADSs at the applicable treaty withholding rate.

Dividends paid to shareholders (either directly or through a depositary) who have not provided the relevant documentation to the relevant party that they are eligible for the reduced rate, will be subject to withholding tax of 25%. The beneficial owners will in this case have to apply to the Central Office - Foreign Tax Affairs for a refund of the excess amount of tax withheld.

Corporate shareholders that carry on business activities in Norway, and whose shares or ADSs are effectively connected with such activities are not subject to withholding tax. For such shareholders, 3% of the received dividends are subject to the standard income tax rate (reduced from 25% in 2016 to 24% in 2017).

Taxation on the realisation of shares and ADSs

Corporate shareholders resident in Norway for tax purposes are not subject to tax in Norway on gains derived from the sale, redemption or other disposal of shares or ADSs in Norwegian companies. Capital losses are not deductible.

Individual shareholders residing in Norway for tax purposes are subject to tax in Norway on the sale, redemption or other disposal of shares or ADSs. Gains or losses in connection with such realisation are included in the individual's ordinary taxable income in the year of disposal, which is subject to the standard income tax rate, being reduced from 25% in 2016 to 24% in 2017. However, in 2017 the taxable gain or deductible loss is grossed up with a factor of 1.24 before included in the ordinary taxable income, resulting in an effective tax rate of 29.76% (24% x 1.24).

The taxable gain or deductible loss (before gross up) is calculated as the sales price adjusted for transaction expenses minus the taxable basis. A shareholder's tax basis is normally equal to the acquisition cost of the shares or ADSs. Any unused allowance pertaining to a share may be deducted from a taxable gain on the same share or ADS, but may not lead to or increase a deductible loss. Furthermore, any unused allowance may not be set off against gains from the realisation of the other shares or ADSs.

If the shareholder disposes of shares or ADSs acquired at different times, the shares or ADSs that were first acquired will be deemed to be first sold (the "FIFO" principle) when calculating gain or loss for tax purposes.

From 2017, individual shareholders may hold listed shares in companies resident within EEA through a stock savings account. If the conditions for the stock savings account are met, taxable gain or loss on shares owned through the stock savings account will be payable when deposits are withdrawn from the account whereas loss on shares will be deductible when the account is terminated. Dividends are not comprised by the stock savings account scheme and will thus be taxed pursuant to the ordinary rules described above.

A corporate shareholder or an individual shareholder who ceases to be tax resident in Norway due to domestic law or tax treaty provisions may, in certain circumstances, become subject to Norwegian exit taxation on capital gains related to shares or ADSs.

Shareholders not residing in Norway are generally not subject to tax in Norway on capital gains, and losses are not deductible on the sale, redemption or other disposal of shares or ADSs in Norwegian companies, unless the shareholder carries on business activities in Norway and such shares or ADSs are or have been effectively connected with such activities.

Wealth tax
The shares or ADSs are included in the basis for the computation of wealth tax imposed on individuals resident in Norway for tax purposes. Norwegian limited companies and certain similar entities are not subject to wealth tax. The current marginal wealth tax rate is 0.85% of the value assessed. The assessment value of listed shares (including ADSs) is 90% of the listed value of such shares or ADSs on 1 January in the assessment year.

Non-resident shareholders are not subject to wealth tax in Norway for shares and ADSs in Norwegian limited companies unless the shareholder is an individual and the shareholding is effectively connected with the individual's business activities in Norway.

Inheritance tax and gift tax
No inheritance or gift tax is imposed in Norway.

Transfer tax
No transfer tax is imposed in Norway in connection with the sale or purchase of shares or ADSs.

United States tax matters
This section describes the material United States federal income tax consequences for US holders (as defined below) of owning shares or ADSs. It only applies to you if you hold your shares or ADSs as capital assets for tax purposes and are not a member of a special class of holders subject to special rules, including dealers in securities, insurance companies, partnerships, persons liable for the alternative minimum tax, persons that actually or constructively own 10% of the voting stock of Statoil, persons that hold shares or ADSs as part of a straddle or a hedging or conversion transaction, or persons whose functional currency is not USD.

This section is based on the Internal Revenue Code of 1986, as amended, its legislative history, existing and proposed regulations, published rulings and court decisions, and the Convention between the United States of America and the Kingdom of Norway for the Avoidance of Double Taxation and the Prevention of Fiscal Evasion with Respect to Taxes on Income and Property (the "Treaty"). These laws are subject to change, possibly on a retroactive basis. In addition, this section is based in part upon the representations of the depositary and the assumption that each obligation in the deposit agreement and any related agreement will be performed in accordance with its terms. For United States federal income tax purposes, if you hold ADRs evidencing ADSs, you will generally be treated as the owner of the ordinary shares represented by those ADRs. Exchanges of shares for ADRs and ADRs for shares will not generally be subject to United States federal income tax.

A "US holder" is a beneficial owner of shares or ADSs that is: (i) a citizen or resident of the United States; (ii) a United States domestic corporation; (iii) an estate whose income is subject to United States federal income tax regardless of its source; or (iv) a trust if a United States court can exercise primary supervision over the trust's administration and one or more United States persons are authorised to control all substantial decisions of the trust.

You should consult your own tax adviser regarding the United States federal, state and local and Norwegian and other tax consequences of owning and disposing of shares and ADSs in your particular circumstances.

Taxation of dividends
The gross amount of any dividend (including any Norwegian tax withheld from the dividend payment) paid by Statoil out of its current or accumulated earnings and profits (as determined for United States federal income tax purposes) is taxable for you when you, in the case of shares, or the depositary, in the case of ADSs, receive the dividend, actually or constructively. If you are a non-corporate US holder, dividends paid to you will be eligible to be taxed at the preferential rates applicable to long-term capital gains as long as, in the year that you receive the dividend, the shares or ADSs are readily tradable on an established securities market in the United States or Statoil is eligible for benefits under the Treaty. To qualify for the preferential rates, you must hold the shares or ADSs for more than 60 days during the 121-day period beginning 60 days before the ex-dividend date and meet certain other requirements. The dividend will not be eligible for the dividends-received deduction generally allowed to United States corporations in respect of dividends received from other United States corporations.

The amount of the dividend distribution that you must include in your income as a US holder will be the value in USD of the payments made in NOK determined at the spot NOK/USD rate on the date the dividend distribution is includible in your income, regardless of whether or not the payment is in fact converted into USD. Distributions in excess of current and accumulated earnings and profits, as determined for United States federal income tax purposes, will be treated as a non-taxable return of capital to the extent of your tax basis in the shares or ADSs and, to the extent in excess of your tax basis, will be treated as capital gain.

Subject to certain limitations, the 15% Norwegian tax withheld in accordance with the Treaty and paid to Norway will be creditable or deductible against your United States federal income tax liability, unless a refund of the tax withheld is available to you under Norwegian law. Special rules apply when determining the foreign tax credit limitation with respect to dividends that are subject to the preferential rates. Dividends will be income from sources outside the United States and will generally, depending on your circumstances, be either "passive" or "general" income for purposes of computing the foreign tax credit allowable to you. Any gain or loss resulting from currency exchange rate fluctuations during the period from the date you include the dividend payment in income until the date you convert the payment into USD will generally be treated as US-source ordinary income or loss and will not be eligible for the special tax rate.

Taxation of capital gains
If you sell or otherwise dispose of your shares or ADSs, you will generally recognise a capital gain or loss for United States federal income tax purposes equal to the difference between the value in USD of the amount that you realise and your tax basis, determined in USD, in your shares or ADSs. A capital gain of a non-corporate US

holder is generally taxed at preferential rates if the property is held for more than one year. The gain or loss will generally be income or loss from sources within the United States for foreign tax credit limitation purposes. If you receive any foreign currency on the sale of shares or ADSs, you may recognise ordinary income or loss from sources within the United States as a result of currency fluctuations between the date of the sale of the shares or ADSs and the date the sales proceeds are converted into USD. You should consult your own tax adviser regarding how to account for payments made or received in a currency other than USD.

PFIC rules

We believe that the shares and ADSs should not be treated as stock of a PFIC for United States federal income tax purposes, but this conclusion is a factual determination that is made annually and thus may be subject to change. If we were to be treated as a PFIC, a gain realised on the sale or other disposition of the shares or ADSs would in general not be treated as a capital gain. Instead, unless you elect to be taxed annually on a mark-to-market basis with respect to the shares or ADSs, you would be treated as if you had realised such gain and certain "excess distributions" ratably over your holding period for the shares or ADSs. Amounts allocated to the year in which the gain is realised or the “excess distribution” is received or to a taxable year before we were classified as a PFIC would be subject to tax at ordinary income tax rates, and amounts allocated to all other years would be taxed at the highest tax rate in effect for each such year to which the gain or distribution was allocated, together with an interest charge in respect of the tax attributable to each such year. With certain exceptions, your shares or ADSs will be treated as stock in a PFIC if we were a PFIC at any time during the period you held the shares or ADSs. Dividends that you receive from us will not be eligible for the preferential tax rates if we are treated as a PFIC with respect to you, either in the taxable year of the distribution or the preceding taxable year, but will instead be taxable at rates applicable to ordinary income.

Foreign Account Tax Compliance Withholding

A 30% withholding tax will be imposed on certain payments to certain non-US financial institutions that fail to comply with information reporting requirements or certification requirements in respect of their direct and indirect United States shareholders and/or United States accountholders. To avoid becoming subject to the 30% withholding tax on payments to them, we and other non-US financial institutions may be required to report information to the IRS regarding the holders of shares or ADSs and to withhold on a portion of payments under the shares or ADSs to certain holders that fail to comply with the relevant information reporting requirements (or hold shares or ADSs directly or indirectly through certain non-compliant intermediaries). However, such withholding will not apply to payments made before January 1, 2019. The rules for the implementation of this legislation have not yet been fully finalised, so it is impossible to determine at this time what impact, if any, this legislation will have on holders of the shares and ADSs.

EXCHANGE RATES

The table below shows the high, low, average and end-of-period exchange rates for the Norwegian krone for USD 1.00 as announced by Norges Bank (Norway's central bank).

The average is computed using the quarterly average exchange rates announced by Norges Bank during the period indicated.

For the year ended 31 December	Low	High	Average	End of Period
2012	5.5349	6.1471	5.8172	5.5664
2013	5.4438	6.2154	5.8753	6.0837
2014	5.8611	7.6111	6.3011	7.4332
2015	7.3593	8.8090	8.0637	8.8090
2016	7.9766	8.9578	8.4014	8.6200

	Low	High
2016		
September	8.0517	8.3483
October	7.9766	8.2810
November	8.1780	8.6138
December	8.3662	8.7277
2017		
January	8.2641	8.6676
February	8.1953	8.3868
March (up to and including 8 March 2017)	8.4134	8.4798

On 8 March 2017, the exchange rate announced by the Norges Bank for the Norwegian krone was USD 1.00 = NOK 8.4798

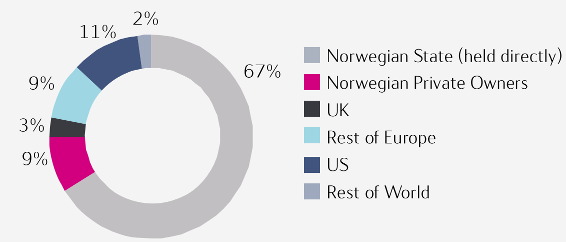
Fluctuations in the exchange rate between the NOK and USD will affect the amounts in USD received by holders of American Depositary Shares (ADSs) on the conversion of dividends, if any, paid in Norwegian kroner on the ordinary shares, and they may affect the USD price of the ADSs on the New York Stock Exchange.

ADDITIONAL INFORMATION

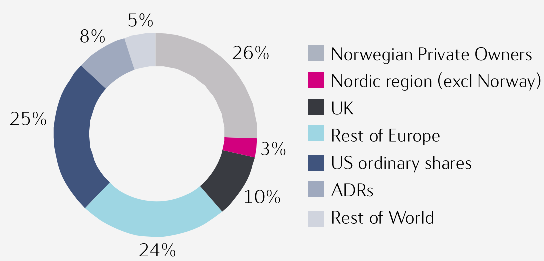
MAJOR SHAREHOLDERS

The Norwegian State is the largest shareholder in Statoil, with a direct ownership interest of 67%. Its ownership interest is managed by the Norwegian Ministry of Petroleum and Energy.

Distribution of shareholders at year end 2016



Free float breakdown



Pursuant to the exchange ratio agreed in connection with the merger with Hydro's oil and gas activities, the State's ownership interest in the merged company was 62.5%, or 1,992,959,739 shares, on 1 October 2007. In accordance with the Norwegian parliament's decision of 2001 concerning a minimum state shareholding in Statoil of two-thirds, the Government built up the State's ownership interest in Statoil by buying shares in the market during the period from June 2008 to March 2009. In March 2009, the Government announced that the State's direct ownership interest had reached 67% and the Government's direct purchase of Statoil shares was completed.

As of 31 December 2016, the Norwegian State had a 67% direct ownership interest in Statoil and a 3.22% indirect interest through the National Insurance Fund (Folketrygdfondet), totaling 70.22%. Also, the Norwegian State has entered into an agreement where it commits for each quarterly dividend where a scrip option is offered to receive newly issued shares for a fraction of its shareholdings equal to the average participation among the other shareholders. This to ensure that the States ownership share is not impacted by the scrip programme.

Statoil has one class of shares, and each share confers one vote at the general meeting. The Norwegian State does not have any voting rights that differ from the rights of other ordinary shareholders. Pursuant to the Norwegian Public Limited Liability Companies Act, a majority of at least two-thirds of the votes cast as well as of the votes represented at a general meeting is required to amend our articles of association. As long as the Norwegian State owns more than one-third of our shares, it will be able to prevent any amendments to our articles of association. Since the Norwegian State, acting through the Norwegian Minister of Petroleum and Energy, has in excess of two-thirds of the shares in the company, it has sole power to amend our articles of association. In addition, as majority shareholder, the Norwegian State has the power to control any decision at general meetings of our shareholders that requires a majority vote, including the election of the majority of the corporate assembly, which has the power to elect our board of directors and approve the dividend proposed by the board of directors.

The Norwegian State endorses the principles set out in "The Norwegian Code of Practice for Corporate Governance", and it has stated that it expects companies in which the State has ownership interests to adhere to the code. The principle of ensuring equal treatment of different groups of shareholders is a key element in the State's own guidelines. In companies in which the State is a shareholder together with others, the State wishes to exercise the same rights and obligations as any other shareholder and not act in a manner that has a detrimental effect on the rights or financial interests of other shareholders. In addition to the principle of equal treatment of shareholders, emphasis is also placed on transparency in relation to the State's ownership and on the general meeting being the correct arena for owner decisions and formal resolutions.

	Shareholders at December 2016	Number of Shares	Ownership in %
1	Government of Norway	2,174,183,105	67.00%
2	Folketrygdfondet	104,403,441	3.22%
3	BlackRock Institutional Trust Company, N.A.	29,242,733	0.90%
4	Lazard Asset Management, L.L.C.	28,711,525	0.88%
5	SAFE Investment Company Limited	24,698,519	0.76%
6	INVESCO Asset Management Limited	22,281,500	0.69%
7	Fidelity Management & Research Company	21,301,248	0.68%
8	The Vanguard Group, Inc.	21,120,974	0.65%
9	State Street Global Advisors (US)	18,293,972	0.61%
10	Schroder Investment Management Ltd. (SIM)	19,493,851	0.60%
11	Storebrand Kapitalforvaltning AS	17,611,950	0.54%
12	KLP Forsikring	16,761,633	0.52%
13	DNB Asset Management AS	16,032,525	0.49%
14	UBS Asset Management (UK) Ltd.	12,890,335	0.40%
15	Fidelity Worldwide Investment (UK) Ltd.	11,731,543	0.36%
16	TIAA Global Asset Management	11,413,046	0.35%
17	Allianz Global Investors GmbH	11,397,417	0.35%
18	Epoch Investment Partners, Inc.	11,194,404	0.35%
19	Legal & General Investment Management Ltd.	10,152,188	0.31%
20	AXA Investment Managers UK Ltd.	9,304,532	0.29%

Source: Data collected by third party, authorized by Statoil, December 2016.

EXCHANGE CONTROLS AND LIMITATIONS

Under Norwegian foreign exchange controls currently in effect, transfers of capital to and from Norway are not subject to prior government approval. An exception applies to the physical transfer of payments in currency exceeding certain thresholds, which must be declared to the Norwegian custom authorities. This means that non-Norwegian resident shareholders may receive dividend payments without Norwegian exchange control consent as long as the payment is made through a licensed bank or other licensed payment institution.

There are no restrictions affecting the rights of non-Norwegian residents or foreign owners to hold or vote for our shares.

5.2 ACCOUNTING STANDARDS (IFRS) AND non-GAAP MEASURES

Since 2007, Statoil has been preparing the Consolidated financial statements in accordance with International Financial Reporting Standards (IFRS) as adopted by the EU and as issued by the International Accounting Standards Board. The IFRS standards have been applied consistently to all periods presented in the Consolidated financial statements. See note 2 Significant accounting policies to the Consolidated financial statements for a discussion of key accounting estimates and judgements.

Non-GAAP MEASURES

Statoil is subject to SEC regulations regarding the use of "non-GAAP financial measures" in public disclosures. Non-GAAP financial measures are defined as numerical measures that either exclude or include amounts that are not excluded or included in the comparable measures calculated and presented in accordance with generally accepted accounting principles, which in Statoil's case refers to IFRS. The following financial measures may be considered non-GAAP financial measures:

- Return on average capital employed (ROACE)
- Net debt to capital employed ratio before adjustments
- Net debt to capital employed ratio adjusted
- Adjusted earnings after tax
- Organic capital expenditures

For information regarding Organic capital expenditures, see Investments in section 2.9 Liquidity and capital resources.

Return on average capital employed (ROACE)

This measure provides useful information for both the group and investors about performance during the period under evaluation. Statoil uses ROACE to measure the return on capital employed, regardless of whether the financing is through equity or debt. The use of ROACE should not be viewed as an alternative to income before financial items, income taxes and minority interest, or to net income, which are measures calculated in accordance with GAAP or ratios based on these figures. Impacted by impairments, ROACE was negative 4.7% in 2016 compared to negative 8.9% in 2015 and 3.4% in 2014. The change from 2015 is mainly due to an increase in net income adjusted for financial items.

Calculation of numerator and denominator used in ROACE calculation	For the year ended 31 December				
(in USD million, except percentages)	2016	2015	2014	16-15 change	15-14 change
Net income for the year	(2,902)	(5,169)	3,887		
- Net financial items	(258)	(1,311)	20		
- Tax on financial items	(75)	1,259	1,466		
+ Accretion expense net after tax	21	(124)	(175)		
Net income adjusted for financial Items after tax (A1)	(2,548)	(5,241)	2,226	51%	N/A
Capital employed before adjustments to net interest-bearing debt: 1)					
Year End 2016	53,471				
Year End 2015	54,159	54,159			
Year End 2014		63,311	63,311		
Year End 2013			68,092		
Sum of capital employed for two years (B1)	107,630	117,470	131,403		
Calculated average capital employed:					
Average capital employed before adjustments to net interest-bearing debt (B1/2)	53,815	58,735	65,702	(8%)	(11%)
Calculated ROACE:					
Return on average capital employed (A1/(B1/2))	(4.7%)	(8.9%)	3.4%	47%	N/A

1) Capital employed before adjustments for each year is reconciled in the table in section 5.2 Net debt to capital employed ratio.

Net debt to capital employed ratio

In the Company's view, the calculated net debt to capital employed ratio gives a more complete picture of the Group's current debt situation than gross interest-bearing financial liabilities.

The calculation uses balance sheet items relating to gross interest bearing financial liabilities and adjusts for cash, cash equivalents and current financial investments. Certain adjustments are made, such as collateral deposits classified as cash and cash equivalents in the Consolidated balance sheet but considered non cash in the non-GAAP calculations. The financial investments held in Statoil Forsikring AS are excluded in the non-GAAP calculations as they are deemed restricted. These two adjustment are increasing the net debt and give a stricter definition of the net debt to capital employed ratio than the IFRS based definition. Similarly, certain net interest-bearing debts incurred from activities pursuant to the Owners Instruction from the Norwegian State are set off against receivables on the Norwegian State's direct financial interest (SDFI).

The net interest-bearing debt adjusted for these items is included in the average capital employed. The table below reconciles the net interest-bearing liabilities adjusted, capital employed and net debt to capital employed adjusted ratio with the most directly comparable financial measure or measures calculated in accordance with IFRS.

Calculation of capital employed and net debt to capital employed ratio (in USD million, except percentages)	For the year ended 31 December 2016	2015	2014
Shareholders' equity	35,072	40,271	51,225
Non-controlling interests (Minority interest)	27	36	57
Total equity (A)	35,099	40,307	51,282
Current bonds, bank loans, commercial papers and collateral liabilities	3,674	2,326	3,561
Bonds, bank loans and finance lease liabilities	27,999	29,965	27,593
Gross interest-bearing financial liabilities (B)	31,673	32,291	31,154
Cash and cash equivalents	5,090	8,623	11,182
Current financial investments	8,211	9,817	7,968
Cash and cash equivalents and current financial investments (C)	13,301	18,440	19,150
Net interest-bearing liabilities before adjustments (B1) (B-C)	18,372	13,852	12,004
Other interest-bearing elements [1)]	1,216	1,111	1,081
Marketing instruction adjustment [2)]	(199)	(214)	(212)
Adjustment for project loan [3)]	0	0	(18)
Net interest-bearing liabilities adjusted (B2)	19,389	14,748	12,855
Calculation of capital employed:			
Capital employed before adjustments to net interest-bearing liabilities (A+B1)	53,471	54,159	63,286
Capital employed adjusted (A+B2)	54,488	55,055	64,137
Calculated net debt to capital employed:			
Net debt to capital employed before adjustments (B1/(A+B1)	34.4%	25.6%	19.0%
Net debt to capital employed adjusted (B2/(A+B2)	35.6%	26.8%	20.0%

1) Other interest-bearing elements are cash and cash equivalents adjustments regarding collateral deposits classified as cash and cash equivalents in the Consolidated balance sheet but considered as non-cash in the non-GAAP calculations as well as financial investments in Statoil Forsikring AS classified as current financial investments.

2) Marketing instruction adjustment is an adjustment to gross interest-bearing financial debt due to the SDFI part of the financial lease in the Snøhvit vessels that are included in Statoil's Consolidated balance sheet.

3) Adjustment for project loan is adjustment to gross interest-bearing debt due to the BTC project loan structure.

Adjusted earnings after tax

Adjusted earnings are based on net operating income and adjusts for certain items affecting the income for the period in order to separate out effects that management considers may not be well correlated to Statoil's underlying operational performance in the individual reporting period. Management considers adjusted earnings to be a supplemental measure to Statoil's IFRS measures that provides an indication of Statoil's underlying operational performance in the period and facilitates a better understanding of operational trends between the periods, and uses this metric in determining variable remuneration and awards of LTI grants to members of the corporate executive committee. Adjusted earnings adjusts for the following items:

- Certain gas contracts are, due to pricing or delivery conditions, deemed to contain embedded derivatives, required to be carried at fair value. Certain transactions related to historical divestments include contingent consideration, carried at fair value. The accounting impacts of changes in fair value of the aforementioned are excluded from adjusted earnings. In addition, adjustments are also made for changes in the unrealised **fair value of derivatives** related to some natural gas trading contracts. Due to the nature of these gas sales contracts, these are classified as financial derivatives to be measured at fair value at the balance sheet date. Unrealised gains and losses on these contracts reflect the value of the difference between current market gas prices and the actual prices to be realised under the gas sales contracts. Only realised gains and losses on these contracts are reflected in adjusted earnings. This presentation best reflects the underlying performance of the business as it replaces the effect of temporary timing differences associated with the re-measurements of the derivatives to fair value at the balance sheet date with actual realised gains and losses for the period
- **Periodisation of inventory hedging effect**: Commercial storage is hedged in the paper market. Commercial storage is accounted for by using the lower of cost and market price. If market prices increase above cost price, there will be a loss in the IFRS income statement since the derivatives always reflect changes in the market price. An adjustment is made to reflect the unrealised market value of the commercial storage. As a result, loss on derivatives is matched by a similar adjustment for the exposure being managed. If market prices decrease below cost price, the write-down and the derivative effect in the IFRS income statement will offset each other and no adjustment is made
- **Over/underlift** is accounted for using the sales method and therefore revenues are reflected in the period the product is sold rather than in the period it is produced. The over/underlift position depends on a number of factors related to our lifting programme and the way it corresponds to our entitlement share of production. The effect on income for the period is therefore adjusted, to show estimated revenues and associated costs based upon the production for the period which management believes reflects operational performance and increase comparability with peers
- Statoil holds **operational storage** which is not hedged in the paper market due to inventory strategies. Cost of goods sold is measured based on the FIFO (first-in, first-out) method, and includes realised gains or losses that arise due to changes in market prices. These gains or losses will fluctuate from one period to another and are not considered part of the underlying operations for the period
- **Impairment** and **reversal of impairment** are excluded from adjusted earnings since they affect the economics of an asset for the lifetime of that asset; not only the period in which it is impaired or the impairment is reversed. Impairment and reversal of impairment can impact both the exploration expenses and the depreciation, amortisation and impairment line items
- **Gain or loss from sales** is eliminated from the measure since the gain or loss does not give an indication of future performance or periodic performance; such a gain or loss is related to the cumulative value creation from the time the asset is acquired until it is sold
- **Internal unrealised profit on inventories**: Volumes derived from equity oil inventory will vary depending on several factors and inventory strategies, i.e. level of crude oil in inventory, equity oil used in the refining process and level of in-transit cargoes. Internal profit related to volumes sold between entities in the group, and still in inventory at period end, is eliminated according to IFRS (write down to production cost). The proportion of realised versus unrealised gain will fluctuate from one period to another due to inventory strategies and accordingly impact net operating income. This impact is not assessed to be a part of the underlying operational performance, and elimination of internal profit related to equity volumes is excluded in adjusted earnings
- **Other items of income and expense** are adjusted when the impacts on income in the period are not reflective of Statoil's underlying operational performance in the reporting period. Such items may be unusual or infrequent transactions but they may also include transactions that are significant which would not necessarily qualify as either unusual or infrequent. Other items can include transactions such as provisions related to reorganisation, early retirement, etc

The measure **adjusted earnings after tax** excludes net financial items and the associated tax effects on net financial items. It is based on adjusted earnings less the tax effects on all elements included in adjusted earnings (or calculated tax on operating income and on each of the adjusting items using an estimated marginal tax rate). In addition, tax effect related to tax exposure items not related to the individual reporting period is excluded from adjusted earnings after tax. Management considers adjusted earnings after tax, which reflects a normalised tax charge associated with its operational performance excluding the impact of financing, to be a supplemental measure to Statoil's net income. Certain net USD denominated financial positions are held by group companies that have a USD functional currency that is different from the currency in which the taxable income is measured. As currency exchange rates change between periods, the basis for measuring net financial items for IFRS will change disproportionally with taxable income which includes exchange gains and losses from translating the net USD denominated financial positions into the currency of the applicable tax return. Therefore, the effective tax rate may be significantly higher or lower than the statutory tax rate for any given period.

Management considers that adjusted earnings after tax provides a better indication of the taxes associated with underlying operational performance in the period (excluding financing), and therefore better facilitates a comparison between periods. However, the adjusted taxes included in adjusted earnings after tax should not be considered indicative of the amount of current or total tax expense (or taxes payable) for the period.

Adjusted earnings and adjusted earnings after tax should be considered additional measures rather than substitutes for net operating income and net income, which are the most directly comparable IFRS measures. There are material limitations associated with the use of adjusted earnings and adjusted earnings after tax compared with the IFRS measures since they do not include all the items of revenues/gains or expenses/losses of Statoil which are needed to evaluate its profitability on an overall basis. Adjusted earnings and adjusted earnings after tax are only intended to be indicative of the underlying developments in trends of our on-going operations for the production, manufacturing and marketing of our products and exclude pre and post-tax impacts of net financial items. We reflect such underlying development in our operations by eliminating the effects of certain items that may not be directly associated with the period's operations or financing. However, for that reason, adjusted earnings and adjusted earnings after tax are not complete measures of profitability. The measures should therefore not be used in isolation.

Adjusted earnings equal the sum of net operating income less all applicable adjustments. Adjusted earnings after tax equals the sum of net operating income less income tax in business areas and adjustments to operating income taking the applicable marginal tax into consideration. See the table below for details.

Calculation of adjusted earnings after tax	For the year ended 31 December	
(in USD million)	2016	2015
Net operating income	**80**	**1,366**
Total revenues and other income	**1,020**	**(924)**
Changes in fair value of derivatives	738	356
Periodisation of inventory hedging effect	360	(39)
Impairment from associated companies	25	153
Over-/underlift	232	(96)
Other adjustments	-	(53)
Gain/loss on sale of assets	(333)	(1,750)
Provisions	-	639
Eliminations	-	(133)
Purchases [net of inventory variation]	**(9)**	**262**
Operational storage effects	(228)	262
Eliminations	219	-
Operating and administrative expenses	**617**	**843**
Over-/underlift	(59)	236
Other adjustments	168	322
Gain/loss on sale of assets	86	-
Provisions	422	285
Depreciation, amortisation and impairment	**1,300**	**5,990**
Impairment	2,946	7,710
Reversal of impairment	(1,646)	(1,649)
Other adjustments	-	(72)
Exploration expenses	**1,061**	**2,096**
Impairment	1,141	2,265
Reversal of impairment	(149)	(312)
Other adjustments	41	24
Provisions	28	119
Sum of adjustments to net operating income	**3,990**	**8,267**
Adjusted earnings	**4,070**	**9,633**
Tax on adjusted earnings	**(4,277)**	**(7,168)**
Adjusted earnings after tax	**(208)**	**2,465**

5.3 LEGAL PROCEEDINGS

Statoil is involved in a number of proceedings globally concerning matters arising in connection with the conduct of its business. No further update is provided on previously reported legal or arbitration proceedings which Statoil does not believe will, individually or in the aggregate, have a significant effect on Statoil's financial position, profitability, results of operations or liquidity. See also note 9 Income taxes and note 23 Other commitments, contingent liabilities and contingent assets in Consolidated financial statements.

5.4 PAYMENTS TO GOVERNMENTS

Reporting in accordance with the Norwegian transparency rule

The Norwegian regulation regarding reporting on payments to governments ("Forskrift om land-for-land rapportering") was approved by the Norwegian parliament in December 2013 and came into effect 1 January 2014. It requires companies involved in extractive and logging activities to disclose payments they make to governments at project and country level. Additional contextual information must be disclosed, consisting of certain legal, monetary, numerical and production volume information, related to the extractive part of the operations or to the entire group.

Statoil has prepared this report in accordance with this Norwegian regulation. The reporting under the Norwegian regulation goes beyond the requirements of the EU directive for member states and EEA countries that was approved in June 2013 ("Directive on the annual financial statements, consolidated financial statements and related reports of certain types of undertakings"). Statoil is committed to and engaged in revenue transparency for activities in the extractives sector, and has found this practise conducive to establish trust between stakeholder groups. Statoil supports consistency in regulation on revenue transparency between jurisdictions. More information can be found on Statoil.com.

Basis for preparation

The regulation requires Statoil to prepare a consolidated report for the previous financial year on direct payments to governments, including payments made by subsidiaries, joint operations and joint ventures, or on behalf such entities involved in extractive activities. Statoil has assessed the reporting obligations to be as described below.

Scope and validity

Statoil activities covering the exploration, prospecting, discovery, development and extraction of oil and natural gas ('extractive activities') are included in this report. Additional contextual information is disclosed for legal entities engaged in extractive activities or for the entire group, on a country or legal entity basis, as applicable.

Reporting principles

Within the scope of this report are payment types made directly by Statoil to governments, such as taxes and royalties. Payments made by the operator of an oil and/or gas licence on behalf of the licensed partners, such as area fees, are also included in this report. For assets where Statoil is the operator, the full payment made on behalf of the whole partnership (100%) is included. No payment will be disclosed in cases where Statoil is not the operator, unless the operator is a state-owned entity and it is possible to distinguish the payment from other cost recovery items.

Host government entitlements paid by the licence operator are also included in the report. The size of such entitlements can in some cases constitute the most significant payments to governments.

For some of our projects, we have established a subsidiary to hold the ownership in a joint venture. For these projects, payments may be made to governments in the country of operation as well as to governments in the country where the subsidiary resides.

Payments to governments are reported in the year that the actual cash payment was made (cash principle). Amounts included as contextual information are reported in the year the transaction relates to, regardless of when the cash transaction occurred (accrual principle). Amounts are subject to rounding. Rounding differences may occur in summary tables.

Changes from last year

In 2016 Statoil's reporting currency was changed from Norwegian kroner (NOK) to US Dollars (USD). For 2015 the listing of subsidiaries included all companies with minority ownership interest. In the 2016 report this has been changed to include only subsidiaries, i.e. companies in which Statoil has more than 50% ownership interest.

Government

In the context of this report, a government is defined as any national, regional or local authority of a country. It includes any department, agency or undertaking (i.e. corporation) controlled by that government.

Project definition

A project is defined as the operational activity governed by a single contract, licence, lease, concession or similar legal agreement and that forms the basis for payment obligations to a government.

Payments not directly linked to a specific project but levied at the company entity level, are reported at that level.

Materiality

Payments constitute a single payment, or a series of related payments that equal or exceed NOK 800,000 (approximately USD 100,000 at average annual 2016 exchange rates) during the year. Payments below the threshold in a given country will not be included in the overview of projects and payments.

Reporting currency

Payments to governments in foreign currencies (those other than USD) are converted to USD using the average annual 2016 exchange rate.

Payment types disclosed at project or legal entity level that are relevant for Statoil

The following payment types are disclosed for legal entities involved in extractive activities. They are presented on a cash basis (cash principle), net of any interest expenses, whether paid in cash or in-kind. In-kind payments are reported in millions of barrels of oil equivalent and the equivalent cash value They include:

- Tax levied on the income, production or profits of companies. Includes severance tax and taxes paid in-kind. The value of taxes paid in-kind is calculated based on the market price at the time of the in-kind payment. Taxes levied on consumption, such as value added tax, personal income tax, sales tax, withholding tax, property tax and environmental tax, are excluded
- Royalties are usage-based payments for the right to the on-going use of an asset
- Fees are typically levied on the right to use a geographical area for exploration, development and production and include rental fees, area fees, entry fees, concession fees and other considerations for licences and/or concessions. Administrative government fees that are not specifically related to the extractive activities or to access extractive resources, are excluded
- Bonuses are payments made when signing an oil and gas lease, when discovering natural resources and/or when production has commenced. Bonuses often include signature, discovery and production bonuses and are a commonly used payment type, depending on the petroleum fiscal regime. Bonuses can also include elements of social contribution
- Host government entitlements are the host government's share of production after oil production has been allocated to cover costs and expenses under a production sharing agreement (PSA). Host government entitlements are most often paid in-kind. The value of these payments is calculated based on the market price at the time of the in-kind payment. For some PSAs, the host government entitlements are sold by the operator, and the cost split between the partners. For these contracts, Statoil does not make payments directly to governments, but to the operator. See basis for preparation for more information

Contextual information at country level

The report discloses contextual information for legal entities engaged in extractive activities in Statoil, as listed below. All information is disclosed in accordance with the accrual principle.

- Investments are defined as additions to property, plant and equipment (including capitalised finance leases), capitalised exploration expenditures, intangible assets, long-term share investments and investments in associated companies
- Revenues associated with the production of crude oil and natural gas related to our extractive activities. Revenues include third party revenues and other income, inter-segment revenues and net income from equity accounted investments
- Cost shows the sum of operating expenses, SG&A (sales, general and administrative expenses) and exploration expenses, adjusted for net impairments
- Production volumes are the volumes that correspond to Statoil's ownership interest in a particular field and do not include production of the Norwegian State's share of oil and natural gas

Contextual information at entity level

The following contextual information is disclosed for all of Statoil's subsidiaries as of 31 December 2016:

- Country of incorporation is the jurisdiction in which the company is registered
- Country of operation is the country where the company performs its main activities
- Number of employees (per subsidiary) is based on the registered company location. The actual number of employees present in a country can deviate from the reported figures due to expatriation. In some subsidiaries there are no employees. These may purchase man-hours from other companies in the Statoil group, as applicable
- Net intercompany interest is the company's net intercompany interest expense (interest expense minus interest income) to subsidiaries in another jurisdiction. Interest between companies within the same jurisdiction is eliminated. Intercompany interest is the interest levied on long-term and short-term borrowings within the Statoil group

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ADDITIONAL INFORMATION

Consolidated overview

The consolidated overview below discloses the sum of Statoil's payments to governments in each country, according to the payment type. The overview is based on the location of the receiving government. The total payments to each country may be different from the total payments disclosed in the overview of payments for each project in the report. This is because payments disclosed for each project relate to the country of operation, irrespective of the location of the receiving government.

In 2016, the downward trend in overall payments from previous years continued, a result of continued low oil and gas prices. In 2016 Statoil had no new major exploration awards that triggered signatory bonuses.

(in USD million)	Taxes 1)	Royalties	Fees	Bonuses	Host government entitlements (value)	Host government entitlements (mmboe)	Total (value) 2016	Total (value) 2015 2)
Algeria	5.9	-	0.3	-	109.8	4.5	116.0	190.3
Angola	370.8	-	-	10.8	858.1	20.7	1,239.7	1,750.7
Australia	-	-	0.0	-	-	-	0.0	0.2
Azerbaijan	10.6	-	-	-	483.8	11.3	494.4	652.0
Brazil	-	44.8	-	-	-	-	44.8	71.7
Canada	-	45.1	4.0	-	-	-	49.0	60.4
Colombia	0.4	-	-	-	-	-	0.4	0.5
Faroe Islands	-	-	-	-	-	-	-	0.4
Indonesia	0.0	-	0.1	-	-	-	0.1	1.0
Iran	1.4	-	-	-	-	-	1.4	2.3
Ireland	-	-	0.2	-	-	-	0.2	-
Libya	-	-	-	-	-	-	-	4.1
New Zealand	-	-	0.1	-	-	-	0.1	0.1
Nicaragua	-	-	0.5	-	-	-	0.5	0.1
Nigeria	194.0	-	48.4	-	104.3	2.5	346.7	390.7
Norway	3,934.2	-	61.1	-	-	-	3,995.3	7,609.2
Russia	2.7	2.2	-	-	37.5	0.9	42.4	42.5
South Korea	0.2	-	-	-	-	-	0.2	-
Tanzania	-	-	0.1	-	-	-	0.1	0.1
UK	4.9	-	1.7	-	-	-	6.5	(6.5)
USA [3]	81.9	32.6	5.4	4.8	-	-	124.8	261.3
Total	4,607.2	124.6	121.7	15.6	1,593.4	39.9	6,462.6	11,031.1

[1] Includes taxes paid in-kind.
[2] Payments in 2015 have been converted to USD using the average annual 2015 exchange rate.
[3] USA - The amount was understated by USD 90 million in the 2015 report. This has now been adjusted in this table.

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Country details – payment per project and receiving government entity

(in USD million)	Taxes	Royalties	Fees	Bonuses	Host government entitlements (value)	Host government entitlements (mmboe)	Total (value) 2016
Algeria							
Payments per project							
Statoil North Africa Gas AS	4.9	-	-	-	-	-	4.9
Statoil North Africa Oil AS	1.0	-	-	-	-	-	1.0
In Amenas	-	-	-	-	37.6	1.2	37.6
In Salah	-	-	-	-	72.2	3.3	72.2
Exploration Algeria	-	-	0.3	-	-	-	0.3
Total	5.9	-	0.3	-	109.8	4.5	116.0
Payments per government							
Direction des Grandes Enterprises	-	-	0.3	-	-	-	0.3
Sonatrach [1)]	5.9	-	-	-	109.8	4.5	115.7
Total	5.9	-	0.3	-	109.8	4.5	116.0
Angola							
Payments per project							
Statoil Angola Block 15 AS	44.5	-	-	-	-	-	44.5
Statoil Angola Block 17 AS	157.1	-	-	-	-	-	157.1
Statoil Angola Block 31 AS	47.0	-	-	-	-	-	47.0
Statoil Dezassete AS	118.9	-	-	-	-	-	118.9
Statoil Quatro AS	3.4	-	-	-	-	-	3.4
Block 15	-	-	-	-	238.2	5.8	238.2
Block 17	-	-	-	-	592.5	14.2	592.5
Block 31	-	-	-	-	27.4	0.7	27.4
Block 39 [2)]	-	-	-	10.8	-	-	10.8
Total	370.8	-	-	10.8	858.1	20.7	1,239.7
Payments per government							
Banco Nacional de Angola	370.8	-	-	-	-	-	370.8
Sonangol EP	-	-	-	10.8	858.1	20.7	868.9
Total	370.8	-	-	10.8	858.1	20.7	1,239.7
Azerbaijan							
Payments per project							
Statoil Apsheron AS	10.6	-	-	-	-	-	10.6
ACG	-	-	-	-	483.8	11.3	483.8
Total	10.6	-	-	-	483.8	11.3	494.4
Payments per government							
Ministry of Taxes Azerbaijan	10.6	-	-	-	-	-	10.6
SOCAR - The State Oil Company of the Azerbaijan Republic	-	-	-	-	483.8	11.3	483.8
Total	10.6	-	-	-	483.8	11.3	494.4

ADDITIONAL INFORMATION

(in USD million)	Taxes	Royalties	Fees	Bonuses	Host government entitlements (value)	Host government entitlements (mmboe)	Total (value) 2016
Brazil							
Payments per project							
Peregrino	-	44.8	-	-	-	-	44.8
Total	-	44.8	-	-	-	-	44.8
Payments per government							
Ministerio da Fazenda	-	44.8	-	-	-	-	44.8
Total	-	44.8	-	-	-	-	44.8
Canada							
Payments per project							
Exploration Canada offshore	-	-	2.6	-	-	-	2.6
Hibernia	-	18.6	-	-	-	-	18.6
Leismer asset	-	1.3	1.4	-	-	-	2.7
Terra Nova	-	25.1	-	-	-	-	25.1
Total	-	45.1	4.0	-	-	-	49.0
Payments per government							
Alberta Energy Regulator	-	-	0.5	-	-	-	0.5
Canada-Newfoundland and Labrador Offshore Petr. Board	-	-	0.6	-	-	-	0.6
Goverment of Alberta	-	-	0.8	-	-	-	0.8
Government of Canada	-	30.6	2.0	-	-	-	32.6
Government of Newfoundland and Labrador	-	13.1	-	-	-	-	13.1
Lac La Biche County	-	-	0.0	-	-	-	0.0
Minister of Finance - PT Mineral	-	1.3	-	-	-	-	1.3
Total	-	45.1	4.0	-	-	-	49.0
Colombia							
Payments per project							
Statoil Eta Netherlands B.V.	0.4	-	-	-	-	-	0.4
Total	0.4	-	-	-	-	-	0.4
Payments per government							-
National Directorate of Taxes and Customs	0.4	-	-	-	-	-	0.4
Total	0.4	-	-	-	-	-	0.4
Indonesia							
Payments per project							
Statoil Indonesia Halmahera	0.1	-	-	-	-	-	0.1
Exploration Indonesia offshore	-	-	0.1		-	-	0.1
Total	0.1	-	0.1	-	-	-	0.2
Payments per government							-
SKK Migas	-	-	0.1		-	-	0.1
Stavanger kemnerkontor	0.1	-	-	-	-	-	0.1
Total	0.1	-	0.1	-	-	-	0.2

(in USD million)	Taxes	Royalties	Fees	Bonuses	Host government entitlements (value)	Host government entitlements (mmboe)	Total (value) 2016
Iran							
Payments per project							
Statoil SP GAS AS	2.2	-	-	-	-	-	2.2
Statoil Zagros O&G AS	1.7	-	-	-	-	-	1.7
Statoil Iran as	0.1	-	-	-	-	-	0.1
Total	4.0	-	-	-	-	-	4.0
Payments per government							-
Sazmane Omoore Maliatie	1.4	-	-	-	-	-	1.4
Stavanger kemnerkontor	2.6	-	-	-	-	-	2.6
Total	4.0	-	-	-	-	-	4.0
Ireland							
Payments per project							
Exploration Ireland Offshore	-	-	0.2	-	-	-	0.2
Total	-	-	0.2	-	-	-	0.2
Payments per government							
Dept. of Communications, Energy and Natural Resources	-	-	0.2	-	-	-	0.2
Total	-	-	0.2	-	-	-	0.2
New Zealand							
Payments per project							
Exploration New Zealand offshore	-	-	0.1	-	-	-	0.1
Total	-	-	0.1	-	-	-	0.1
Payments per government							
New Zealand Petroleum & Minerals	-	-	0.1	-	-	-	0.1
Total	-	-	0.1	-	-	-	0.1
Nicaragua							
Payments per project							
Exploration Nicaragua offshore	-	-	0.5	-	-	-	0.5
Total	-	-	0.5	-	-	-	0.5
Payments per government							
Ministerio de Energia y Minas	-	-	0.5	-	-	-	0.5
Total	-	-	0.5	-	-	-	0.5
Nigeria							
Payments per project							
Statoil Nigeria Ltd.	194.0	-	-	-	-	-	194.0
Agbami	-	-	48.4	-	104.3	2.5	152.7
Total	194.0	-	48.4	-	104.3	2.5	346.7
Payments per government							
Central Bank of Nigeria Education Tax	-	-	23.2	-	-	-	23.2
Central Bank of Nigeria NESS fee	-	-	0.4	-	-	-	0.4
Niger Delta Development Commission	-	-	24.8	-	-	-	24.8
Nigerian National Petroleum Corporation [3)]	194.0	-	-	-	104.3	2.5	298.3
Total	194.0	-	48.4	-	104.3	2.5	346.7

(in USD million)	Taxes	Royalties	Fees	Bonuses	Host government entitlements (value)	Host government entitlements (mmboe)	Total (value) 2016
Norway							
Payments per project							
Statoil Petroleum AS	3,931.7	-	-	-	-	-	3,931.7
Exploration Barents Sea	-	-	7.9	-	-	-	7.9
Exploration Norwegian Sea	-	-	16.4	-	-	-	16.4
Exploration North Sea	-	-	34.9	-	-	-	34.9
Other	-	-	1.9	-	-	-	1.9
Total	3,931.7	-	61.1	-	-	-	3,992.8
Payments per government							
Oljedirektoratet	-	-	61.1	-	-	-	61.1
Oljeskattekontoret	3,932.8	-	-	-	-	-	3,932.8
Oslo kemnerkontor	(0.3)	-	-	-	-	-	(0.3)
Seoul Regional Taxpayers Association	0.2	-	-	-	-	-	0.2
Stavanger kemnerkontor	(1.1)	-	-	-	-	-	(1.1)
Total	3,931.7	-	61.1	-	-	-	3,992.8
Russia							
Payments per project							
Kharyaga	2.7	2.2	-	-	37.5	0.9	42.4
Total	2.7	2.2	-	-	37.5	0.9	42.4
Payments per government							
Zarubezhneft-Production Kharyaga LL	2.7	2.2	-	-	-	-	4.9
Treasury of the Russian Federation	-	-	-	-	37.5	0.9	37.5
Total	2.7	2.2	-	-	37.5	0.9	42.4
Suriname							
Payments per project							
Statoil Suriname AS	0.1	-	-	-	-	-	0.1
Total	0.1	-	-	-	-	-	0.1
Payments per government							
Stavanger kemnerkontor	0.1	-	-	-	-	-	0.1
Total	0.1	-	-	-	-	-	0.1
Tanzania							
Payments per project							
Exploration Tanzania Offshore	-	-	0.1	-	-	-	0.1
Total	-	-	0.1	-	-	-	0.1
Payments per government							
Tanzania Petroleum Development Corporation	-	-	0.1	-	-	-	0.1
Total	-	-	0.1	-	-	-	0.1

(in USD million)	Taxes	Royalties	Fees	Bonuses	Host government entitlements (value)	Host government entitlements (mmboe)	Total (value) 2016
UK							
Payments per project							
Statoil UK Ltd	4.9	-	-	-	-	-	4.9
Bressay	-	-	0.5	-	-	-	0.5
Mariner	-	-	0.1	-	-	-	0.1
Mariner East	-	-	0.2	-	-	-	0.2
Exploration UK Offshore	-	-	0.9	-	-	-	0.9
Total	4.9	-	1.7	-	-	-	6.5
Payments per government							
Department of Energy and Climate Change	-	-	1.7	-	-	-	1.7
HM Revenue & Customs	4.9	-	-	-	-	-	4.9
Total	4.9	-	1.7	-	-	-	6.5
USA							
Payments per project							
Bakken [4)]	62.6	8.2	-	-	-	-	70.8
Ceasar-Tonga	-	3.0	-	-	-	-	3.0
Eagle Ford [4)]	7.9	1.1	-	-	-	-	9.0
Heildelberg	-	2.0	-	-	-	-	2.0
Marcellus [4)]	11.4	0.2	-	-	-	-	11.6
Spiderman	-	(0.3)	-	-	-	-	(0.3)
Tahiti	-	18.4	-	-	-	-	18.4
Exploration USA offshore	-	-	5.4	4.8	-	-	10.2
Total	81.9	32.5	5.4	4.8	-	-	124.7
Payments per government							
Montana Dept. of Revenue	1.6	-	-	-	-	-	1.6
North Dakota Office of State Tax [5)]	61.0	-	-	-	-	-	61.0
Office of Natural Resources Revenue [6)]	-	25.5	5.4	4.8	-	-	35.7
Pennsylvania Game Commision	-	0.1	-	-	-	-	0.1
Richland County Montana	-	0.0	-	-	-	-	0.0
Roosevelt County Montana	-	0.2	-	-	-	-	0.2
State of Montana	-	0.1	-	-	-	-	0.1
State of North Dakota	-	5.8	-	-	-	-	5.8
State of Ohio	0.1	-	-	-	-	-	0.1
State of West Virginia	11.3	-	-	-	-	-	11.3
Texas Comptroller of Public Accounts	7.9	0.0	-	-	-	-	7.9
Texas General Land Office	-	0.8	-	-	-	-	0.8
Other	0.0	0.2	-	-	-	-	0.2
Total	81.9	32.5	5.4	4.8	-	-	124.7

- Algeria – In-kind payments to Sonatrach, 0.9 mmboe valued at USD 5.9 million. These are in addition to the Host government entitlements.
- Angola - Signature bonus to Sonangol USD 10.8 million. This is the last instalment of Statoil's commitment towards social projects under the Kwanza concession.
- Nigeria - In-kind payments to Nigerian National Petroleum Corporation (NNPC), 3.6 mmboe valued at USD 194.0 million. There is an ongoing dispute regarding the allocation of oil volumes between NNPC and the partners in the Agbami field. In addition to the in-kind payments there are Host government entitlements.
- USA - Bakken is owned by Statoil Oil & Gas LP. Eagle Ford is owned by Statoil Texas Onshore Properties LLC. Marcellus is owned by Statoil USA Onshore Properties Inc.
- USA - In North Dakota Statoil pays oil severance tax on the taxable oil value produced from Bakken. In 2016 the payment was USD 60 million. Equivalent payments for 2015 and 2014 were USD 94 million and USD 178 million, respectively. These amounts were not reported in previous years' reports as they were paid by a Statoil midstream company, a company outside the scope of the payments to governments reporting.
- USA - Statoil paid USD 4.8 million in signature bonuses related to the award of three offshore blocks in the Gulf of Mexico.

ADDITIONAL INFORMATION

Contextual information at country level

The contextual information provides a broader picture of our overall economic impact in the countries where we have business activities and adds context to the reported payments to governments. The information is disclosed for each country and relates to the entities engaged in extractive activities. It consists of: investments; revenues; cost; and production volumes.

The contextual information reported is based on data collected mainly for the purpose of financial reporting.

(in USD million)	Investments	Revenues	Cost	Production volume(mmboe)
Algeria	140.5	361.4	97.0	19.0
Angola	532.5	2,263.5	635.0	76.8
Australia	9.0	(0.0)	20.1	-
Azerbaijan	122.2	410.5	89.1	19.7
Brazil	2,479.1	371.6	547.1	13.7
Canada	364.9	507.1	691.2	12.5
Colombia	0.7	-	16.7	-
Faroe Islands	-	3.3	3.2	-
Greenland	-	0.0	3.1	-
Indonesia	0.0	0.0	8.6	-
Ireland	13.7	180.8	52.9	6.4
Libya	2.7	0.1	7.1	-
Mexico	-	-	22.4	-
Myanmar	3.0	-	7.9	-
Netherlands	37.9	(24.7)	65.8	-
New Zealand	1.0	-	11.2	-
Nicaragua	-	-	4.1	-
Nigeria	106.2	489.1	112.9	16.9
Norway	5,678.1	13,018.8	3,077.5	451.9
Russia	42.7	118.0	85.5	3.4
Suriname	-	-	4.4	-
Sweden	1,228.7	(77.9)	-	-
Tanzania	1.7	0.0	36.9	-
Turkey	18.0	-	3.6	-
UK	574.7	22.3	111.6	1.0
USA	1,824.5	2,090.4	1,722.9	98.7
Venezuela	0.2	(0.6)	(3.5)	3.8
Total	**13,182.0**	**19,733.7**	**7,434.3**	**724.0**

Contextual information at Statoil group level: Subsidiaries, number of employees and intercompany interest

The table below provides an overview as of 31 December 2016 of all subsidiaries in the Statoil group, their country of incorporation and operation, number of employees and each company's net intercompany interest to companies in other jurisdictions. A negative number implies a net intercompany interest income for the company, whereas a positive number implies a net intercompany interest expense.

During 2016, Statoil proceeded with its plan to transfer services related to internal bank operations from Belgium to Norway. Operational cash management tasks continue to be run out of Mechelen in Belgium.

Subsidiaries	Country of incorporation	Country of operation	Number of employees	Net intercompany interest (in USD million)
Doggerbank Project 1A Statoil Limited	United Kingdom	United Kingdom	-	-
Doggerbank Project 1B Statoil Limited	United Kingdom	United Kingdom	-	-
Doggerbank Project 2A Statoil Limited	United Kingdom	United Kingdom	-	-
Doggerbank Project 2B Statoil Limited	United Kingdom	United Kingdom	-	-
Doggerbank Project 3A Statoil Limited	United Kingdom	United Kingdom	-	-
Doggerbank Project 3B Statoil Limited	United Kingdom	United Kingdom	-	-
Doggerbank Project 4A Statoil Limited	United Kingdom	United Kingdom	-	-
Doggerbank Project 4B Statoil Limited	United Kingdom	United Kingdom	-	-
Doggerbank Project 5A Statoil Limited	United Kingdom	United Kingdom	-	-
Doggerbank Project 5B Statoil Limited	United Kingdom	United Kingdom	-	-
Doggerbank Project 6A Statoil Limited	United Kingdom	United Kingdom	-	-
Doggerbank Project 6B Statoil Limited	United Kingdom	United Kingdom	-	-
Dudgeon Offshore Wind Limited	United Kingdom	United Kingdom	-	-
Gravitude AS	Norway	Norway	-	-
Hyperbar Mottaks Beredskap AS	Norway	Norway	-	-
Hywind (Scotland) Limited	United Kingdom	United Kingdom	-	-
Hywind AS	Norway	Norway	-	-
K/S Rafinor A/S	Norway	Norway	-	-
KKD Oil Sands Partnership	Canada	Canada	-	-
Mongstad Heat and Power Plant AS	Norway	Norway	-	(12.5)
Mongstad Refining DA	Norway	Norway	-	-
Mongstad Terminal DA	Norway	Norway	-	(0.1)
North America Properties LLC	USA	USA	-	-
Octio AS	Norway	Norway	-	-
Onshore Holdings LLC	USA	USA	-	-
Petroleum Royalties of Ireland Ltd	Ireland	Ireland	2	-
PT Statoil Indonesia	Indonesia	Indonesia	-	-
Rafinor AS	Norway	Norway	-	-
Reveal Energy Services Inc	USA	USA	-	-
Sandsli Vest AS	Norway	Norway	-	-
Sandsliveien 90 AS	Norway	Norway	-	-
South Atlantic Holding BV	Netherlands	Brazil	-	(2.7)
Spinnaker (BVI) 242 LTD	British Virgin Island	Nigeria	-	-
Spinnaker Exploration (BVI) 256 LTD	British Virgin Island	Nigeria	-	-
Spinnaker Exploration 256 LTD (Nigeria)	Nigeria	Nigeria	-	-
Spinnaker Exploration Holdings (BVI) 256 LTD	British Virgin Island	Nigeria	-	-
Spinnaker FR Spar Co, LLC	USA	USA	-	-
Spinnaker Holdings (BVI) 242 LTD	British Virgin Island	Nigeria	-	-
Spinnaker Nigeria 242 LTD	Nigeria	Nigeria	-	-
Statholding AS	Norway	Norway	-	(5.4)
Statoil (Beijing) Technology Service Co., Ltd	China	China	4	-
Statoil Abu Dhabi B.V.	Netherlands	United Arab Emirates	-	-
Statoil Algeria AS	Norway	Algeria	28	-

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Subsidiaries	Country of incorporation	Country of operation	Number of employees	Net intercompany interest (in USD million)
Statoil Algeria B.V.	Netherlands	Algeria	-	-
Statoil Angola AS	Norway	Angola	-	-
Statoil Angola Block 15 AS	Norway	Angola	-	0.1
Statoil Angola Block 15/06 Award AS	Norway	Angola	-	(0.1)
Statoil Angola Block 17 AS	Norway	Angola	16	(1.2)
Statoil Angola Block 22 AS	Norway	Angola	-	0.1
Statoil Angola Block 25 AS	Norway	Angola	-	-
Statoil Angola Block 31 AS	Norway	Angola	-	(0.5)
Statoil Angola Block 38 AS	Norway	Angola	-	(0.4)
Statoil Angola Block 39 AS	Norway	Angola	-	(0.1)
Statoil Angola Block 40 AS	Norway	Angola	-	-
Statoil Apsheron AS	Norway	Azerbaijan	10	(0.6)
Statoil ASA	Norway	Norway	18,020	(519.3)
Statoil Asia Pacific PTE Ltd	Singapore	Singapore	32	-
Statoil Australia AS	Norway	Australia	-	-
Statoil Australia Oil & Gas AS	Norway	Australia	-	-
Statoil Australia Theta B.V.	Netherlands	Australia	-	-
Statoil Azerbaijan AS	Norway	Azerbaijan	-	(0.7)
Statoil Banarli Turkey B.V.	Netherlands	Turkey	-	-
Statoil Brasil Óleo e Gás Ltda	Brazil	Brazil	263	3.4
Statoil BTC Caspian AS	Norway	Azerbaijan	-	-
Statoil BTC Finance AS	Norway	Norway	-	(0.7)
Statoil Canada Holdings Corp.	Canada	Canada	-	-
Statoil Canada Ltd.	Canada	Canada	318	0.7
Statoil China AS	Norway	China	3	-
Statoil Coordination Center NV	Belgium	Belgium	15	(121.1)
Statoil Cyrenaica AS	Norway	Libya	-	-
Statoil Danmark A/S	Denmark	Denmark	-	0.4
Statoil Deutschland GmbH	Germany	Germany	8	0.1
Statoil Deutschland Property GmbH	Germany	Germany	-	-
Statoil Deutschland Storage GmbH	Germany	Germany	7	-
Statoil Dezassete AS	Norway	Angola	-	(0.4)
Statoil do Brasil Ltda	Brazil	Brazil	-	-
Statoil E&P Americas AS	Norway	USA	-	(1.0)
Statoil E&P Americas Investment LLC	USA	USA	-	-
Statoil E&P Americas LP	USA	USA	-	-
Statoil E&P Mexico, S.A. de C.V.	Mexico	Mexico	-	-
Statoil Egypt AS	Norway	Egypt	-	-
Statoil Egypt AS	Norway	Egypt	-	-
Statoil Egypt El Dabaa Offshore AS	Norway	Egypt	-	-
Statoil Energy Belgium NV	Belgium	Belgium	54	-
Statoil Energy Netherlands B.V.	Netherlands	Netherlands	-	(46.0)
Statoil Energy Trading Inc.	USA	USA	-	-
Statoil Energy Ventures Fund B.V.	Netherlands	Netherlands	-	-
Statoil Epsilon Netherlands B.V.	Netherlands	Russia	-	-
Statoil Eta Netherlands B.V.	Netherlands	Colombia	-	-
Statoil Exploration Ireland Limited	Ireland	Ireland	-	4.9
Statoil Exploration U.K. Limited	United Kingdom	United Kingdom	-	-
Statoil Exploration Company	USA	USA	-	-
Statoil Forsikring as	Norway	Norway	-	-
Statoil Færøyene AS	Norway	Faroe Islands	1	(0.2)

Subsidiaries	Country of incorporation	Country of operation	Number of employees	Net intercompany interest (in USD million)
Statoil Gas Hibernia Ltd	Ireland	Ireland	-	-
Statoil Gas Marketing Europe AS	Norway	Norway	-	-
Statoil Gas Trading Limited	United Kingdom	United Kingdom	-	-
Statoil Global Employment Limited	United Kingdom	United Kingdom	-	-
Statoil Global New Ventures 2 AS	Norway	Russia	-	-
Statoil Global New Ventures AS	Norway	Ghana	-	(0.3)
Statoil Greenland AS	Norway	Greenland	-	-
Statoil GTL AS	Norway	Norway	-	(0.1)
Statoil Gulf of Mexico Inc.	USA	USA	-	-
Statoil Gulf of Mexico LLC	USA	USA	-	-
Statoil Gulf of Mexico Response Company LLC	USA	USA	-	-
Statoil Gulf Properties Inc	USA	USA	-	-
Statoil Gulf Services LLC	USA	USA	721	-
Statoil Hassi Mouina AS	Norway	Algeria	-	(0.2)
Statoil Holding Netherlands B.V.	Netherlands	Netherlands	11	(0.1)
Statoil Holding Switzerland AG	Switzerland	Switzerland	-	-
Statoil India Netherlands B.V.	Netherlands	India	-	-
Statoil Indonesia Aru AS	Norway	Indonesia	-	-
Statoil Indonesia Aru Trough I B.V.	Netherlands	Indonesia	20	-
Statoil Indonesia AS	Norway	Indonesia	-	-
Statoil Indonesia Halmahera II AS	Norway	Indonesia	-	-
Statoil Indonesia Karama AS	Norway	Indonesia	-	-
Statoil Indonesia North Ganal AS	Norway	Indonesia	-	-
Statoil Indonesia North Makassar Strait AS	Norway	Indonesia	-	(0.2)
Statoil Indonesia Obi AS	Norway	Indonesia	-	-
Statoil Indonesia West Papua IV AS	Norway	Indonesia	-	(0.3)
Statoil International Netherlands B.V	Netherlands	Canada	-	-
Statoil International Venezuela AS	Norway	Venezuela	23	-
Statoil International Well Response Company AS	Norway	Norway	-	-
Statoil Iran AS	Norway	Iran	-	-
Statoil Kapitalforvaltning ASA	Norway	Norway	13	-
Statoil Kazakstan AS	Norway	Norway	-	-
Statoil Kharyaga AS	Norway	Russia	-	-
Statoil Ksi Netherlands B.V.	Netherlands	Netherlands	-	-
Statoil Kufra AS	Norway	Libya	-	-
Statoil Latin America AS	Norway	Norway	-	-
Statoil Libya AS	Norway	Libya	3	-
Statoil Mabruk AS	Norway	Libya	-	(0.1)
Statoil Marketing & Trading (US) Inc.	USA	USA	-	-
Statoil Metanol ANS	Norway	Norway	-	(0.2)
Statoil Mexico AS	Norway	Mexico	-	-
Statoil Middle East Operations AS	Norway	Norway	3	-
Statoil Middle East Services Netherlands B.V.	Netherlands	Iraq	-	-
Statoil Mozambique A5-A B.V.	Netherlands	Mozambique	-	-
Statoil Mu Netherlands B.V.	Netherlands	Russia	-	-
Statoil Murzuq Area 146 AS	Norway	Libya	-	-
Statoil Murzuq AS	Norway	Libya	-	(0.2)
Statoil Myanmar Private Limited	Singapore	Myanmar	-	-
Statoil Natural Gas LLC	USA	USA	-	(1.9)
Statoil New Energy AS	Norway	Norway	-	(0.3)
Statoil New Zealand B.V.	Netherlands	New Zealand	-	-

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ADDITIONAL INFORMATION

Subsidiaries	Country of incorporation	Country of operation	Number of employees	Net intercompany interest (in USD million)
Statoil Nicaragua Holdings B.V.	Netherlands	Nicaragua	-	-
Statoil Nigeria AS	Norway	Nigeria	-	(0.4)
Statoil Nigeria Deep Water AS	Norway	Nigeria	-	(0.1)
Statoil Nigeria Deep Water Limited	Nigeria	Nigeria	-	-
Statoil Nigeria LTD	Nigeria	Nigeria	10	(1.1)
Statoil Nigeria Outer Shelf AS	Norway	Nigeria	-	(0.4)
Statoil Nigeria Outer Shelf Limited	Nigeria	Nigeria	-	-
Statoil Norsk LNG AS	Norway	USA	-	(0.3)
Statoil North Africa Gas AS	Norway	Algeria	-	(0.6)
Statoil North Africa Oil AS	Norway	Algeria	-	-
Statoil North Caspian AS	Norway	Kazakhstan	1	-
Statoil Nu Netherlands B.V.	Netherlands	Netherlands	-	-
Statoil Oil & Gas Brazil AS	Norway	Brazil	-	(3.6)
Statoil Oil & Gas LP	USA	USA	-	-
Statoil Oil & Gas Mozambique AS	Norway	Mozambique	-	(0.1)
Statoil Oil & Gas Services Inc.	USA	USA	-	-
Statoil Orient AG	Switzerland	Switzerland	-	-
Statoil Orinoco AS	Norway	Venezuela	-	-
Statoil OTS AB	Sweden	Sweden	-	3.7
Statoil Pensjon	Norway	Norway	-	-
Statoil Petroleum AS	Norway	Norway	-	408.2
Statoil Pipelines LLC	USA	USA	-	-
Statoil Production (UK) Limited	United Kingdom	United Kingdom	100	-
Statoil Projects Inc.	USA	USA	-	-
Statoil Quatro AS	Norway	Angola	-	(0.5)
Statoil Refining Denmark A/S	Denmark	Denmark	321	-
Statoil Refining Norway AS	Norway	Norway	-	11.5
Statoil Rho Netherlands B.V.	Netherlands	Netherlands	-	-
Statoil Russia AS	Norway	Russia	44	0.1
Statoil Russia Services AS	Norway	Russia	-	-
Statoil Russland AS	Norway	Russia	-	-
Statoil Shah Deniz AS	Norway	Azerbaijan	-	(3.4)
Statoil Shipping, Inc.	USA	USA	-	-
Statoil Sincor AS	Norway	Venezuela	-	(0.4)
Statoil Sincor Netherlands B.V.	Netherlands	Venezuela	-	(0.1)
Statoil South Africa B.V.	Netherlands	South Africa	-	-
Statoil South Korea Co., Ltd	South Korea	South Korea	-	-
Statoil South Riding Point, LLC	USA	Bahamas	59	-
Statoil SP Gas AS	Norway	Iran	-	(0.4)
Statoil Suriname B.V.	Netherlands	Suriname	-	-
Statoil Suriname B59 B.V.	Netherlands	Suriname	-	-
Statoil Sverige Kharyaga AB	Sweden	Russia	-	0.5
Statoil Tanzania AS	Norway	Tanzania	21	-
Statoil Technology Invest AS	Norway	Norway	-	(0.2)
Statoil Texas Onshore Properties LLC	USA	USA	-	-
Statoil Trinta e Quatro AS	Norway	Angola	-	(0.3)
Statoil UK Holdings Limited	United Kingdom	United Kingdom	-	-
Statoil UK Limited	United Kingdom	United Kingdom	275	25.8
Statoil UK Properties Limited	United Kingdom	United Kingdom	-	-
Statoil Upsilon Netherlands B.V.	Netherlands	Netherlands	-	-
Statoil Uruguay B.V.	Netherlands	Uruguay	-	-

ADDITIONAL INFORMATION

Subsidiaries	Country of incorporation	Country of operation	Number of employees	Net intercompany interest (in USD million)
Statoil US Holdings Inc.	USA	USA	132	272.1
Statoil USA E&P Inc.	USA	USA	-	-
Statoil USA Onshore Properties Inc.	USA	USA	-	-
Statoil USA Properties Inc.	USA	USA	-	-
Statoil Venezuela AS	Norway	Venezuela	-	(0.1)
Statoil Venture AS	Norway	Norway	-	(0.7)
Statoil Wind I A/S	Denmark	Denmark	-	-
Statoil Wind II A/S	Denmark	Denmark	-	-
Statoil Wind III A/S	Denmark	Denmark	-	-
Statoil Wind Limited	United Kingdom	United Kingdom	-	-
Statoil Wind US LLC	USA	USA	-	-
Statoil Zagros Oil and Gas AS	Norway	Iran	-	-
Statoil Zeta Netherlands B.V.	Netherlands	Azerbaijan	-	-
Svanholmen 8 AS	Norway	Norway	-	-
Tjeldbergodden Luftgassfabrikk DA	Norway	Norway	-	-
Wind Power AS	Norway	Norway	-	-
Currency adjustments			-	(2.1)
Total			**20,538**	**0.0**

Independent Limited Assurance Report to Statoil ASA on the payments to governments report

We were engaged by management of Statoil ASA to provide assurance on the Payments to governments report for the year ended 31 December 2016 ("the Report").

Statoil ASA's Responsibilities

The board of directors and management are responsible for properly preparing and presenting the Report that is free from material misstatement in accordance with the Norwegian Accounting Act §3-3d and the detailed regulation included in "Forskrift om land-for-land rapportering" and the reporting principles as set out in the Report and for the information contained therein. This responsibility includes: designing, implementing and maintaining internal control relevant to the preparation and presentation of the Report that is free from material misstatement, whether due to fraud or error.

Our Responsibilities

Our responsibility is to examine the Report prepared by Statoil ASA and to report thereon in the form of an independent limited assurance conclusion based on the procedures we have performed and the evidence obtained. We conducted our engagement in accordance with the International Standard for Assurance Engagements (ISAE) 3000: Assurance Engagements other than Audits or Reviews of Historical Financial Information, issued by the International Auditing and Assurance Standards Board. That standard requires that we plan and perform our procedures to obtain a meaningful level of assurance about whether the Report is properly prepared and presented, in all material respects, as the basis for our limited assurance conclusion.

The firm applies International Standard on Quality Control 1 and accordingly maintains a comprehensive system of quality control including documented policies and procedures regarding compliance with ethical requirements, professional standards and applicable legal and regulatory requirements.

We have complied with the Code of Ethics for Professional Accountants (IESBA Code) issued by the International Ethics Standards Board for Accountants, which sets out ethical requirements, including independence and other requirements founded on fundamental principles of integrity, objectivity, professional competence and due care, confidentiality and professional behaviour.

A limited assurance engagement in accordance with ISAE 3000 involves assessing the risks of material misstatement of the Report, whether due to fraud or error, responding to the assessed risks as necessary in the circumstances of the engagement and evaluating the overall presentation of the Report. The nature, timing and extent of procedures selected depend on our understanding of the Report and other engagement circumstances, and our consideration of areas of the Report where material misstatements are likely to arise.

In developing our understanding of the Report, we developed an understanding of internal control over the preparation and presentation of the Report in order to design assurance procedures that are appropriate in the circumstances, but not for the purposes of expressing a conclusion as to the effectiveness of Statoil ASA's internal control over the preparation and presentation of the Report.

Limited assurance is less than absolute assurance and reasonable assurance. A limited assurance engagement is substantially less in scope than a reasonable assurance engagement in relation to both the risk assessment procedures, including an understanding of internal control, and the evidence-gathering procedures performed in response to the assessed risks, which vary in nature and timing from and are substantially less in scope than for a reasonable assurance engagement. As a result, the level of assurance obtained in a limited assurance engagement is substantially lower than the assurance that would have been obtained had we performed a reasonable assurance engagement.

The procedures we performed were based on our professional judgment and included inquiries, observation of processes performed, inspection of documents, analytical procedures, evaluating the appropriateness of quantification methods and reporting policies and agreeing or reconciling the Report with underlying records.

We do not express a reasonable assurance conclusion about whether the Report has been prepared and presented, in all material respects, in accordance with the Norwegian Accounting Act §3-3d and the detailed regulation included in "Forskrift om land-for-land rapportering" and the reporting principles as set out in the Report and for the information contained therein.

Limited Assurance Conclusion
Our conclusion has been formed on the basis of, and is subject to, the matters outlined in this report. We believe that the evidence we have obtained is sufficient and appropriate to provide a basis for our conclusion.

Based on the procedures we have performed and the evidence we have obtained, described in this limited assurance report, nothing has come to our attention that causes us to believe that the Report for the year ended 31 December 2016 is not prepared and presented, in all material respects, in accordance with the Norwegian Accounting Act §3-3d and the detailed regulation included in "Forskrift om land-for-land rapportering" and the reporting principles as set out in the Report.

Oslo, 9 March 2017

KPMG AS

Mona I. Larsen

Mona Irene Larsen
State Authorised Public Accountant (Norway)

5.5 STATEMENTS ON THIS REPORT

Board statement on Reporting of payments to governments

Today, the board of directors and the chief executive officer have reviewed and approved the board of director's report prepared in accordance with the Norwegian Securities Trading Act section 5-5a regarding Reporting on payments to governments as of 31 December 2016.

To the best of our knowledge, we confirm that:

- The information presented in the report has been prepared in accordance with the requirements of the Norwegian Securities Trading Act section 5-5a and associated regulations

Oslo, 9 March 2017

THE BOARD OF DIRECTORS OF STATOIL ASA

ØYSTEIN LØSETH
CHAIR

ROY FRANKLIN
DEPUTY CHAIR

BJØRN TORE GODAL

LILL-HEIDI BAKKERUD

JEROEN VAN DER VEER

MARIA JOHANNA OUDEMAN

REBEKKA GLASSER HERLOFSEN

INGRID ELISABETH DI VALERIO

STIG LÆGREID

WENCHE AGERUP

ELDAR SÆTRE
PRESIDENT AND CEO

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Statement on compliance

Today, the board of directors, the chief executive officer and the chief financial officer reviewed and approved the 2016 Annual report and Form 20-F, which includes the board of directors' report and the Statoil ASA Consolidated and parent company annual financial statements as of 31 December 2016.

To the best of our knowledge, we confirm that:

- the Statoil Consolidated annual financial statements for 2016 have been prepared in accordance with IFRS and IFRIC as adopted by the European Union (EU), IFRS as issued by the International Accounting Standards Board (IASB) and additional Norwegian disclosure requirements in the Norwegian Accounting Act, and that
- the parent company financial statements for Statoil ASA for 2016 have been prepared in accordance with simplified IFRS pursuant to the Norwegian Accounting Act §3-9 and regulations regarding simplified application of IFRS issued by the Norwegian Ministry of Finance, and that
- the board of directors' report for the group and the parent company is in accordance with the requirements in the Norwegian Accounting Act and Norwegian Accounting Standard no 16, and that
- the information presented in the financial statements gives a true and fair view of the company's and the group's assets, liabilities, financial position and results for the period viewed in their entirety, and that
- the board of directors' report gives a true and fair view of the development, performance, financial position, principle risks and uncertainties of the company and the group

Oslo, 9 March 2017

THE BOARD OF DIRECTORS OF STATOIL ASA

ØYSTEIN LØSETH
CHAIR

ROY FRANKLIN DEPUTY CHAIR	BJØRN TORE GODAL	LILL-HEIDI BAKKERUD
JEROEN VAN DER VEER	MARIA JOHANNA OUDEMAN	REBEKKA GLASSER HERLOFSEN
INGRID ELISABETH DI VALERIO	STIG LÆGREID	WENCHE AGERUP
	HANS JAKOB HEGGE CHIEF FINANCIAL OFFICER	ELDAR SÆTRE PRESIDENT AND CEO

Recommendation of the corporate assembly

Resolution:
At its meeting of 17 March 2017 the corporate assembly discussed the 2016 annual accounts of Statoil ASA and the Statoil group, and the board of directors' proposal for the allocation of net income.

The corporate assembly recommends that the annual accounts and the allocation of net income proposed by the board of directors are approved.

Oslo, 17 March 2017

Tone Cathrine Lunde Bakker
Chair of the corporate assembly

Corporate assembly

Sun Lehmann	Greger Mannsverk	Ingvald Strømmen	Siri Kalvig	Brit Gunn Ersland
Nils Bastiansen	Steinar Olsen	Rune Bjerke	Terje Venold	Steinar Kåre Dale
Jarle Roth	Kathrine Næss	Birgitte Ringstad Vartdal	Kjersti Kleven	Per Martin Labråten
Anne K.S. Horneland	Jan-Eirik Feste	Hilde Møllerstad	Per Helge Ødegård	Dag-Rune Dale
				Tone Cathrine Lunde Bakker

5.6 TERMS AND ABBREVIATIONS

Organisational abbreviations

- ADS – American Depositary Share
- ADR – American Depositary Receipt
- ACG - Azeri-Chirag-GunashliX
- ACQ - Annual contract quantity
- AFP - Agreement-based early retirement plan
- AGM - Annual general meeting
- ÅTS - Åsgard transport system
- APA - Awards in pre-defined areas
- ARO - Asset retirement obligation
- BTC - Baku-Tbilisi-Ceyhan pipeline
- CCS - Carbon capture and storage
- CH4 - Methane
- CO2 - Carbon dioxide
- DKK - Danish Krone
- DPI - Development and Production International
- DPN - Development and Production Norway
- DPUSA - Development and Production USA
- DST - Drill Stem Test
- D&W - Drilling and Well
- EEA - European Economic Area
- EFTA - European Free Trade Association
- EMTN - Euro medium-term note
- EU - European Union
- EU ETS - EU Emissions Trading System
- EUR - Euro
- EXP - Exploration
- FPSO - Floating production, storage and offload vessel
- GAAP - Generally Accepted Accounting Principals
- GBP - British Pound
- GBS - Gravity-based structure
- GDP - Gross domestic product
- GHG - Greenhouse gas
- GSB - Global Strategy and Business Development
- HSE - Health, safety and environment
- HTHP - High-temperature/high pressure
- IASB - International Accounting Standards Board
- ICE - Intercontinental Exchange
- IEA - International Energy Agency
- IFRS - International Financial Reporting Standards
- IOR - Improved oil recovery
- LNG - Liquefied natural gas
- LPG - Liquefied petroleum gas
- MMP - Marketing, Midstream and Processing
- MPE - Norwegian Ministry of Petroleum and Energy
- MW - Mega watt
- NCS - Norwegian continental shelf
- NES – New Energy Solutions
- NIOC - National Iranian Oil Company
- NOK - Norwegian kroner
- NOx- Nitrogen oxide
- OECD - Organisation of Economic Co-Operation and Development
- OML - Oil mining lease
- OPEC - Organization of the Petroleum Exporting Countries
- OTC - Over-the-counter
- OTS - Oil trading and supply department
- P5+1 – UN Security Council`s five permanent members
- PDO - Plan for development and operation
- PDQ – Production drilling quarters
- PIO - Plan for installation and operation
- PRD - Project Development organisation
- PSA - Production sharing agreement
- PSC – Production sharing contract
- PSR - Procurement and Supplier Relations
- RDI - Research, Development and Innovation
- R&D - Research and development
- ROACE - Return on average capital employed
- RRR - Reserve replacement ratio
- SAGD - Steam-assisted gravity drainage
- SCP - South Caucasus Pipeline System
- SDFI - Norwegian State's Direct Financial Interest
- SEC - Securities and Exchange Commission
- SEK - Swedish Krona
- SFR - Statoil Fuel & Retail
- SIF - Serious Incident Frequency
- TAP - Trans Adriatic Pipeline AG
- TEX - Technology Excellence
- TLP - Tension leg platform
- TPD - Technology, projects and drilling
- TRIF - Total recordable injuries per million hours worked
- TSP - Technical service provider
- UKCS - UK continental shelf
- USD - United States dollar
- WTG - Wind Turbine Generators

Metric abbreviations etc.

- bbl - barrel
- mbbl - thousand barrels
- mmbbl - million barrels
- boe - barrels of oil equivalent
- mboe - thousand barrels of oil equivalent
- mmboe - million barrels of oil equivalent
- mmcf - million cubic feet
- MMBtu - million british thermal units
- bcf - billion cubic feet
- tcf - trillion cubic feet
- scm - standard cubic metre
- mcm - thousand cubic metres
- mmcm - million cubic metres
- bcm - billion cubic metres
- mmtpa - million tonnes per annum
- km - kilometre
- ppm - part per million
- one billion - one thousand million

Equivalent measurements are based upon

- 1 barrel equals 0.134 tonnes of oil (33 degrees API)
- 1 barrel equals 42 US gallons
- 1 barrel equals 0.159 standard cubic metres
- 1 barrel of oil equivalent equals 1 barrel of crude oil
- 1 barrel of oil equivalent equals 159 standard cubic metres of natural gas
- 1 barrel of oil equivalent equals 5,612 cubic feet of natural gas
- 1 barrel of oil equivalent equals 0.0837 tonnes of NGLs
- 1 billion standard cubic metres of natural gas equals 1 million standard cubic metres of oil equivalent
- 1 cubic metre equals 35.3 cubic feet
- 1 kilometre equals 0.62 miles
- 1 square kilometre equals 0.39 square miles
- 1 square kilometre equals 247.105 acres
- 1 cubic metre of natural gas equals 1 standard cubic metre of natural gas
- 1,000 standard cubic meter gas equals 1 standard cubic meter oil equivalent
- 1,000 standard cubic metres of natural gas equals 6.29 boe
- 1 standard cubic foot equals 0.0283 standard cubic metres
- 1 standard cubic foot equals 1000 British thermal units (btu)

ADDITIONAL INFORMATION

- 1 tonne of NGLs equals 1.9 standard cubic metres of oil equivalent
- 1 degree Celsius equals minus 32 plus five-ninths of the number of degrees Fahrenheit

Miscellaneous terms

- Appraisal well: A well drilled to establish the extent and the size of a discovery
- Backwardation and contango are terms used in the crude oil market. Contango is a condition where forward prices exceed spot prices, so the forward curve is upward sloping. Backwardation is the opposite condition, where spot prices exceed forward prices, and the forward curve slopes downward
- Biofuel: A solid, liquid or gaseous fuel derived from relatively recently dead biological material and is distinguished from fossil fuels, which are derived from long dead biological material
- BOE (barrels of oil equivalent): A measure to quantify crude oil, natural gas liquids and natural gas amounts using the same basis. Natural gas volumes are converted to barrels on the basis of energy content
- Clastic reservoir systems: The integrated static and dynamic characteristics of a hydrocarbon reservoir formed by clastic rocks of a specific depositional sedimentary succession and its seal
- Condensates: The heavier natural gas components, such as pentane, hexane, iceptane and so forth, which are liquid under atmospheric pressure - also called natural gasoline or naphtha
- Crude oil, or oil: Includes condensate and natural gas liquids
- Development: The drilling, construction, and related activities following discovery that are necessary to begin production of crude oil and natural gas fields
- Downstream: The selling and distribution of products derived from upstream activities
- Equity and entitlement volumes of oil and gas: Equity volumes represent volumes produced under a production sharing agreement (PSA) that correspond to Statoil's percentage ownership in a particular field. Entitlement volumes, on the other hand, represent Statoil's share of the volumes distributed to the partners in the field, which are subject to deductions for, among other things, royalties and the host government's share of profit oil. Under the terms of a PSA, the amount of profit oil deducted from equity volumes will normally increase with the cumulative return on investment to the partners and/or production from the licence. The distinction between equity and entitlement is relevant to most PSA regimes, whereas it is not applicable in most concessionary regimes such as those in Norway, the UK, Canada and Brazil. The overview of equity production provides additional information for readers, as certain costs described in the profit and loss analysis were directly associated with equity volumes produced during the reported years
- Heavy oil: Crude oil with high viscosity (typically above 10 cp), and high specific gravity. The API classifies heavy oil as crudes with a gravity below 22.3° API. In addition to high viscosity and high specific gravity, heavy oils typically have low hydrogen-to-carbon ratios, high asphaltene, sulphur, nitrogen, and heavy-metal content, as well as higher acid numbers
- High grade: Relates to selectively harvesting goods, to cut the best and leave the rest. In reference to exploration and production this entails strict prioritisation and sequencing of drilling targets
- Hydro: A reference to the oil and energy activities of Norsk Hydro ASA, which merged with Statoil ASA
- IOR (improved oil recovery): Actual measures resulting in an increased oil recovery factor from a reservoir as compared with the expected value at a certain reference point in time. IOR comprises both of conventional and emerging technologies
- Liquids: Refers to oil, condensates and NGL
- LNG (liquefied natural gas): Lean gas - primarily methane - converted to liquid form through refrigeration to minus 163 degrees Celsius under atmospheric pressures
- LPG (liquefied petroleum gas): Consists primarily of propane and butane, which turn liquid under a pressure of six to seven atmospheres. LPG is shipped in special vessels
- Midstream: Processing, storage, and transport of crude oil, natural gas, natural gas liquids and sulphur
- Naphtha: inflammable oil obtained by the dry distillation of petroleum
- Natural gas: Petroleum that consists principally of light hydrocarbons. It can be divided into 1) lean gas, primarily methane but often containing some ethane and smaller quantities of heavier hydrocarbons (also called sales gas) and 2) wet gas, primarily ethane, propane and butane as well as smaller amounts of heavier hydrocarbons; partially liquid under atmospheric pressure
- NGL (natural gas liquids): Light hydrocarbons mainly consisting of ethane, propane and butane which are liquid under pressure at normal temperature
- Oil sands: A naturally occurring mixture of bitumen, water, sand, and clay. A heavy viscous form of crude oil
- Oil and gas value chains: Describes the value that is being added at each step from 1) exploring; 2) developing; 3) producing; 4) transportation and refining; and 5) marketing and distribution
- Organic capital expenditures: Capital expenditures excluding acquisitions, capital leases and other investments with significant different cash flow pattern
- Oslo Børs : Oslo stock exchange
- Peer group: Statoil's peer group consists of Statoil, Shell, ExxonMobil, OMV, ConocoPhillips, BP, Marathon, Chevron, Total, Repsol, Anadarko and Eni
- Petroleum: A collective term for hydrocarbons, whether solid, liquid or gaseous. Hydrocarbons are compounds formed from the elements hydrogen (H) and carbon (C). The proportion of different compounds, from methane and ethane up to the heaviest components, in a petroleum find varies from discovery to discovery. If a reservoir primarily contains light hydrocarbons, it is described as a gas field. If heavier hydrocarbons predominate, it is described as an oil field. An oil field may feature free gas above the oil and contain a quantity of light hydrocarbons, also called associated gas
- Proved reserves: Reserves claimed to have a reasonable certainty (normally at least 90% confidence) of being recoverable under existing economic and political conditions, and using existing technology. They are the only type the US Securities and Exchange Commission allows oil companies to report
- Refining reference margin: Is a typical average gross margin of our two refineries, Mongstad and Kalundborg. The reference margin will differ from the actual margin, due to variations in type of crude and other feedstock, throughput, product yields, freight cost, inventory etc
- Rig year: A measure of the number of equivalent rigs operating during a given period. It is calculated as the number of days rigs are operating divided by the number of days in the period
- Upstream: Includes the searching for potential underground or underwater oil and gas fields, drilling of exploratory wells, subsequent operating wells which bring the liquids and or natural gas to the surface
- VOC (volatile organic compounds): Organic chemical compounds that have high enough vapour pressures under normal conditions to significantly vaporise and enter the earth's atmosphere (e.g. gasses formed under loading and offloading of crude oil)

5.7 FORWARD-LOOKING STATEMENTS

This Annual Report on Form 20-F contains certain forward-looking statements that involve risks and uncertainties, in particular in the sections "Business overview" and "Strategy and market overview". In some cases, we use words such as "aim", "ambition", "anticipate", "believe", "continue", "could", "estimate", "expect", "intend", "likely", "objective", "outlook", "may", "plan", "schedule", "seek", "should", "strategy", "target", "will", "goal" and similar expressions to identify forward-looking statements. All statements other than statements of historical fact, including, among others, statements regarding future financial position, results of operations and cash flows; future financial ratios and information; future financial or operational portfolio or performance; future market position and conditions; future credit rating; business strategy; growth strategy; sales, trading and market strategies; research and development initiatives and strategy; market outlook and future economic projections and assumptions; competitive position; projected regularity and performance levels; expectations related to our recent transactions and projects, such as the sale of interests in the Shah Deniz project and the South Caucasus Pipeline, interests in the Marcellus onshore play in the US, interests in Trans Adriatic Pipeline, interests in Gudrun and acquisition of interests in Eagle Ford in the US, the UK Mariner project, the Peregrino phase II project in Brazil, in addition to the Johan Sverdrup and Aasta Hansteen projects on the NCS, discoveries on the NCS and internationally; our ownership share in Gassled; completion and results of acquisitions, disposals and other contractual arrangements; reserve information; recovery factors and levels; future margins; projected returns; future levels or development of capacity, reserves or resources; future decline of mature fields; planned turnarounds and other maintenance; plans for cessation and decommissioning; oil and gas production forecasts and reporting; growth, expectations and development of production, projects, pipelines or resources; estimates related to production and development levels and dates; operational expectations, estimates, schedules and costs; exploration and development activities, plans and expectations; projections and expectations for upstream and downstream activities; expectations relating to licences; oil, gas, alternative fuel and energy prices and volatility; oil, gas, alternative fuel and energy supply and demand; renewable energy production, industry outlook and carbon capture and storage; organisational structure and policies; planned responses to climate change; technological innovation, implementation, position and expectations; future energy efficiency; projected operational costs or savings; our ability to create or improve value; future sources of financing; exploration and project development expenditure; our goal of safe and efficient operations; effectiveness of our internal policies and plans; our ability to manage our risk exposure; our liquidity levels and management; estimated or future liabilities, obligations or expenses; expected impact of currency and interest rate fluctuations; expectations related to contractual or financial counterparties; capital expenditure estimates and expectations; projected outcome, impact or timing of HSE regulations; HSE goals and objectives of management for future operations; expectations related to regulatory trends; impact of PSA effects; projected impact or timing of administrative or governmental rules, standards, decisions, standards or laws (including taxation laws); projected impact of legal claims against us; plans for capital distribution and amounts of dividends are forward-looking statements. You should not place undue reliance on these forward-looking statements. Our actual results could differ materially from those anticipated in the forward-looking statements for many reasons, including the risks described above in "Risk review", and in "Operational review", and elsewhere in this Annual Report on Form 20-F.

These forward-looking statements reflect current views about future events and are, by their nature, subject to significant risks and uncertainties because they relate to events and depend on circumstances that will occur in the future. There are a number of factors that could cause actual results and developments to differ materially from those expressed or implied by these forward-looking statements, including levels of industry product supply, demand and pricing; exchange rate and interest rate fluctuations; the political and economic policies of Norway and other oil-producing countries; EU directives; general economic conditions; political and social stability and economic growth in relevant areas of the world; Euro-zone uncertainty; global political events and actions, including war, terrorism and sanctions; security breaches, including breaches of our digital infrastructure (cybersecurity); changes or uncertainty in or non-compliance with laws and governmental regulations; the timing of bringing new fields on stream; an inability to exploit growth opportunities; material differences from reserves estimates; unsuccessful drilling; an inability to find and develop reserves; ineffectiveness of crisis management systems; adverse changes in tax regimes; the development and use of new technology, particularly in the renewable energy sector; geological or technical difficulties; operational problems; operator error; inadequate insurance coverage; the lack of necessary transportation infrastructure when a field is in a remote location and other transportation problems; the actions of competitors; the actions of field partners; the actions of the Norwegian state as majority shareholder; counterparty defaults; natural disasters, adverse weather conditions, climate change, and other changes to business conditions; failure to meet our ethical and social standards; an inability to attract and retain personnel and other factors discussed elsewhere in this report.

Although we believe that the expectations reflected in the forward-looking statements are reasonable, we cannot assure you that our future results, level of activity, performance or achievements will meet these expectations. Moreover, neither we nor any other person assumes responsibility for the accuracy and completeness of the forward-looking statements. Unless we are required by law to update these statements, we will not necessarily update any of these statements after the date of this Annual Report, either to make them conform to actual results or changes in our expectations.

5.8 SIGNATURE PAGE

The registrant hereby certifies that it meets all of the requirements for filing on Form 20-F and that it has duly caused and authorised the undersigned to sign this Annual Report on its behalf.

STATOIL ASA
(Registrant)

By: /s/Hans Jakob Hegge
Name: Hans Jakob Hegge
Title: Executive Vice President and Chief Financial Officer

Dated: 17 March 2017

5.9 EXHIBITS

The following exhibits are filed as part of this Annual Report:

Exhibit no	Description
Exhibit 1	Articles of Association of Statoil ASA, as amended, effective from 26 October 2016 (English translation).
Exhibit 2.1	Form of Indenture among Statoil ASA (formerly known as StatoilHydro ASA), Statoil Petroleum AS (formerly known as Statoil Hydro Petroleum AS) and Deutsche Bank Trust Company Americas (incorporated by reference to Exhibit 4.1 of Statoil ASA's and Statoil Petroleum AS's Post-Effective Amendment No. 1 to their Registration Statement on Form F-3 (File No. 333-143339) filed with the Commission on April 2, 2009).
Exhibit 2.2	Amended and Restated Agency Agreement, dated as of 5 February 2016, by and among Statoil ASA, as Issuer, Statoil Petroleum AS as Guarantor, the Bank of New York Mellon, as Agent and the Bank of New York Mellon (Luxembourg) S.A. as Paying Agent in respect of a €20,000,000 Euro Medium Term Note Programme.
Exhibit 2.3	Deed of Covenant, dated as of 5 February 2016, of Statoil ASA in respect of a €20,000,000 Euro Medium Term Notes Programme.
Exhibit 2.4	Deed of Guarantee, dated as of 5 February 2016, of Statoil Petroleum AS in respect of a €20,000,000 Euro Medium Term Notes Programme.
Exhibit 4(a)(i)	Technical Services Agreement between Gassco AS and Statoil Petroleum AS, dated November 24, 2010.
Exhibit 4(c)	Employment agreement with Eldar Sætre as of 4 February 2015.
Exhibit 7	Calculation of ratio of earnings to fixed charges.
Exhibit 8	Subsidiaries (see Significant subsidiaries included in section 2.7 Corporate in this Annual Report).
Exhibit 12.1	Rule 13a-14(a) Certification of Chief Executive Officer.
Exhibit 12.2	Rule 13a-14(a) Certification of Chief Financial Officer.
Exhibit 13.1	Rule 13a-14(b) Certification of Chief Executive Officer.[1)]
Exhibit 13.2	Rule 13a-14(b) Certification of Chief Financial Officer.[1)]
Exhibit 15(a)(i)	Consent of KPMG AS.
Exhibit 15(a)(ii)	Consent of DeGolyer and MacNaughton.
Exhibit 15(a)(iii)	Report of DeGolyer and MacNaughton.

1) Furnished only.

The total amount of long term debt securities of Statoil ASA and its subsidiaries authorized under instruments other than those listed above does not exceed 10% of the total assets of Statoil ASA and its subsidiaries on a consolidated basis. The company agrees to furnish copies of any or all such instruments to the Commission upon request.

5.10 Cross reference to Form 20-F

		Sections
Item 1.	Identity of Directors, Senior Management and Advisers	N/A
Item 2.	Offer Statistics and Expected Timetable	N/A
Item 3.	Key Information	
	A. Selected Financial Data	Key Figures and Highlights
	B. Capitalisation and Indebtedness	N/A
	C. Reasons for the Offer and Use of Proceeds	N/A
	D. Risk Factors	2.10 (Risk review—Risk factors)
Item 4.	Information on the Company	
	A. History and Development of the Company	Statoil at a Glance; 2.2 (Business Overview); 2.3 (DPN - Development and production Norway); 2.4 (DPI - Development and production international); 2.5 (MMP - Marketing, Midstream and processing); 2.6 (Other group); 2.9 (Liquidity and capital resources—Reviews of cash flows); 2.9 (Liquidity and Capital Resources—Investments); note 4 (Acquisitions and disposals) to Statoil's Consolidated financial statements)
	B. Business Overview	2.1 (Strategy and market overview); 2.2 (Business overview); 2.3 (DPN - Development and production Norway); 2.4 (DPI - Development and production international); 2.5 (MMP - Marketing, midstream and processing); 2.6 (Other group); 2.7 (Corporate)
	C. Organisational Structure	2.2 (Business overview—Corporate structure); 2.2 (Business Overview—Segment reporting); 2.7 (Corporate—Subsidiaries and properties)
	D. Property, Plants and Equipment	2.3 (DPN - Development and production Norway); 2.4 (DPI - Development and production international); 2.5 (MMP - Marketing, midstream and processing); 2.7 (Corporate—Property, plant and equipment); 2.9 (Liquidity and Capital Resources—Investments); notes 10 (Property, plant and equipment) and 22 (Leases) to Statoil's Consolidated financial statements
	Oil and Gas Disclosures	2.8 (Operating and financial performance—Proved oil and gas reserves); 2.8 (Operating and financial performance—Production volumes and pricing); Exhibit 15(a)(iii)
Item 4A.	Unresolved Staff Comments	None
Item 5.	Operating and Financial Review and Prospects	
	A. Operating Results	2.8 (Operating and financial performance); 2.7 (Corporate—Applicable laws and regulations); 2.9 (Liquidity and capital resources—Impact of reduced prices); 2.10 (Risk review—Risk management—Managing operational risks); note 25 (Financial instruments: fair value measurement and sensitivity analysis of market risk) to Statoil's Consolidated financial statements 3.12; 4.1.
	B. Liquidity and Capital Resources	2.9 (Liquidity and capital resources); 2.10 (Risk review—Risk management); notes 5 (Financial risk management), 15 (Trades and other receivables); 18 (Finance debt), 23 (Other commitments, contingent liabilities and contingent assets) and 25 (Financial instruments: fair value measurement and sensitivity analysis of market risk) to Statoil's Consolidated financial statements
	C. Research and development, Patents and Licenses, etc.	2.2 (Business overview—Research and development); note 7 (Other expenses) to Statoil's consolidated financial statements
	D. Trend Information	passim
	E. Off�Balance Sheet Arrangements	2.9 (Liquidity and capital resources—Principal Contractual obligations); 2.9 (Liquidity and capital resources—Off balance sheet arrangements); notes 22 (Leases) and 23 (Other commitments, contingent liabilities and contingent assets) to Statoil's Consolidated financial statements
	F. Tabular Disclosure of Contractual Obligations	2.9 (Liquidity and capital resources—Principal contractual obligations)
	G. Safe Harbor	5.7 (Forward-Looking Statements)
Item 6.	Directors, Senior Management and Employees	

	A. Directors and Senior Management	3.8 (Board of directors); 3.8 (Management)
	B. Compensation	3.11 (Remuneration to the board of directors and corporate assembl); 3.12 (Remuneration to the executive committee)
	C. Board Practices	3.8 (Corporate assembly, board of directors and management)
	D. Employees	2.12 (Our people—Employees in Statoil); 2.12 (Our people—Unions and representatives)
	E. Share Ownership	3.11 (Remuneration to the board of directors an corporate assembly); 3.12 (Remuneration to the corporate executive committee); 5.1 (Shareholder information—Shares purchased by the issuer—Statoil's share savings plan)
Item 7.	Major Shareholders and Related Party Transactions	
	A. Major Shareholders	5.1 (Shareholder information—Major shareholders)
	B. Related Party Transactions	2.7 (Corporate—Related party transactions); note 24 (Related parties) to Statoil's Consolidated financial statement
	C. Interests of Experts and Counsel	N/A
Item 8.	Financial Information	
	A. Consolidated Statements and Other Financial Information	4.1 (Consolidated financial statements of Statoil); 5.3 (Legal proceedings)
	B. Significant Changes	note 28 (Subsequent events) to Statoil's Consolidated financial statements)
Item 9.	The Offer and Listing	
	A. Offer and Listing Details	5.1 (Shareholder information); 5.1 (Shareholder information—Share Prices)
	B. Plan of Distribution	N/A
	C. Markets	5.1 (Shareholder Information)
	D. Selling Shareholders	N/A
	E. Dilution	N/A
	F. Expenses of the Issue	N/A
Item 10.	Additional Information	
	A. Share Capital	N/A
	B. Memorandum and Articles of Association	2.10 (Risk review—Risks related to state ownership); 3.1 (Implementation and reporting); 3.6 (General meeting of shareholders); 5.1 (Shareholder information); 5.1 (Shareholder Information—Major Shareholders) and note 17 (Shareholders' Equity and dividends) to Statoil's Consolidated financial statements
	C. Material Contracts	N/A
	D. Exchange Controls	5.1 (Shareholder information—Exchange controls and limitations
	E. Taxation	5.1 (Shareholder information—Taxation)
	F. Dividends and Paying Agents	N/A
	G. Statements by Experts	N/A
	H. Documents On Display	About this Report
	I. Subsidiary Information	N/A
Item 11.	Quantitative and Qualitative Disclosures About Market Risk	2,10 (Risk review—Risk management); notes 5 (Financial risk management) and 25 (Financial instruments; fair value measurement and sensitivity analysis of market risk) to Statoil's Consolidated financial statements
Item 12.	Description of Securities Other than Equity Securities	
	A. Debt Securities	N/A
	B. Warrants and Rights	N/A
	C. Other Securities	N/A
	D. American Depositary Shares	5.1 (Shareholder Information—Statoil ADR Programme Fees)
Item 13.	Defaults, Dividend Arrearages and Delinquencies	None
Item 14.	Material Modifications to the Rights of Security Holders and Use of Proceeds	None
Item 15.	Controls and Procedures	3.10 (Risk management and internal control);
Item 16A.	Audit Committee Financial Expert	3.9 (The work of the board of directors)
Item 16B.	Code of Ethics	3.10 (Risk management and internal control)

ADDITIONAL INFORMATION

Item 16C.	Principal Accountant Fees and Services	3.15 (External Auditor)
Item 16D.	Exemptions from the Listing Standards for Audit Committees	3.1 (Introduction—Compliance with NYSE listing rules)
Item 16E.	Purchases of Equity Securities by the Issuer and Affiliated Purchases	5.1 (Shareholder Information—Shares purchased by the Issuer)
Item 16F.	Changes in Registrant's Certifying Accountant	N/A
Item 16G.	Corporate Governance	3.1 (Introduction—Compliance with NYSE listing rules)
Item 16H	Mine Safety Disclosure	None
Item 17.	Financial Statements	N/A
Item 18.	Financial Statements	4.1 (Financial statements of Statoil)

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, DC 20549

FORM 20-F

(Mark One)

☐ **REGISTRATION STATEMENT PURSUANT TO SECTION 12(b) OR 12(g) OF THE SECURITIES EXCHANGE ACT OF 1934**

OR

☒ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the fiscal year ended December 31, 2016

OR

☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the transition period from _________ to _________

OR

☐ **SHELL COMPANY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

Date of event requiring this shell company report _________

Commission file number 1-15200

Statoil ASA

(Exact Name of Registrant as Specified in Its Charter)

N/A

(Translation of Registrant's Name Into English)

Norway

(Jurisdiction of Incorporation or Organization)

Forusbeen 50, N-4035, Stavanger, Norway

(Address of Principal Executive Offices)

Hans Jakob Hegge
Chief Financial Officer
Statoil ASA
Forusbeen 50, N-4035
Stavanger, Norway
Telephone No.: 011-47-5199-0000
Fax No.: 011-47-5199-0050

(Name, Telephone, E-mail and/or Facsimile number and Address of Company Contact Person)

Securities registered or to be registered pursuant to Section 12(b) of the Act:

Title of Each Class	Name of Each Exchange On Which Registered
American Depositary Shares	**New York Stock Exchange**
Ordinary shares, nominal value of NOK 2.50 each	**New York Stock Exchange***

*Listed, not for trading, but only in connection with the registration of American Depositary Shares, pursuant to the requirements of the Securities and Exchange Commission

Securities registered or to be registered pursuant to Section 12(g) of the Act: **None**

Securities for which there is a reporting obligation pursuant to Section 15(d) of the Act: **None**

ADDITIONAL INFORMATION

Indicate the number of outstanding shares of each of the issuer's classes of capital or common stock as of the close of the period covered by the annual report.

Ordinary shares of NOK 2.50 each	**3,245,049,411**

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act.

☒ Yes ☐ No

If this report is an annual or transition report, indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934.

☐ Yes ☒ No

Note – Checking the box above will not relieve any registrant required to file reports pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934 from their obligations under those Sections.

Indicate by check mark whether the registrant: (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.

☒ Yes ☐ No

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files).**

☐ Yes ☐ No

**This requirement does not apply to the registrant in respect of this filing.

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, or a non-accelerated filer. See definition of "accelerated filer and large accelerated filer" in Rule 12b-2 of the Exchange Act. (Check one):

Large accelerated filer ☒ Accelerated filer ☐ Non-accelerated filer ☐

Indicate by check mark which basis of accounting the registrant has used to prepare the financial statements included in this filing:

U.S. GAAP ☐ International Financial Reporting Standards as issued by the International Accounting Standards Board ☒ Other ☐

If "Other" has been checked in response to the previous question, indicate by check mark which financial statement item the registrant has elected to follow.

Item 17 ☐

Item 18 ☐

If this is an annual report, indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act).

☐ Yes ☒ No

STATOIL ASA
BOX 8500
NO-4035 STAVANGER
NORWAY
TELEPHONE: +47 51 99 00 00

www.statoil.com

PUBLIC COPY - CONFIDENTIAL INFORMATION REMOVED

2015

Annual Report on Form 20-F

The Annual Report on Form 20-F is our SEC filing for the fiscal year ended December 31, 2015, as submitted to the US Securities and Exchange Commission.

STATOIL ASA
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TELEPHONE: +47 51 99 00 00

www.statoil.com

Cover photo: Øyvind Hagen

2015 Annual Report on Form 20-F

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, DC 20549

FORM 20-F

(Mark One)

☐ **REGISTRATION STATEMENT PURSUANT TO SECTION 12(b) OR 12(g) OF THE SECURITIES EXCHANGE ACT OF 1934**

OR

☒ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the fiscal year ended December 31, 2015

OR

☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the transition period from _________ to _________

OR

☐ **SHELL COMPANY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

Date of event requiring this shell company report _________

Commission file number 1-15200

Statoil ASA

(Exact Name of Registrant as Specified in Its Charter)

N/A

(Translation of Registrant's Name Into English)

Norway

(Jurisdiction of Incorporation or Organization)

Forusbeen 50, N-4035, Stavanger, Norway

(Address of Principal Executive Offices)

Hans Jakob Hegge
Chief Financial Officer
Statoil ASA
Forusbeen 50, N-4035
Stavanger, Norway
Telephone No.: 011-47-5199-0000
Fax No.: 011-47-5199-0050

(Name, Telephone, E-mail and/or Facsimile number and Address of Company Contact Person)

Securities registered or to be registered pursuant to Section 12(b) of the Act:

Title of Each Class	Name of Each Exchange On Which Registered
American Depositary Shares	**New York Stock Exchange**
Ordinary shares, nominal value of NOK 2.50 each	**New York Stock Exchange***

*Listed, not for trading, but only in connection with the registration of American Depositary Shares, pursuant to the requirements of the Securities and Exchange Commission

Securities registered or to be registered pursuant to Section 12(g) of the Act: **None**

Securities for which there is a reporting obligation pursuant to Section 15(d) of the Act: **None**

Indicate the number of outstanding shares of each of the issuer's classes of capital or common stock as of the close of the period covered by the annual report.

Ordinary shares of NOK 2.50 each **3,188,647,103**

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act.

☒ Yes ☐ No

If this report is an annual or transition report, indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934.

☐ Yes ☒ No

Note – Checking the box above will not relieve any registrant required to file reports pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934 from their obligations under those Sections.

Indicate by check mark whether the registrant: (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.

☒ Yes ☐ No

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files).**

☐ Yes ☐ No

**This requirement does not apply to the registrant in respect of this filing.

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, or a non-accelerated filer. See definition of "accelerated filer and large accelerated filer" in Rule 12b-2 of the Exchange Act. (Check one):

Large accelerated filer ☒ Accelerated filer ☐ Non-accelerated filer ☐

Indicate by check mark which basis of accounting the registrant has used to prepare the financial statements included in this filing:

U.S. GAAP ☐ International Financial Reporting Standards as issued by the International Accounting Standards Board ☒ Other ☐

If "Other" has been checked in response to the previous question, indicate by check mark which financial statement item the registrant has elected to follow.

Item 17 ☐

Item 18 ☐

If this is an annual report, indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act).

☐ Yes ☒ No

1 Introduction

1.1 About the report

Statoil's Annual Report on Form 20-F for the year ended 31 December 2015 ("Annual Report on Form 20-F") is available online at www.statoil.com.

Statoil is subject to the information requirements of the US Securities Exchange Act of 1934 applicable to foreign private issuers. In accordance with these requirements, Statoil files its Annual Report on Form 20-F and other related documents with the Securities and Exchange Commission (the SEC). It is also possible to read and copy documents that have been filed with the SEC at the SEC's public reference room located at 100 F Street, N.E., Washington, D.C. 20549, US. You can also call the SEC at 1-800-SEC-0330 for further information about the public reference rooms and their copy charges, or you can log on to www.sec.gov. The report can also be downloaded from the SEC website at www.sec.gov.

Statoil discloses on its website at www.statoil.com/en/about/corporategovernance/statementofcorporategovernance/pages/default.aspx, and in its Annual Report on Form 20-F (Item 16G) significant ways (if any) in which its corporate governance practices differ from those mandated for US companies under the New York Stock Exchange (the "NYSE") listing standards.

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1.2 Key figures and highlights

Statoil publishes financial data in accordance with International Financial Reporting Standards (IFRS) as issued by the International Accounting Standards Board (IASB) and as adopted by the European Union (EU).

(in NOK billion, unless stated otherwise)	For the year ended 31 December 2015	2014	2013	2012	2011
Financial information					
Total revenues and other income[4]	**482.8**	622.7	634.5	718.2	670.0
Net operating income	**14.9**	109.5	155.5	206.6	211.8
Net income	**(37.3)**	22.0	39.2	69.5	78.4
Non-current finance debt	**264.0**	205.1	165.5	101.0	111.6
Net interest-bearing debt before adjustments	**122.0**	89.2	58.0	39.3	71.0
Total assets	**966.7**	986.4	885.6	784.4	768.6
Share capital	**8.0**	8.0	8.0	8.0	8.0
Non-controlling interest	**0.3**	0.4	0.5	0.7	6.2
Total equity	**355.1**	381.2	356.0	319.9	285.2
Net debt to capital employed ratio before adjustments	**25.6%**	19.0%	14.0%	10.9%	19.9%
Net debt to capital employed ratio adjusted	**26.8%**	20.0%	15.2%	12.4%	21.1%
Calculated ROACE based on Average Capital Employed before adjustments	**(8.0%)**	**2.7%**	**11.3%**	**18.7%**	**22.1%**
Operational information					
Equity oil and gas production (mboe/day)	**1,971**	1,927	1,940	2,004	1,850
Proved oil and gas reserves (mmboe)	**5,060**	5,359	5,600	5,422	5,426
Reserve replacement ratio (three-year average)	**0.81**	0.97	1.15	1.01	0.90
Production cost equity volumes (NOK/boe, last 12 months)	**48**	49	44	42	42
Share information[1]					
Diluted earnings per share NOK	**(11.8)**	6.87	12.50	21.60	24.70
Share price at Oslo Børs (Norway) on 31 December in NOK	**123.70**	131.20	147.00	139.00	153.50
Dividend per share NOK [2]	**7.62**	7.20	7.00	6.75	6.50
Dividend per share USD [2,3]	**1.07**	0.97	1.15	1.21	1.08
Weighted average number of ordinary shares outstanding (in thousands)	**3,179,443**	3,179,959	3,180,684	3,181,546	3,182,113

1) See section 6 *Shareholder information* for a description of how dividends are determined and information on share repurchases.
The board of directors will propose the total 2015 dividend for approval at the annual general meeting scheduled for 11 May 2016.

2) Proposed cash dividend for 2015. For 2015, the NOK amount covers first quarter while the USD amount is for second, third and fourth quarter.
Figure presented for 2015 using the Central Bank of Norway 2015 year end rate for Norwegian kroner, which was USD 1.00 = 8.8090 NOK.

3) Figures presented using the Central Bank of Norway year end rate for Norwegian kroner.

4) Total revenues and other income for 2013 and 2012 are restated.

2 Strategy and market overview

The profitability of the oil and gas industry continues to be challenged and Statoil's financial results in 2015 were influenced by the fall in oil prices. Stricter project prioritisation and a comprehensive efficiency programme are showing progress and are expected to continue to improve cash flow and profitability. Statoil proposes to the annual general meeting a scrip dividend from the fourth quarter of 2015. Statoil's strong financial position provides a firm basis on which to balance capital investment and dividends to shareholders, which Statoil expects to grow in line with its long-term earnings.

Last year Statoil outlined plans to further strengthen its competitiveness, and is now reinforcing its effort and commitment to deliver on priorities of high value creation, increased efficiency and competitive shareholder returns. Through Statoil`s flexibility in its investment programme Statoil believes that it is well prepared for potential sustained market volatility and uncertainty.

Statoil's ambition to further reduce costs and improve efficiency was presented at the capital markets update (CMU) on 6 February 2015. Then, the company announced that it was targeting annual savings of USD 1.7 billion from 2016 (pre-tax) as measured against the cost base of 2013. Having already realised $1.9 billion in savings (pre-tax), Statoil announced a new goal at the CMU on 4 February 2016. The company will step up its efficiency programme by 50% with a goal to realise USD 2.5 billion in annual savings from 2016 (pre-tax), again as measured against the cost base of 2013. The step-up of $0.8 billion is expected to be divided by two-thirds capital expenditures (capex) and one-third operational expenditures (opex).

Improvement programmes are Statoil's response to the industrial challenges characterised by high costs and declining returns. More specifically, the ambition is to realise positive production effects and cost savings to improve Statoil's financial results and cash-flows.

These forward-looking statements reflect current views about future events and are, by their nature, subject to significant risks and uncertainties because they relate to events and depend on circumstances that will occur in the future. See section 10 *Forward-Looking Statements* for more information.

2.1 Statoil's business environment

2.1.1 Market overview

Global economic GDP growth eased in 2015, to 2.4% from 2.6% in 2014. This largely reflects weakness in non-OECD economies where activity decelerated over the year. Growth in OECD, on the other hand, held up relatively well at around 2%, supporting overall economic growth and energy demand.

The underlying fundamentals of the United States economy remain sound and GDP growth ticked up slightly to 2.5% in 2015 from 2.4% in 2014. GDP growth also accelerated nominally in the Eurozone to 1.5%, supported by low energy prices, reduced fiscal headwinds, more monetary stimulus and a weak euro. UK GDP growth slowed in 2015, but remains decent at 2.4%, whereas Japan barely avoided its fourth recession in five years. Growth in emerging countries slipped to 3.6% in 2015, reflecting both weakness in commodity prices and domestic challenges. Deep recessions have emerged in Brazil and Russia, whilst China continues on an intended path of gradual deceleration and consequent structural reforms. Net commodity importers such as India are doing much better, and India's GDP growth rate outpaced China's in 2015.

Several major forces are at play in the global economy and will continue to affect demand, including soft commodity prices and persistently low interest rates, increasingly divergent monetary policies across major economies, and weak world trade. In particular, the sharp decline in oil prices since mid-2014 has supported global economic activity and is expected to continue to do so in 2016.

Global oil demand grew by a healthy 1.6 mmbbl per day in 2015, driven by a colder than normal winter in the US and Northern Europe and the lower prices of crude oil. Demand growth in absolute terms was highest in China, despite 2015 being a challenging year for Chinese stock markets and the Chinese economy in general. Non-Opec producers have proven to be resilient to lower prices and grew production by 1.3 mmbbl per day in 2015 while Opec added 1.1 mmbbl per day to their production, mainly from Saudi Arabia and Iraq. This has postponed the rebalancing between supply and demand and has led to a continued drop in oil prices.

2015 saw moderate growth in gas supply and demand of 1.5%, which is below the growth rates of the previous years. The United States is the main driver behind the growth. Europe experienced a weather-driven increase in demand as compared to 2014. Gas consumption declined in Japan and South Korea due to weak power sector gas demand caused by the (re)start of coal and nuclear power plants. Gas demand growth slowed in China and other emerging markets, with more competitively priced oil products being one contributing factor. In the United States, a multi-year wave of gas supply growth came to an end in 2015, but demand could not keep up with supply growth, and prices fell. A strong supply of pipeline gas to Europe and an emerging oversupply of LNG have further depressed gas prices.

The global economic situation continues to be fragile, with development partly driven by uncertain political environments in key countries and regions, in addition to normal supply and demand factors. The situation at the end of 2015, with high storage levels and low prices, will continue to put pressure on international oil companies to increase efficiency and reduce costs. This will contribute to a gradual rebalancing of markets for oil and gas. The impact of this on price levels and price developments is very uncertain.

2.1.2 Oil prices and refining margins

High volatility characterised the oil market in 2015, with the price of Brent in a range between USD 66 per barrel in May to USD 35 per barrel at the end of December. Refinery margins were well above normal levels due to low crude prices throughout the year.

Oil prices

The average price for dated Brent crude in 2015 was USD 53/bbl, down 47% from 2014. The price was at USD 55/bbl in the beginning of 2015, on a downward trajectory. A temporary low was reached at just above USD 45/bbl in the middle of January before the prices started climbing again. A positive market sentiment drove the price of dated Brent up in the second quarter. Signs of a downturn in the Chinese economy and the nuclear deal between P5+1 and Iran contributed to a declining market sentiment and prices fell again to a new low in August. The price of dated Brent recovered somewhat again in the 3rd quarter and in to the 4th quarter, before the 168th Opec meeting on the 4th of December. No action was agreed by the Opec member countries and the price of Brent went below USD 40/bbl for the first time since the spring of 2009. The dated Brent price was USD 36/bbl on 31 December 2015, a year-end level not seen for a decade. The futures market for Brent at the Intercontinental Exchange (ICE) was in contango throughout 2015. See section 9 *Terms and definitions* for further details.

Although the conflict level in Syria increased further and the armed conflict in Yemen added tension in the Middle East, geopolitical events had less effect on the crude oil prices in 2015, compared with the previous year.

Opec's decision, in late 2014, to not balance the market, marked the change of a 30-year old strategy. Subsequent to this the oil market was highly volatile throughout 2015, while the participants endeavoured to find the new price level of crude oil. Although oil demand increased by 1.6 mmbbl per day, much due to a cold winter and low prices, the market remained oversupplied throughout the whole year, with total supply growth of 2.4 mmbbl per day of production. As a consequence, the global oil stocks were at historically high levels by year-end.

2015 was an eventful year for North American (NA) crude. The price of US WTI crude, as quoted at the Cushing tank farm in Oklahoma, averaged USD 49/bbl in 2015, down 47% from 2014. The price of WTI was USD 53/bbl at the beginning of the year. On 31 December 2015 the WTI price was at USD 37/bbl, roughly at par with first month Brent. With low crude prices through 2015, rig counts have dropped and production growth has faltered. At the same time, crude inventories have continued to grow, further weighing on crude prices. New pipeline and crude distillation capacity, coupled with slower production growth, have created a tighter balance for US light crude, easing the large price discounts of inland crudes relative to Brent. The easing of discounts has challenged the economics of more expensive transport solutions such as rail relative to pipeline, such that crude by rail loadings have declined dramatically during 2015. In late 2015, the US government passed legislation allowing unrestricted export of crude oil for the first time since the 1970s. While little impact is expected in the global market short term, given the current oversupplied global crude market, unrestricted US crude exports provides producers with greater access to higher value global crude markets and could impact price differentials.

Refining margins

Refinery margins in Northwest Europe, as calculated against dated Brent crude, were well above normal in 2015. One reason for the strength was the weak crude oil market, with dated Brent priced below the first forward month at the ICE exchange throughout the year. Further, the price differentials vs. Brent for the crude oils actually used were lower than last year. The other main factor was a very strong gasoline market. Low price levels at the pump led to rising demand in the US, and gasoline demand in Europe stopped falling. Changes to the Chinese economy led to more emphasis on the consumer sector. New car sales in China almost matched that of the US, and some 80% were net additions to the fleet. Chinese gasoline demand therefore rose almost as much as in the US, and strong growth was also seen in India and Pakistan. This demand growth led to capacity constraints at refineries, in particular for high-octane components. Europe, being in net surplus on gasoline, was able to export more into these markets, with parts of it going as high-octane components at strong price premiums. For naphtha, which is a feedstock both for the petrochemical industry and for making gasoline, Asian demand for imports from Europe rose through the year and gave very strong margins here. On the other hand, new refineries in Asia and the Middle East were geared towards diesel production. New diesel volumes exported to Europe led to rising inventory levels here, despite a quite strong demand growth. The situation became dramatic in the fourth quarter of 2015, when high refinery throughputs in order to make enough gasoline and naphtha led to excess diesel production. This made diesel tanks go full and the diesel margin decreased. LPG was oversupplied due to high exports from the US. Heavy fuel oil was oversupplied due to declining demand. However, against the low Brent crude oil prices, both products still saw quite normal margins.

2.1.3 Natural gas prices

Natural gas prices fell during 2015 in most markets. European gas prices reached the lowest level since early 2010. Reasons include weak demand, good supplies and low prices for coal, oil and other competing fuels. Henry Hub gas prices in the United States also declined during 2015, and the prices at year-end were at the lowest level since the 1990s.

Gas prices - Europe
European gas market prices averaged USD 6.5/mmBtu in 2015, down 20% from 2014. EU gas consumption for heating purposes recovered in 2015 as temperatures returned to more normal levels after a particularly mild winter in 2014. The use of gas for power generation increased in Southern Europe due to high summer temperatures, but declined in other parts of Europe. High availability of wind in 2015 and a steady growth in renewable generation capacity made inroads in the overall need for gas-fired and other thermal power plants in Europe.

Norwegian exports of pipeline gas reached record-levels of 108 bcm in 2015. EU indigenous gas production fell by 10% to 125 bcm as the Dutch government lowered existing production caps at the large Groningen field as a response to earthquake activity. Russia exported more than 150 bcm of pipeline gas to Europe in 2015, close to recent historical highs. Europe imported around 50 bcm LNG in 2015, more than in 2014, but still 35 bcm below the peak a few years ago.

Gas prices - North America
First quarter prices centered on USD 3/mmBtu, while second and third quarter prices fluctuated around USD 2.75/mmBtu, with weather-related ups and downs. However, in the fourth quarter prices fell and reached USD 1.50/mmBtu at the end of the year, as storage rose to new record highs and an El Niño weather event quashed demand in the winter peak season. As a result, the Henry Hub average of USD 2.6/mmBtu was the lowest annual price in over a decade, down from USD 4.4/mmBtu in 2014.

US gas producers responded to the falling prices by withdrawing rigs. Gas production peaked at the end of the summer and supply has been falling since. Demand for gas was strong in 2015, with natural gas for the first time exceeding coal use in the power sector for most of the year.

Global LNG prices
Global prices for LNG have plummeted. Prices under long-term LNG contracts to buyers in Asia are tracking oil prices with a lag, and contract prices were typically down 40% from 2014. The price assessment for spot LNG cargoes in Asia reached USD 7.5/mmBtu over the year compared to USD 14/mmBtu in 2014. LNG prices are now back to levels prior to the Fukushima nuclear disaster in March 2011. The global LNG market has entered a period where the growth of supplies from Australian, US and other liquefaction projects could exceed demand.

2.2 Statoil's corporate strategy

Statoil creates value by accessing, exploring, developing, and producing energy sources globally, and by enhancing the value of such production through its mid- and downstream positions.

Fundamental changes are happening in the oil and gas industry. The industry faces new challenges, such as increased pressure on margins, changing patterns of energy supply and consumption, geopolitical instability and rising climate change concerns.

Statoil's top priorities remain to conduct safe and reliable operations with zero harm to people and the environment, and to grow value through disciplined investments and prudent financial management with competitive redistribution of capital to shareholders. To succeed going forward in turning Statoil's vision into reality, Statoil pursues a strategy that will:

- Deepen and prolong Statoil's NCS position
- Grow material and profitable international positions
- Pursue focused and value-adding mid- and downstream activities
- Provide energy for a low carbon future

In addition, Statoil will research, develop, and deploy technology to create opportunities and enhance the value of Statoil's current and future assets.

Deepen and prolong Statoil's NCS position

For more than 40 years, Statoil has explored, developed and produced oil and gas from the Norwegian continental shelf (NCS). Statoil aims to deepen and prolong its position by accessing and maturing opportunities into valuable production. At the same time Statoil plans to improve the reliability and lifespan of fields already in production.

- **Exploration:** Statoil has proven to be a committed NCS explorer across mature, growth, and frontier areas. In the last year, Statoil participated in 21 completed exploration wells of which 10 were discoveries. Statoil announced discoveries in the Aasta Hansteen area, the Krafla area, and the King Lear area. Statoil applied for new acreage in the Barents Sea as part of the 23rd licensing round and entered the Barents Sea Exploration Collaboration with four other oil and gas explorers to address common operational challenges. Statoil also applied for additional NCS licenses during the 2015 Awards in Predefined Areas (APA) with the results awarded in 2016
- **Development:** Statoil received approval from the Norwegian Ministry of Petroleum and Energy for the plan for development and operation (PDO) for Johan Sverdrup Phase I and awarded several related key contracts to suppliers. The development plan for Johan Sverdrup Phase II, along with other projects, continues to be matured. In 2015, Statoil delayed the concept selection for Johan Castberg, Snorre 2040 and Trestakk (sanctioned early 2016) to secure robust development solutions. Gina Krog's expected start-up is now 2017 with the steel jacket having been installed and predrilling of the production wells started
- **Production:** Statoil began production from Valemon, Oseberg Delta 2, Gullfaks South Oil, Smørbukk South Extension and the Lundin-operated Edvard Grieg field. Three major projects to increase recovery have been delivered in 2015; at Troll A two new gas compressors were installed, the Åsgard subsea compression, the world's first subsea gas compression plant, came on stream, and the world's first subsea wet gas compressor is nearing completion at Gullfaks

Statoil made further portfolio adjustments to improve its NCS position. Statoil increased its share in the Alfa Sentral project, which straddles the border of the NCS and UK continental shelf (UKCS). Statoil's equity share now stands at 24% in licence P312 on the UKCS and 62% in licence PL046 on the NCS (Statoil-operated); the two licenses together comprise the Alfa Sentral field. Statoil also farmed down in the Gudrun field. Statoil remains the operator of the field.

The target to reduce CO_2 emissions on the NCS was increased to 1.2 million tonnes by 2020, which is up 50% from the initial target of 800,000 tonnes. The initial target was set in 2008 and is expected to be reached in 2016.

Grow material and profitable international positions

International oil and gas production represents approximately 37% of Statoil's equity production and now stands at 739 kboe/d. Statoil will continue to explore, develop, and produce oil and gas opportunities outside Norway to enhance Statoil's upstream portfolio.

- **Exploration:** Statoil is an active international explorer for oil and gas. In the last year, Statoil participated in 18 completed exploration wells of which eight were discoveries. Statoil focused in Canada, Tanzania, Brazil, the UK and the US Gulf of Mexico. Statoil announced a gas discovery in Tanzania (Mdalasini-1). Statoil accessed new acreage in Canada, New Zealand, Indonesia, Mozambique, Russia, and the US Gulf of Mexico, and entered three new countries, Nicaragua, South Africa, and Uruguay. Government approval is pending for the newly acquired acreage in Mozambique, South Africa, and Uruguay. Statoil exited both our operated and non-operated licenses in the Chukchi Sea (Alaska). Statoil also closed its office in the Faroe Islands following the relinquishment of our exploration acreage
- **Development:** In Europe, the partner-operated Corrib gas field in Ireland came on stream at the end of 2015; meanwhile, Statoil postponed the Mariner field's start-up date to 2018. In the US Gulf of Mexico, the partner-operated Heidelberg project entered its final stages in 2015 as it prepared for first oil in early 2016, meanwhile Big Foot was postponed due to technical challenges in the final project stage
- **Production:** Production has steadily increased from fields such as CLOV in Angola and Jack/St. Malo in the US Gulf of Mexico. In the US, further optimisation of the onshore portfolio targeting cost improvements has been on-going, including the reorganisation of some of the activities to extract greater synergies

Statoil made further portfolio adjustments to improve its international exploration portfolio. Statoil sees value in gaining operatorships, and in 2015 Statoil became the operator in BM-C-33 offshore Brazil, which contains the Pão de Açúcar, Seat, and Gávea discoveries. Statoil also completed an agreement to reduce Statoil's average working interest in Statoil's non-operated US southern Marcellus onshore asset from 29% to 23%. In another transaction, Statoil acquired an additional 13% interest in Statoil's Eagle Ford joint venture and became its sole operator.

Pursue focused and value-adding mid- and downstream activities

The prime objective for Statoil's mid- and downstream activities is to process and transport its oil and gas production (including the Norwegian State's petroleum) competitively to premium markets, securing maximum value realisation. The priorities are:

- High regularity in midstream operation and continuous improvement within HSE, efficiency and costs
- Market Statoil's equity production (crude oil, natural gas, related products) and the State's Direct Financial Interest (SDFI) volumes for maximum value creation
- Develop the Asset Backed Trading model across commodities
- Maintain the position as a leading European gas supplier
- A capital lean asset structure

Strategic focus is directed at optimising the value of Statoil's flexible Norwegian gas production assets that supply Europe and Statoil's midstream activities in North America, where Statoil's onshore un-conventionals portfolio is progressing and where margin capture is important. Statoil achieved strong trading results across all commodities and robust refinery results through good margins, cost reductions and high availability.

Strategic progress in Statoil's mid- and downstream portfolio has been made in 2015. Export pipelines for the Utsira High and the Norwegian Sea (Polarled) were installed. Statoil agreed to divest its 20% stake in the Trans Adriatic Pipeline AG in 2015 following earlier divestments in 2014.

Providing energy for a low carbon future

Statoil recognises that opportunities are increasingly available in producing low carbon energy. In 2015, Statoil created a new business area, New Energy Solutions, to further access, develop, and produce low carbon energy when and where it is deemed valuable.

- **Development:** In the 4th quarter 2015, Statoil sanctioned Hywind Scotland Offshore Floating Test Park in Scotland; Statoil's ownership share is 100%. The park will have a total installed capacity of 30 MW and planned production start-up is 2017. The Dudgeon Offshore Wind Park sanctioned in 2014 is progressing as planned towards start-up in 2017; Statoil's ownership share is 35%. The park will have a total installed capacity of 402 MW. The Forewind consortium, comprising Statoil, Statkraft, RWE and SSE, all with a 25% owner stake, continues to mature projects and has received consent for four 1.2 GW projects in the Dogger Bank Area off the UK east coast
- **Production:** Statoil is a non-operating partner in the Scira consortium (40% owner stake) which produces electricity from the Sherringham Shoal wind park in the UK. The park has an installed capacity of 317 MW

Research, development, and deployment of technology to unlock opportunities and enhance value

Statoil believes that technology is a critical success factor in the current business environment. Statoil's technology development activities aim to reduce field development, drilling and operating costs, and CO_2 and other greenhouse gas emissions. Statoil's technology efforts focus on the following priority areas:

- **Business-critical technologies**: Upstream technologies are prioritised, primarily in the areas of Exploration, Reservoir, Drilling and Well and Subsea production systems. Statoil's main focus has been on cost reduction, for example further development of the steerable drilling liner system to reduce well construction costs
- **Strengthening Statoil's licence to operate**: Statoil's commitment to sustainability continues. Statoil's ongoing "Powering collaboration" agreement with GE aims to accelerate the development of more sustainable energy solutions by addressing CO_2 and methane emissions, water usage and energy optimisation of operations. Statoil is also addressing energy efficiency of operating assets by, e.g. implementing on-line water wash systems on gas turbines
- **Expanding Statoil's capabilities**: Statoil's technical capabilities are expanding to meet the challenges of the New Energy Solutions business area for renewable and low carbon energy solutions. Technology development is conducted in-house, in collaboration with suppliers and through venture activities. A key technological focus area is finding more efficient ways of producing clean energy, particularly by reducing costs in the areas of construction and maintenance for both fixed and floating offshore wind applications

2.3 Group outlook

Statoil's plans address the current environment while continuing to invest in high-quality projects. Statoil continues to reiterate its efforts and commitment to deliver on its priorities of high value creation, increased efficiency and competitive shareholder return.

- Organic capital expenditures for 2016 (i.e. excluding acquisitions, capital leases and other investments with significant different cash flow pattern) are estimated at around USD 13 billion
- Statoil intends to continue to mature the large portfolio of exploration assets and estimates a total exploration activity level of around USD 2 billion for 2016, excluding signature bonuses
- Statoil aims to deliver efficiency improvements with pre-tax cash flow effects of around USD 2.5 billion annually from 2016
- Statoil's ambition is to keep the unit of production cost in the top quartile of Statoil's peer group
- For the period 2014 - 2017, organic production growth [7] is expected to come from new projects resulting in around 1% CAGR (Compound Annual Growth Rate) from a 2014 level rebased for divestments
- The equity production for 2016 is estimated to be somewhat lower than the 2015 level [7]
- Scheduled maintenance activity is estimated to reduce quarterly production by approximately 25 mboe per day in the first quarter of 2016 of which the majority is liquids internationally. In total, the maintenance is estimated to reduce equity production by around 60 mboe per day for the full fiscal year 2016, which is higher than the 2015 impact
- Indicative effects from Production Sharing Agreement (PSA-effect) and US royalties are estimated to be around 135 mboe per day in 2016 based on an oil price of USD 40 per barrel and 165 mboe per day based on an oil price of USD 70 per barrel [4]
- Deferral of production to create future value, gas off-take, timing of new capacity coming on stream and operational regularity represent the most significant risks related to the production guidance
- The board of directors proposes to the annual general meeting (AGM) maintaining a dividend of USD 0.2201 per share for the fourth quarter 2015 and to introduce a two-year scrip dividend programme for eligible shareholders starting from the fourth quarter 2015
- With effect from first quarter of 2016, Statoil will change to USD as presentation currency

These forward-looking statements reflect current views about future events and are, by their nature, subject to significant risks and uncertainties because they relate to events and depend on circumstances that will occur in the future. For further information see section 10 *Forward-Looking Statements*.

3 Business overview

3.1 Our history

Statoil was formed in 1972 by a decision of the Norwegian parliament and listed on the stock exchanges in Oslo and New York in 2001.

Statoil was incorporated as a limited liability company under the name Den norske stats oljeselskap AS on 18 September 1972. As a company wholly owned by the Norwegian State, Statoil's role was to be the government's commercial instrument in the development of the oil and gas industry in Norway.

In 2001, the company became a public limited company listed on the Oslo and New York stock exchanges, and it changed its name to Statoil ASA.

Statoil has grown in parallel with the Norwegian oil and gas industry, which dates back to the late 1960s. Initially, Statoil's operations were primarily focused on exploration, development and production of oil and gas on the Norwegian continental shelf (NCS), as a partner.

In the 1970s, Statoil commenced its own operations, made important discoveries and began oil refining operations, which have been of great importance to the further development of the NCS.

Statoil grew substantially in the 1980s through the development of large fields on the NCS (Statfjord, Gullfaks, Oseberg, Troll and others). Statoil also became a major player in the European gas market by securing large sales contracts for the development and operation of gas transport systems and terminals. During the same decade, Statoil was involved in manufacturing and marketing in Scandinavia and established a comprehensive network of service stations.

Since 2000, our business has grown as a result of substantial investments on the NCS and internationally. Our ability to fully realise the potential of the NCS was strengthened through the merger with Hydro's oil and gas division on 1 October 2007.

In recent years, Statoil has utilised their expertise to design and manage operations in various environments in order to grow our upstream activities outside our traditional area of offshore production. This includes the development of heavy oil and shale gas projects.

In 2010, Statoil carried out an initial public offering of Statoil Fuel & Retail ASA on the Oslo Børs, partially divesting and reducing our interest in the business relating to service stations. In 2012, all of the remaining shares in Statoil Fuel & Retail ASA were divested.

Statoil also participates in projects that focus on other forms of energy, such as offshore wind and carbon capture and storage, in anticipation of the need to expand energy production, strengthen energy security and combat adverse climate change.

3.2 Our business

Statoil is a technology-driven energy company primarily engaged in oil and gas exploration and production activities.

Statoil ASA is a public limited liability company organised under the laws of Norway and subject to the provisions of the Norwegian Public Limited Liability Companies Act. The Norwegian State is the largest shareholder in Statoil ASA, with a direct ownership interest of 67%.

Statoil's head office is located in Stavanger, Norway. Statoil has business operations in more than 30 countries and employs about 21,600 employees worldwide.

Statoil is the leading operator on the Norwegian continental shelf (NCS) and also has substantial international activities. Statoil is present in several of the most important oil and gas provinces in the world. In 2015, 37% of Statoil's equity production came from international activities and the company also holds operatorships internationally.

Our access to crude oil in the form of equity, governmental and third party volumes makes Statoil a large net crude oil seller, and Statoil is the second-largest supplier of natural gas to the European market. Processing and refining are also part of our operations. Statoil is also participating in projects that focus on other forms of energy, such as offshore wind and carbon capture and storage, in anticipation of the need to expand energy production, strengthen energy security and combat adverse climate change.

Statoil's business address is Forusbeen 50, N-4035 Stavanger, Norway. Its telephone number is +47 51 99 00 00.

3.3 Our competitive position

There is intense competition in the oil and gas industry for customers, production licences, operatorships, capital and experienced human resources.

Statoil competes with large integrated oil and gas companies, as well as with independent and state-owned companies, for the acquisition of assets and licences for the exploration, development and production of oil and gas, and for the refining, marketing and trading of crude oil, natural gas and related products. Key factors affecting competition in the oil and gas industry are oil and gas supply and demand, exploration and production costs, global production levels, alternative fuels, and environmental and governmental regulations. In addition, Statoil competes to develop wind energy opportunities.

Statoil's ability to remain competitive will depend, among other things, on the company's management continuing to focus on reducing unit costs and improving efficiency, and maintaining long-term growth in reserves and production through continuing technological innovation. It will also depend on our ability to seize international opportunities in areas where our competitors may also be actively pursuing exploration and development opportunities. Statoil believes it is in a position to compete effectively in each of our business segments.

The information about Statoil's competitive position in the business overview and strategy, and operational review sections, is based on a number of sources. They include investment analyst reports, independent market studies, and our internal assessments of our market share based on publicly available information about the financial results and performance of market players.

Statoil has endeavoured to be accurate in our presentation of information based on other sources, but has not independently verified such information.

Improvement programmes

Statoil's ambition to further reduce cost and improve efficiency was presented at the capital markets update (CMU) on 6 February 2015, targeting annual savings of USD 1.7 billion from 2016. At the CMU on 4 February 2016, Statoil announced that it will step up its efficiency programme by 50% with a goal to realise USD 2.5 billion in annual savings from 2016.

Improvement programmes are Statoil's response to the industrial challenge characterised by reducing prices for our products, escalating cost and declining returns. More specifically, the ambition is to realise positive production effects and capex and operating cost savings to improve financial results and cash-flows.

3.4 Corporate structure

Statoil's operations are managed through the following business areas:

Development and Production Norway (DPN)

DPN comprises our upstream activities on the Norwegian continental shelf (NCS). DPN aims to continue its leading role and ensure maximum value creation on the NCS. Through excellent HSE and improved operational performance and cost, DPN strives to maintain and strengthen Statoil's position as a world-leading operator of producing offshore fields. DPN seeks to open new acreage and to mature improved oil recovery and exploration prospects. New and existing fields are primarily developed using an industrial approach, in which speed of delivery and cost improvements through standardisation and repeated use of proved solutions are key elements.

Development and Production International (DPI)

DPI comprises our worldwide upstream activities that are not included in the DPN and Development and Production USA (DPUSA) business areas. DPI's ambition is to build a large and profitable international production portfolio comprising activities ranging from accessing new opportunities to delivering on existing projects and managing a production portfolio. DPI endeavours to ensure the delivery of profitable projects in a range of complex technical and stakeholder environments, and it manages a broad non-operated production portfolio that will be complemented with operated positions.

Development and Production United States (DPUSA)

DPUSA comprises our upstream activities in the USA and Mexico. DPUSA's ambition is to develop a material and profitable position in the US and Mexico, including the deep water regions of the Gulf of Mexico and unconventional oil and gas in the US. In this connection, Statoil aims to further strengthen its capabilities in deep water and unconventional oil and gas operations.

Marketing, Midstream and Processing (MMP)

MMP comprises our marketing and trading of oil products and natural gas, transportation, processing and manufacturing, and the development of oil and gas value chains. MMP's ambition is to maximise value creation in Statoil's midstream, marketing and renewable energy business.

Technology, Projects and Drilling (TPD)

TPD's ambition is to provide safe, efficient and cost-competitive global well and project delivery, technological excellence, and research and development. Cost-competitive procurement is an important contributory factor, although group-wide procurement services are also expected to help to drive costs in the group down.

Exploration (EXP)

EXP's ambition is to position Statoil as one of the leading global exploration companies. This is achieved through accessing high potential new acreage in priority basins, globally prioritising and drilling more significant wells in growth and frontier basins, delivering near-field exploration on the NCS and other select areas, and achieving step-change improvements in performance.

New Energy Solutions (NES)

NES reflects Statoil's aspirations to gradually complement its oil and gas portfolio with profitable renewable energy and other low-carbon energy solutions. NES is responsible for wind parks, carbon capture and storage as well as other renewable energy and low-carbon energy solutions.

Global Strategy and Business Development (GSB)

GSB sets the corporate strategy, business development and merger and acquisition (M&A) activities for Statoil. The ambition of the GSB business area is to closely link corporate strategy, business development and M&A activities to actively drive Statoil's corporate development.

Reporting segments

Statoil reports its business in the following reporting segments: Development and Production Norway (DPN); Development and Production International (DPI), which combines the DPI and DPUSA business areas; Marketing, Midstream and Processing (MMP); and Other.

The Other reporting segment includes activities in New Energy Solutions (NES), Technology, Projects and Drilling (TPD), Global Strategy and Business Development (GSB) and Corporate staffs and support functions. Activities relating to the Exploration (EXP) business area are allocated to, and presented in, the respective development and production segments.

Presentation

In the following sections, the operations of each reporting segment are presented. Underlying activities or business clusters are presented according to how the reporting segment organises its operations. The Exploration business area's activities, which include group discoveries and the appraisal of new exploration resources, are presented as part of the various development and production reporting segments (Development and Production Norway, and Development and Production International).

As required by the SEC, Statoil prepares its disclosures about oil and gas reserves and certain other supplementary oil and gas disclosures based on geographical areas. The geographical areas are defined by country and continent. They consist of Norway, Eurasia excluding Norway, Africa, and the Americas.

See note 3 *Segments* in the Consolidated financial statement for more details.

3.5 Development and Production Norway (DPN)

3.5.1 DPN overview

Development and Production Norway (DPN) is responsible for field development and operational activities on the Norwegian continental shelf (NCS).

Statoil's equity and entitlement production on the NCS was 1,232 mboe per day in 2015. That was about 68% of Statoil's total entitlement production and 62.5% of Statoil's equity production.

DPN has organised the production operations into four business clusters: Operations North (Barents Sea) located in Harstad, Operations Mid-Norway (Norwegian Sea) located in Stjørdal near Trondheim, Operations West (North Sea) located in Bergen and Operation South (North Sea) located in Stavanger. Partner-operated fields cover the entire NCS and are internally included in the Operations South business cluster.

When possible, the fields in each cluster use common infrastructure, such as production installations and oil and gas transport facilities. This reduces the investments required to develop new fields. DPN's efforts in these core areas also focus on finding and developing smaller fields through the use of existing infrastructure and on increasing production by improving the recovery factor.

DPN is also working to extend production from our existing fields through improved reservoir management and the application of new technology.

Key events and portfolio developments in 2015:

- In January 2015, Statoil announced the start-up of production at the Valemon oil and gas field in the North Sea
- Statoil announced production start up on fast track projects at the Oseberg Delta in February, Gullfaks Sør Olje in July and Smørbukk Sør Extension in September
- In November the start up of production at the Edvard Grieg field was announced by Lundin
- The major redevelopment projects Åsgard Subsea compression and two new compressors on the Troll A platform have started up
- A total of seven turnarounds were planned to be performed during 2015. Four turnarounds were carried out, and three turnarounds were deferred from 2015 to 2016 to coordinate with other activities due to reduce production losses and reduce costs
- Plan for Development and Operations (PDO) for the Johan Sverdrup field and Gullfaks Rimfaksdalen Fast track project were approved by the Ministry of Petroleum and Energy (MPE) and the PDO for Oseberg Vestflanken 2 was submitted to the MPE
- An extensive exploration drilling program in 2015 resulted in 21 completed wells, of which 10 were discoveries. A total of 16 wells were Statoil operated
- Statoil has delivered an extensive application for the 23rd concession round and has been awarded interest in 24 licenses on the NCS in the Awards in Predefined Areas (APA) 2015, 13 of those as operator and 11 as partner
- In December Statoil announced that it farmed down to Repsol a 15% interest in the Gudrun field. Statoil remains as operator and largest equity holder with a 36% interest

The profitability of our industry continues to be challenged. Statoil's response to the industrial challenge characterised by high costs and declining returns is addressed in the section 2 *Strategy and market overview*.

3.5.2 Fields in production on the NCS

Statoil's entitlement production at NCS was about 68% of Statoil's total entitlement production in 2015.

The following table shows DPN's average daily entitlement production of oil, including NGL and condensates, and natural gas for the years ending 31 December 2015, 2014 and 2013. Field areas are groups of fields operated as a single entity.

	For the year ended December 31,								
	2015			2014			2013		
	Oil and NGL	Natural gas		Oil and NGL	Natural gas		Oil and NGL	Natural gas	
Area production	mbbl	mmcm	mboe/day	mbbl	mmcm	mboe/day	mbbl	mmcm	mboe/day
Operations North	32	7	78	36	7	80	24	5	56
Operations Mid	113	17	218	126	17	235	126	15	222
Operations West	267	51	591	264	43	535	290	48	589
Operations South	134	13	214	107	11	177	94	12	167
Partner Operated Fields	50	13	132	55	16	157	58	20	182
Total	595	101	1,232	588	95	1,184	591	99	1,217

The following table shows the NCS production by fields and field areas in which Statoil was participating as of 31 December 2015.

Business cluster	Geographical area	Statoil's equity interest in %	Operator	On stream	Licence expiry date	Average daily production in 2015 mboe/day
Operations North						
Snøhvit	The Barents Sea	36.79	Statoil	2007	2035	47.1
Norne	The Norwegian Sea	39.10	Statoil	1997	2026	5.9
Alve	The Norwegian Sea	85.00	Statoil	2009	2029	10.6
Urd	The Norwegian Sea	63.95	Statoil	2005	2026	14.2
Total Operations North						77.9
Operations Mid-Norway						
Åsgard	The Norwegian Sea	34.57	Statoil	1999	2027	92.1
Morvin	The Norwegian Sea	64.00	Statoil	2010	2027	16.3
Mikkel	The Norwegian Sea	43.97	Statoil	2003	2020 1)	14.3
Tyrihans	The Norwegian Sea	58.84	Statoil	2009	2029	49.6
Kristin	The Norwegian Sea	55.30	Statoil	2005	2033 2)	24.5
Heidrun	The Norwegian Sea	13.04	Statoil	1995	2024 3)	8.7
Njord	The Norwegian Sea	20.00	Statoil	1997	2021 4)	6.1
Hyme	The Norwegian Sea	35.00	Statoil	2013	2014 5)	6.2
Total Operations Mid-Norway						217.8
Operations West						
Troll Phase 1 (Gas)	The North Sea	30.58	Statoil	1996	2030	185.2
Troll Phase 2 (Oil)	The North Sea	30.58	Statoil	1995	2030	38.2
Fram	The North Sea	45.00	Statoil	2003	2024	16.9
Fram H Nord	The North Sea	49.20	Statoil	2014	2024	2.3
Oseberg	The North Sea	49.30	Statoil	1988	2031	86.4
Tune	The North Sea	50.00	Statoil	2002	2032 6)	1.9
Gullfaks	The North Sea	51.00	Statoil	1986	2036	69.4
Gimle	The North Sea	65.13	Statoil	2006	2034 7)	2.6
Kvitebjørn	The North Sea	39.55	Statoil	2004	2031	64.0
Valemon	The North Sea	57.76	Statoil	2015	2031	16.4
Visund	The North Sea	53.20	Statoil	1999	2034	48.5
Grane	The North Sea	36.66	Statoil	2003	2030	45.8
Volve	The North Sea	59.60	Statoil	2008	2028	10.0
Veslefrikk	The North Sea	18.00	Statoil	1989	2020 8)	3.1
Total Operation West						590.5
Operations South						
Sleipner Vest	The North Sea	58.35	Statoil	1996	2028	49.2
Sleipner Øst	The North Sea	59.60	Statoil	1993	2028	44.4
Gungne	The North Sea	62.00	Statoil	1996	2028	10.0
Gudrun	The North Sea	36.00	Statoil	2014	2028 9)	6.1
Statfjord Unit	The North Sea	44.34	Statoil	1979	2026	42.6
Statfjord Øst	The North Sea	31.69	Statoil	1994	2026 10)	1.3
Statfjord Nord	The North Sea	21.88	Statoil	1995	2026	1.2
Sygna	The North Sea	30.71	Statoil	2000	2026 10)	0.8
Snorre	The North Sea	33.28	Statoil	1992	2015 11)	35.6
Vigdis area	The North Sea	41.50	Statoil	1997	2024	14.6
Tordis area	The North Sea	41.50	Statoil	1994	2024	8.2
Total Operations South						214.0

Business cluster	Geographical area	Statoil's equity interest in %[1]	Operator	On stream	Licence expiry date	Average daily production in 2015 mboe/day
Partner Operated Fields						
Ormen Lange	The Norwegian Sea	25.35	Shell	2007	2041 [12]	47.8
Skarv	The Norwegian Sea	36.17	BP Norge AS	2013	2033 [13]	46.8
Ekofisk area	The North Sea	7.60	ConocoPhillips	1971	2028	14.3
Marulk	The North Sea	50.00	Eni Norge AS	2012	2025	13.2
Vilje	The North Sea	28.85	Marathon Oil	2008	2021	4.0
Sigyn	The North Sea	60.00	ExxonMobil	2002	2022	3.8
Ringhorne Øst	The North Sea	14.82	ExxonMobil	2006	2030	1.7
Edvard Grieg	The North Sea	15.00	Lundin Norway AS	2015	2035	0.4
Total Partner Operated Fields						131.9
Total						1,232.0

[1] PL092 expires in 2020 and PL121 expires in 2022.
[2] PL134B expires in 2027 and PL199 expires in 2033.
[3] PL095 expires in 2024 and PL124 expires in 2025.
[4] PL107 expires in 2021 and PL132 expires in 2023.
[5] PL348 expires in 2029.
[6] PL034 expires in 2020. PL053 expires in 2031 and PL190 in 2032.
[7] PL120B expires in 2034 and PL050DS expires in 2023.
[8] PL052 expires in 2020 and PL053 in 2031.
[9] The 2015 Statoil farm down transaction with Repsol completed 31 December 2015 (From ownership 51% to 36% at Gudrun field)
[10] PL037 expires in 2026 and PL089 expires in 2024.
[11] PL089 expires in 2024 and PL057 expires in 2016.
[12] PL209/250 expires in 2041 and PL208 expires in 2040.
[13] PL212/262 expires in 2033 and PL159 expires in 2029.

The following sections provide information about the main producing assets. See section 4.1.4 *DPN profit and loss analysis* for a discussion of results of operations for 2015, 2014 and 2013.

3.5.2.1 Operations North

The main producing fields in the Operations North area are Snøhvit and Norne.

The Norwegian Sea region is characterised by petroleum reserves located at water depths between 340 and 380 metres. In the Barents Sea the petroleum reserves are located at water depths between 310 and 340 meters. The Gulf Stream keeps the sea free of ice all year round, but winter storms can make surface installations difficult to operate.

Snøhvit was the first field developed in the Barents Sea. It is one of the first major developments using onshore production facilities. All offshore installations are subsea. The natural gas is transported to shore and then processed at our Liquefied Natural Gas (LNG) plant on Melkøya. The LNG are shipped to customers in Europe, Asia, North and South America in tankers. The CO_2 in the feed-gas from Snøhvit and Albatross is removed due to freezing constraints in the process system. To reduce carbon dioxide emissions to the air the removed CO_2 is liquefied, transported through a pipeline, and then injected into a storage reservoir in Snøhvit. The LNG plant has produced according to plan in 2015, with high production efficiency, improved HSE results and enhanced cost efficiency. As of 1 January 2016 responsibility for operation of Snøhvit onshore facilities is transferred from DPN to MMP.

Norne is an oil field in the Norwegian Sea. The field has been developed using a floating production, storage and offloading vessel (FPSO) connected to subsea templates. Alve, Marulk, Urd and Skuld are tie-in fields connected to the Norne FPSO.

3.5.2.2 Operations Mid-Norway

The main producing fields in the Operations Mid-Norway area are Åsgard, Kristin, Tyrihans and Heidrun.

Operation Mid-Norway operates in a mature part of the Norwegian Sea, and is a significant contributor to Statoil's equity production. Main focus is to capitalise existing fields through profitable realisation of increased oil recovery and successful implementation of new developments. There is still exploration potential in the area and a targeted exploration effort is in execution.

The **Åsgard** field includes the Åsgard A production and storage ship for oil, the Åsgard B semi-submersible floating production platform for gas, and the Åsgard C storage vessel for condensate. In September 2015 Statoil started the world first subsea gas compressor on Åsgard. The compressor increases the Åsgard recovery rate from 67% to 87% thereby extending the reservoirs' productive lives. Mikkel and Morvin are tie ins to Åsgard.

Tyrihans is a subsea field with five templates. The well stream of oil and gas is tied back to Kristin for processing. Tyrihans receives seawater injection from Kristin and gas injection from Åsgard B.

Kristin is a gas and condensate field. The Kristin development is the first high-temperature/high-pressure (HTHP) field developed with subsea installations. The pressure and temperature in the reservoir are among the highest of all developed fields on the NCS.

Heidrun is developed with a floating concrete tension leg platform. The oil is transferred to the floating storage unit, Heidrun B, operated from June 2015.

The **Njord** field is located in the Norwegian Sea and the field has been developed with a floating steel platform unit, Njord A, with both drilling and processing facilities. The subsea field Hyme is tied back to Njord A.
As a result of structural integrity issues Njord A was temporarily shut down and extensive reinforcement work was completed through a long turnaround period from Sept 2013 to July 2014. Since July 2014 conditional monitoring and precautionary evacuation in forecasted bad weather conditions have been applied. In addition there is no drilling activity. The Project "Njord Future" is established to secure long term production for both the Njord and Hyme fields and to act as a tie-in host candidate for discoveries in the area.

3.5.2.3 Operations West

The main producing fields in the Operations West area are Troll, Oseberg, Gullfaks, Kvitebjørn, Visund and Grane

Operation West produces approximately half of Statoil's equity production in Norway. Its main focus is prolonging and increasing production through increased oil recovery, exploration and new field developments.

Troll is the largest gas field on the NCS and a major oil field. The Troll field is split into three hydrocarbon-bearing regions connected to three platforms: Troll A, B and C. The Troll gas is mainly exported and produced at the Troll A platform, while oil is mainly produced at Troll B and C. Fram and Fram H Nord are tie-ins to Troll C.

In October 2015 Troll A finalised the third and fourth pre-compressor project as described in the original PDO for the Troll field. The purpose of the project is to increase gas production by installing two extra pre-compressors on the Troll A platform.

The **Oseberg** area includes the Oseberg Field Centre, Oseberg C, Oseberg East and Oseberg South production platforms. Oil and gas from the satellites are transported in pipelines to the Oseberg Field Centre for processing and transportation.

The Delta2 facilities project on Oseberg Field Center was completed in 2015. Drilling operations related to the project have been on-going throughout 2015 and were finalised in January 2016. The Vestflanken2 project at Oseberg Field Center was sanctioned December 2015 with drilling to be performed by the Cat-J rig on the new unmanned wellhead platform, both under construction, with drilling expected to start third quarter in 2017. The Tender Support Vessel (TSV) project at Oseberg Øst is expected to commence drilling support operations in 2016.

Gullfaks has been developed with three large concrete production platforms. Since production started on Gullfaks in 1986, five satellite fields have been developed with subsea wells that are remotely controlled from the Gullfaks A and C platforms.

Drilling of the new Gullfaks South Increased Oil Recovery (GSO IOR) project wells is ongoing. Operations on the satellites will continue with a mobile rig until September 2016 and plan for development and operation for Shetland/Lista was delivered in second quarter of 2015.

The Gullfaks Rimfaksdalen (PDO) was submitted in 2014 and production will start up in the fourth quarter of 2016. Drilling of wells was completed in 2015. The projects Gullfaks B Drilling Upgrade and Gullfaks South IOR both started up in 2015.

Kvitebjørn is a gas and condensate field. The field is developed with an integrated accommodation, drilling and processing facility with a steel jacket.

The **Valemon** field is a gas and condensate field between Kvitebjørn and Gullfaks South. Valemon is built as a normally not manned, fixed steel platform with separation facilities for gas, condensate and water. The condensate is piped to Kvitebjørn for stabilisation and from there to the Mongstad refinery near Bergen. The production started in January 2015.

Visund is an oil and gas field development that includes floating drilling, production and living quarter units and two subsea templates, in the northern and southern parts of the field.

Grane is Statoil's largest producing heavy oil field. The Svalin field is a tie-in to Grane platform.

The Heimdal platforms are a hub for the processing and distribution of gas to the European gas markets. The hub consists of an integrated steel platform and a riser platform. During 2015 Heimdal has plugged and abandoned its production wells in the main reservoir. Heimdal will start production in 2016 from one new well drilled from the modular rig which was temporarily installed for plugging and abandonment activity.

3.5.2.4 Operations South

The main producing fields in Operations South are Sleipner, Gudrun, Statfjord and Snorre.

Operation South represents a mature oil and gas province. However, it still remains a significant contributor to Statoil's equity production and new fields are under development in the area. Main focus in the area is to capitalise on existing fields through profitable realisation of increased oil potential and successful implementation of new developments.

Sleipner consists of the Sleipner East, Gungne and Sleipner West gas and condensate fields. The gas from Sleipner has a high level of CO. This is extracted at the field and re-injected into a sand layer beneath the seabed to reduce carbon dioxide emissions to the air. Sleipner also processes gas, condensate and oil from Gudrun, Volve and Sigyn. The Gina Krog field, currently under development, will also be tied back to Sleipner.

The **Gudrun** field is a separate steel jacket-based process platform for separation of oil and gas, with separate pipelines transporting gas and partly stabilised oil from Gudrun to Sleipner.

Statfjord has been developed using three fully integrated platforms supported by gravity-based structures with concrete storage cells and an offshore loading system. Statfjord North, Statfjord Øst and Sygna are satellite fields have all been developed using subsea templates tied back to Statfjord C.

The **Snorre** field has two floating platforms and one subsea production system connected to the Snorre A platform. In addition, the satellite fields Tordis and Vigdis are part of Snorre business unit and are tied back to Gullfaks C and Snorre A, respectively.

3.5.2.5 Partner-operated fields

Partner-operated fields account for approximately 11% of our total oil and gas production on the NCS. The main producing fields are Ormen Lange, Skarv and Ekofisk.

Statoil's partner operated fields NCS portfolio is organised under Operations South.

Ormen Lange operated by Shell, is a deepwater gas field in the Norwegian Sea. The well stream is transported to an onshore processing and export plant at Nyhamna.

Skarv is an oil and gas field located in the Norwegian Sea, with BP as operator. The field development includes a floating production, storage and offloading vessel (FPSO) and five subsea multi-well installations.

Ekofisk is operated by ConocoPhillips. It consists of the Ekofisk, Eldfisk and Embla fields, and Tor. The Eldfisk II project delivered a new PDQ platform early 2015 that will serve as Eldfisk field center.

Edvard Grieg is an oil field located in the Utsira High Area. The field development includes a fixed steel jacket with processing and export facilities. Edvard Grieg is operated by Lundin. Production started on 28 November 2015 according to plan. Two wells were ready at start-up. Drilling will continue and a total of 10 production wells and four injection wells are planned.

3.5.3 Exploration on the NCS

Continued high exploration activity on the NCS

An extensive drilling program in 2015 resulted in 21 completed wells, of which 10 were discoveries. A total of 16 wells were Statoil operated.

Statoil has delivered an application for the 23rd concession round on the NCS. The round covers 57 blocks and parts of blocks, with three in the Norwegian Sea and 54 in the Barents Sea. South-East Barents Sea is the first new exploration acreage area opened on the NCS since 1994. Statoil and 15 other companies cooperate in the Barents Sea Exploration Collaboration (BaSEC) project to find common solutions for exploration operations in the Barents Sea and to ensure cost-effectiveness and good safety standards.

Statoil has been awarded interest in 24 licences in the Awards in Predefined Areas (APA) round 2015 on the NCS, 13 of those as operator and 11 as partner. Statoil has been awarded new licences in all three NCS provinces - North Sea, Norwegian Sea and the Barents Sea.

In general, Statoil's exploration strategy on the NCS is reflected in its diverse exploration portfolio, which ranges from frontier drilling to infra-structure led exploration close to existing infrastructure.

The table below shows the exploration and development wells drilled on the NCS in the last three years.

	2015	2014	2013
North Sea			
Statoil operated exploratory	11	11	11
Partner operated exploratory	3	7	10
Norwegian Sea			
Statoil operated exploratory	5	0	7
Partner operated exploratory	1	1	1
Barents Sea			
Statoil operated exploratory	0	9	2
Partner operated exploratory	1	1	4
Totals			
Exploratory	21	29	35
Exploration extension wells	3	2	7

Potential producing areas

In addition to producing areas, Statoil operates a significant number of exploration licences. Exploration takes place in undeveloped frontier areas as well as near existing infrastructure and producing fields.

Area	Square km (NCS Total)	Square km (Statoil)	Change vs 2014	Number of licenses (NCS Total)	Number of licenses (Statoil equity)	Number of licenses (Statoil operated)	New licenses (Statoil equity)	New licenses (Statoil operated)
North Sea	43,928	13,884	(1,006)	304	125	95	9	7
Norwegian Sea	37,784	12,581	(1,681)	144	79	55	9	4
Barents Sea	32,998	13,802	(135)	63	31	19	1	-
NCS total	114,710	40,267	(2,822)	511	235	169	19	11

North Sea

In the North Sea, Statoil participated in 14 exploration wells. Statoil operated ten of the exploration wells with seven discoveries.

Norwegian Sea

In the Norwegian Sea, Statoil participated in six exploration wells. Statoil operated five of the exploration wells with three discoveries.

Barents Sea

No Statoil operated wells in 2015. One partner operated well was completed in 2015.

3.5.4 Fields under development on the NCS

The main sanctioned development projects on the NCS.

The table below shows some key figures as of 31 December 2015 for Statoil's major development projects on the NCS.

Sanctioned projects	Operator	Statoil's equity share	Time of sanctioning	Production start
Aasta Hansteen	Statoil	51.00%	2013	2018
Johan Sverdrup	Statoil	40.01%	2015	2019
Gina Krog	Statoil	58.70%	2012	2017
Ivar Aasen	Det Norske	41.47%	2012	2016
Goliat	Eni	35.00%	2009	2016
Martin Linge	Total	19.00%	2011	2016

Johan Sverdrup is an oil discovery in the southern part of the North Sea, approximately 140 km west of Stavanger. A plan for development and operation was submitted in February 2015 and approved by the Norwegian authorities in August 2015. The Phase 1 of the development will consist of 35 production and water injection wells and a field center with four platforms: A living quarter platform, a wellhead platform with permanent drilling facility, a processing platform and a riser and utility platform. The crude oil will be exported to Mongstad through a 274 km long dedicated pipeline, and the gas will be exported to the gas processing facility at Kårstø through a 156 km long pipeline via a subsea connection to the Statpipe pipeline. The expected production start-up is in the fourth quarter of 2019.

Aasta Hansteen is a deep water gas discovery in the Norwegian Sea. The development concept includes three subsea templates tied in to a floating processing unit with gas export through a new pipeline, Polarled, to Nyhamna and further exportation through the Langeled pipeline. The Aasta Hansteen processing unit can also serve as a hub for other potential discoveries in the area. Expected production start-up is in 2018.

Gina Krog is an oil and gas discovery in the North Sea approximately 30 kilometres north of the Sleipner field. The field development concept includes a steel-jacket platform. Oil will be exported via offshore loading from a floating storage unit. Due to the high condensate content, the rich gas will be exported via Sleipner, where it will be further processed. The development concept also includes gas injection in order to maximise the recovery factor for the field. The development concept includes a total of 15 wells. Expected production start-up is in 2017.

Ivar Aasen is an oil and gas field located in the Utsira High Area. The development includes a fixed steel jacket with partial processing and living quarters tied in as a satellite to Edvard Grieg for further processing and export. The Ivar Aasen development is operated by Det norske, The operator expects production start-up in the fourth quarter of 2016.

Goliat is the first oil field to be developed in the Barents Sea. The field is being developed by means of subsea wells tied back to a circular floating production, storage and offloading vessel (FPSO). The oil will be offloaded to shuttle tankers. The Goliat development is operated by Eni who expects production start-up during first quarter of 2016.

Martin Linge is an oil and gas field, operated by Total, near the British sector in the North Sea. The reservoir is complex with gas under high pressure and high temperatures. The development includes a platform as a fixed steel jacket with processing and export facilities. Electrical power will be supplied from Kollsnes. The operator expects production start-up in 2018.

Redevelopment on the NCS - Improved oil recovery (IOR)
In 2015 Statoil started the world's first subsea gas compression plant at the Åsgard field. Processing on the seabed, particularly gas compression, is important for developing seabed solutions for areas of deeper water and in colder and more challenging areas. Åsgard's subsea compression, the world's first subsea gas compression plant, is one of Statoil's most demanding technology projects. The compressors will increase recovery from the Midgard reservoir on Åsgard from 67 percent to 87 percent, and from the Mikkel reservoir from 59 percent to 84 percent, extending the operational life of the fields up to 2032 and contributing to significant reduction in energy consumption and CO_2 emissions over the fields' lifetimes.

The **Gullfaks subsea compression** project the second largest subsea gas compression project being developed by Statoil on the NCS. Subsea gas compression will have a significant impact on the Gullfaks field as this technology, combined with conventional low-pressure production, is expected to lift the recovery rate from the Gullfaks South Brent reservoir from 62% to 74%.

The **Smørbukk South Extension** project, in the Åsgard field, is a world class project production from tight formations previously regarded as infeasible. Production began in September 2015 through the combination of wells with long well sections and "fishbones", a new completion technology implemented for the first time on the NCS, and further utilisation of existing infrastructure at Åsgard.

Troll A field's two new topside compressors started operating in October 2015. Installation of these compressors is an important step to achieve the Troll field's long-term production profile, which now extends to 2063. They are operated with power from shore, which reduces the field's CO_2 emissions significantly.

The **Gullfaks South Oil (GSO)** project started production in July 2015 and will increase recovery from the Gullfaks area. It includes two subsea templates, four production wells, two gas injectors, a gas injection pipeline and umbilicals and power cables for pipeline heating. The project utilise spare processing capacity and will extend the Gullfaks A platform life beyond 2030.

The **Gullfaks B lifetime extension** project aims at extending the drilling program on the Gullfaks B platform until 2032. Operation started on August 2015. Many of the future wells in Gullfaks B are water injection wells that will help maintain production from all three of the platforms in the field through increased pressure support in the reservoir. The drilling upgrade also provides the opportunity to connect to smaller producers from the surrounding area.

The **Ormen Lange** onshore compression project being executed as part of the overall expansion of the Nyhamna facility to handle third-party gas entering the plant through the new Polarled pipeline. The two 37 MW onshore compressors are scheduled for start-up in July 2017.

These projects are all examples of Statoil's efforts to maximise recovery from existing fields. They have also opened opportunities for technology application to realise volumes from other fields with similar conditions.

3.5.5 Decommissioning on the NCS

Under the Petroleum Act, the Norwegian government has imposed strict procedures for removal and disposal of offshore oil and gas installations. The Convention for the Protection of the Marine Environment of the Northeast Atlantic (OSPAR) stipulates similar procedures.

Glitne ceased production in February 2013 and decommissioning of the field has been ongoing 2013 - 2015. Permanent plugging and abandonment of the seven wells completed in October 2014. All facilities/equipment were removed from the field in 2015. Safety zones in the area have been repealed and national maps updated.

Huldra ceased production in September 2014, after 13 years in production. Permanent plugging and abandonment of six wells is planned for 2016 and the plan is that the Huldra topside facilities will be removed in 2019.

Yttergryta is a subsea field with one production well that ceased production in 2013. Permanent plugging of the well was completed early in 2015.

On **Heimdal** a modular drilling rig has been successfully installed in order to plug and abandon all 12 wells at the Heimdal main reservoir. The plug and abandonment project started in the fourth quarter 2014, and is scheduled to be finalised by second quarter 2016.

During 2015 there were permanent plugging and abandonment operations at Statfjord Øst, Statfjord A, Sleipner and Tordis. In addition Åsgard decommissioned part of the Midgard flowline loop in 2015.

For further information about decommissioning see note 2 *Significant accounting policies* to the Consolidated financial statements.

3.6 Development and Production International (DPI)

3.6.1 DPI overview

Statoil is present in several of the most important oil and gas provinces in the world.

Development and Production International (DPI) is responsible for all development and production of oil and gas outside the Norwegian continental shelf (NCS).

In 2015, DPI was engaged in production in 11 countries: Algeria, Angola, Azerbaijan, Brazil, Canada, Ireland, Nigeria, Russia, the UK, the US, and Venezuela. DPI produced 37% of Statoil's total equity production of oil and gas in 2015.

As of 31 December 2015, Statoil has exploration licenses in North America (Canada and US), South America and sub-Saharan Africa (Angola, Brazil, Colombia, Mozambique, Nicaragua, Suriname, South Africa and Tanzania), North Africa (Algeria and Libya), Europe and Asia (Azerbaijan, Greenland, Indonesia, Myanmar, Russia and the UK) as well as Oceania (Australia and New Zealand). The main development projects in which DPI is involved are in Brazil, Canada, the UK, and the US.

Statoil also has representative offices in Kazakhstan, Mexico and United Arab Emirates.

Statoil closed its office in Iran in 2013 but has residual payment obligations for tax and social security under legacy contracts in Iran. These will be dealt with in accordance with all applicable sanctions. See section 5.1.1 *Risks related to our business* for information regarding sanctions towards Iran.

The map shows Statoil's international producing countries and additional countries where Statoil has discoveries and/or exploration acreage.

Key events and portfolio developments in 2015:

- Eight wells (exploration and appraisal) were announced as discoveries in 2015, including the Piri 2, Tangawizi 2 and Mdalasini (Statoil-operated) discoveries in Tanzania
- Statoil accessed new acreage in Lampyrus in Russia, Mozambique, Nicaragua, Flemish Pass basin and Nova Scotia in East Coast Canada and South Africa
- In January, a transaction with Southwestern Energy was closed. The agreement reduced Statoil's working interest in the non-operated US southern **Marcellus** onshore asset from 29% to 23%
- Delay of **Big Foot** development first oil in the US Gulf of Mexico. The operator Chevron expects first oil in 2018. Initial plans called for production to start in late 2015, however, installation was halted and the tension leg plarform (TLP) moved to sheltered waters following damage to subsea installation tendons in late May 2015
- In April, the **Kizomba Satellites Phase 2** project in Block 15 offshore Angola started production
- In April, Statoil completed its sale of its remaining 15.5% interest in **Shah Deniz** and the **South Caucasus Pipeline (SCP)** to the Malaysian oil and gas company PETRONAS. The effective date was 1 January 2014
- In August, the **Peregrino** field offshore Brazil passed a significant milestone with 100 million barrels of oil produced since production started in April 2011
- On 30 December, the Shell operated **Corrib** gas field in Ireland started production
- In December, Statoil completed the sale of its 20% interest in **Trans Adriatic Pipeline AG (TAP)** to the Italian gas infrastructure company Snam. TAP is an 882 km-long section of the Southern Gas Corridor, linking Shah Deniz Stage 2 to gas markets in Europe
- In December, transactions with Repsol were announced. As a result of these transactions, Statoil's working interest in the US **Eagle Ford** increased from 50% to 63% and Statoil took full operatorship. In addition, Statoil will assume operatorship of the **BM-C-33** licence in Brazil's Campos basin and acquire a 31% equity share in the UK licence for **Alfa Sentral**, a field which spans the UK-Norway maritime border. The transactions for BM-C-33 and Alfa Sentral are pending approval from relevant government authorities
- In February 2016, the In Salah Gas joint venture announced the start- up of operations at the **In Salah Southern Fields** project in Algeria
- Significant impairment losses on assets and oil and gas prospects and signature bonuses were recognised in 2015, see section 4.1.5 *DPI profit and loss analysis* for further details

The profitability of our industry continues to be challenged. Statoil's response to the industrial challenge characterised by high costs and declining returns is addressed in the section 2 *Strategy and market overview*.

3.6.2 International production

Statoil's entitlement production outside Norway was about 32% of Statoil's total entitlement production in 2015.

The following table shows DPI's average daily entitlement production of liquids and natural gas for the years ending 31 December 2015, 2014 and 2013. Entitlement production figures are after deductions for production sharing and profit sharing. For US assets entitlement production are expressed net of royalty interests. For all other countries royalties paid in-cash are included in entitlement production and royalties payable in-kind are excluded.

	For the year ended 31 December		
Entitlement production	2015	2014	2013
Oil and NGL (mboe per day)	436	383	354
Natural gas (mmcm per day)	23	26	23
Total (mboe per day)	580	546	502

The table below provides information about the fields that contributed to production in 2015

Producing fields during calendar year 2015

Field	Statoil's equity interest in %	Operator	On stream	Licence expiry date	Average daily equity production mboe/day	Average daily entitlement production mboe/day
North America					282.3	239.7
US: Marcellus [1]	Varies	Statoil/others	2008	HBP[2]	115.7	96.9
US: Bakken [1]	Varies	Statoil/others	2011	HBP[2]	61.6	49.3
US: Eagle Ford [1]	Varies	Statoil	2010	HBP[2]	34.7	26.6
US: Tahiti	25.00	Chevron	2009	HBP[2]	16.9	13.9
US: Caesar Tonga	23.55	Anadarko	2012	HBP[2]	9.1	8.7
US: St. Malo	21.50	Chevron	2014	HBP[2]	7.6	7.6
US: Jack	25.00	Chevron	2014	HBP[2]	6.6	6.6
Canada: Leismer Demo	100.00	Statoil	2010	HBP[2]	19.9	19.9
Canada: Terra Nova	15.00	Suncor	2002	2022	5.4	5.4
Canada: Hibernia/Hibernia southern extension[3]	Varies	HMDC	1997	2027	4.8	4.8
South America					43.5	43.5
Brazil: Peregrino	60.00	Statoil	2011	2034	43.5	43.5
Sub-Saharan Africa					273.3	197.8
Angola, Block 17	23.33	Total	2001	2022-34[4]	161.9	113.9
Angola, Block 15	13.33	ExxonMobil	2004	2026-32[4]	41.8	22.6
Angola, Block 31	13.33	BP	2012	2031	20.9	19.0
Angola: Block 4/05[5]	20.00	Sonangol P&P	2009	2026	1.4	1.3
Nigeria: Agbami	20.21	Chevron	2008	2024	47.3	41.0
North Africa					49.6	43.6
Algeria: In Salah	31.85	Sonatrach/BP/Statoil	2004	2027	32.5	30.6
Algeria: In Amenas	45.90	Sonatrach/BP/Statoil	2006	2022	17.1	13.3
Libya: Mabruk	12.50	Mabruk Oil Operations	1995	2033	0.0	(0.0)[6]
Libya: Murzuq	10.00	Akakus Oil Operations	2003	2033	0.0	(0.2)[6]
Europe and Asia					78.3	43.9
Azerbaijan: ACG	8.56	BP	1997	2024	54.3	24.2
Azerbaijan: Shah Deniz [7]	15.50	BP	2006	2041	12.0	10.0
Russia: Kharyaga	30.00	Total	1999	2032	9.4	7.1
UK: Alba	17.00	Chevron	1994	2018	2.5	2.5
UK: Jupiter	30.00	ConocoPhillips	1995	HBP[2]	0.1	0.1
Ireland: Corrib[8]	36.50	Shell	2015	2031	0.0	0.0
Total Development and Production International (DPI)					727.0	568.5
Equity accounted production						
Venezuela: Petrocedeño[9]	9.68	Petrocedeño	2008	2033	11.6	11.6
Total Development and Production International (DPI) including share of equity accounted					738.7	580.2

1) Statoil's actual working interest can vary depending on wells and area
2) Held by Production (HBP): A company's right to own and operate an oil and gas lease is perpetuated beyond its original primary term, as long thereafter as oil and gas is produced in paying quantities. In the case of Canada, besides continue being in production status, other regulatory requirements must be met
3) Statoil's working interests are 5.0% in Hibernia and 9.0% in Hibernia southern extension
4) Varies by field
5) Statoil relinguished Block 4/05 in September 2015
6) Zero production in 2015, adjustment of 2014 volume
7) Statoil divested the asset on 30 April 2015
8) New gas field which started production on 30 December 2015
9) Petrocedeño is a non-consolidated company and accounted for pursuant to the equity accounting method

The table below provides information about production per country in 2015.

Country	Average daily equity production mboe/day[1]	Average daily entitlement production mboe/day
North America	282.3	239.7
US	252.2	209.6
Canada	30.1	30.1
South America	43.5	43.5
Brazil	43.5	43.5
Sub-Saharan Africa	273.3	197.8
Angola	226.0	156.8
Nigeria	47.3	41.0
North Africa	49.6	43.6
Algeria	49.6	43.9
Libya	0.0	-0.3
Europe and Asia	78.3	43.9
Azerbaijan	66.3	34.2
Russia	9.4	7.1
UK	2.6	2.6
Total Development and Production International (DPI)	727.0	568.5
Equity accounted production		
Venezuela: Petrocedeño[2]	11.6	11.6
Total Development and Production International (DPI) including share of equity accounted production	738.7	580.2

1) In PSA countries our share of capital expenditures and operational expenses are computed on the basis of equity production.

2) Petrocedeño is accounted for pursuant to the equity accounting method.

The following sections provide information about the main producing assets internationally. See section 4.1.5 *DPI profit and loss analysis* for a discussion of the results of operations for year end 2015.

3.6.2.1 North America

Production in North America comprises the US and Canada.

US

Statoil is positioned in the fast-growing US onshore oil and gas industry. Statoil has had strong growth in production within US shale since entering the first play in 2008.

Statoil entered the **Marcellus** shale gas play, located in the Appalachian region in north east US, in 2008 through a partnership with Chesapeake Energy Corporation, acquiring 32.5% of Chesapeake's 1.8 million acres in Marcellus. Statoil has continued to acquire acreage within the play, with a net acreage position of 410,000 acres. The most recent divestments occurred in 2014 with Southwestern. The divested share represents approximately 30,000 acres. Southwestern took over operatorship in this US southern Marcellus area through a transaction with Chesapeake in December 2014.

Statoil entered the **Bakken** tight oil play through the acquisition of Brigham Exploration Company in December 2011. Statoil's net acreage position in Bakken and Three Forks shale formation at the end of 2015 was 249,000 acres.

Statoil entered the **Eagle Ford** shale formation located in southwest Texas in 2010. Through agreements with Enduring Resources LLC and Talisman Energy Inc., Statoil acquired 67,000 net acres. In 2013, Statoil became operator for 50% of the Eagle Ford acreage in 2010 and gradually took over full operatorship of the Statoil operated acreage in 2013. As part of a global transaction in December 2015 with Repsol, which acquired Talisman in May 2015, Statoil increased its working interest and took full operatorship of all of the assets in the Eagle Ford Shale. As a consequence, Statoil has a total working interest of 63% representing an addition of 15,000 net acres for a total of 72,000 leaseholds. Our joint venture partner, Repsol, continues to hold 37% working interest.

Statoil is positioned in the Gulf of Mexico for the following offshore developments:

The **Tahiti** oil field is located in the Green Canyon area. The development includes a floating spar facility. As of 31 December 2015, there were nine production and three water injection wells in operation, and additional wells will be phased in over time to fully develop the field.

The **Caesar Tonga** oil field is located in the Green Canyon area. As of 31 December 2015, there were six producing wells tied back to the Anadarko-operated Constitution spar host, and additional production wells will be phased in over time.

The **Jack** and **St. Malo** oil fields are located in the Walker Ridge area. The fields are subsea tie-backs to the Chevron operated Walker Ridge Regional Host facility. First production was achieved in December 2014. As of 31 December 2015, there were three wells producing on Jack and three wells producing for St. Malo. Additional production wells will be phased in over time.

Canada

Statoil entered the Alberta oil sands in 2007 through a corporate acquisition of North American Oil Sands Corporation. In May, 2014, Statoil and PTTEP completed a transaction to divide their respective interests in the Kai Kos Dehseh (KKD) oil sands project with an effective date of 1 January 2013.

Following the transaction with PTTEP, Statoil continues as operator and 100% working interest owner for the Leismer and Corner projects which together comprise 123,200 net acres of oil sands leases in Alberta. **The Leismer Demonstration Plant** (LDP) is the first phase of the KKD development and has been in operation since 2010. The in-situ technology known as SAGD (steam assisted gravity drainage), injects steam into the oil bearing formation to recover bitumen which is then pumped to the surface. Further oil sands development could involve expanding production capacity of the Leismer facility and/or the greenfield development of the Corner project. At this time, there are no near term plans to further develop either project.

In addition, we have interests in the Jeanne d'Arc Basin offshore the province of Newfoundland and Labrador in the partner operated producing oil fields **Terra Nova, Hibernia** and **Hibernia Southern Extension**. On 1 December 2015, Statoil's interest in Hibernia Southern Extension was reduced from 10.5% to 9.0% due to a redetermination process.

3.6.2.2 South America

Statoil's production activities in South America comprise the Peregrino operatorship in Brazil and the Petrocedeño project in Venezuela.

Brazil

The **Peregrino** field is a heavy oil field located in the Campos Basin, about 85 kilometres off the coast of Rio de Janeiro. The field came on stream in 2011.The oil is produced from two wellhead platforms with drilling capability and it is processed on the Peregrino FPSO. Statoil holds a 60% ownership interest in the field and is operator. In August 2015, the Peregrino field passed a significant milestone with 100 million barrels of oil produced since production start.

Venezuela

Petrocedeño produces extra-heavy crude oil from the Junin area in the Orinoco Belt. The oil is transported through pipeline to a plant at the Jose Industrial Complex at the coast nearby Puerta La Cruz where it is upgraded into a light crude and exported.
For information related to Venezuela's financial risk see section 5.2.2 *Managing financial risk*.

3.6.2.3 Sub-Saharan Africa

Statoil's production activities in Sub-Saharan Africa comprise Angola and Nigeria.

Angola

The deep water blocks 17, 15, 31 and 4/05 contributed with 40% of Statoil's equity liquid production outside Norway in 2015. Each block is governed by a production sharing agreement (PSA) which sets out the rights and obligations of the Parties, including mechanisms for sharing of the production with the Angolan state oil company Sonangol.

Block 17 comprises production from four FPSOs; **CLOV**, **Dalia**, **Girassol** and **Pazflor**.

Block 15 has production from four FPSOs: **Kizomba A**, **Kizomba B**, **Kizomba C-Mondo**, and **Kizomba C-Saxi Batuque**. In April 2015, the **Kizomba Satellites phase 2 project**, which consists of the fields Bavuka, Kakocha, and Mondo South started production. The fields are developed with subsea wells and infrastructure tied back to the Kizomba B and Mondo FPSO vessels.

Block 31 has production from the **PSVM** FPSO.

Statoil had production from the **Gimboa** FPSO on **Block 4/05** until the company exited the Block in September 2015.

The FPSOs serve as production hubs and receive oil from a large number of wells and more than one field each. In 2015, new wells were added and set into production on Block 15, Block 17 and Block 31.

Nigeria
In Nigeria, Statoil has a 20.2% interest in the Agbami deep water field which is located 110 km off the coast of the Central Niger Delta region. The field is developed with subsea wells connected to an FPSO. The **Agbami** field straddles the two licenses OML 127 and OML 128 and is operated by Chevron under a Unit Agreement. Statoil has 53.85% interest in OML 128.

For information related to the Agbami redetermination process and the dispute between the Nigerian National Petroleum Corporation and the partners in Oil Mining Lease (OML) 128 concerning certain terms of the OML 128 Production Sharing Contract, see section 5.3 *Legal proceedings* and note 23 *Other commitments and contingencies*.

3.6.2.4 North Africa

Statoil had in 2015 production in North Africa from Algeria.

Algeria
The **In Salah** onshore gas development, in which Statoil has a working interest of 31.85%, is Algeria's third-largest gas development. A PSA including mechanisms for revenue sharing, governs the rights and obligations of the Parties and establishes a joint operatorship between Sonatrach, BP and Statoil.

In February 2016, the In Salah Gas joint venture announced the introduction of gas in the **In Salah Southern Fields** processing facilities. Gas export from the project started in March. This project, which is led by Statoil on behalf of the Joint Venture, will mature the remaining four discoveries into production. The southern fields (Gour Mahmoud, In Salah, Garet el Befinat and Hassi Moumene) will tie in to existing facilities in the northern fields.

The **In Amenas** onshore development is the fourth-largest gas development in Algeria. It also contains significant liquid volumes. The facilities are operated through a joint operatorship between Sonatrach, BP and Statoil, where Statoil's share of financing the investments (working interest) is 45.9%. A PSA, including mechanisms for revenue sharing, governs the rights and obligations of the Parties and establishes a joint operatorship between Sonatrach, BP and Statoil.

The In Amenas plant has since April 2013 produced from two out of three trains. The production has been relatively stable. The third train, which also was damaged in the January 2013 terrorist attack, is expected to restart in the second quarter of 2016.

Libya
There has not been any oil production from the **Mabruk** or the **Murzuq** assets in 2015 due to the security situation in the country.

3.6.2.5 Europe and Asia

Statoil's production in Europe and Asia encompasses Azerbaijan, Russia, the United Kingdom and Ireland.

Azerbaijan
The **Azeri-Chirag-Gunashli (ACG)** oil field in the Caspian Sea has production from 6 fixed platforms. The oil is transported through pipelines to the Sangachal onshore terminal near Baku. From the terminal the oil is exported to the world markets.

Statoil has an 8.7% stake in the 1,760 km Baku-Tbilisi-Ceyhan (BTC) oil pipeline that is used to transport ACG oil to the southern Turkish port of Ceyhan.

In April 2015, Statoil completed the sale of its remaining 15.5% interest in **Shah Deniz** and the **South Caucasus Pipeline (SCP)** to the Malaysian oil and gas company PETRONAS. See note 4 *Acquisitions and dispositions* of the Consolidated financial statements for further details.

Russia
The **Kharyaga** oil field is located onshore in the Timan Pechora basin in north-west Russia. The field is governed by a PSA.
For information related to risk in Russia see section 5.1.1 *Risks related to our business*.

United Kingdom
The **Alba** oil field is located in the central part of the UK North Sea. **Jupiter** is a gas field located in the southern part of the UK North Sea. The decommissioning of the Jupiter wells is planned to start in 2016.

Ireland
On 30 December 2015 production started on **Corrib** gas field off Ireland's northwest coast. Corrib consists of a subsea development with a pipeline to an onshore processing terminal from which gas will be transported to the Irish market. The onshore processing terminal is located approximately 9 km inland.

3.6.3 International exploration

Statoil continued with high international exploration activity in 2015.

In 2015 Statoil carried out significant international exploration activity, as is shown by the company's involvement in 18 completed wells (including both Statoil-operated and partner-operated activities). Eight wells (exploration and appraisal) were announced as discoveries in the period, including the Piri 2, Tangawizi 2 and Mdalasini (Statoil-operated) discoveries in Tanzania.

The table below shows the exploratory wells drilled internationally in the last three years.

		2015	2014	2013
North America	- Statoil operated	8	3	7
	- Partner operated	0	0	4
South America/sub-Saharan Africa	- Statoil operated	3	8	6
	- Partner operated	5	9	4
North Africa	- Statoil operated	0	0	0
	- Partner operated	0	0	1
Europe and Asia	- Statoil operated	2	2	0
	- Partner operated	0	1	2
	Totals	18	23	24

The regions where Statoil had exploration activity in 2015 are presented below.

North America

US
Statoil operated five wells in the Gulf of Mexico (Yeti-1, Yeti Side track, Yeti Appraisal, Thorvald-1 and Power Nap). Yeti-1 and its side track were discoveries, Yeti appraisal confirmed the volumes discovered. Power Nap is ongoing at year end.

Statoil has cancelled the contract for the Discoverer Americas rig in December 2015. Statoil was in the current environment unable to secure additional activity for the rig for the remainder of the contract period, ending in May 2016.

Canada
The West Hercules rig arrived in Canada in November 2014, for a 550 days drilling campaign, which continues into early-2016. The programme has focused on appraisal and near field exploration wells in the greater Bay du Nord discovery area, as well as select exploration prospects in the greater Flemish Pass Basin.

Statoil and its partners were the successful bidders for six exploration licences in the Flemish Pass Basin, offshore Newfoundland, and two licences offshore Nova Scotia in East Coast Canada in 2015. Statoil will operate seven of the eight leases awarded.

South America and sub-Saharan Africa

Angola Kwanza
Statoil acquired a solid acreage position in the pre-salt play of the Kwanza Basin in 2011 with the operatorship in Block 38 and 39 and a partner position in Blocks 22, 25 and 40. The work program included eight commitment wells, two Statoil operated and six partner operated. So far six wells have been completed. In 2015 two partner operated wells were drilled, Umbundu in block 40, Catchimanha in Block 22. For more information see note 12 *Intangible assets*.

Brazil
All exploratory well operations during 2015 were conducted on BM-C-33 license as part of Pão de Açucar and Seat appraisal activities. The Pão de Açucar discovery was fully evaluated by drilling two wells (PdA-A1 and PdA-A2) and performing a successful DST (Drill Stem Test) on PdA-A2. The Seat-2 well was re-entered to perform a DST. In agreement with its licence partners, Statoil will assume operatorship of the BM-C-33 licence subject to receiving government approval.

Colombia
Statoil has accessed three licences in 2014, representing access at scale in relatively frontier acreage. In the COL-4 licence, an environmental and social impact study has been completed.

Statoil farmed-in to a 10% equity share in the Tayrona licence and a 20% share in the Gua Off licence in 2014. The Orca-1 well in the Tayrona licence was announced as a gas discovery in 2014.

Mozambique
The 5th licence round was announced during the third quarter of 2015. Statoil together with partners submitted a winning bid in the A5-A block located in the Angoche area. Eni is the operator of the joint venture with 34% participating interest. Statoil's equity is 25.5%. Final award is expected mid-2016 subject to successful negotiations.

Tanzania
The Tanzania drilling campaign using the Discoverer Americas rig was completed in 2015 after having drilled the Mdalasini prospect and the Tangawizi-2 appraisal well. The discoveries of natural gas in Mdalasini-1, Piri-1 and Giligiliani-1 have significantly increased the total in-place volumes in Block 2.

South Africa
Statoil completed a farm-in transaction in October 2015 with ExxonMobil acquiring a 35% interest in the ER 12/3/154 Tugela South Exploration Right. The Operator is Exxon with 40% equity. The farm-in represents a country entry for Statoil into South Africa. Statoil intends to participate at an early phase of exploration with a step-wise exploration programme.

Nicaragua
In 2015, Statoil together with partner Empresa Nicaraguense del Petroleo (Petronic) has been awarded four licences offshore the Nicaraguan Pacific. Statoil is the operator with 85% equity with the Petronic holding the remaining equity. 2D seismic data has been acquired and processed during 2015 and subsurface studies are underway.

North Africa

Algeria
Statoil and Shell were awarded the Timissit licence in the Berkin basin onshore Algeria in September 2014. Statoil is the operator with 30% equity.

The award represents an opportunity to test a potentially large unconventional (shale) resource play.

The work commitment (up to the first exit point in 2018) is 3D seismic and two vertical wells.

Europe (excluding Norway), Asia and Australia

UK
In 2014 Statoil was awarded interests in 12 exploration licences in the UK 28th licensing round, nine as operator. Significant positions have been taken both in mature parts of the Central North Sea, such as in the vicinity of the Mariner and Bressay projects, and in plays largely untested in UK waters. 11 of the licences are in the North Sea and one is west of the Hebrides. In 2015 two exploration wells were drilled. The Boatswain well in licence P1758 west of the Mariner field was a discovery. The Wall well in licence P2067 was dry. Work now continues to mature the broader UK exploration portfolio.

Greenland
Statoil, along with partners ConocoPhillips and Nunaoil, was awarded block 6 in the East Greenland licence round in December 2013. Statoil is the operator of the block. The licence has a 16-year exploration period.

Russia
Statoil is engaged in a strategic cooperation with Rosneft Oil Company (Rosneft) including a joint cooperation project aimed at undertaking seismic surveys and geological exploration, appraisal, development and production of potential hydrocarbons in four licences on the Russian continental shelf - the Magadan 1, Lisyansky and Kashevarovsky licences in the Sea of Okhotsk (south of the Arctic Circle), and the Perseevsky licence in the Barents Sea (north of the Arctic Circle). Two exploration wells are to be drilled in the Magadan 1 and Lisyansky licences in 2016. Additionally there are two joint cooperation projects onshore; pilot drilling and testing of the onshore heavy oil reservoir layer PK1 in the North Komsomolsky discovery, and the Domanik Sediments Difficult-to-Extract Hydrocarbons Project, aimed at pilot drilling and testing of the limestone Domanik formation in the Russian Volga-Urals basin. For each of these projects, Rosneft holds the majority interest, while Statoil holds a minority interest.

See section 5.1.1 *Risks related to our business* for information regarding sanctions against Russia.

Azerbaijan
The Joint Study Agreement (JSA) with SOCAR for the North Absheron area was completed in 2014. Exploration screening and prospect evaluation is being carried out on an ongoing basis for Azerbaijan offshore areas in order to identify new access opportunities.

Indonesia
Statoil signed the new offshore Aru Trough I PSC licence agreement in May 2015. The licence is adjacent to Statoil's existing exploration acreage in the Aru and West Papua IV licences. This is a low-cost access route into a frontier area with potential where Statoil is already present. This position strengthens the optionality in Statoil's long-term portfolio and secures potential upsides from existing exploration acreage.

Myanmar
Statoil and ConocoPhillips were awarded one exploration block (AD-10) in the Myanmar waters of the Bay of Bengal in 2014. A production sharing contract was signed in May 2015. Statoil (as operator) has completed the IEE (Initial Environmental Examination) and has set up a country office in Yangon.

Australia
In the Ceduna sub-basin in the Great Australian Bight, Statoil holds 30% interest in four exploration licences with BP as operator.

In October 2014, Statoil obtained 100% equity share in an exploration licence in the Exmouth Plateau in North Carnarvon basin.

New Zealand

Statoil is operator with 100% equity share in petroleum exploration permits 55781 and 57057 in the Reinga Basin offshore Northland's west coast. The licences were awarded in the New Zealand Block Offer 2013 and 2014 respectively.

The work programme is designed to fully evaluate the prospectivity of the licences in a step-wise manner within the 15-year licence time frame. Statoil completed 2D seismic data early 2015. Following an analysis and interpretation of this data, Statoil will decide whether to enter into the second exploration phase by mid-2017.

In the New Zealand Block Offer 2014 Statoil was also awarded 50% working interest in blocks 57083, 57085 and 57087 with Chevron as operator. The licences are located in the East Coast and Pegasus basins, southeast off New Zealand's North Island. The partnership is committed to acquire 2D seismic and 3D seismic within the first exploration period.

Faroe Islands

Following disappointing exploration activities, Statoil have relinquished all licences. The Statoil office in Torshavn closed down in 2015.

3.6.4 Fields under development internationally

The sanctioned development projects in which DPI is involved are in Algeria, Brazil, Canada, the UK, and the US.

This section covers selected projects under development and significant pre-sanctioned projects.

Sanctioned projects	Operator	Statoil's equity share	Time of sanctioning	Production start
US: Julia	Exxon Mobil	50.00%	2013	2016
US: Heidelberg	Anadarko	12.00%	2013	2016
US: Stampede	Hess	25.00%	2014	2018
US: Big foot	Chevron	27.50%	2010	2018
Canada: Hebron	Exxon Mobil	9.01%	2012	2017
Algeria: In Amenas Compression project	Sonatrach/BP/Statoil	45.90%	2010	2016
UK, Mariner	Statoil	65.11%	2012	2018
Brazil, Peregrino Phase II[1)]	Statoil	60.00%	2015	2019/20

1) Statoil made the investment decision on Peregrino Phase II project in December 2014 and submitted the Plan of Development to Brazilian authorities in January 2015.

3.6.4.1 North America

Statoil has a number of significant ongoing development projects in North America.

US Gulf of Mexico

The **Julia** oil field is located in the Walker Ridge area of the Gulf of Mexico near Jack and St Malo, and will be developed with subsea wells tied back to the shared JSM host facility. First oil is expected within mid-2016.

The **Heidelberg** oil field is located in the Green Canyon area. The development includes a Spar facility and first oil is expected within early-2016.

The **Stampede** oil field is located in the Green Canyon area. The development includes a tension-leg platform (TLP) with downhole gas lift and water injection from start of production. First oil is expected in 2018.

The **Big foot** oil field is located in Walker Ridge area. The development includes a dry tree TLP with a drilling rig. The operator Chevron expects first oil from Big Foot in 2018. Initial plans called for production to start in late 2015, however, installation was halted and the TLP moved to sheltered waters following damage to subsea installation tendons in late May 2015

US Onshore
US Onshore operations use hydraulic fracturing to liberate resources. Despite reduction in investment and activity level in recent years in shale plays **Bakken**, **Eagle Ford** and **Marcellus**, production growth continues. The increase in onshore production despite investment reduction is attributed to higher recovery per well due to enhanced completion and improved operational efficiency. See section 3.6.2.1 *North America* for further information.

Canada
The **Hebron** field is located in the Jeanne d'Arc basin offshore Newfoundland near the partner-operated producing fields Terra Nova, Hibernia and Hibernia Southern Extension. The Hebron field will be developed using a fixed gravity base structure (GBS) and first oil is expected in 2017. Effective January 1, 2016, Statoil's interest in Hebron was reduced from 9.7% to 9.0% due to a redetermination process.

Statoil has made oil discoveries in the Flemish Pass offshore Newfoundland comprising the **Bay du Nord** project, and work is on-going to assess options for developing this project. Statoil is the operator of Bay du Nord and holds a 65% working interest.

3.6.4.2 South America

In January 2015 Statoil submitted the Plan of Development (PoD) for Peregrino Phase II project in Brazil.

In December 2014, Statoil approved the investment decision for the development of the second phase of the Peregrino oil field. In January 2015 the PoD was submitted to the Brazilian National Agency of Petroleum, Natural Gas and Biofuels (ANP) for approval. **Peregrino Phase II** project includes the Peregrino South and South West discoveries. The development consists of one wellhead platform tied back to the existing FPSO.

3.6.4.3 Sub-Saharan Africa

In Sub-Saharan Africa, Statoil is participating in the planning and development of Block 2 in Tanzania.

Tanzania
Statoil has made several large gas discoveries in Block 2 offshore Tanzania. Statoil is the operator of Block 2 and holds a 65% working interest. Work is on-going to assess options for developing the discoveries, including the construction of an onshore LNG plant jointly with the co-venturers in Blocks 1, 3 and 4 operated by BG.

3.6.4.4 North Africa

In 2015, Statoil's field developments in the North Africa were in Algeria.

The **In Amenas Gas Compression** project in Algeria, which is led by BP, was sanctioned in late 2010. The compressors are expected to come on stream in the fourth quarter of 2016. This will make it possible to reduce wellhead pressure and maintain plateau production. The In Amenas facilities are operated through a joint operatorship between Sonatrach, BP and Statoil.

In February 2016, the In Salah Gas joint venture announced the start- up of operations at the **In Salah Southern Fields** project in Algeria. For more information see section 3.6.2.4 *North Africa*.

3.6.4.5 Europe and Asia

In Europe and Asia, Statoil is participating in the planning and development of projects in the UK

United Kingdom
Statoil is the operator for the **Mariner** heavy oil project. In December 2012, Statoil made the investment decision to develop the Mariner oil field. The field development plan was approved by the UK authorities in February 2013. The concept selected includes a production, drilling and quarters platform based on a steel jacket, with a floating storage unit. Statoil expects production start in 2018.

The field development plan for Mariner includes a possibility of a future subsea tie-in of Mariner East, a small heavy oil discovery. Statoil is the operator of Mariner East.

Following completion of the farm down of 20.89% of P.726 (Mariner East) and 28.89% of P.979 (Mariner South) by Statoil to JX Nippon in third quarter 2015, Statoil holds a 65.11% interest in all Mariner licences.

Statoil is the operator for, and holds an 81.6% interest in **Bressay**. Bressay is also a heavy oil discovery. In February 2016, Statoil decided to pause the concept selection work on Bressay.

In November 2015, Statoil completed the purchase of First Oil's 24% equity share in the UK continental shelf (UKCS) licence P312. This UK licence and licence PL046 on the NCS comprise the **Alfa Sentral**, a gas and condensate field planned to be developed as a tie-back to the existing Sleipner infrastructure on the NCS. A pre unit agreement is in place between the UKCS and NCS Alfa Sentral Licenses, with an unitisation agreement to be negotiated prior to the investment decision.

In February 2016, Statoil signed an agreement with Talisman Sinopec North Sea Limited to acquire their 31% interest in the UK Alfa Sentral Licence P312. The transaction is pending government approval. The transaction will increase Statoil's ownership interest from 24% to 55% when completed. JX remains the operator with a 45% interest.

3.7 Marketing, Midstream and Processing (MMP)

3.7.1 MMP overview

Marketing, Midstream and Processing (MMP) is responsible for marketing and trading of crude oil, natural gas, gas liquids, refined products, for transportation and processing of commodities and for operation of refineries, terminals and processing plants.

MMP markets Statoil's own volumes, the Norwegian state's direct financial interest (SDFI) equity production of crude oil and third-party volumes, approximately 50% of all Norwegian liquids exports. MMP is also responsible for marketing SDFI's gas. In total, Statoil is responsible for marketing approximately 70% of all Norwegian gas exports. See sections 3.12.3 *The Norwegian State's participation* and 3.12.4 *SDFI oil and gas marketing and sale* for further details regarding the Norwegian state's direct financial interest.

MMP operates two refineries, two gas processing plants, one LNG plant (from 1 January 2016), one methanol plant and three crude oil terminals. In addition, MMP is responsible for developing transportation solutions for natural gas, liquids and crude oil from the Statoil assets including pipelines, shipping, trucking and rail.

In 2015, MMP sold 36.9 billion cubic metres (bcm) of natural equity gas from the Norwegian continental shelf (NCS) on our own behalf, in addition to approximately 37.2bcm of NCS gas on behalf of the Norwegian state. Statoil's total US gas sales, including third-party gas, amounted to 11.2 bcm in 2015. In 2015, MMP also sold 644 million barrels of crude oil and condensate, approximately 15 million tonnes of natural gas liquids (NGL), and approximately 1.2 million tonnes of methanol. Of the total 644 million barrels sold in 2015, approximately 50% represented Statoil equity volumes, while approximately 37% of the total 15 million tonnes of NGL sold in 2015 were Statoil equity volumes.

In 2015 the European gas market was characterised by falling prices due to record supplies and stagnating demand. Statoil's overall gas production increased somewhat compared to 2014. In the US the cold winter in North East US and Canada created large regional arbitrage margins. The LNG market showed continued regional price differences and geographical arbitrage margins. An oversupplied oil market globally has resulted in weak oil prices in 2015.

Refinery margins were higher than in 2014. Facilities have been operated with good regularity. HSE results are at the same level as in 2014 for Serious Incident Frequency (SIF) and Total Recordable Incident Frequency (TRIF), while there has been an increase in number of oil and gas leakages mainly due technical and operational issues. With effect from 1 June 2015, the Renewable Energy business cluster was transferred from MMP to New Energy Solutions (NES). The remaining business activities are organised in the following business clusters: Marketing and Trading; Asset Management and Processing and Manufacturing.

Key events in 2015:

- The operatorship for Azerbaijan Gas Supply Company and the commercial operatorship for South Caucasus Pipeline Company were transferred from Statoil to The State Oil Company of Azerbaijan Republic (SOCAR) effective from 1 May 2015 following the completion of the sale of Statoil's shares to SOCAR, BP and PETRONAS in 2014
- Following the divestment of its share in the Shah Deniz gas field in Azerbaijan, Statoil agreed to sell its 20% interest in Trans Adriatic Pipeline AG (TAP) to the Italian gas infrastructure company Snam
- Edvard Grieg oil pipeline and Utsira High gas pipeline became operational late 2015 and provide export of oil and gas for the Edvard Grieg field and in the future also for the Ivar Aasen field currently under construction
- The 482 kilometer long Polarled pipeline was laid at the Aasta Hansteen field at a depth of 1,260 meters in the Norwegian Sea
- Statoil signed an agreement with Centrica in May to increase the volume of gas supplies under an existing supply agreement. The gas supplied to the UK from the ten year agreement will increase from 5 bcm/year to 7.3 bcm/year from October 2015
- Statoil extended gas supply agreement with UK's SSE. Starting 1 October 2015, the gas supplied from the six year agreement will increase from approximately 0.5 bcm/year to approximately 2.5 bcm/year

The profitability of our industry continues to be challenged. Statoil's response to the industrial challenge characterised by escalating cost and declining returns is addressed in the Section *Strategy and market overview*.

3.7.2 Marketing and Trading

The Marketing and Trading business cluster (MT) is responsible for the marketing and trading of all the products from Statoil's upstream, processing and refining business.

3.7.2.1 Marketing and trading of gas and LNG

MMP is responsible for Statoil's marketing and trading of natural gas worldwide, for power and emissions trading and for overall gas supply planning and optimisation, including the SFDI.

The gas marketing and trading business is conducted from Norway (Stavanger) and from offices in Belgium, the UK, Germany and the US.

Statoil transports and markets approximately 70% of all NCS gas and continues to develop its position in the US.

A significant proportion of Statoil's gas sales are sold under long-term contracts. These sales are carried out with large industrial customers, power producers and local distribution companies. Gas is also sold through short-term contracts and through trading on European and US liquid marketplaces. In the US, gas is sold through bilateral contracts.

A few of Statoil's long-term gas contracts contain contractual price review mechanisms that can be triggered by the buyer or seller at regular intervals, or under certain given circumstances. Statoil is currently in price reviews with some of its customers.

Statoil expects to continue to optimise the market value of the gas delivered to Europe through a mix of long-term contracts and short-term marketing and trading. This is done both as a response to customer needs and in order to capture new business opportunities as the markets become more liberalised and liquid. Statoil has flexibility in terms of production and transportation systems. Combined with its downstream assets this is used to optimise the value of the gas sold.

Europe
The major export markets for gas from the NCS are Germany, France, the UK, Belgium, the Netherlands, Italy and Spain. Our longer term customers include large national or regional gas companies such as ENGIE, ENI Gas & Power, British Gas Trading (a subsidiary of Centrica), RWE and GasTerra.

Our European gas trading business conducts activities with over 85 counterparties on all European liquid trading locations. MMP is active on both physical and exchange markets such as Intercontinental Exchange (ICE).

US
The US is the world's largest and most liquid gas market. Statoil Natural Gas LLC (SNG), a wholly-owned subsidiary, has a gas marketing and trading organization in Stamford, Connecticut that markets natural gas to local distribution companies, industrial customers and power generators.

SNG also markets the gas equity production from Statoil's assets in the US Gulf of Mexico.

Statoil's entry into the Marcellus and the Eagle Ford shale gas plays has resulted in a significant increase in the volume of gas marketed and traded by Statoil in the US over the last few years.

SNG has entered into gas transportation agreements which enable Statoil to transport some of the produced gas from the Northern Marcellus production area to Manhattan, NY and to the US/Canadian border at Niagara, providing access to the greater Toronto area in Canada.

In addition SNG has long-term capacity contracts with Dominion Resources Inc., which owns the Cove Point LNG re-gasification terminal in Maryland, with a total capacity of 10.4 bcm per year. LNG is sourced from the Snøhvit LNG facility in Norway. Due to continuing low gas prices in the US, most of Statoil's LNG cargoes have been diverted away from the US and delivered into higher-priced markets in Europe, South-America and Asia.

Algeria
Statoil has a participating interest in the In Salah gas field, Algeria's third-largest gas development. The field is operated by a joint venture constituted by Statoil, BP and Sonatrach. Statoil receives its income from gas which is sold under long-term contracts.

3.7.2.2 Marketing and trading of liquids

MMP is responsible for the sale of the group's and the Norwegian state's direct financial interest (SDFI) production of crude oil and natural gas liquids.

Statoil is among the world's major net sellers of crude oil. The company operates from sales offices in Stavanger, Oslo, London, Singapore, Stamford and Calgary and markets and trades crude oil, condensate, NGLs as well as refined products.

The main crude oil market for Statoil is northwest Europe. Most of the crude oil volumes are sold in the spot market, based on publicly quoted market prices.

The liquids marketing and trading business is responsible for commercial optimisation of the Mongstad and Kalundborg refineries as well as crude terminals located at Mongstad, Sture and South Riding Point in the Bahamas. MMP is also responsible for Statoil's liquefied petroleum gas (LPG) liftings at the Sture terminal, as well as Statoil's naphtha lifting from Kårstø and Braefoot Bay, liftings of LPG from Kårstø, Mongstad, Braefoot Bay and Teesside terminals in addition to marketing of condensate and LPG from the In Amenas field In Algeria. Statoil lifts waterborne ethane from Kårstø and Teesside, condensate from Nyhamna, and condensate and LPG volumes from Melkøya.

In addition, MMP markets equity crude oil, condensate and NGL production from Statoil's unconventional assets in North America. They include the Alberta oil sands, Bakken, Eagle Ford, and Marcellus. Unconventional volumes were mostly sold in the spot market based on publicly quoted prices. Production from Eagle Ford is primarily transported by pipeline while the most part of crude oil from Bakken is transported to the best paying markets by rail.

MMP also markets equity volumes from DPI assets located in Canada, US, Brazil, Angola, Nigeria, Algeria, Russia, Azerbaijan and UK, as well as third party volumes.

Value is maximised through the use of own and leased capacity such as terminals, storages, pipelines, railcars and vessels.

3.7.3 Asset Management

The Asset Management business cluster (AM) is the owner of all mid- and downstream assets in Statoil, ranging from refineries to pipelines, storage terminals, shipping activities and other infrastructure lease commitments.

AM is responsible for securing flow assurance for gas and oil in order to bring production to the markets. This includes management and development of existing assets and contracts as well as being responsible for Statoil's mid and downstream investment projects. Furthermore AM ensures that the Marketing and Trading business cluster (MT) has efficient access to assets for trading purposes.

3.7.3.1 Production plants

AM is the owner of Statoil`s two refineries in Norway and Denmark and a combined heat and power plant in Norway. AM manages Statoil`s majority ownership share of a methanol production plant, as well as Statoil`s minority share in an NGL and condensate processing facility.

Mongstad
Statoil holds 100% ownership and is operator of the Mongstad refinery in Norway. The refinery was built in 1975, and significantly expanded and upgraded in the late 1980s. In addition it has been subject to considerable investments over the last 15 years in order to meet new product specifications and to improve energy efficiency. The refinery is a medium-sized, modern refinery, with a crude oil and condensate distillation capacity of 226,000 barrels per day.

The refinery is directly linked to offshore fields through two crude oil pipelines, through a natural gas liquids (NGL)/condensate pipeline to the crude oil terminal at Sture and the gas processing plant at Kollsnes, and by a gas pipeline to Kollsnes, making it an attractive site for landing and processing of hydrocarbons.

In addition to the refinery, the main facilities at Mongstad consist of a crude oil terminal (Mongstad terminal), an NGL processing unit and terminal (Vestprosess), and a combined heat and power plant (Mongstad Heat and Power Plant).

Statoil owns 34% of Vestprosess, which transports and processes NGL and condensate. The Vestprosess pipeline connects the Kollsnes and Sture plants to Mongstad. The NGL is fractionated in the Vestprosess NGL unit to produce naphtha, propane and butane.

Statoil is the owner of Mongstad Heat and Power Plant, which produces electrical heat and power from gas received from Kollsnes and from the refinery. The combined heat and power plan started commercial operation in 2010 and improved the Mongstad refinery's energy efficiency. It has a capacity of approximately 280 megawatts of electric power and 350 megawatts of process heat.

Kalundborg
Statoil holds 100% ownership and is operator of the Kalundborg refinery in Denmark, which has a crude oil and condensate distillation capacity of 108,000 barrels per day. The Kalundborg refinery is a small, carbon dioxide efficient and flexible oil refinery. While this enables it to produce a variety of products, its main products are low-sulphur gasoline and diesel for markets in Denmark and Sweden. The refinery is connected via one gasoline and one gas oil pipeline to the terminal at Hedehusene near Copenhagen, and most of its products are sold locally.

Tjeldbergodden
The methanol plant at Tjeldbergodden, the largest in Europe, receives natural gas from the Heidrun field in the Norwegian Sea through the Haltenpipe pipeline. Statoil has an ownership interest of 82,0% in Statoil Metanol ANS at Tjeldbergodden. In addition, Statoil holds a 50.9% ownership interest in Tjeldbergodden Luftgassfabrikk DA, which is one of the largest air separation units (ASU) in Scandinavia.

3.7.3.2 Terminals and storage

AM has ownership in two crude oil terminals in Norway. AM also operates the South Riding Point crude oil terminal in the Bahamas.

Mongstad terminal
Statoil has a 65% ownership interest in Mongstad crude oil terminal, while the State holds 35%. Crude oil is landed at Mongstad via two pipelines from Troll and by crude tankers from the market. The Mongstad terminal has a storage capacity of 9.4 million barrels of crude oil. The terminal supports Statoil's global trading, blending and trans-shipment of crude. It is an important tool in the marketing of North Sea crude.

Sture terminal
The Sture crude oil terminal receives crude oil via two pipelines from the Oseberg and Grane areas in the North Sea. The terminal is part of the Oseberg Transportation System (Statoil interest 36.2%). The processing facilities at Sture stabilise Oseberg crude oil and recover LPG mix (propane and butane) and naphtha. Oseberg blend, Grane blend and LPG mix are exported. LPG and naphtha are also transported through the Vestprosess pipeline to Mongstad.

South Riding Point terminal
AM operates the South Riding Point Terminal, which is located on Grand Bahamas Island, and consists of two shipping berths and ten storage tanks of crude oil, with a storage capacity of 6.75 million barrels of crude oil. The terminal has been upgraded to also enable the blending of crude oils, including heavy oils. The blending is carried out onshore and from ship to ship at the jetty. The terminal is intended to both support our global trading activity and improve our handling capacity for heavy oils. The terminal is an integral part of our marketing of equity volumes of heavy oil.

Aldbrough Gas Storage
Statoil UK holds one third share of the interests in the Aldbrough Gas Storage in UK, operated by SSE Hornsea Ltd. At the end of 2015 six out of nine caverns were operational.

Etzel Gas Lager
Statoil Deutschland Storage GmbH holds a 23.7% stake in the Etzel Gas Lager in North Germany which has a total of nineteen caverns and secures regularity for gas deliveries from the NCS.

Teesside terminal
Statoil UK holds a 27.3% stake in the Teesside terminal, which stabilises unstable oil from the Ekofisk area and several other Norwegian and UK fields and recovers NGL.

3.7.3.3 Pipelines

AM is responsible for Statoil's ownership in pipelines globally as well as gathering and initial processing in the US.

Pipelines in operations
Statoil is a significant shipper in the NCS gas pipeline system. This network links gas fields on the Norwegian continental shelf (NCS) with processing plants on the Norwegian mainland and with terminals at six landing points located in France, Germany, Belgium and the UK.

The total length of Norway's gas pipelines is currently 8,100 kilometres, and most gas pipelines on the NCS that are accessed by third-party customers are owned by a single joint venture, Gassled, with regulated third-party access. The Gassled system is operated by the independent system operator Gassco AS, which is wholly owned by the Norwegian state. When new gas infrastructure facilities are merged into Gassled, the ownership interests are adjusted to reflect each owner's relative interest. Hence, Statoil's future ownership interest in Gassled may change. AM is managing Statoil's current 5% ownership share in Gassled.

In addition AM manage Statoil's ownership in the following pipelines in the Norwegian gas transportation system: Oseberg oil transportation system, Grane oil pipeline, Kvitebjørn oil pipeline, Troll oil pipeline I and II, Edvard Grieg oil pipeline, Utsira High gas pipeline, Valemon rich gas pipeline, Haltenpipe,Norpipe and Mongstad gas pipeline.

Statoil Deutschland GmbH indirect holds a 30.8% stake in the Norddeutche Erdgas Transversale (NETRA) overland gas transmission pipeline.

Pipelines under construction
Statoil is the operator and holds a 37.1% ownership share in the Polarled project which will secure a gas export pipeline for fields in the Norwegian Sea. The project is aligned with the Aasta Hansteen field development.

Statoil is the operator and holds a 40% ownership share in the Johan Sverdrup oil and gas pipelines. The pipelines will provide oil and gas export for the Johan Sverdrup field and is scheduled to start-up in 2019.

In the fourth quarter of 2015 Statoil entered into an agreement with Snam to sell our 20% interest in the Trans Adriatic Pipeline (TAP). See note 4 *Acquistitions and dispositions* for further details.

US gathering system
AM is responsible for Statoil's participation in gathering and facilities for initial processing of oil and gas in the Bakken, Eagle Ford and Marcellus assets in the US. This includes crude and natural gas gathering systems, fresh water supply systems, salt water disposal wells, oil and gas treatment and processing facilities to provide flow assurance for Statoil's upstream production. Midstream assets in Bakken are owned and operated 100% by Statoil. In Eagle Ford, Statoil will transition to operator for 100% of the midstream assets outside of the Oak, Karnes, DeWitt and Bee (KDB) area with a working interest of 63%. In the KDB area of Eagle Ford, Statoil has an ownership interest of 25.2% in Edwards Lime Gathering LLC, which is operated by Energy Transfer Partners L.P. For Marcellus Statoil has operated assets in Marcellus South while in the Marcellus non-operated areas both in the North and South, Statoil's working interest ranges from 16.25% to 32.5% depending on gathering system and number of JV partners.

3.7.4 Processing and Manufacturing

The Processing and Manufacturing business cluster (PM) is responsible for the operation of all of Statoil's onshore facilities in Norway and Denmark except for Snøhvit related facilities, and a substantial part of the oil and gas pipelines on the NCS.

This includes the following Statoil operated plants and pipelines: The refineries at Mongstad and Kalundborg, the methanol production plant at Tjeldbergodden, Oseberg transportation system including the Sture Terminal, Vestprosess, Mongstad Terminal, the Grane, Kvitebjørn, Troll and Edvard Grieg oil pipelines and Mongstad gas pipeline.

The following table shows operating statistics for the plants at Mongstad, Kalundborg and Tjeldbergodden.

	Throughput[1]			Distillation capacity[2]			On stream factor %[3]			Utilisation rate %[4]		
Refinery	2015	2014	2013	2015	2014	2013	2015	2014	2013	2015	2014	2013
Mongstad	**11.9**	9.2	11.8	**9.3**	9.3	9.3	**97.6**	93.4	98.9	**93.4**	90.0	95.0
Kalundborg	**5.2**	4.5	5.0	**5.4**	5.4	5.4	**98.5**	91.8	98.2	**91.0**	82.0	86.5
Tjeldbergodden	**0.92**	0.83	0.79	**0.95**	0.95	0.95	**98.5**	88.4	94.4	**98.5**	97.1	96.6

1) Actual throughput of crude oils, condensates, NGL, feed and blendstock, measured in million tonnes.
Higher than distillation capacity for Mongstad due to high volumes of fuel oil and NGL not going through the crude distillation unit.
Higher than distillation capacity for Kalundborg, due to volumes of kero, naphta, gasoil and biodiesel-additive not going through the crude-/condensate units.
2) Nominal crude oil and condensate distillation capacity, and methanol production capacity, measured in million tonnes.
3) Composite reliability factor for all processing units, excluding turnarounds.
4) Composite utilisation rate for all processing units, stream day utilisation.

In addition PM performs the role of technical service provider (TSP) for the Kårstø and Kollsnes gas processing plants in accordance with the technical service agreement between Statoil and the operator Gassco. PM also performs the TSP role for the larger share of the Gassco operated gas pipeline infrastructure.

The processing that takes place at Kollsnes involves separating out the NGL, and compressing the dry gas for export via the Gassled pipeline network to receiving terminals in Europe. The Kollsnes plant was initially developed to receive gas from the Troll field. Kollsnes now also receives gas from the Visund, Kvitebjørn and Fram fields.

Kårstø processes rich gas and condensate from the NCS received via the Statpipe pipeline, the Åsgard Transport pipeline and the Sleipner condensate pipeline. Products produced at Kårstø include ethane, propane, iso-butane, normal butane, naphtha and stabilised condensate. The dry gas is transported to customers through the Gassled pipeline network via receiving terminals in Europe.

As of 1 January 2016 responsibility for operation of Snøhvit onshore facilities has been transferred from DPN to MMP.

For further information about Statoil's operated onshore facilities and pipelines see section 3.7.3 *Asset Management*.

3.8 Other Group

The Other reporting segment includes activities in New Energy Solutions (NES), Global Strategy and Business Development (GSB), Technology, Projects and Drilling (TPD) and corporate staffs and support functions.

3.8.1 New Energy Solutions (NES)

The NES business area reflects Statoil's aspirations to gradually complement its oil and gas portfolio with profitable renewable energy and other low-carbon energy solutions. Offshore wind and carbon capture and storage have been key focus areas in 2015.

In February 2016, Statoil launched a new energy investment fund dedicated to investing in attractive and ambitious growth companies in renewable energy, supporting its strategy of growth in new energy solutions. The new fund, Statoil Energy Ventures, will invest up to USD 200 million over a period of four to seven years.

Key events in 2015:
- In October Statoil made a final investment decision to build the world's first floating offshore wind park: The Hywind pilot park, to be located outside Peterhead in Scotland
- In June Statoil announced that that it would establish NES as a new business area to create new profitable solutions within renewable energy and other low-carbon solutions, combining Statoil's oil and gas portfolio, project delivery capacity and ability to integrate technological solutions. As a starting point the existing offshore wind portfolio constitutes the main activities in this area. The ambition is to grow and potentially expand into other sources of renewable energy

Sheringham Shoal
The Sheringham Shoal wind farm, located off the coast of Norfolk, UK, was formally opened in September 2012. The wind farm is in full production with 88 turbines and an installed capacity of 317 megawatt (MW). Following divestment in 2014, it is now owned 40% by Statkraft, a Norwegian wholly state-owned company, 40% by Statoil and 20% by the UK Green Investment Bank (GIB). The wind farm's annual production is approximately 1.1 terawatt hours (TWh) and it has the capacity to provide power to approximately 220,000 households.

Dudgeon offshore wind project
Statoil acquired a 70% share in the Dudgeon offshore wind farm project in October 2012 together with Statkraft (30%). In 2014 Statoil reduced its share to 35%, bringing in Masdar as a new partner. The project is located in the Greater Wash Area off the English east coast, not far from Sheringham Shoal. A final investment decision for the 402 MW project was made in July 2014. All construction contracts are awarded and construction has started. The wind farm is expected to produce 1.7 TWh yearly from 67 turbines, with the capacity to provide power for approximately 410,000 households. It is expected to be in full operation by year end 2017.

Dogger Bank
Statoil and Statkraft, together with RWE and SSE, are partners in the Forewind consortium, each with a 25% equity stake. The Dogger Bank area has a total consented capacity of 4.8 GW, and is potentially the largest offshore wind farm development in the world. The consortium received consent for four projects, each with a capacity of 1200 MW by the UK Government in February and August 2015.

Hywind
The world's first full-scale floating offshore wind turbine has been in operation as a demonstration facility off the coast of Karmøy for six years. Hywind's overall performance has exceeded expectations and has experienced several storms with extreme wind of over 40m/s and maximum waves of 19 m height without any damage influencing technical integrity of the structure or turbine. Statoil is continuously working on improving the operating model. Statoil`s strategy has been to utilise the experience gained from this demo project to develop a floating wind park pilot, which Statoil has achieved with Hywind Scotland.

Hywind Scotland pilot project
Hywind Scotland is a floating wind pilot park using the Hywind concept developed and owned by Statoil. The business case is to demonstrate cost-efficient and low risk solutions for commercial scale parks. This will be done by verifying the use of larger Wind Turbine Generators (WTG), optimising the design and demonstrating scale effects in a wind farm layout. Statoil will install 5 Siemens 6.0MW turbines, a total capacity of 30MW. The project is located at Buchan Deep, approximately 25 km off Peterhead on the West coast of Scotland. Production is expected to be 0.14 TWh/year. The project was sanctioned in October 2015 and planned first deliveries to the grid is fourth quarter 2017. This is the next step in our strategy towards deployment of our first utility scale floating wind farms.

Carbon capture and Storage (CCS)
Since 1996 Statoil has proven experience in CCS and has continued to develop competence through research engagement in the Technical Centre Mongstad (TCM) and offshore operations in Sleipner and Snøhvit. Statoil will seek to deploy our competence and experience in other CCS projects, continue to evaluate opportunities to reduce carbon dioxide emissions and explore carbon dioxide for enhanced oil recovery (EOR) possibilities.

3.8.2 Global Strategy and Business Development (GSB)

The Global Strategy and Business Development (GSB) business area is Statoil's functional centre for strategy and business development.

GSB is responsible for Statoil's global strategy processes, and identifies, develops and delivers inorganic business development opportunities. This is achieved through close collaboration across geographic locations and business areas. Statoil's strategy forms the basis for guiding the company's business development focus.

GSB's business activities are organised in the following areas:
- **Corporate strategy and analysis:** Managing corporate strategy development processes, competitor intelligence, industry analysis
- **Political Analysis:** Monitoring political developments nationally, regionally and globally. The unit assesses geopolitical issues and trends impacting our business, political risk related to specific countries and projects, and changes to the broader security threat picture
- **Corporate Sustainability:** Shaping Statoil's strategic response to sustainability issues, development of relevant policies and reporting on the company's sustainability performance
- **Business Development Origination**: Identifying and originating business development opportunities, sharing on-the-ground context and intelligence across the organisation
- **Mergers, Acquisitions and Divestments**: Executing of business development and merger/corporate acquisition/divestment options, sharing deal activity context and intelligence across the organisation
- **Project Support and Execution**: Commercial negotiation support, commercial and technical valuation, business development best practice

3.8.3 Technology, Projects and Drilling (TPD)

Technology, Projects and Drilling (TPD) business area is responsible for delivering projects and wells and providing global support on standards and procurement. TPD is also responsible for developing Statoil as a technology company.

Key events in 2015:
- 117 offshore wells were delivered, including 29 exploration wells
- Drilling efficiency has been significantly enhanced over the last three years. During 2015, the average number of metres drilled per day increased 25% from 2014
- Valemon came on stream: Statoil's first platform to be controlled remotely from shore. Once drilling is completed, the platform will transform into a normally unmanned platform
- The first subsea gas compression plant in the world was brought on line at Åsgard. Another subsea gas compression plant is being developed at Gullfaks
- Fast-track projects Oseberg Delta 2, Smørbukk South extension and Gullfaks South improved oil recovery were brought on stream
- The construction of the fast-track project Gullfaks Rimfaksdalen started
- Three major pipelays were completed: Polarled gas pipeline, Edvard Grieg oil export pipeline and Utsira high gas export pipeline
- The world's largest system for four-dimensional permanent reservoir monitoring was installed at Snorre and Grane, improving the oil recovery rate. 700 kilometres of seismic cables were installed on the seabed
- Two new compressors were brought on line on the Troll A platform
- A new floating storage vessel was brought into operation at Heidrun
- The development of Aasta Hansteen, Gina Krog and Mariner fields continued through 2015
- The construction of the Johan Sverdrup project started. In 2015, contracts worth more than NOK 50 billion were awarded
- The plan for development and operation of Oseberg Vestflanken 2 was submitted to the Ministry of Petroleum and Energy. The field is being developed using an unmanned wellhead platform, a new, cost-effective solution in Statoil's field development toolbox
- A decision was made to develop Hywind Scotland pilot park. The commercial scale, floating wind farm is being developed using Hywind, a floating wind turbine concept developed and owned by Statoil. The construction of Dudgeon offshore wind farm progressed through 2015
- There has been a certain overcapacity in the offshore rig portfolio owing to reduced demand and increased efficiency
- 18 specific and profitable projects aimed at reducing the environmental footprint have been established under the General Electric/Statoil powering collaboration, launched in 2015
- During 2015, 101 new technologies were developed. 20 selected high-value technologies were implemented in 59 different locations, a 50% increase from 2014
- Statoil has captured significant market effects through renegotiating and rebidding most of the agreement portfolio with suppliers during 2015

From 1 January 2016, Statoil has gathered all project expertise in TPD, into one integrated, cost-effective Project Development organisation (PRD), to ensure lean and effective execution and decision-making. From the same date, Technology Excellence and Research, Development and Innovation were merged into one integrated Research and Technology organisation (R&T), reinforcing innovation and technology effectiveness.

TPD business activities were in 2015 organised in the following business clusters:

Research, Development and Innovation (RDI)
RDI is responsible for carrying out research and technology development to meet Statoil's business needs on short and long term.

RDI is organised in four research programmes closely aligned with Statoil's technology strategy: Exploration, Mature area developments and improved oil recovery, Frontier developments and Un-conventionals. In addition, there are two other units: Innovation and Projects. RDI has four research centres in Norway with world-leading laboratories and large-scale test facilities. Internationally, RDI is currently active in our operations in Rio de Janeiro (Brazil), Houston and Austin (the US), St. Johns (Canada) and Beijing (China). Cooperation with external environments plays an important role for R&D in Statoil, and RDI has an Academia programme which coordinates cooperation with Norwegian and international universities.

Technology Excellence (TEX)
TEX is globally responsible for delivering technical expertise to projects, business developments and assets, and for implementing new technologies.

TEX is responsible for driving simplification and standardisation and delivers technological expertise within the areas of petroleum, subsea and marine, facilities and operations, and safety and sustainability technologies enhancing Statoil's operational performance. Technology development and implementation are used to achieve corporate targets for production growth, improved efficiency and regularity, reserve growth and reduced costs. Through Statoil technology invest (STI), TEX supports innovators and entrepreneurs with technology development and commercialisation activities.

Projects (PRO)
PRO is responsible for planning and executing all major facilities development, modification and field decommissioning projects in Statoil.

The project portfolio is diverse, ranging from major new field developments to both small and large development projects on the NCS and internationally. During 2015, around 50 projects were in the execution phase, and at year-end, 30 projects were in the early phase. The proportion of larger projects in the portfolio has increased over the last three years.

Drilling and Well (D&W)
D&W is responsible for providing cost-efficient well delivery, ensuring fit-for-purpose drilling facilities and providing expertise and advice to Statoil's global drilling and well operations.

D&W operated 35 rig years in 2015, compared to 40 in 2014, and delivered production and exploration wells offshore on the NCS and Brazil, and exploration wells in Canada, the Gulf of Mexico, Tanzania and the UK.

Procurement and Supplier Relations (PSR)
PSR is responsible for global procurement aligned with Statoil's business needs, and for managing Statoil's supply chain. Statoil's procurements originate from approximately 12,000 active suppliers.

The procurement process is based on competition and the principles of openness, non-discrimination and equality. PSR encourages and facilitates collaboration with suppliers through communication and by managing supplier relations. By maintaining strong relations with high-quality suppliers, Statoil aims to ensure lasting, long-term competitive advantages. PSR has a strategy for increasing diversity, competition and flexibility in the market to better utilise industry capacity and expertise.

3.8.4 Corporate staffs and support functions

Corporate Staffs and support functions comprise the non-operating activities supporting Statoil.

They include headquarters and central functions that provide business support such as corporate communication, safety, audit, legal services and people and organisation.

3.9 Significant subsidiaries

The following table shows significant subsidiaries and equity accounted companies as of 31 December 2015.

Our voting interest in each company is equivalent to our equity interest.

Ownership in certain subsidiaries and other equity accounted companies

Name	in %	Country of incorporation	Name	in %	Country of incorporation
Statholding AS	100	Norway	Statoil Nigeria Deep Water AS	100	Norway
Statoil Angola Block 15 AS	100	Norway	Statoil Nigeria Outer Shelf AS	100	Norway
Statoil Angola Block 15/06 Award AS	100	Norway	Statoil Norsk LNG AS	100	Norway
Statoil Angola Block 17 AS	100	Norway	Statoil North Africa Gas AS	100	Norway
Statoil Angola Block 31 AS	100	Norway	Statoil North Africa Oil AS	100	Norway
Statoil Angola Block 38 AS	100	Norway	Statoil Orient AG	100	Switzerland
Statoil Angola Block 39 AS	100	Norway	Statoil OTS AB	100	Sweden
Statoil Angola Block 40 AS	100	Norway	Statoil Petroleum AS	100	Norway
Statoil Apsheron AS	100	Norway	Statoil Shah Deniz AS	100	Norway
Statoil Azerbaijan AS	100	Norway	Statoil Sincor AS	100	Norway
Statoil BTC Finance AS	100	Norway	Statoil SP Gas AS	100	Norway
Statoil Coordination Centre NV	100	Belgium	Statoil Tanzania AS	100	Norway
Statoil Danmark AS	100	Denmark	Statoil Technology Invest AS	100	Norway
Statoil Deutschland GmbH	100	Germany	Statoil UK Ltd	100	United Kingdom
Statoil do Brasil Ltda	100	Brazil	Statoil Venezuela AS	100	Norway
Statoil Exploration Ireland Ltd.	100	Ireland	Statoil Venture AS	100	Norway
Statoil Forsikring AS	100	Norway	Statoil Metanol ANS	82	Norway
Statoil Færøyene AS	100	Norway	Mongstad Refining DA	79	Norway
Statoil Hassi Mouina AS	100	Norway	Mongstad Terminal DA	65	Norway
Statoil Indonesia Karama AS	100	Norway	Tjeldbergodden Luftgassfabrikk DA	51	Norway
Statoil New Energy AS	100	Norway	Naturkraft AS	50	Norway
Statoil Nigeria AS	100	Norway	Vestprosess DA	34	Norway

3.10 Production volumes and prices

The business overview is in accordance with our segment's operations as of 31 December 2015, whereas certain disclosures on oil and gas reserves are based on geographical areas as required by the Securities and Exchange Commission (SEC).

For further information about extractive activities, see sections 3.5 *Development and Production Norway* and 3.6 *Development and Production International*, respectively.

Statoil prepares its disclosures for oil and gas reserves and certain other supplemental oil and gas disclosures by geographical area, as required by the SEC. The geographical areas are defined by country and continent. They are Norway, Eurasia excluding Norway, Africa and the Americas.

For further information about disclosures concerning oil and gas reserves and certain other supplemental disclosures based on geographical areas as required by the SEC, see section 3.11 *Proved oil and gas reserves.*

3.10.1 Entitlement production

This section describes our oil and gas production and sales volumes.

The following table shows Statoil's Norwegian and international entitlement production of oil and natural gas for the periods indicated. The stated production volumes are the volumes to which Statoil is entitled, pursuant to conditions laid down in licence agreements and production-sharing agreements. The production volumes are net of royalty oil paid in kind, and of gas used for fuel and flaring. Our production is based on our proportionate participation in fields with multiple owners and does not include production of the Norwegian State's oil and natural gas. Production of an immaterial quantity of bitumen is included as oil production. NGL includes both LPG and naphtha. The only field containing more than 15% of total proved reserves based on oil equivalent barrels is the Troll field. For further information on production volumes see section 9 *Terms and definitions*.

	For the year ended 31 December		
Entitlement production	2015	2014	2013
Norway			
Oil and Condensate (mmbbls)	174	173	174
NGL (mmbbls)	44	42	42
Natural gas (bcf)	1,306	1,229	1,264
Combined oil, condensate, NGL and gas (mmboe)	450	434	441
Eurasia excluding Norway			
Oil and Condensate (mmbbls)	13	14	15
Natural gas (bcf)	16	56	72
Combined oil, condensate, NGL and gas (mmboe)	16	24	28
Africa			
Oil and Condensate (mmbbls)	75	64	58
NGL (mmbbls)	3	2	1
Natural gas (bcf)	63	38	40
Combined oil, condensate, NGL and gas (mmboe)	88	72	66
Americas			
Oil and Condensate (mmbbls)	62	55	50
NGL (mmbbls)	7	7	4
Natural gas (bcf)	215	242	196
Combined oil, condensate, NGL and gas (mmboe)	107	106	89
Total			
Oil and Condensate (mmbbls)	324	306	298
NGL (mmbbls)	54	51	47
Natural gas (bcf)	1,600	1,565	1,571
Combined oil, condensate, NGL and gas (mmboe)	662	635	625
Troll field [1)]			
Oil and Condensate (mmbbls)	14	14	14
NGL (mmbbls)	2	2	2
Natural gas (bcf)	386	317	304
Combined oil, condensate, NGL and gas (mmboe)	85	73	70

1) Note that Troll is also included in Norway stated above.

3.10.2 Sales prices

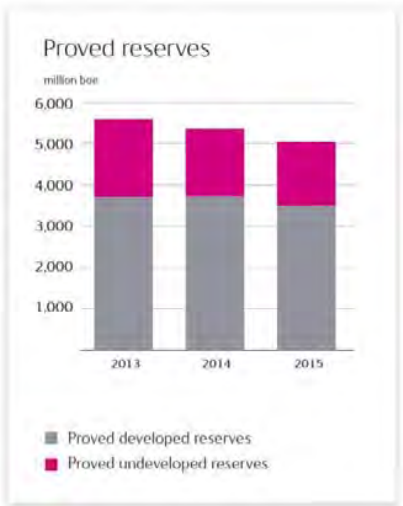
The following tables present realised sales prices.

	Norway	Eurasia excluding Norway	Africa	Americas
Year ended 31 December 2015				
Average sales price oil and condensate in USD per bbl	52.2	50.7	49.4	39.4
Average sales price NGL in USD per bbl	30.1	-	26.2	12.5
Average sales price natural gas in NOK per Sm3	2.2	1.4	1.7	0.8
Year ended 31 December 2014				
Average sales price oil and condensate in USD per bbl	98.3	101.3	95.6	78.3
Average sales price NGL in USD per bbl	59.3	-	59.7	37.3
Average sales price natural gas in NOK per Sm3	2.3	1.3	2.2	1.0
Year ended 31 December 2013				
Average sales price oil and condensate in USD per bbl	109.1	110.5	107.3	89.1
Average sales price NGL in USD per bbl	67.4	-	69.7	59.2
Average sales price natural gas in NOK per Sm3	2.4	0.9	2.1	0.8

3.11 Proved oil and gas reserves

Proved oil and gas reserves were estimated to be 5,060 mmboe at year end 2015, compared to 5,359 mmboe at the end of 2014.

Statoil's proved reserves are estimated and presented in accordance with the Securities and Exchange Commission (SEC) Rule 4-10 (a) of Regulation S-X, revised as of January 2009, and relevant Compliance and Disclosure Interpretations (C&DI) and Staff Accounting Bulletins, as issued by the SEC staff. For additional information, see section Proved oil and gas reserves in note 2 *Significant accounting policies* to the Consolidated financial statements. For further details on proved reserves, see also note 27 *Supplementary oil and gas information (unaudited)* in the Consolidated financial statements.



Changes in proved reserves estimates are most commonly the result of revisions of estimates due to observed production performance, extensions of proved areas through drilling activities or the inclusion of proved reserves in new discoveries through the sanctioning of new development projects. These are sources of additions to proved reserves that are the result of continuous business processes and can be expected to continue to add reserves in the future.

Proved reserves can also be added or subtracted through the acquisition or disposal of assets. Changes in proved reserves can also be due to factors outside management control, such as changes in oil and gas prices. Lower oil and gas prices normally allow less oil and gas to be recovered from the accumulations. However for fields with production sharing agreements (PSAs) and similar contracts a reduced oil price may result in higher entitlement to the produced volume. These changes are included in the revisions category in the table below.

The principles for booking proved gas reserves are limited to contracted gas sales or gas with access to a robust gas market.

In Norway and the UK, Statoil recognises reserves as proved when a development plan is submitted, as there is reasonable certainty that such a plan will be approved by the regulatory authorities. Outside these territories, reserves are generally booked as proved when regulatory approval is received, or when such approval is imminent. Reserves from new discoveries, upward revisions of reserves and purchases of proved reserves are expected to contribute to maintaining proved reserves in future years. Undrilled well locations onshore are generally booked as proved undeveloped reserves when a development plan has been adopted and the well locations are scheduled to be drilled within five years,

Approximately 89% of our proved reserves are located in OECD countries. Norway is by far the most important contributor in this category, followed by the United States of America (US), Canada, Ireland and the United Kingdom (UK).

Of Statoil's total proved reserves, 9% are related to production-sharing agreements (PSAs) in non-OECD countries such as Azerbaijan, Angola, Algeria, Nigeria, Libya and Russia. Other non-OECD reserves are related to concessions in Brazil and Venezuela, representing less than 3% of Statoil's total proved reserves. These are included in proved reserves in the Americas.

Significant changes in our proved reserves in 2015 were:

- Negative revisions due to lower commodity prices compared to last year, which resulted in a reduction of approximately 350 million boe. A large portion of this is related to undeveloped fields where lower commodity prices resulted in earlier economic cut-off, such as the Mariner field in the UK which is under development and is expected to start production in 2018, and uneconomic undeveloped well locations onshore US. The negative revisions are partly offset by positive revisions due to better performance of producing fields, maturing of improved recovery projects, and reduced uncertainty due to further drilling and production experience. The net effect of the positive and negative revisions is a reduction of 42 million boe in 2015. The estimated reduction due to change in prices is a rough estimate derived by using last year's prices on this year's volume base. In the calculation no adjustments have been made for the possible effect on the activity level, operating cost or development cost. For more information regarding prices see section 27 *Supplementary oil and gas information (unaudited)*
- Proved reserves from new discoveries have also been added through the sanctioning of new field development projects in 2015, Johan Sverdrup being the largest contributor. The new projects added a total of 476 million boe
- Further drilling in the Bakken, Marcellus and Eagle Ford onshore plays in the US increased the proved reserves in 2015, and some of these additions are presented as extensions. Extension of proved area on existing field added a total of 150 million boe of new proved reserves in 2015
- The net effect of purchase and sale reduced the reserves by 221 million boe in 2015
- The 2015 entitlement production was 662 million boe, an increase of 4.3% compared to 2014. New discoveries with proved reserves booked in 2015 are all expected to start production within a period of five years

Summary of proved reserves as of 31 December 2015

	Proved reserves			
Reserves category	Oil and Condensate (mmboe)	NGL (mmboe)	Natural Gas (bcf)	Total oil and gas (mmboe)
Developed				
Norway	505	235	10,664	2,641
Eurasia excluding Norway	48	-	32	53
Africa	248	9	206	294
Americas	303	45	999	526
Total Developed proved reserves	1,104	290	11,901	3,515
Undeveloped				
Norway	711	56	2,278	1,173
Eurasia excluding Norway	29	-	161	57
Africa	30	6	160	64
Americas	217	12	124	251
Total Undeveloped proved reserves	987	74	2,723	1,546
Total proved reserves	2,091	364	14,624	5,060

Statoil's proved reserves of bitumen in the Americas are included as oil in the table above since they represent less than 2% of Statoil's proved reserves, which is regarded as immaterial.

The basis for equivalents is presented in the section *Terms and definitions*.

Reserves replacement

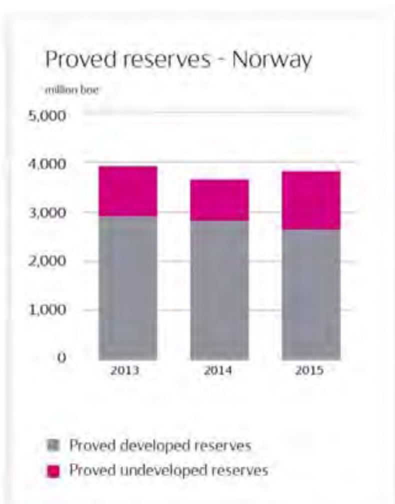
The reserves replacement ratio is defined as the sum of additions and revisions of proved reserves divided by produced volumes in any given period. The following table presents the changes in reserves in each category relating to the reserve replacement ratio for the years 2015, 2014 and 2013.

	For the year ended 31 December		
(million boe)	2015	2014	2013
Revisions and improved recovery	(42)	356	395
Extensions and discoveries	627	253	523
Purchase of petroleum-in-place	13	20	14
Sales of petroleum-in-place	(235)	(233)	(131)
Total reserve additions	363	395	802
Production	(662)	(635)	(625)
Net change in proved reserves	(299)	(240)	177

The reserves replacement ratio for 2015 was 0.55 compared to 0.62 in 2014. The 2015 reserves replacement ratio, excluding purchases and sales of petroleum in place, was 0.88. The average replacement ratio for the last three years was 0.81, or 1.10 excluding purchases and sales.

	For the year ended 31 December		
Reserves replacement ratio (including purchases and sales)	2015	2014	2013
Annual	0.55	0.62	1.28
Three-year-average	0.81	0.97	1.15

The usefulness of the reserves replacement ratio is limited by the volatility of oil prices, the influence of oil and gas prices on PSA reserve booking, sensitivity related to the timing of project sanctions and the time lag between exploration expenditure and the booking of reserves.

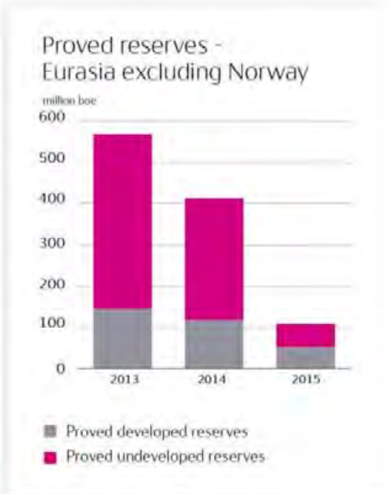


Proved reserves in Norway

A total of 3,814 million boe is recognised as proved reserves in 58 fields and field development projects on the NCS, representing 75% of Statoil's total proved reserves. Of these, 54 fields and field areas are currently in production, 42 of which are operated by Statoil. Four new field development projects added reserves during 2015, Johan Sverdrup, Oseberg Vestflanken 2, Fram C-Øst Brent and Opal categorised as extensions and discoveries. Production experience, further drilling and improved recovery on several of Statoil's producing fields in Norway also contributed positively to the revisions of the proved reserves in 2015.

Sales of reserves are related to the agreement with Repsol. This has reduced Statoil's share of proved reserves on Gudrun.

Of the proved reserves on the NCS, 2,641 million boe, or 69%, are proved developed reserves. Of the total proved reserves in this area, 60% are gas reserves related to large offshore gas fields such as Troll, Snøhvit, Oseberg, Ormen Lange, Tyrihans, Visund, Aasta Hansteen and Åsgard and 40% are liquid reserves.

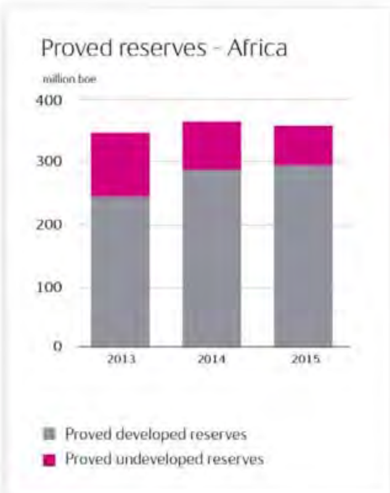


Proved reserves in Eurasia, excluding Norway

In this area, Statoil has proved reserves of 111 million boe related to four fields and field developments in Azerbaijan, the UK, Ireland and Russia. Eurasia excluding Norway represents 2% of Statoil's total proved reserves, Azerbaijan being the main contributor with the Azeri-Chirag-Gunashli fields. All fields are producing. The effect of the farm out of Shah Deniz reduced the proved reserves at year end 2015.

Proved undeveloped reserves were reduced due to negative revisions linked to lower commodity prices resulting in earlier economic cut-off for the fields, primarily the Mariner field in the UK which is under development and is expected to start production in 2018.

Of the proved reserves in Eurasia, 53 million boe or 48% are proved developed reserves. Of the total proved reserves in this area, 69% are liquid reserves and 31% are gas reserves.



Proved reserves in Africa

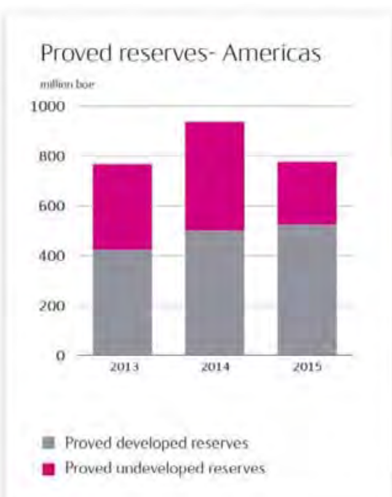
Statoil recognises proved reserves of 358 million boe related to 29 fields and field developments in several West and North African countries, including Algeria, Angola, Libya and Nigeria. Africa represents 7% of Statoil's total proved reserves. Angola is the primary contributor to the proved reserves in this area, with 24 of the 29 fields.

In Angola, Statoil has proved reserves in three blocks, Block 15, Block 17 and Block 31, with production from all blocks. During 2015 Statoil exited Block 4/05, Gimboa is therefore removed from proved reserves this year.

All fields are in production in Algeria and Nigeria. Murzuq and Mabruk are currently not producing due to the unrest in Libya.

The disputed equity determination at Agbami will potentially alter Statoil's equity share in this field. The effect on the proved reserves will be included once the redetermination is finalised and the effect is known.

Of the total proved reserves in Africa, 294 million boe, or 82%, are proved developed reserves. Of the total proved reserves in this area, 82% are liquid reserves and 18% are gas reserves.



Proved reserves in the Americas

In North and South America, Statoil has proved reserves equal to 777 million boe in a total of 17 fields and field development projects. This represents 15% of Statoil's total proved reserves. Ten of these fields are located in the US, seven of which are offshore field developments in the Gulf of Mexico and three are onshore tight reservoir assets. Five are located in Canada and two in South America.

In the US, four of the seven fields in the Gulf of Mexico are in production. Field development is ongoing on Big Foot, Heidelberg and Stampede. The onshore tight reservoir assets Marcellus, Eagle Ford and Bakken are all in production. In Canada, proved reserves are related both to offshore field developments, and to the Leismer field in the Kai Kos Dehseh oil sands project in Alberta.

Proved undeveloped reserves were reduced due to negative revisions linked to lower commodity prices, primarily resulting in undeveloped well locations onshore US becoming uneconomic.

Several transactions were completed during 2015, both purchases and sales. The largest were the transaction with Southwestern Energy reducing the reserves in Marcellus, and the agreement with Repsol increasing the reserves in Eagle Ford. The transactions offset each other and the net effect on proved reserves is zero.

Of the total proved reserves in the Americas, 526 million boe, or 68%, are proved developed reserves. Of the total proved reserves in this area, 74% are liquid reserves and 26% gas reserves.

3.11.1 Development of reserves

In 2015, approximately 438 million boe were converted from undeveloped to developed proved reserves.

The start-up of production from Edvard Grieg, Oseberg Delta 2 and Valemon in Norway together with Bavuca and Kakocha in Angola and Corrib in Ireland increased the developed reserves by 69 million boe during 2015. The rest of the converted volume is related to development activities on producing fields.

Net proved reserves in million barrels oil equivalent	Total	Developed	Undeveloped
At 31 December 2014	5,359	3,725	1,635
Revisions and improved recovery	(42)	96	(138)
Extensions and discoveries	627	-	627
Purchase of reserves-in-place	13	6	7
Sales of reserves-in-place	(235)	(88)	(147)
Production	(662)	(662)	-
Moved from undeveloped to developed	-	438	(438)
At 31 December 2015	5,060	3,515	1,546

The new development projects in Norway, added a total of 476 million boe of proved undeveloped reserves in 2015, the largest being Johan Sverdrup. Further drilling in the Bakken, Marcellus and Eagle Ford onshore plays in the US increased the proved area and added proved undeveloped reserves. These additions are categorised as extensions and together with extensions on existing fields and new discoveries this added a total of 627 million boe of proved undeveloped reserves.

Revision of estimate on existing fields added 96 million boe proved developed reserves and reduced proved undeveloped reserves by 138 million boe. These revisions are based on new information available either from drilling of new wells or from production experience, resulting in an improved understanding of the fields. The negative revisions are mainly linked to lower commodity prices resulting in earlier economic cut-off for the fields and undeveloped well locations becoming uneconomic.

The net effect of the transactions done in 2015, reduced the proved undeveloped reserves by 139 million boe.

		Oil and Condensate (mmboe)	NGL (mmboe)	Natural gas (bcf)	Total (mmboe)
2015	**Proved reserves end of year**	**2,091**	**364**	**14,624**	**5,060**
	Developed	1,104	290	11,901	3,515
	Undeveloped	987	74	2,723	1,546
2014	**Proved reserves end of year**	**1,942**	**403**	**16,919**	**5,359**
	Developed	1,156	310	12,677	3,725
	Undeveloped	786	93	4,242	1,635
2013	**Proved reserves end of year**	**1,877**	**441**	**18,416**	**5,600**
	Developed	1,052	330	13,073	3,711
	Undeveloped	826	111	5,343	1,888

As of 31 December 2015, the total proved undeveloped reserves amounted to 1,546 million boe, 76% of which are related to fields in Norway. The Troll, Snøhvit, Visund, Grane and Oseberg fields, which have continuous development activities, represent the largest undeveloped assets in Norway together with fields not yet in production, such as Johan Sverdrup, Aasta Hansteen, Gina Krogh, Ivar Aasen and Goliat. The largest assets with respect to undeveloped proved reserves outside Norway are Bakken and Stampede in the US, Peregrino in Brazil, Hebron in Canada, Corrib in Ireland and In Salah in Algeria.

In 2015, Statoil incurred NOK 85 billion in development costs relating to assets carrying proved reserves, NOK 70 billion of which was related to proved undeveloped reserves.

Large fields with continuous development activity may contain reserves that are expected to remain undeveloped for five years or more. Examples are Johan Sverdrup, Troll, Snøhvit, Gina Krogh and Aasta Hansteen in Norway. These are large field developments with several billion dollars invested in complex infrastructure and with continuous development that will require extensive, sustained drilling of wells for a long period of time. It is highly unlikely that these field development projects will be prematurely terminated, since this would result in a significant loss of capital.

Additional information about proved oil and gas reserves is provided in note 27 *Supplementary oil and gas information (unaudited)* to the Consolidated financial statements.

3.11.2 Preparations of reserves estimates

Statoil's annual reporting process for proved reserves is coordinated by a central team.

The corporate reserves management (CRM) team consists of qualified professionals in geosciences, reservoir and production technology and financial evaluation. The team has an average of more than 20 years' experience in the oil and gas industry. CRM reports to the senior vice president of finance and control in the Technology, Drilling and Projects business area and is thus independent of the Development & Production business areas in Norway, North America and International. All the reserves estimates have been prepared by Statoil's technical staff.

Although the CRM team reviews the information centrally, each asset team is responsible for ensuring that it is in compliance with the requirements of the SEC and Statoil's corporate standards. Information about proved oil and gas reserves, standardised measures of discounted net cash flows related to proved oil and gas reserves and other information related to proved oil and gas reserves, is collected from the local asset teams and checked by CRM for consistency and conformity with applicable standards. The final numbers for each asset are quality-controlled and approved by the responsible asset manager, before aggregation to the required reporting level by CRM.

The aggregated results are submitted for approval to the relevant business area management teams and the corporate executive committee.

The person with primary responsibility for overseeing the preparation of the reserves estimates is the chair of the CRM team. The person who presently holds this position has a bachelor's degree in earth sciences from the University of Gothenburg, and a master's degree in petroleum exploration and exploitation from Chalmers University of Technology in Gothenburg, Sweden. She has 30 years' experience in the oil and gas industry, 29 of them with Statoil. She is a member of the Society of Petroleum Engineering (SPE) and vice-chair of the UNECE Expert Group on Resource Classification (EGRC).

DeGolyer and MacNaughton report

Petroleum engineering consultants DeGolyer and MacNaughton have carried out an independent evaluation of Statoil's proved reserves as of 31 December 2015. The evaluation accounts for 100% of Statoil's proved reserves. The aggregated net proved reserves estimates prepared by DeGolyer and MacNaughton do not differ materially from those prepared by Statoil when compared on the basis of net equivalent barrels.

Net proved reserves at 31 December 2015	Oil and Condensate (mmbbls)	NGL/LPG (mmbbl)	Sales Gas (bcf)	Oil Equivalent (mmboe)
Estimated by Statoil	2,091	364	14,624	5,060
Estimated by DeGolyer and MacNaughton	2,159	379	14,309	5,087

A reserves audit report summarising this evaluation is included as Exhibit 15 (a)(iv).

3.11.3 Operational statistics

Operational statistics include information about acreage and the number of wells drilled.

Developed and undeveloped acreage

The table below shows the total gross and net developed and undeveloped oil and gas acreage, in which Statoil had interests at 31 December 2015.

A gross value reflects wells or acreage in which Statoil has interests (presented as 100%). The net value corresponds to the sum of the fractional working interests owned in gross wells or acres.

At 31 December 2015 (in thousands of acres)		Norway	Eurasia excluding Norway	Africa	Americas	Oceania	Total
Developed and undeveloped oil and gas acreage							
Acreage developed	- gross	871	90	858	494	-	2,312
	- net	322	21	271	114	-	729
Acreage undeveloped	- gross	9,038	41,146	13,569	23,075	18,531	105,359
	- net	3,419	17,495	4,637	10,073	11,160	46,784

The largest concentrations of developed acreage in Norway are in the Troll, Skarv, Snøhvit, Ormen Lange and Oseberg areas. In Africa, the Algerian gas development projects In Amenas and In Salah represent the largest concentrations of developed acreage (gross and net).

Statoil's largest undeveloped acreage concentration is in Russia with 18% of the total acreage and 48% of the total acreage in Eurasia excluding Norway. In Russia, Statoil participates in a joint venture with Rosneft. The net acreage given in the table above represents Statoil's share of the joint venture. The largest concentration of undeveloped acreage in the Americas is Nicaragua, with 33% of the total for this geographic area. In Africa, the largest acreage concentration is in Angola, representing 56% of the total for this geographic area.

Statoil holds acreage in numerous concessions, blocks and leases. The terms and conditions regarding expiration dates vary significantly from property to property. Work programs are designed to ensure that the exploration potential of any property is fully evaluated before expiration.

Acreage related to several of these concessions, blocks and leases are scheduled to expire within the next three years. Any acreage which has already been evaluated to be non-profitable may be relinquished prior to the current expiration date. In other cases, Statoil may decide to apply for an extension if more time is needed in order to fully evaluate the potential of the properties. Historically, Statoil has generally been successful in obtaining such extensions.

Most of the undeveloped acreage that will expire within the next three years is related to early exploration activities where no production is expected in the foreseeable future. The expiration of these leases, blocks and concessions will therefore not have any material impact on our reserves.

Productive oil and gas wells

The number of gross and net productive oil and gas wells, in which Statoil had interests at 31 December 2015, are shown in the table below.

At 31 December 2015		Norway	Eurasia excluding Norway	Africa	Americas	Total
Number of productive oil and gas wells						
Oil wells	- gross	821	166	468	3,130	4,585
	- net	281.4	24.2	71.3	706.4	1,083.2
Gas wells	- gross	189	6	85	1,953	2,233
	- net	81.6	1.9	32.7	486.3	602.4

The total gross number of productive wells as of end 2015 includes 383 oil wells and 12 gas wells with multiple completions or wells with more than one branch.

Net productive and dry oil and gas wells drilled

The following tables show the net productive and dry exploratory and development oil and gas wells completed or abandoned by Statoil in the past three years. Productive wells include exploratory wells in which hydrocarbons were discovered, and where drilling or completion has been suspended pending further evaluation. A dry well is one found to be incapable of producing sufficient quantities to justify completion as an oil or gas well.

	Norway	Eurasia excluding Norway	Africa	Americas	Oceania	Total
Year 2015						
Net productive and dry exploratory wells drilled	10.2	1.0	2.5	2.6	-	16.3
- Net dry exploratory wells drilled	4.6	0.4	0.5	0.9	-	6.4
- Net productive exploratory wells drilled	5.6	0.7	2.0	1.7	-	9.9
Net productive and dry development wells drilled	32.1	4.1	10.6	228.8	-	275.6
- Net dry development wells drilled	3.6	-	4.3	0.3	-	8.2
- Net productive development wells drilled	28.6	4.1	6.3	228.5	-	267.4
Year 2014						
Net productive and dry exploratory wells drilled	12.0	1.0	4.7	3.4	3.6	24.7
- Net dry exploratory wells drilled	3.4	1.0	2.7	1.6	3.6	12.2
- Net productive exploratory wells drilled	8.6	-	2.0	1.9	-	12.5
Net productive and dry development wells drilled	26.9	2.7	8.5	386.1	-	424.2
- Net dry development wells drilled	3.5	-	1.1	1.2	-	5.8
- Net productive development wells drilled	23.4	2.7	7.4	384.9	-	418.4
Year 2013						
Net productive and dry exploratory wells drilled	19.3	0.3	2.2	2.3	-	24.0
- Net dry exploratory wells drilled	7.3	0.3	2.2	2.3	-	12.0
- Net productive exploratory wells drilled	12.0	-	-	-	-	12.0
Net productive and dry development wells drilled	26.7	2.3	5.9	321.9	-	356.7
- Net dry development wells drilled	1.7	-	0.7	1.3	-	3.7
- Net productive development wells drilled	24.9	2.3	5.3	320.6	-	353.1

Exploratory and development drilling in process

The following table shows the number of exploratory and development oil and gas wells in the process of being drilled by Statoil at 31 December 2015.

At 31 December 2015		Norway	Eurasia excluding Norway	Africa	Americas	Total
Number of wells in progress						
Development wells	- gross	68	4	13	202	287
	- net	24.5	0.3	2.7	67.7	95.2
Exploratory wells	- gross	1	-	-	8	9
	- net	0.4	-	-	5.4	5.8

3.11.4 Delivery commitments

This section describes the long-term NCS commitments for the contract gas years 2015-2018.

On behalf of the Norwegian State's direct financial interest (SDFI), Statoil is responsible for managing, transporting and selling the Norwegian state's oil and gas from the Norwegian continental shelf (NCS). These reserves are sold in conjunction with Statoil's own reserves. As part of this arrangement, Statoil delivers gas to customers under various types of sales contracts. In order to meet the commitments, we utilise a field supply schedule that ensures the highest possible total value for Statoil and SDFI's joint portfolio of oil and gas.

The majority of our gas volumes in Norway are sold under long-term contracts with take-or-pay clauses. Statoil's and SDFI's annual delivery commitments under these agreements are expressed as the sum of the expected off-take under these contracts. As of 31 December 2015, the long-term commitments from NCS for the Statoil/SDFI arrangement totalled approximately 14.51 trillion cubic feet (tcf) (411 bcm).

Statoil and SDFI's delivery commitments, expressed as the sum of expected off-take for the gas years 2015, 2016, 2017 and 2018, are 2.28, 1.89, 1.56 and 1.22 tcf (64.7, 53.5, 44.2 and 44.0 bcm), respectively. The remaining volumes are sold to large industrial end users or on the short-term market.

Statoil's currently developed gas reserves in Norway are more than sufficient to meet our share of these commitments for the next three years.

3.12 Applicable laws and regulations

Statoil operates in more than 30 countries and is exposed to, and committed to compliance with, a number of laws and regulations globally.

This article focuses primarily on Norwegian laws, taking into account that the majority of Statoil's production is produced on the NCS, the ownership structure of the company and that Statoil is registered and has its headquarters in Norway.

3.12.1 Norwegian petroleum laws and licensing system

The principal laws governing Statoil's petroleum activities in Norway are the Norwegian Petroleum Act and the Norwegian Petroleum Taxation Act.

Norway is not a member of the European Union (EU), but Norway is a member of the European Free Trade Association (EFTA). The EU and the EFTA Member States have entered into the Agreement on the European Economic Area, referred to as the EEA Agreement, which provides for the inclusion of EU legislation covering the four freedoms - the free movement of goods, services, persons and capital - in the national law of the EFTA Member States (except Switzerland). An increasing volume of regulations affecting Statoil is adopted in the EU and then applied to Norway under the EEA Agreement. As a Norwegian company operating within both EFTA and the EU, Statoil's business activities are subject to both the EFTA Convention governing intra-EFTA trade and EU laws and regulations adopted pursuant to the EEA Agreement.

For further information about the jurisdictions in which Statoil operates, see sections 3 *Business overview and* 5 *Risk review.*

Under the Petroleum Act, the Norwegian Ministry of Petroleum and Energy is responsible for resource management and for administering petroleum activities on the NCS. The main task of the Ministry of Petroleum and Energy is to ensure that petroleum activities are conducted in accordance with the applicable legislation, the policies adopted by the Norwegian Parliament (the Storting) and relevant decisions of the Norwegian State.

The Storting's role in relation to major policy issues in the petroleum sector can affect Statoil in two ways: firstly, when the Norwegian State acts in its capacity as majority owner of Statoil shares and, secondly, when the Norwegian State acts in its capacity as regulator:

- The Norwegian State's shareholding in Statoil is managed by the Ministry of Petroleum and Energy. The Ministry of Petroleum and Energy will normally decide how the Norwegian State will vote on proposals submitted to general meetings of the shareholders. However, in certain exceptional cases, it may be necessary for the Norwegian State to seek approval from the Storting before voting on a certain proposal. This will normally be the case if Statoil issues additional shares and such issuance would significantly dilute the Norwegian State's holding, or if such issuance would require a capital contribution from the Norwegian State in excess of government mandates. A decision by the Norwegian State to vote against a proposal on Statoil's part to issue additional shares would prevent Statoil from raising additional capital in this manner and could adversely affect Statoil's ability to pursue business opportunities. For more information about the Norwegian State's ownership, see sections 5.1.3 *Risks related to state ownership* and 6.8 *Major shareholders*

- The Norwegian State exercises important regulatory powers over Statoil, as well as over other companies and corporations on the NCS. As part of its business, Statoil or the partnerships to which Statoil is a party, frequently need to apply for licences and other approval of various kinds from the Norwegian State. In respect of certain important applications, such as for the approval of major plans for the operation and development of fields, the Ministry of Petroleum and Energy must obtain the consent of the Storting before it can approve the relevant partnership's application. This may take additional time and affect the content of the decision. Although Statoil is majority-owned by the Norwegian State, it does not receive preferential treatment with respect to licences granted by or under any other regulatory rules enforced by the Norwegian State

The principal laws governing Statoil's petroleum activities in Norway and on the NCS are the Norwegian Petroleum Act of 29 November 1996 (the "Petroleum Act") and the regulations issued thereunder, and the Norwegian Petroleum Taxation Act of 13 June 1975 (the "Petroleum Taxation Act"). The Petroleum Act sets out the principle that the Norwegian State is the owner of all subsea petroleum on the NCS, that exclusive right to resource management is vested in the Norwegian State and that the Norwegian State alone is authorised to award licences for petroleum activities as well as determine its terms. Licensees are required to submit a plan for development and operation (PDO) to the Ministry of Petroleum and Energy for approval. For fields of a certain size, the Storting has to accept the PDO before it is formally approved by the Ministry of Petroleum and Energy. Statoil is dependent on the Norwegian State for approval of its NCS exploration and development projects and its applications for production rates for individual fields.

Production licences are the most important type of licence awarded under the Petroleum Act and are normally awarded for an initial exploration period, which is typically six years, but which can be shorter. The maximum period is ten years. During this exploration period, the licensees must meet a specified work obligation set out in the licence. If the licensees fulfil the obligations set out in the initial license period, they are entitled to require that the licence be prolonged for a period specified at the time when the licence is awarded, typically 30 years.

However, the Ministry of Petroleum and Energy is not entitled to award Statoil a licence in an area until the Storting has decided to open the area in question for exploration. The terms of the production licences are decided by the Ministry of Petroleum and Energy. A production licence grants the holder an exclusive right to explore for and produce petroleum within a specified geographical area. The licensees become the owners of the petroleum produced from the field covered by the licence. Production licences are awarded to group of companies forming a joint venture at the Ministry's discretion. The members of the joint venture are jointly and severally responsible to the Norwegian State for obligations arising from petroleum operations carried out under the licence. The Ministry of Petroleum and Energy decides the form of the joint operating agreements and accounting agreements.

The governing body of the joint venture is the management committee. In licences awarded since 1996 where the state's direct financial interest (SDFI) holds an interest, the Norwegian State, acting through Petoro AS, may veto decisions made by the joint venture management committee, which, in the opinion of the Norwegian State, would not be in compliance with the obligations of the licence with respect to the Norwegian State's exploitation policies or financial interests. This power of veto has never been used.

Interests in production licences may be transferred directly or indirectly subject to the consent of the Ministry of Petroleum and Energy and the approval of the Ministry of Finance of a corresponding tax treatment position. In most licences, there are no pre-emption rights in favour of the other licensees. However, the SDFI, or the Norwegian State, as appropriate, still holds pre-emption rights in all licences.

The day-to-day management of a field is the responsibility of an operator appointed by the Ministry of Petroleum and Energy. The operator is in practice always a member of the joint venture holding the production licence, although this is not legally required. The terms of engagement of the operator are set out in the joint operating agreement. A change of operator requires the consent of the Ministry of Petroleum and Energy. In special cases, the Ministry of Petroleum and Energy can order a change of operator.

Licensees are required to submit a plan for development and operation (PDO) to the Ministry of Petroleum and Energy for approval. For fields of a certain size, the Storting has to accept the PDO before it is formally approved by the Ministry of Petroleum and Energy.

If important public interests are at stake, the Norwegian State may instruct Statoil and other licensees on the NCS to reduce the production of petroleum. The last time the Norwegian State instructed a reduction in oil production was in 2002.

A licence from the Ministry of Petroleum and Energy is also required in order to establish facilities for the transportation and utilisation of petroleum. Ownership of most facilities for the transportation and utilisation of petroleum in Norway and on the NCS is organised in the form of joint ventures. The participants' agreements are similar to the joint operating agreements.

Licensees are required to prepare a decommissioning plan before a production licence or a licence to establish and use facilities for the transportation and utilisation of petroleum expires or is relinquished, or the use of a facility ceases. On the basis of the decommissioning plan, the Ministry of Petroleum and Energy makes a decision as to the disposal of the facilities.

For an overview of Statoil's activities and shares in Statoil's production licences on the NCS, see section 3.5 *Development and Production Norway (DPN).*

3.12.2 Gas sales and transportation from the NCS

Statoil markets gas from the NCS on its own behalf and on the Norwegian State's behalf. Gas is transported through the Gassled pipeline network to customers in the UK and mainland Europe.

Most of Statoil's and the Norwegian State's gas produced on the NCS is sold under gas contracts to customers in the European Union (EU). The EU internal energy market has been high on the European Commission's agenda, and this market has thus been subject to continuous legislative initiatives. Such changes in EU legislation may affect Statoil's marketing of gas.

The Norwegian gas transport system, consisting of the pipelines and terminals through which licensees on the NCS transport their gas, is owned by a joint venture called Gassled. The Norwegian Petroleum Act of 29 November 1996 and the pertaining Petroleum Regulation establish the basis for non-discriminatory third-party access to the Gassled transport system. The ownership structure in Gassled and the pertaining regulations are intended to ensure the effectiveness of the system and to prevent conflicts of interest.

To ensure neutrality, the petroleum regulations also stipulate that all booking and allocation of capacity is administrated by Gassco AS, an independent system operator wholly owned by the Norwegian State. Spare capacity is released and allocated to shippers by Gassco based on standard procedures. Capacity that has already been allocated to a shipper may also be transferred bilaterally between shippers.

The tariffs for the use of capacity in the transport system are determined by applying a formula set out in separate tariff regulations stipulated by the Ministry of Petroleum and Energy. The tariffs are paid on the basis of booked capacity, not on the basis of the volumes actually transported. The Ministry's main objective when setting the tariffs is to ensure that the profits are extracted in the production fields on the NCS and not in the transport system.

For further information see section 3.7.3.3 *Pipelines.*

3.12.3 The Norwegian State's participation

The Norwegian State's policy as a shareholder in Statoil has been and continues to be to ensure that petroleum activities create the highest possible value for the Norwegian State.

Initially, the Norwegian State's participation in petroleum operations was largely organised through Statoil. In 1985, the Norwegian State established the State's direct financial interest (SDFI) through which the Norwegian State has direct participating interests in licences and petroleum facilities on the NCS. As a result, the Norwegian State holds interests in a number of licences and petroleum facilities in which Statoil also hold interests. Petoro AS, a company wholly owned by the Norwegian State, was formed in 2001 to manage the SDFI assets.

3.12.4 SDFI oil and gas marketing and sale

Statoil markets and sells the Norwegian State's oil and gas together with Statoil's own production. The arrangement has been implemented by the Norwegian State.

At an extraordinary general meeting held on 27 February 2001, the Norwegian State, as sole shareholder, revised Statoil's articles of association by adding a new article that requires Statoil to continue to market and sell the Norwegian State's oil and gas together with its own oil and gas. At an extraordinary general meeting held on 25 May 2001, the Norwegian State, as sole shareholder, approved an instruction to Statoil setting out specific terms for the marketing and sale of the Norwegian State's oil and gas. This resolution is referred to as the Owner's instruction.

The Norwegian State has a coordinated ownership strategy aimed at maximising the aggregate value of its ownership interests in Statoil and the Norwegian State's oil and gas. This is reflected in the Owner's instruction. It contains a general requirement that, in Statoil's activities on the NCS, it must take account of these ownership interests in decisions that could affect the execution of this marketing arrangement.

The principal provisions of the Owner's instruction are set out below.

Objectives
The overall objective of the marketing arrangement is to obtain the highest possible total value for Statoil's oil and gas and the Norwegian State's oil and gas, and to ensure an equitable distribution of the total value creation between the Norwegian State and Statoil.

Statoil's tasks
Statoil's main tasks under the Owner's instruction are to market and sell the Norwegian State's oil and gas and to carry out all the necessary related activities, other than those carried out jointly with other licensees under production licences. This includes, but is not limited to, responsibility for processing, transport and marketing.

Costs
The Norwegian State does not pay Statoil a specific consideration for performing these tasks, but reimburses its proportionate share of certain costs, which, under the Owner's instruction, may be Statoil's actual costs or an amount specifically agreed.

Price mechanisms
Payment to the Norwegian State for sales of the Norwegian State's natural gas, both to Statoil and to third parties, is based either on the prices achieved, a net back formula or market value. Statoil purchases all of the Norwegian State's oil and NGL. Pricing of the crude oil is based on market-reflective prices. NGL prices are based on either achieved prices, market value or market-reflective prices.

Lifting mechanism
To ensure neutral weighting between the Norwegian State's and Statoil's own natural gas volumes, a list has been established for deciding the lifting priority between each individual field. The different fields are ranked in accordance with their assumed total value creation for the Norwegian State and Statoil, assuming that all of the fields meet our profitability requirements if we participate as a licensee and the Norwegian State's profitability requirements if the State is a licensee. Within each individual field in which both the Norwegian State and Statoil are licensees, the Norwegian State and Statoil will deliver volumes and share income in proportion to our respective participating interests.

The Norwegian State's oil and NGL is lifted together with our oil and NGL in accordance with applicable lifting procedures for each individual field and terminal.

Withdrawal or amendment
The Norwegian State may at any time utilise its position as majority shareholder of Statoil to withdraw or amend the owner's instruction.

3.12.5 HSE regulation

Statoil's petroleum operations are subject to extensive laws and regulations relating to health, safety and the environment (HSE).

With business operations in more than 30 countries, Statoil is subject to a wide variety of HSE laws and regulations concerning its products, operations and activities. Laws and regulations may be jurisdiction specific, but also international regulations, conventions or treaties, as well as EU directives and regulations, are relevant.

In Norway, under the Norwegian Petroleum Act of 29 November 1996, Statoil's oil and gas operations must be conducted in compliance with a reasonable standard of care, taking into consideration the safety of employees, the environment and the economic values represented by installations and vessels. The Petroleum Act specifically requires that petroleum operations be carried out in such a manner that a high level of safety is maintained and developed in step with technological developments. Statoil is also required at all times to have a plan to deal with emergency situations in our petroleum operations. During an emergency, the Norwegian Ministry of Labour/Norwegian Ministry of Fisheries and Coastal Affairs/Norwegian Coastal Administration may decide that other parties should provide the necessary resources, or otherwise adopt measures to obtain the necessary resources, to deal with the emergency for the licensees' account.

As a result of the Macondo incident, in 2011, the US Department of the Interior created two new agencies to administer operations and activities in the Gulf of Mexico - the Bureau of Safety and Environmental Enforcement (BSEE) and the Bureau of Offshore Energy Management (BOEM). The department also issued new regulations to address the respective roles of the new agencies. Application of these regulations has the potential to affect Statoil's operations in the US. Similarly, the effects from implementing the EU offshore Safety Directive in EU-member states' legislation will affect operations in relevant EU member countries.

See also section 5.1 *Risk factors.*

3.12.6 Taxation of Statoil

Statoil is subject to ordinary Norwegian corporate income tax and to a special petroleum tax relating to its offshore activities in Norway. Internationally, Statoil's activities are mainly subject to tax in the countries where it operates.

Taxation in Norway
Statoil's Norwegian petroleum activities are subject to ordinary corporate income tax and to a special petroleum tax. In addition, there are taxes on both carbon dioxide emissions and emissions of nitrogen oxide (NOx).

Corporate income tax

Statoil's profits, both from offshore oil and natural gas activities and from onshore activities, are subject to Norwegian corporate income tax. The standard corporate income tax rate has been reduced from 27% in 2015 to 25% in 2016. Statoil's profits are computed in accordance with ordinary Norwegian corporate income tax rules, subject to certain modifications that apply to companies engaged in petroleum operations. Gross revenue from oil production is determined on the basis of norm prices. Norm prices are decided on a daily basis by the Petroleum Price Board, and published quarterly. The Petroleum Tax Act states that the norm prices shall correspond to the prices that could have been obtained in a sale of petroleum between independent parties in a free market.

The maximum rate of depreciation of development costs relating to offshore production installations and pipelines is 16.67% per year. Depreciation starts when the cost is incurred. Exploration costs may be deducted in the year in which they are incurred. Financial costs related to the offshore activity are calculated directly based on a formula set out in the Petroleum Tax Act. The financial costs deductible under the offshore tax regime are the total interest costs and exchange gains and losses related to interest-bearing debt multiplied by 50% of the tax values covered by the petroleum tax regime divided by the average interest-bearing debt. All other financial costs and income are allocated to the onshore tax regime.

Abandonment costs incurred can be deducted as operating expenses. Provisions for future abandonment costs are not tax deductible.

Any tax losses can be carried forward indefinitely against subsequent income earned. 50% of losses relating to activity conducted onshore in Norway can be deducted from NCS income subject to the standard income tax rate (reduced from 27% in 2015 to 25% in 2016). Losses on foreign activities cannot be deducted from NCS income.

By using group contributions between Norwegian companies in which Statoil holds more than 90% of the shares and votes, tax losses and taxable income can be offset to a great extent. Group distributions are not deductible from Statoil's NCS income.

Dividends received are subject to tax in Norway. The basis for taxation is 3% of the dividends received, which is subject to the standard income tax rate (reduced from 27% in 2015 to 25% in 2016). Dividends received from Norwegian companies and from similar companies resident in the EEA for tax purposes, in which the recipient holds more than 90% of the shares and votes, are fully exempt from tax. Dividends from companies resident in the EEA that are not similar to Norwegian companies, companies in low-tax countries and portfolio investments outside the EEA will, under certain circumstances, be subject to the standard income tax rate (reduced from 27% in 2015 to 25% in 2016) based on the full amounts received.

Capital gains from the realisation of shares are exempt from tax. Exceptions apply to shares held in companies resident in low-tax countries or portfolio investments in companies resident outside the EEA for tax purposes, where, under certain circumstances, capital gains will be subject to the standard income tax rate (reduced from 27% in 2015 to 25% in 2016) and capital losses will be deductible.

Special petroleum tax

A special petroleum tax is levied on profits from petroleum production and pipeline transportation on the NCS. The special petroleum tax rate has been increased from 51% in 2015 to 53% in 2016. The special petroleum tax rate is applied to relevant income in addition to the standard income tax rate, resulting in a 78% marginal tax rate on income subject to the special petroleum tax. The basis for computing the special petroleum tax is the same as for income subject to ordinary corporate income tax, except that onshore losses are not deductible from the special petroleum tax basis, and a tax-free allowance, or uplift, is granted at a rate of 5.5% per year. The uplift is computed on the basis of the original capitalised cost of offshore production installations. The uplift can be deducted from taxable income for a period of four years, starting in the year in which the capital expenditure is incurred. Unused uplift can be carried forward indefinitely. For further information see note 9 *Income taxes*.

Taxation outside Norway

Statoil's international petroleum activities are subject to tax pursuant to local legislation. Fiscal regulation of Statoil's upstream operations is generally based on corporate income tax regimes and/or production sharing agreements (PSA). Royalties may apply in either case. Statoil is subject to excess (or "windfall") profit tax in some of the countries in which it produces crude oil or condensate.

Production sharing agreements (PSA)

Under a PSA, the host government typically retains the right to the hydrocarbons in place. The contractor normally receives a share of the oil produced to recover its costs, and is also entitled to an agreed share of the oil as profit ("profit oil"). The state's share of profit oil typically increases based on a success factor, such as surpassing certain specified internal rates of return, production rates or accumulated production. The contractor is usually subject to income tax on its own share of the profit oil. Normally, the contractors carry the exploration costs and risk prior to a commercial discovery and are then entitled to recover those costs during the production phase. Fiscal provisions in a PSA are to a large extent negotiable and are unique to each PSA.

Income tax regimes

Under an income tax/royalty regime, companies are granted licences by the government to extract petroleum, and the state may be entitled to royalties, which are generally assessed on gross revenue from production, and a profit tax, which is generally based on the company's net taxable income from production as defined in a country's domestic tax legislation. In some countries, income from petroleum activities is also subject to a special petroleum tax in addition to ordinary corporate tax. In general, the fiscal terms surrounding these licences are non-negotiable and the company is subject to legislative changes in the tax laws.

3.13 Property, plant and equipment

Statoil has interests in real estate in many countries throughout the world. However, no individual property is significant.

Statoil's head office is located at Forusbeen 50, NO-4035, Stavanger, Norway and comprises approximately 135,000 square metres of office space. In June 2015 Statoil closed a sales transaction for the sale of the company's head office building in Stavanger, and at the same time, Statoil entered into a 15 year operating lease agreement for the building. For more information see note 4 *Acquisitions and disposals* to the Consolidated financial statements.

In October 2012, Statoil moved into a new 65,500-square-metre office building located at Fornebu on the outskirts of Norway's capital Oslo. Statoil as tenant has signed a long-term lease agreement with the owner of the office building, IT-Fornebu AS. The new office building provides an environmentally friendly workplace for up to 2,500 employees.

For a description of our significant reserves and sources of oil and natural gas, see note 27 *Supplementary oil and gas information (unaudited)* to the Consolidated financial statements.

3.14 Related party transactions

See note 24 *Related parties* to the Consolidated financial statements for information concerning related parties.

3.15 Insurance

Statoil maintains insurance coverage that includes coverage for physical damage to its oil and gas properties, third-party liability, workers' compensation and employers' liability, general liability, sudden pollution and other coverage.

Statoil's insurance coverage includes deductibles that must be met prior to recovery. Statoil's external insurance is subject to caps, exclusions and limitations, and there is no assurance that such coverage will adequately protect Statoil against liability from all potential consequences and damages.

Our well control policies, which cover costs relating to well control incidents (including pollution and clean-up costs) are subject to the following limits for the two of the areas Statoil operates:

NCS
- NOK 2,500 million plus USD 1,500 million per incident for exploration wells
- NOK 2,000 million per incident for production wells

Gulf of Mexico
- Local well control limit (typically in the area of USD 300 million) plus USD 1,500 million per incident for exploration wells
- Local well control limit (typically in the area of USD 300 million) for production wells

The above limits assume a 100% ownership interest in a given well and would scaled to be equivalent to our percentage ownership interest in a given well. In addition to the well control insurance programmes, we have in place a third-party liability insurance programme with a gross limit of USD 800 million per incident.

3.16 People and the group

3.16.1 Employees in Statoil

The Statoil group employs approximately 21,600 employees. Of these, approximately 19,000 are employed in Norway and approximately 2,600 outside Norway.

	Number of employees			Women		
Permanent employees and percentage of women in the Statoil group	2015	2014	2013	2015	2014	2013
Norway	18,977	19,670	20,336	30%	30%	30%
Rest of Europe	855	909	935	29%	31%	30%
Africa	98	117	140	35%	34%	33%
Asia	97	135	140	36%	52%	53%
North America	1,265	1,375	1,559	35%	34%	35%
South America	289	310	303	38%	40%	38%
TOTAL	21,581	22,516	23,413	30%	31%	31%
Non-OECD	**590**	**677**	**690**	**40%**	**40%**	**39%**

Total workforce by region, employment type and new hires in the Statoil group in 2015

Geographical Region	Permanent employees	Consultants	Total Workforce[1]	Consultants (%)	Part time (%)	New hires
Norway	18,977	424	19,401	2%	3%	103
Rest of Europe	855	99	954	10%	1%	70
Africa	98	5	103	5%	NA	6
Asia	97	5	102	5%	NA	2
North America	1,265	112	1,377	8%	0%	142
South America	289	3	292	1%	0%	8
TOTAL	21,581	648	22,229	3%	3%	331
Non-OECD	590	15	605	2%	na	19

1) Enterprise personnel, defined as third-party service providers who work at our onshore and offshore operations, are not included. These were roughly estimated to be around 30,500 in 2015.

Statoil works systematically with recruitment and development programmes in order to build a diverse workforce by attracting, recruiting and retaining people of both genders and different nationalities and age groups across all types of positions.

In 2015, 19% of employees and 22% of our managerial staff held nationalities other than Norwegian. Outside Norway, Statoil aims to increase the number of people and managers who are locally recruited and to reduce the long-term use of expats in business operations. In 2015, 73% of new hires in Statoil were non-Norwegians and 35% were women.

In Statoil, the total turnover rate for 2015 was 3.6%. On 31 December 2015, the Statoil group employed 21.581 permanent employees and 3% of the workforce worked part-time. In the annual organisational and working environment survey, which continued to have a high response of 85%, our employees reported an overall satisfaction of 4.6. This is a slight increase from the score of 4.5 in 2014.

Our people performance data relates to permanent employees in our direct employment. Statoil defines consultants as contracted personnel that are mainly based in our offices. Temporary employees and enterprise personnel are not included in the workforce table. Enterprise personnel are defined as third party service providers and work on our on-shore and off-shore operations. These were roughly estimated to be around 30,500 in 2015. The information about people policies applies to Statoil ASA and its subsidiaries.

3.16.2 Equal opportunities

We are committed to building a workplace that promotes diversity and inclusion through its people processes and practices.

We promote diversity among our employees. We try to create the same opportunities for everyone and do not tolerate discrimination or harassment of any kind in our workplace. In 2015, we continued to focus on strengthening women in leadership and professional positions and on building broad international experience in our workforce. Our commitment to diversity and inclusion was demonstrated in the 2015 Global People Survey, where we maintained our high score of 5.1 (6 being the highest) for the existence of zero tolerance for discrimination and harassment within the workplace.

In 2015, the overall percentage of women in the company was 30%. The percentage of women in the board of directors is 50% (67% among the employee representatives and 43% among members elected by the shareholders). In the corporate executive committee the female representation has increased from last year's 11% to 18% in 2015. We pay close attention to male-dominated positions and discipline areas, and in 2015 the proportion of female engineers remained stable at 27% in Statoil ASA. Among staff engineers with up to 20 years' experience, the proportion of women increased to 31%. We continue to strive to increase the number of female managers through our development programmes, and in 2015 despite the overall reduction of 181 leadership positions, we increased the share of women in management by 0.5%. The percentage of appointment of women in new leadership positions in 2015 was 36%.

At Statoil we reward our people on the basis of their performance, giving equal emphasis to delivery and behaviour. Our reward approach is adapted to local market conditions at the locations in which we operate and is transparent, non-discriminatory and supports equal opportunities. Given the same position, experience and performance, our employees will be at the same remuneration level relative to the local market. This is demonstrated in the salary ratio between women and men at different levels in Statoil ASA. In 2015 we have maintained a high ratio, with an average of 98%.

The intake of apprentices in Norway is an important part of the company's recruitment of skilled workers and commitment to the education and training of young technicians and operators in the oil and gas industry. In 2015, apprenticeships were given to 130 new students; of these 42 were female. The total number of apprentices in Statoil is 282.

3.16.3 Unions and representatives

Statoil's cooperation with employee representatives and trade unions is based on confidence, trust and continuous dialogue between management and the people in various cooperative bodies.

In Statoil ASA, 70% of the employees in the parent company are members of a trade union. Work councils and working environment committees are established where required by law or agreement. Town hall meetings are also used for information and consultations in accordance with requirements and usage in each country.

In Norway, the formal basis for collaboration with labour unions is established in the Basic Agreements between the Confederation of Norwegian Enterprise (NHO) and the corresponding respective national labour confederations (unions).

Statoil promotes good employee and industrial relations practices through various networks and forums, including IndustriALL Global Union (IndustriAll) and International Labour Organisation (ILO).

In 2015, management and employee representatives collaborated closely, in particular on the three corporate change initiatives Statoil technical efficiency programme (STEP), Organisational efficiency programme (OE) and Corporate Review 2015. In addition, the European Works Council continued to be an important channel between the company and employees.

We collaborate with employee representatives in the change processes, and we strive to find solutions that are satisfactory both for our employees and for the company. To handle redundancies resulting from the ongoing change processes in 2015, we used measures such as internal deployment, severance packages and early retirement.

3.17 Safety, security and sustainability

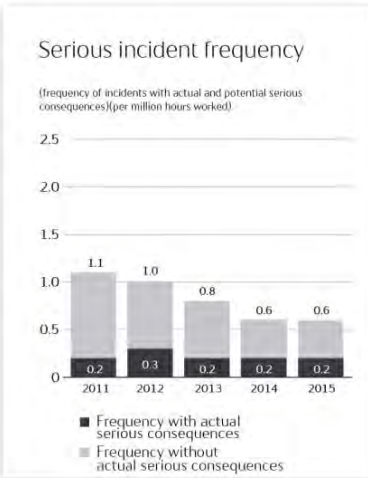
Statoil's ambition is to be an industry leader in safety, security and carbon efficiency.

Safety and security

Statoil's ambition is to ensure safe and secure operations that protect people, the environment, communities and assets. Statoil's approach to safety and security entails preventing accidents and incidents, avoiding oil spills, ensuring a healthy work environment and developing a strong security culture.

Statoil works closely with industry peers on incident prevention and emergency preparedness. Through assurance activities, and by analysing Statoil's own incidents along with those of the industry at large, Statoil aims to ensure a dynamic approach to safety and security performance management. A global oil spill response system has been established, which includes close collaboration with industry peers and national and local communities. Trained response teams and sufficient equipment are ready to be mobilised when and where needed.

Everyone working for Statoil, and in the joint ventures controlled by Statoil, is required to comply with Statoil's safety, health and security standards. Statoil actively engages with contractors and joint ventures to encourage the embedding of a strong safety and security culture in the workforce.



Statoil uses serious incident frequency (SIF) as a key indicator to monitor safety performance. This indicator (number of serious incidents, including near misses, per million hours worked) combines actual consequences of incidents and the potential for incidents to develop into serious or major accidents. The SIF has significantly improved over the last years, from 1.1 incidents per million hours worked in 2011 to 0.6 incidents per million hours worked in 2015.

Total recordable injuries per million hours worked (TRIF) improved from 3.0 in 2014 to 2.7 in 2015. The TRIF for Statoil's employees was 2.3 and the TRIF for Statoil's contractors was 2.8.

Regrettably, there were three fatalities related to Statoil's operations in 2015. One person died and two persons were injured as a result of a breaking wave that hit the drilling rig COSL Innovator on 30 December 2015. Two separate road accidents in the USA resulted in two fatalities.

Accidental oil spills were significantly reduced from 2014 to 2015. The total volume spilt was 23 m^3 in 2015, down from 125 m^3 in 2014.

Preventing oil and gas leakages is important to avoid major accidents. In 2015, the total number of serious leakages (leakages above 0.1kg/sec) increased to 21, up from 13 in 2014. All leakages are undergoing formal investigations and in-depth studies in order to capture learning and prevent similar incidents in the future.

Security is a key issue for the oil and gas industry because it operates in many unstable regions. At Statoil, security risk is systematically assessed on a continuous basis in order to achieve effective and proportionate security risk management. No security incidents with major consequences for Statoil were recorded in 2015. The two-year Security Improvement Programme, established to significantly raise security capabilities and develop a stronger security culture, was finished on schedule in 2015. A road map has been established to further strengthen our security culture and capabilities by 2020.

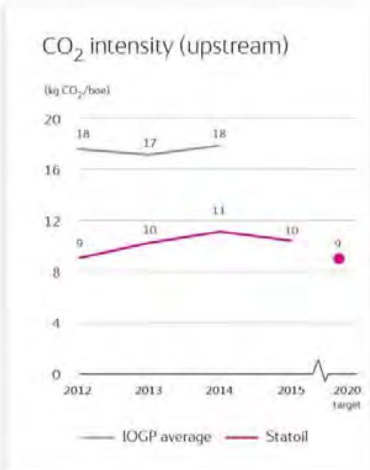
Climate change

Statoil recognises the ambition to limit the average global temperature rise to below two degrees centigrade compared to pre-industrial levels. The Paris agreement on climate change negotiated at the UN Conference of Parties (COP21) in December 2015 provides the prospect of improved policy support around the world for accelerating the shift to low carbon solutions. Statoil welcomes the agreement and believes that the company is well positioned to play its part.

Statoil's approach to climate change entails four key aspects:

- supporting the development of viable global climate policies
- managing climate risks and opportunities
- managing emissions
- developing low carbon energy solutions

Statoil carefully monitors and assesses the potential impact of climate change. Both the corporate executive committee and board of directors frequently discuss the business risks and opportunities associated with climate change, including market, regulatory and physical risk factors. Tools such as internal carbon pricing, scenario planning and stress testing of projects against various oil and gas price assumptions, are used. Statoil regularly assesses how the development of technologies and changes in regulations, including the introduction of stringent climate policies, may impact the oil price, the costs of developing new oil and gas assets, and the demand for oil and gas.



Statoil's efforts to reduce direct greenhouse gas (GHG) emissions includes improving energy efficiency; reducing methane emissions; eliminating routine flaring and scaling up carbon capture and storage.

The production from Statoil-operated assets increased from 997 mmboe in 2014 to 1073 mmboe in 2015[1]. The total direct GHG emissions from Statoil's operated assets remained stable at 16.3 million tonnes CO_2 equivalents in 2015. GHG emissions include carbon dioxide (CO_2) and methane (CH_4), where CO_2 constitutes the largest part (15.4 million tonnes in 2015).

In 2015, Statoil established a 2020 carbon intensity target of 9 kg CO_2/boe for its upstream activities. Statoil's upstream carbon intensity was 10kg CO_2/boe in 2015 – less than 60% of the industry average of 18kg as measured by the International Association of Oil and Gas Producers (Environmental Performance Indicators, 2014 data).

Indirect (scope 2) GHG emissions were 0.3 million tonnes CO_2 equivalents in 2015, using a location based emission factor. Scope 3 GHG emissions (emissions from the use of Statoil's equity production) were estimated to 295 million tonnes CO_2 equivalents.

Statoil's operations in Europe are subject to emissions allowances according to the EU Emissions Trading System (EU ETS). Statoil's Norwegian operations are subject to both the Norwegian offshore CO_2 tax and EU ETS quotas. In 2015, Statoil paid some NOK 4.0 billion in CO_2 tax and quotas.

In 2015, Statoil announced a new business area for New Energy Solutions. Statoil's approach to growth opportunities within renewables and new energy solutions includes both commercial investments and research and development (R&D). Statoil has made investments in offshore wind projects and continues to be engaged in carbon capture and storage. A significant proportion of Statoil's R&D efforts address energy efficiency, carbon capture and renewables. See section 3.8.1 *New Energy Solutions (NES)* for more information.

Environmental impact and resource efficiency

Statoil is committed to using resources efficiently and strives to apply high standards for waste management, emissions to air and impact on ecosystems – in all operations. Statoil's fresh water consumption decreased from 14.8 million cubic metres in 2014 to 14.5 million cubic metres in 2015. Improving water efficiency in the onshore activities in North America through means such as water recycling and substituting fresh water with brackish water, is a priority.

Working with suppliers

Statoil is committed to using suppliers who operate consistently in accordance with Statoil's values and who maintain high standards of safety, security and sustainability. These aspects are incorporated in all phases of the procurement process. All potential suppliers must meet Statoil's minimum requirements in order to qualify as a supplier and these include safety, security and sustainability criteria.

After awarding a contract, a supplier follow-up strategy is established, based on a risk assessment. Statoil's expectations regarding safety, security and sustainability are communicated to the supplier in the contract start-up meeting and throughout the contract period. Assurance activities are conducted, such as follow-up meetings, verifications and audits to manage identified risks. Supply chain personnel are trained in safety, security and sustainability risk handling through classroom courses, e-learning courses and awareness sessions.

Human rights

Statoil seeks to conduct its business in a way that is consistent with the ten UN Guiding Principles on Business and Human Rights (the UN Guiding Principles), the UN Global Compact principles and the Voluntary Principles on Security and Human Rights. Statoil is committed to respecting internationally recognised human rights as laid out in the International Bill of Human Rights, the International Labour Organisation's 1998 Declaration on Fundamental Rights and Principles at Work, and applicable standards of international humanitarian law.

Throughout 2015, a stand-alone human rights policy was developed, to give greater weight to Statoil's long-standing commitment to respect human rights. The policy was based on consultations and workshops with relevant experts and stakeholders. A gap analysis has been initiated to identify how Statoil's human rights processes and practices need to further evolve to reflect the new policy. Human rights aspects are integrated into relevant internal management processes, tools and training. On-going activities, business relationships and new business opportunities are assessed for potential human rights impacts and aspects, following a risk-based approach. In 2015, supplier verification practices were enhanced. Human rights training is provided to employees based on risk and relevance.

[1] Climate and environmental performance data represent total figures from Statoil-operated assets (operational control), except from scope 3 emissions, which are calculated based on Statoil's equity production.

4 Financial review

4.1 Operating and financial review

4.1.1 Sales volumes

Sales volumes include lifted entitlement volumes, the sale of SDFI volumes and marketing of third-party volumes.

In addition to Statoil's own volumes, we market and sell oil and gas owned by the Norwegian State through the Norwegian State's share in production licences. This is known as the State's Direct Financial Interest or SDFI. For additional information, see section 3.12.4 *SDFI oil and gas marketing and sale*. The following table shows the SDFI and Statoil sales volume information on crude oil and natural gas for the periods indicated. The Statoil natural gas sales volumes include equity volumes sold by the MMP segment, natural gas volumes sold by the DPI segment and ethane volumes.

	For the year ended 31 December		
Sales Volumes[1]	2015	2014	2013
Statoil:[2]			
Crude oil (mmbbls)[3]	**378**	353	347
Natural gas (bcf)	**1,645**	1,596	1,622
Combined oil and gas (mmboe)	**671**	637	636
Third party volumes:[4]			
Crude oil (mmbbls)[3]	**290**	304	303
Natural gas (bcf)	**304**	285	434
Combined oil and gas (mmboe)	**344**	355	380
SDFI assets owned by the Norwegian State:[5]			
Crude oil (mmbbls)[3]	**149**	148	155
Natural gas (bcf)[1]	**1,400**	1,254	1,351
Combined oil and gas (mmboe)	**398**	371	396
Total:			
Crude oil (mmbbls)[3]	**816**	805	805
Natural gas (bcf)	**3,348**	3,134	3,407
Combined oil and gas (mmboe)	**1,413**	1,363	1,412

1) The volumes in columns 2014 and 2013 are updated to reflect total sales volumes of crude oil (mmbbls) and natural gas (bcf). Previously only volumes from MMP were disclosed.

2) The Statoil volumes included in the table above are based on the assumption that volumes sold were equal to lifted volumes in the relevant year. Volumes lifted by DPI but not sold by MMP, and volumes lifted by DPN or DPI and still in inventory or in transit may cause these volumes to differ from the sales volumes reported elsewhere in this report by MMP.

3) Sales volumes of crude oil include NGL and condensate. All sales volumes reported in the table above include internal deliveries to our manufacturing facilities.

4) Third party volumes of crude oil include both volumes purchased from partners in our upstream operations and other cargos purchased in the market. The third party volumes are purchased either for sale to third parties or for our own use. Third party volumes of natural gas include third party LNG volumes related to our activities at the Cove Point regasification terminal in the US.

5) The line item SDFI assets owned by the Norwegian State include sales of both equity production and third party gas.

4.1.2 Group profit and loss analysis

Net operating income was down by 86% in 2015, impacted by significantly lower prices and increased net impairment losses.

Operational data	For the year ended 31 December 2015	2014	2013	15-14 change	14-13 change
Prices					
Average Brent oil price (USD/bbl)	**55.3**	98.9	108.7	(44%)	(9%)
Development and Production Norway average liquids price (USD/bbl)	**48.2**	90.6	101.0	(47%)	(10%)
Development and Production International average liquids price (USD/bbl)	**42.9**	85.6	98.4	(50%)	(13%)
Group average liquids price (USD/bbl)	**45.9**	88.6	100.0	(48%)	(11%)
Group average liquids price (NOK/bbl) [1]	**370.7**	558.5	587.8	(34%)	(5%)
Transfer price natural gas (NOK/scm) [9]	**1.58**	1.57	1.92	1%	(18%)
Average invoiced gas prices - Europe (NOK/scm) [8]	**2.16**	2.28	2.45	(5%)	(7%)
Average invoiced gas prices - North America (NOK/scm) [8]	**0.79**	1.04	0.83	(24%)	25%
Refining reference margin (USD/bbl) [2]	**8.0**	4.7	4.1	70%	15%
Entitlement production (mboe per day)					
Development and Production Norway entitlement liquids production	**595**	588	591	1%	(1%)
Development and Production International entitlement liquids production	**436**	383	354	14%	8%
Group entitlement liquids production	**1,032**	971	945	6%	3%
Development and Production Norway entitlement gas production	**637**	595	626	7%	(5%)
Development and Production International entitlement gas production	**144**	163	148	(12%)	10%
Group entitlement gas production	**781**	758	773	3%	(2%)
Total entitlement liquids and gas production [3]	**1,812**	1,729	1,719	5%	1%
Equity production (mboe per day)					
Development and Production Norway equity liquids production	**595**	588	591	1%	(1%)
Development and Production International equity liquids production	**569**	538	524	6%	3%
Group equity liquids production	**1,165**	1,127	1,115	3%	1%
Development and Production Norway equity gas production	**637**	595	626	7%	(5%)
Development and Production International equity gas production	**170**	205	200	(17%)	3%
Group equity gas production	**806**	801	825	1%	(3%)
Total equity liquids and gas production [4]	**1,971**	1,927	1,940	2%	(1%)
Liftings (mboe per day)					
Liquids liftings	**1035**	**967**	**950**	7%	2%
Gas liftings	**802**	**779**	**792**	3%	(2%)
Total liquids and gas liftings	**1837**	**1,746**	**1,742**	5%	0%
Marketing, Midstream and Processing sales volumes					
Crude oil sales volumes (mmbl)	**829**	811	809	2%	0%
Natural gas sales Statoil entitlement (bcm)	**44.0**	43.1	44.3	2%	(3%)
Natural gas sales third-party volumes (bcm)	**8.6**	8.1	12.3	6%	(34%)
Production cost (NOK/boe, last 12 months)					
Production cost entitlement volumes	**52**	55	50	(5%)	10%
Production cost equity volumes	**48**	49	44	(2%)	11%

Total equity liquids and gas production (see section 9 *Terms and definitions)* was 1,971 mboe, 1,927 mboe and 1,940 mboe per day in 2015, 2014 and 2013, respectively.

The 2% increase in total equity production from 2014 to 2015 was primarily due to start-up and ramp-up on various fields, higher gas sales from the NCS and improved operational performance. Expected natural decline and reduced ownership shares as a result of divestments and redeterminations partially offset the increase.

The total equity production in 2014 was slightly lower compared to 2013. Start-up and ramp-up of production on various fields and higher production regularity compared to last year were offset by expected natural decline and reduced ownership shares from divestments.

Total entitlement liquids and gas production was 1,812 mboe per day in 2015 compared to 1,729 mboe in 2014 and 1,719 mboe per day in 2013.

The total entitlement production in 2015 was up 5% for the same reasons as described above. The benefit of lower effect from production sharing agreements (PSA effect) mainly driven by the reduction in prices, added to the increase in entitlement production. From 2013 to 2014 the development in total entitlement production was almost flat for the same reasons as described above and the benefit from lower PSA-effects.

The PSA effect was 116 mboe, 157 mboe and 182 mboe per day in 2015, 2014 and 2013, respectively.

Over time, the volumes lifted and sold will equal our entitlement production, but they may be higher or lower in any period due to differences between the capacity and timing of the vessels lifting our volumes and the actual entitlement production during the period, see section 9 *Terms and definitions* for more information.

Income statement under IFRS (in NOK billion)	For the year ended 31 December 2015	2014 (restated)	2013 (restated)	15-14 change	14-13 change
Revenues	465.3	606.8	616.6	(23%)	(2%)
Net income from equity accounted investments	(0.3)	(0.3)	0.1	2%	>(100%)
Other income	17.8	16.1	17.8	11%	(10%)
Total revenues and other income	482.8	622.7	634.5	(22%)	(2%)
Purchases [net of inventory variation]	(211.2)	(301.3)	(306.9)	(30%)	(2%)
Operating expenses and selling, general and administrative expenses	(91.9)	(80.2)	(81.9)	15%	(2%)
Depreciation, amortisation and net impairment losses	(133.8)	(101.4)	(72.4)	32%	40%
Exploration expenses	(31.0)	(30.3)	(18.0)	2%	69%
Net operating income	14.9	109.5	155.5	(86%)	(30%)
Net financial items	(10.6)	(0.0)	(17.0)	>100%	(100%)
Income before tax	4.3	109.4	138.4	(96%)	(21%)
Income tax	(41.6)	(87.4)	(99.2)	(52%)	(12%)
Net income	(37.3)	22.0	39.2	>(100%)	(44%)

Total revenues and other income amounted to NOK 482.8 billion in 2015 compared to NOK 622.7 billion in 2014 and NOK 634.5 billion in 2013. Revenues are generated from both the sale of lifted crude oil, natural gas and refined products produced and marketed by Statoil, and from the sale of liquids and gas purchased from third parties. In addition, we market and sell the Norwegian State's share of liquids from the NCS. All purchases and sales of the Norwegian State's production of liquids are recorded as Purchases [net of inventory variations] and Revenues, respectively, while sales of the Norwegian State's share of gas from the NCS are recorded net.

The 23% decrease in **revenues** from 2014 to 2015 was mainly due to the significant reduction in both liquids and gas prices measured in NOK. Stronger refinery margins in 2015 and higher volumes of both liquids and gas sold partially offset the decrease.

The 2% decrease in revenues from 2013 to 2014 was mainly due to decreased prices for liquids and European gas and reduced volumes of liquids and gas sold, partly offset increased US gas prices and the exchange rate development (USD/NOK). Also, revenues in 2014 were positively impacted by gains from derivatives, mainly due to a significant drop in the forward curve in the oil market.

Other income was NOK 17.8 billion in 2015 compared to NOK 16.1 billion in 2014 and NOK 17.8 billion in 2013. Other income in 2015 was mainly related to gains from sales of certain ownership interest the Shah Deniz project (NOK 12.4 billion), the Trans Adriatic Pipeline (NOK 1.4 billion) and the Gudrun field (NOK 1.2 billion). Also, gain from sales of office buildings in Norway (NOK 2.1 billion) impacted other income in 2015.

Other income in 2014 consisted of the gain from the sale of certain ownership interests on the NCS to Wintershall (NOK 5.9 billion) and the divestment of working interests in the Shah Deniz Project and South Caucasus Pipeline (NOK 5.4 billion.) In addition, an arbitration settlement (NOK 2.8 billion) following an arbitration ruling in Statoil's favour, impacted other income in 2014. In 2013, other income consisted of gains from sale of certain ownership interests on the NCS to OMV (NOK 10.1 billion) and Wintershall (NOK 6.4 billion).

As a result of the factors explained above, **total revenue and other income** decreased by 22% in 2015. In 2014, the decrease was 2%.

Purchases [net of inventory variation] include the cost of liquids purchased from the Norwegian State, which is pursuant to the Owner's instruction, and the cost of liquids and gas purchased from third parties. See section 3.12.4 *SDFI oil and gas marketing and sale* for more details.

Purchases [net of inventory variation] amounted to NOK 211.2 billion in 2015 compared to 301.3 billion in 2014 and NOK 306.9 billion in 2013. The 30% decrease from 2014 to 2015 was mainly related to the significant lower prices for liquids and gas and other oil products and a write-down of inventories from cost to market value of NOK 3.9 billion, partially offset by the USD/NOK exchange rate development. The 2% decrease from 2013 to 2014 was mainly related to lower prices for liquids and gas including the write-down of inventories from cost-to-market value of NOK 4.0 billion and reduced third-party volumes. These effects were partially offset by the USD/NOK exchange rate development.

Operating expenses and selling, general and administrative expenses amounted to NOK 91.9 billion in 2015 compared to NOK 80.2 billion in 2014, and NOK 81.9 billion in 2013.

The 15% increase from 2014 to 2015 was mainly due to the USD/NOK exchange rate development in 2015 and because a curtailment gain related to the change of pension plan was included in 2014 (discussed below). Lower operation and maintenance costs, lower royalties due to reduced liquids prices, lower transportation costs and portfolio changes in addition to positive effects from on-going cost initiatives, partially offset the increase. Excluding the USD/NOK exchange rate development and the effect of the curtailment gain in 2014, operating expenses and selling, general and administrative expenses decreased by 3%.

The 2% decrease from 2013 to 2014 was mainly due to a curtailment gain of NOK 3.5 billion recognised upon the decision to change the company's pension plan in Norway in 2014 and an onerous contract provision of NOK 4.9 billion related to the Cove Point terminal in the US recognised in 2013. These effects were offset by increased expenses in 2014 mainly due to new fields coming on stream, onshore production ramp-up and increased transportation costs in the North America. In addition, the exchange rate development (NOK/USD) increased the expenses in 2014 compared to 2013.

Depreciation, amortisation and net impairment losses amounted to NOK 133.8 billion in 2015 compared to NOK 101.4 billion in 2014 and NOK 72.4 billion in 2013. Included in these totals were net impairment losses of NOK 47.8 billion, NOK 26.9 billion and NOK 7.0 billion for 2015, 2014 and 2013 respectively, related to the continuously falling commodity prices.

Net impairment losses of NOK 47.8 billion in 2015 were mainly related to unconventional onshore assets in the USA and other conventional assets in the DPI segment (NOK 42.7 billion), conventional offshore assets in the development phase in the DPN segment (NOK 8.7 billion) and a net impairment reversal of NOK 3.5 mainly related to a refinery in the MMP segment. See note 11 *Property, plant and equipment* to the Consolidated financial statements for further details.

Compared to 2014, the 32% increase in 2015 was mainly due to increased impairment charges primarily as a result of the further declining long-term commodity price assumptions in the first quarter of 2015. In addition, the USD/NOK exchange rate development and start-up and ramp-up of production of several fields added to the increase in depreciation. Reduced overall depreciation because of net impairments of assets in both 2014 and 2015 with a corresponding lower basis for depreciation partially offset the increase.

Depreciation, amortisation and net impairment losses increased by 40% in 2014 compared to 2013, mainly due to impairment losses related to Statoil's international operations, primarily driven by reduced short-term oil price forecasts. Also, new investments, higher production and increased asset retirement obligation, with a corresponding higher basis for depreciation, partly offset by increased estimates of proved reserves, added to increased depreciation costs in 2014 compared to 2013.

Exploration expenses (in NOK billion)	For the year ended 31 December 2015	2014	2013	15-14 change	14-13 change
Exploration expenditures (activity)	**23.1**	23.9	21.8	(3%)	10%
Expensed, previously capitalised exploration expenditures	**1.7**	2.4	1.9	(28%)	26%
Capitalised share of current period's exploration activity	**(9.2)**	(7.3)	(6.9)	27%	6%
Impairments, net of reversals	**15.4**	11.3	1.2	36%	>100%
Exploration expenses	**31.0**	30.3	18.0	2%	69%

In 2015, **exploration expenses** were NOK 31.0 billion, a 2% increase compared to 2014 when exploration expenses were NOK 30.3 billion. In 2013, exploration expenses were NOK 18.0 billion

Exploration expenses were up 2% in 2015 mainly due to the USD/NOK exchange rate development and increased impairment of exploration prospects and signature bonuses in 2015. A lower level of drilling activity, a higher capitalisation rate and a lower portion of previously capitalised expenditures being expensed in 2015, partially offset the increase.

The increase in exploration expenses in 2014 compared to 2013 was mainly due to increased impairments of exploration prospects and signature bonuses internationally. Also, the cancellation of a rig contract in 2014 impacted exploration expenses negatively in 2014 compared to 2013.

As a result of the factors explained above, **net operating income** was NOK 14.9 billion in 2015, compared to NOK 109.5 billion in 2014. In 2013, net operating income was NOK 155.5 billion.

Net financial items were negative NOK 10.6 billion in 2015, compared to NOK 0.0 billion in 2014 and negative NOK 17.0 billion in 2013. The decrease in 2015 was mainly related to loss of NOK 3.8 billion on derivatives related to the long term debt portfolio in 2015, compared to a gain of NOK 5.8 billion in 2014, mainly due to changes in the interest yield curves.

In 2014, net financial items improved from negative NOK 17.0 billion in 2013 to NOK 0.0 billion mainly due to a positive change in currency derivatives used for currency and liquidity risk management as a result of changes in underlying currency positions and strengthening of USD towards NOK of 22.2% in 2014 compared to a strengthening of USD towards NOK of 9.3% in 2013. The improvement in 2014 also reflected a positive change on interest rate swap positions related to interest rate management of non-current bonds mainly due to decreased long term USD interest rates by an average of 0.6%-points in 2014 compared to an increase in 2013 by an average of 1.0%-points. These positive changes were partially offset by increased interest and other finance expenses in 2014.

Income taxes were NOK 41.6 billion in 2015, equivalent to an effective tax rate of more than 100%, compared to NOK 87.4 billion, equivalent to an effective tax rate of 79.9% in 2014. In 2013, income taxes were NOK 99.2 billion, equivalent to an effective tax rate of 71.7%.

In 2015, aggregated accounting losses were recognised in countries with higher than average tax rates, hence the "weighted average statutory tax rate" was negative. The **effective tax rate** in 2015 was primarily influenced by losses, mainly caused by impairments recognised in countries where deferred tax assets could not be recognised (NOK 23.5 billion), partially offset by tax exempted gains on sale of assets including Statoil's interest in the Shah Deniz project (NOK 3.7 billion) and the tax effect of foreign exchange losses in entities that are taxable in other currencies than the functional currency (NOK 5.8 billion). These losses are tax deductible, but do not impact the Consolidated statement of income. Furthermore, the effective tax rate in 2015 was influenced by the de-recognition of deferred tax assets within the Development and Production International segment, due to uncertainty related to future taxable income (NOK 4.7 billion), as described in Note 9 *Income taxes* to the Consolidated financial statements.

The effective tax rate in 2014 was primarily influenced by losses, mainly caused by impairments, recognised in countries where deferred tax assets could not be recognised (NOK 12.1 billion), partially offset by tax exempted gains on sale of assets including Norwegian continental shelf (NCS) and Statoil's interest in the Shah Deniz project (NOK 6.2 billion) and the tax effect of foreign exchange losses in entities that are taxable in other currencies than the functional currency (NOK 5.1 billion). These losses are tax deductible, but do not impact the Consolidated statement of income. The effective tax rate in 2014 was also influenced by the recognition of a non-cash tax income (NOK 2.0 billion) following a verdict in the Norwegian Supreme Court in February 2014. The Supreme Court voted in favour of Statoil in a tax dispute regarding the tax treatment of foreign exploration expenditures.

The effective tax rate is calculated as income taxes divided by income before taxes. Fluctuations in the effective tax rates from year to year are principally the result of non-taxable items (permanent differences) and changes in the relative composition of income between Norwegian oil and gas production, taxed at a marginal rate of 78%, and income from other tax jurisdictions. Other Norwegian income, including the onshore portion of net financial items, is taxed at 27% (28% in 2013), and income in other countries is taxed at the applicable income tax rates in those countries.

In 2015, **net income** was negative NOK 37.3 billion compared to positive NOK 22.0 billion in 2014 and NOK 39.2 billion in 2013.

The significant decrease from 2014 to 2015 was mainly due to the drop in prices, leading to lower earnings and impairment losses. Increased losses on net financial items related to derivatives added to the decrease, which was partially offset by the reduction in income taxes.

The 44% decrease in net income from 2013 to 2014 was mainly due to lower prices, resulting in reduced earnings and impairment losses. Increased exploration expenditures added to the decrease, whilst lower income taxes partially offset the decrease.

The board of directors proposes a dividend of USD 0.2201 per share for the fourth quarter 2015 and the introduction of a two-year scrip dividend programme starting from the fourth quarter 2015, subject to approval at the annual general meeting in line with the authorisation from May 2015. The scrip programme will give shareholders the option to receive quarterly dividends in cash or in newly issued shares in Statoil, at a 5% discount for the fourth quarter 2015. The Norwegian Government, as majority shareholder, supports the proposal and will seek the Norwegian Parliament's approval to vote in favour of the proposal at the annual general meeting. The Norwegian government will match subscription of shares by minority shareholders, and thereby maintain its ownership share at 67% throughout the programme. See section 6.1 *Dividend policy* for more information.

Annual ordinary dividends for 2015 amounted to an aggregate total of NOK 23.5 billion. Annual ordinary dividends amounted to an aggregate total of NOK 22.9 billion and NOK 22.3 billion in 2014 and 2013, respectively.

In 2014, following a regular review process of Statoil's 2012 Consolidated financial statements, the Financial Supervisory Authority of Norway (the FSA), concluded that it had identified three errors related to interpretation and application of IFRS accounting principles for determination of cash generating units (CGUs) and impairment evaluations. For two of the matters, Statoil accepted the FSA's interpretations and has applied such interpretations in preparing the Consolidated financial statements. Statoil did not restate prior period financial statements as the impact was immaterial. For the third matter, Statoil does not accept the FSA's conclusion. In accordance with due process for such matters under Norwegian regulation, Statoil has appealed the order to the Norwegian Ministry of Finance, and has been granted a stay in carrying out the FSA's order pending the final outcome of the appeal. See note 23 *Other commitments, contingent liabilities and contingent assets* to the Consolidated financial statements for further details.

With effect from first quarter of 2016, Statoil will change to USD as presentation currency. The change reflects the company`s underlying exposure to the USD as well as better alignment of its reporting to peers.

4.1.3 Segment performance and analysis

Internal transactions in oil and gas volumes occur between our reporting segments before being sold in the market. The pricing policy for internal transfers is based on estimated market prices.

We eliminate intercompany sales when combining the results of reporting segments. Intercompany sales include transactions recorded in connection with our oil and natural gas production in DPN or DPI and also in connection with the sale, transportation or refining of our oil and natural gas production in MMP.

DPN produces oil and natural gas which is sold internally to MMP. A large share of the oil produced by DPI is also sold from MMP. The remaining oil and gas from DPI is sold directly in the market. For intercompany sales and purchases, Statoil has established a market-based transfer pricing methodology for the oil and natural gas that meets the requirements as to applicable laws and regulations.

Effective from the fourth quarter of 2013, revenues generated by the upstream segment in the United States are reported net of royalty interest. This change does not result in a change in net operating income. Historical information has been aligned to the current presentation, reflected in the following tables.

In 2015, the average transfer price for natural gas was NOK 1.58 per scm. The average transfer price was NOK 1.57 per scm in 2014 and NOK 1.92 in 2013. For oil sold from DPN to MMP, the transfer price is the applicable market-reflective price minus a cost recovery rate.

The following table shows certain financial information for the four reporting segments, including intercompany eliminations for each of the years in the three-year period ending 31 December 2015. For additional information please refer to note 3 *Segments* to the Consolidated financial statements.

	For the year ended 31 December		
(in NOK billion)	2015	2014	2013
Development & Production Norway			
Total revenues and other income	**139.5**	182.2	202.2
Net operating income	**57.6**	111.7	137.1
Non-current segment assets[1)]	**244.1**	262.0	247.6
Development & Production International			
Total revenues and other income	**68.4**	85.2	81.9
Net operating income	**(66.9)**	(19.5)	16.4
Non-current segment assets[1)]	**330.1**	333.8	286.5
Marketing, Midstream and Processing			
Total revenues and other income	**467.4**	597.3	608.6
Net operating income	**23.7**	16.2	2.6
Non-current segment assets[1)]	**49.2**	46.3	39.3
Other			
Total revenues and other income	**3.2**	0.3	1.0
Net operating income	**(0.8)**	(1.5)	(1.1)
Non-current segment assets[1)]	**6.1**	5.1	5.6
Eliminations[2)]			
Total revenues and other income	**(195.7)**	(242.3)	(259.1)
Net operating income	**1.2**	2.6	0.4
Non-current segment assets[1)]	-	-	-
Statoil group			
Total revenues and other income	**482.8**	622.7	634.5
Net operating income	**14.9**	109.5	155.5
Non-current segment assets[1)]	**629.5**	647.3	578.9

1) Deferred tax assets, pension assets, equity accounted investments and non-current financial instruments are not allocated to segments.

2) Includes elimination of inter-segment sales and related unrealised profits, mainly from the sale of crude oil and products. Inter-segment revenues are based upon estimated market prices.

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The following tables show total revenues by geographic area.

2015 Total revenues and other income by geographic area (in NOK billion)	Crude oil	Gas	NGL	Refined products	Other	Total sales
Norway	182.4	86.9	39.8	45.4	15.7	370.1
US	29.9	9.1	4.3	12.8	7.7	63.8
Sweden	0.0	0.0	0.0	14.2	1.0	15.2
Denmark	0.0	0.0	0.0	14.1	0.1	14.1
Other	10.8	3.6	0.1	0.0	5.4	19.8
Total revenues (excluding net income (loss) from equity accounted investments) and other income	223.1	99.6	44.2	86.5	29.8	483.1

2014 Total revenues and other income by geographic area (in NOK billion)	Crude oil	Gas	NGL	Refined products	Other	Total sales
Norway	256.2	81.0	55.0	54.4	18.7	465.3
US	49.9	13.8	4.0	14.8	8.6	91.2
Sweden	0.0	0.0	0.0	16.5	1.7	18.2
Denmark	0.0	0.0	0.0	19.1	0.2	19.3
Other	18.6	4.4	0.4	0.0	5.4	28.8
Total revenues (excluding net income (loss) from equity accounted investments and other income	324.6	99.3	59.5	104.8	34.7	622.9

2013 Total revenues and other income by geographic area (in NOK billion)	Crude oil	Gas	NGL	Refined products	Other	Total sales
Norway	238.0	92.7	61.7	69.5	14.0	475.9
US	62.9	13.5	2.5	10.9	4.7	94.5
Sweden	0.0	0.0	0.0	17.2	(0.1)	17.1
Denmark	0.0	0.0	0.0	21.3	0.1	21.4
Other	20.6	4.2	0.3	0.0	0.4	25.5
Total revenues (excluding net income (loss) from equity accounted investments and other income	321.5	110.4	64.5	118.9	19.1	634.4

4.1.4 DPN profit and loss analysis

DPN net operating income was NOK 57.6 billion, down 48% compared to 2014 mainly driven by the drop in liquids prices and increased net impairment charges. Production of liquids and gas was up 3.9%.

The average daily production of liquids and gas (see section 9 *Terms and definitions*) was 1,232 mboe, 1,183 mboe and 1,217 mboe per day in 2015, 2014 and 2013, respectively.

The average daily total production of liquids and gas increased by 4% from 2014 to 2015, mainly due to ramp up of new fields, increased gas sales and good operational performance, partly offset by expected natural decline and divestments.

The average daily production of liquids and gas decreased by 3% from 2013 to 2014. This decrease was mainly due to expected natural decline and divestments, partially offset by new fields in production and higher production regularity in 2014 compared to 2013.

Over time, the volumes lifted and sold will equal entitlement production, but may be higher or lower in any period due to differences between the capacities and timing of the vessels lifting the volumes and the actual entitlement production during the period. See section 9 *Terms and definitions* for more information.

Income statement under IFRS (in NOK billion)	For the year ended 31 December 2015	2014	2013	15-14 change	14-13 change
Revenues	**138.1**	175.3	188.9	(21%)	(7%)
Net income from equity accounted investments	**0.0**	0.1	0.1	(62%)	18%
Other income	**1.4**	6.8	13.2	(79%)	(48%)
Total revenues and other income	**139.5**	182.2	202.2	(23%)	(10%)
Operating expenses and selling, general and administrative expenses	**(25.8)**	(25.2)	(27.4)	3%	(8%)
Depreciation, amortisation and net impairment losses	**(51.4)**	(40.0)	(32.2)	29%	24%
Exploration expenses	**(4.6)**	(5.4)	(5.5)	(14%)	(2%)
Net operating income	**57.6**	111.7	137.1	(48%)	(19%)

Total revenues and other income were NOK 139.5 billion in 2015, NOK 182.2 billion in 2014 and NOK 202.2 billion in 2013.

The 21% decrease in **revenues** from 2014 to 2015 was mainly due to reduced liquids prices. This was partly offset by a positive exchange rate development (NOK/USD), increased lifted volumes and increased gas prices. In addition, in 2015 a re-assessed valuation estimate of earn-out derivatives resulted in an unrealised fair value loss on derivatives and impacted revenues negatively.

The 7% decrease in **revenues** from 2013 to 2014 was mainly due to reduced gas and liquids prices and reduced lifted volumes of both liquids and gas, mainly caused by divestments and expected natural decline. This was partly offset by a positive exchange rate development (NOK/USD). In 2013, a re-assessed valuation estimate of earn-out derivatives resulted in an unrealised fair value loss on derivatives and impacted revenues negatively.

Other income in 2015 was impacted by gains from the sale of certain ownership interest on the NCS to Repsol of NOK 1.2 billion. Other income in 2014 was impacted by gains from the sale of certain ownership interests on the NCS to Wintershall of NOK 5.9 billion. Other income in 2013 was impacted by gains from sale of certain ownership interests on the NCS to OMV and Wintershall (NOK 13.0 billion).

As a result of the factors explained above, **total revenues and other income** decreased by 23% and 10% in 2015 and 2014, respectively.

Operating expenses and selling, general and administrative expenses were NOK 25.8 billion in 2015, compared to NOK 25.2 billion in 2014 and NOK 27.4 billion in 2013. In 2015, expenses increased compared to 2014 mainly due to gain related to changes in pension scheme in 2014 and ramp up of new field during 2015. This was partly offset by cost improvements and reduced turnaround activity level on several fields. In 2014 expenses decreased compared to 2013 mainly due to a gain related to changes in pension scheme and reduced operating costs at several fields due to divestments. This was partly offset by increased environmental tax expenses, operating preparations for new fields coming on stream and new fields commencing production during 2014.

Depreciation, amortisation and net impairment losses were NOK 51.4 billion in 2015, compared to NOK 40.0 billion in 2014 and NOK 32.2 billion in 2013. The increase of 29% from 2014 to 2015 was mainly due to a net impairment loss of NOK 8.6 billion in 2015 (primarily resulting from the reduced oil price forecast), new fields commencing production and ramp-up of new fields in 2015.The increase from 2013 to 2014 was mainly due to increased investments, new fields commencing production, increased asset retirement obligation with a corresponding higher basis for depreciations and an impairment loss. These effects were partly offset by reduced depreciation due to portfolio changes.

Exploration expenses were NOK 4.6 billion in 2015, compared to NOK 5.4 billion in 2014 and NOK 5.5 billion in 2013. The reduction from 2014 to 2015 was mainly due to lower drilling activity, a lower portion of previously capitalised exploration expenditures being expensed in 2015, and idle rig costs in 2014. The reduction from 2013 to 2014 was mainly due to lower drilling activity and less field development work due to sanctioning of Johan Sverdrup, offset by a higher portion of exploration expenditures capitalised in previous periods being expensed in 2014.

Net operating income in 2015 was NOK 57.6 billion, compared to NOK 111.7 billion in 2014 and NOK 137.1 billion in 2013. The NOK 54.0 billion decrease from 2014 to 2015 was mainly due to lower prices on liquids and increased depreciation and net impairment losses. The NOK 25.4 billion decrease from 2013 to 2014 was mainly due to lower prices on liquids and gas and increased depreciation and net impairment losses.

4.1.5 DPI profit and loss analysis

DPI results in 2015 were heavily impacted by lower prices and impairment losses. DPI delivered 6% growth in entitlement production, averaging 580 mboe per day.

The average daily equity liquids and gas production (see section 9 *Terms and definitions*) was 739 mboe in 2015, compared to 744 mboe in 2014 and 723 mboe in 2013. The decrease of 0.7% from 2014 to 2015 was driven primarily by the effect of the divestment of Shah Deniz (Azerbaijan) and a portion of Marcellus (US), and natural decline, primarily at mature fields in Angola. The decrease was partly offset by the ramp-up of fields, mainly CLOV (Angola) and Jack/St. Malo (US).

The increase of 3% from 2013 to 2014 was driven primarily by the ramp-up of fields, including Marcellus (US), CLOV and PSVM (Angola). The increase was partly offset by natural decline, primarily at mature fields in Angola, and the effect of the farm-down of Shah Deniz (Azerbaijan).

The average daily entitlement production of liquids and gas (see section 9 *Terms and definitions*) was 580 mboe per day in 2015, compared to 546 mboe per day in 2014 and 502 mboe per day in 2013. Entitlement production in 2015 was up by 6% due to the benefit of lower effect from production sharing agreements (PSA effect), mainly driven by the decrease in prices. The increase from 2013 to 2014 was driven by increased equity production as described above and a relatively lower PSA effect. The PSA effect was 116 mboe, 157 mboe and 182 mboe per day in 2015, 2014 and 2013, respectively.

Over time, the volumes lifted and sold will equal our entitlement production, but they may be higher or lower in any period due to differences between the capacity and timing of the vessels lifting our volumes and the actual entitlement production during the period. See section 9 *Terms and definitions* for more information.

Income statement under IFRS (in NOK billion)	For the year ended 31 December 2015	2014	2013	15-14 change	14-13 change
Revenues	**57.0**	80.2	78.1	(29%)	3%
Net income from equity accounted investments	**(0.8)**	(0.8)	(0.0)	1%	>100%
Other income	**12.2**	5.8	3.9	>100%	50%
Total revenues and other income	**68.4**	85.2	81.9	(20%)	4%
Purchases [net of inventory]	**(0.1)**	(0.0)	(0.1)	>100%	(85%)
Operating expenses and selling, general and administrative expenses	**(27.3)**	(22.9)	(21.0)	19%	9%
Depreciation, amortisation and net impairment losses	**(81.6)**	(56.8)	(31.9)	44%	78%
Exploration expenses	**(26.3)**	(25.0)	(12.5)	6%	100%
Net operating income	**(66.9)**	(19.5)	16.4	>100%	>(100%)

DPI generated **total revenues and other income** of NOK 68.4 billion in 2015 compared to NOK 85.2 billion in 2014 and NOK 81.9 billion in 2013.

Revenues in 2015 were negatively impacted by lower realised liquids and gas prices, partly offset by a positive currency effect from the NOK/USD development and an increase in lifted volumes. In addition, higher provisions relating to commercial disputes in 2015 compared to 2014 added to the decrease in total revenues. The increase from 2013 to 2014 was mainly caused by an increase in lifted volumes. In addition, lower provisions relating to commercial disputes in 2014 compared to 2013 positively impacted revenues. The increase was partly offset by lower realised liquids and gas prices, partly offset by a positive currency effect from the NOK/USD development.

Other income in 2015 was positively impacted by gains from sales of assets of NOK 12.2 billion in 2015 and NOK 5.8 billion in 2014, related primarily to the sale of ownership interest in the Shah Deniz project and the South Caucasus Pipeline. Other income in 2014 was also positively impacted by increased gains from sales of assets of NOK 2.3 billion.

As a result of the factors explained above, **total revenues and other income** decreased by 20% in 2015. In 2014, total revenues and other income increased by 4%.

Operating expenses and selling, general and administrative expenses were NOK 27.3 billion in 2015, compared to NOK 22.9 billion in 2014 and NOK 21.0 billion in 2013. The 19% increase from 2014 to 2015 was mainly due to the currency effect from the NOK/USD development. Production ramp-up on CLOV in Angola and start-up of the new fields Jack/St Malo in the US in 2014 added to the increase. Reduced operations and maintenance costs, lower royalties caused by lower prices and portfolio changes partially offset the increase. Excluding the USD/NOK exchange rate development, operating expenses and selling, general and administrative expenses decreased by 6%. The 9% increase from 2013 to 2014 was mainly due to higher operating and transportation expenses caused by production growth, primarily in North America. In addition, operating expenses increased due to the start-up of CLOV in 2014.

Depreciation, amortisation and net impairment losses were NOK 81.6 billion in 2015, compared to NOK 56.8 billion in 2014 and NOK 31.9 billion in 2013. The 44% increase from 2014 to 2015 was primarily caused by net impairment losses of NOK 42.7 billion in 2015, mainly related to unconventional onshore assets in North America and certain conventional upstream assets within the DPI reporting segment. The impairment losses resulted primarily from reduced short-term forward prices in combination with reduced long-term oil price forecasts. In addition, depreciation increased due to the NOK/USD development and higher production from start-up and ramp-up on various fields (CLOV, Jack/St Malo). The increases were partly offset by effect from net impairments in 2014 and 2015 and reduced depreciation from higher reserves estimates.

The 78% increase from 2013 to 2014 was mainly due to net impairment losses of NOK 23.8 billion in 2014, mainly related to the Kai Kos Dehseh oil sands project in Canada, unconventional onshore assets in North America and certain conventional upstream assets within the DPI reporting segment. The impairment losses were primarily resulting from reduced short-term oil price forecast. In addition, depreciation increased due to start-up and ramp-up of production from various fields (CLOV, PSVM, Eagle Ford and Bakken). The increases were partly offset by reduced depreciation from increased reserves and divestment of assets.

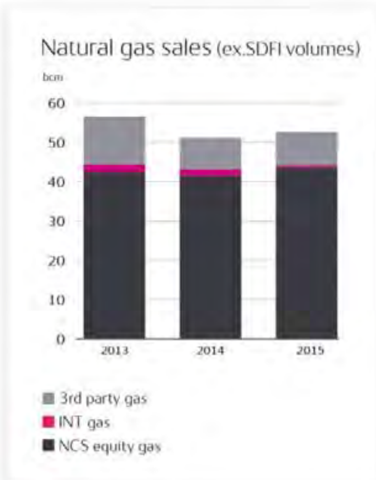
Exploration expenses were NOK 26.3 billion in 2015, compared to NOK 25.0 billion in 2014 and NOK 12.5 billion in 2013. The increase from 2014 to 2015 was mainly due to increased impairments of oil and gas prospects in the Gulf of Mexico, partly offset by a higher portion of exploration expenditure being capitalised in 2015.

Exploration expenses increased by NOK 12.5 billion from 2013 to 2014, primarily due to increased impairments of oil and gas prospects and signature bonuses and write-offs of exploration expenditures, mainly in Angola and the Gulf of Mexico. Also, the cancellation of a rig contract in 2014 impacted exploration expenses negatively in 2014.

Net operating income in 2015 was negative NOK 66.9 billion, compared to negative NOK 19.5 billion in 2014 and positive NOK 16.4 billion in 2013. The negative development from 2014 to 2015 was caused primarily by lower realised liquids and gas prices and impairment losses, and also by higher depreciations and higher operating expenses. The decrease from 2013 to 2014 was caused primarily by impairment losses, and also by lower realised liquids and gas prices, higher depreciations and higher operating expenses.

4.1.6 MMP profit and loss analysis

The 2015 results for MMP have been influenced by improved refining margins, solid liquids trading results and reversal of impairment losses from previous periods. The results were negatively impacted by lower margins for the European gas sales.

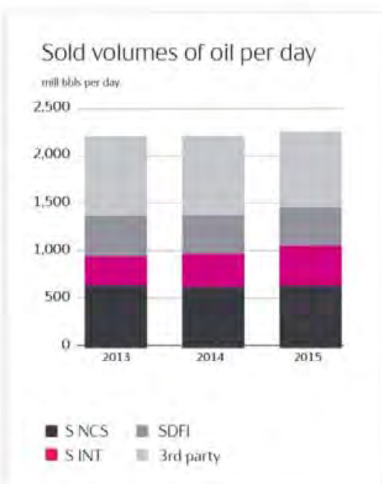


Total natural gas sales volumes were 52.6 bcm in 2015 (1.86 tcf), 51.2 bcm in 2014 (1.80 tcf) and 56.6 bcm (2.00 tcf) in 2013. The 3% increase in total gas volumes sold from 2014 to 2015 was related to higher entitlement production on the NCS in addition to higher third party volumes in Europe, partially offset by lower entitlement production internationally and lower third party volumes in the US. The 9% decrease in gas volumes sold from 2013 to 2014 was mainly related to lower third party volumes primarily in the US, and lower entitlement production on the NCS.

Third party natural gas sales volumes, as presented in the chart do not include volumes sold on behalf of the Norwegian State's direct financial interest (SDFI). MMP sold 37.2, 33.4 bcm and 35.0 bcm of NCS gas on behalf of SDFI in 2015, 2014 and 2013, respectively.

In 2015, the average invoiced natural gas sales price in Europe was NOK 2.16 per scm compared to NOK 2.28 per scm in 2014, a decrease of 5% mainly due to higher share of gas indexation in the gas contract portfolio and effect from drop in oil product prices on oil indexed contracts. LNG has a positive contribution on the European Gas price but less in 2015 as the LNG prices decreased by 23% from 2014 to 2015. The average invoiced natural gas sales price in Europe was approximately 7% lower in 2014 than in 2013, mainly due to general decrease in gas market prices partially offset by improved price premium vs. gas market prices in our gas contract portfolio. In 2015, the average invoiced natural gas sales price in North Americas was NOK 0.80 per scm compared to NOK 1.04 per scm in 2014, a decrease of 23% mainly due to a generally weaker gas market partially offset by USD/NOK exchange rate development. The average invoiced natural gas sales price in North Americas was approximately 25% higher in 2014 than in 2013, mainly due to high market prices in first quarter 2014 as a result of exceptionally cold weather in North East combined with long term pipeline capacity agreements enabling access to premium markets in Toronto and Manhattan.

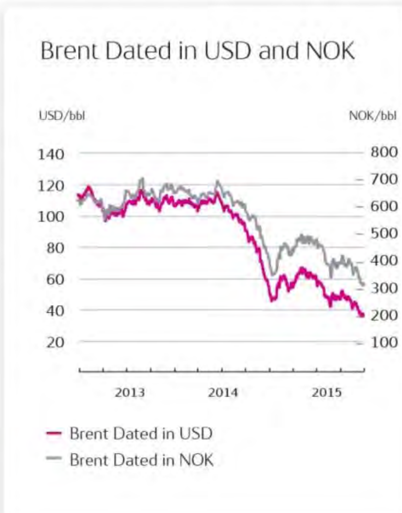
All of Statoil's gas produced on the NCS is sold by MMP, purchased from DPN at a market-based internal price reduced by a cost cover element. Our average internal purchase price for gas was NOK 1.58 per scm in 2015, up 1% from NOK 1.57 per scm in 2014. Reduction in the market-based prices is offset by decreased cost element from 2014 to 2015.



Average crude, condensate and NGL sales were 2.3 mmbbl per day in 2015 of which approximately 1.07 mmbbl were sales of our equity volumes, 0.79 mmbbl sales of third-party volumes and 0.41 mmbbl sales of volumes purchased from SDFI. Our average sales volume was 2.2 mmbbl per day in 2014 and 2013. The average daily third-party volumes sold were 0.83 mmbbl in 2014 and 2013.

MMP's refining margin remained at a high level throughout 2015 reflecting lower crude oil prices and a strong demand for gasoline both in the US and China, while demand in Europe stopped falling. The outlook is that margins will continue to depend on gasoline markets with anticipated further growth in demand in Asia and with limited global capacity additions. Increasing global diesel demand, however, is offset by even higher production capacity. Statoil's refining reference margin was 8.0 USD/bbl in 2015, compared to 4.7 USD/bbl in 2014, an increase of 70%. The refining reference margin was 4.1 USD/bbl in 2013.

Income statement under IFRS (in NOK billion)	For the year ended 31 December 2015	2014 (restated)	2013 (restated)	15-14 change	14-13 change
Revenues	**465.3**	593.0	607.7	(22%)	(2%)
Net income from equity accounted investments	**0.4**	0.5	0.1	(6%)	>100%
Other income	**1.7**	3.8	0.7	(55%)	>100%
Total revenues and other income	**467.4**	597.3	608.6	(22%)	(2%)
Purchases [net of inventory]	**(406.5)**	(544.2)	(565.2)	(25%)	(4%)
Operating expenses and selling, general and administrative expenses	**(37.6)**	(33.2)	(33.7)	13%	(2%)
Depreciation, amortisation and net impairment losses	**0.4**	(3.6)	(7.0)	>(100%)	(48%)
Net operating income	**23.7**	16.2	2.6	47%	>100%



Total revenues and other income were NOK 467.4 billion in 2015, compared to NOK 597.3 billion in 2014 and NOK 608.6 billion in 2013.

The decrease in **revenues** from 2014 to 2015 was mainly due to decrease in crude and gas prices, partially offset by higher volumes for crude, other oil products and gas sold. The average crude price in USD declined by approximately 47% in 2015 compared to 2014, partially offset by weakening USD/NOK average daily exchange rate by approximately 28% in 2015. Revenues in 2015 were positively impacted by gains from derivatives, mainly due to significant drop in the forward curve in the oil and gas market.

The decrease in revenues from 2013 to 2014 was mainly due to decrease in gas and crude prices plus lower volumes of gas sold. The average crude price in USD declined by approximately 9% in 2014 compared to 2013, partially offset by weakening USD/NOK average daily exchange rate by approximately 7% in 2014. Revenues in 2014 were positively impacted by gains from derivatives, mainly due to significant drop in the forward curve in the oil market.

Other income in 2015 was positively impacted by gain on sale of assets of NOK 1.7 billion. In 2014, other income was positively impacted by the Sonatrach Arbitration Settlement of NOK 2.8 billion, following an arbitration ruling in Statoil's favour.

As a result of the factors explained above, **total revenues and other income** decreased by 22% and 2% in 2015 and 2014, respectively.

Purchases [net of inventory] were NOK 406.5 billion in 2015, compared to NOK 544.2 billion in 2014 and NOK 565.2 billion in 2013. The decrease from 2014 to 2015 was mainly due to decrease in crude and gas prices and lower volumes of crude, other oil products and gas sold. The decrease from 2013 to 2014 was mainly due to decrease in gas and crude prices, lower volumes of gas sold and losses on storages due to a significant price reduction.

Operating expenses and selling, general and administrative expenses were NOK 37.6 billion in 2015, compared to NOK 33.2 billion in 2014 and NOK 33.7 billion in 2013. The increase from 2014 to 2015 was mainly due to negative USD/NOK currency effects and onerous contract provisions of NOK 1.6 billion in 2015. This was partially offset by cost reduction due to improvement initiatives. Excluding the USD/NOK exchange rate development, operating expenses and selling, general and administrative expenses were at the same level as last year.

The Cove Point onerous contract provision of NOK 4.1 billion influenced expenses in 2013. Excluding that item, 2014 figures would show an increase in expenses as compared to 2013. The increase was mainly caused by increased activity in the US in addition to negative NOK/USD currency effects.

Depreciation, amortisation and net impairment losses amounted to an income of NOK 0.4 billion in 2015, compared to losses of NOK 3.6 billion in 2014 and NOK 7.0 billion in 2013. The decrease in depreciation, amortisation and net impairment losses from 2014 to 2015 was mainly caused by net reversal of impairment charges of NOK 3.5 billion in 2015. The reversal of impairment was triggered by increased refinery margins and operational improvements. The decrease in depreciation, amortisation and net impairment losses from 2013 to 2014 was mainly as a result of impairment losses of the refineries made in 2013.

Net operating income was NOK 23.7 billion, NOK 16.2 billion, NOK 2.6 billion in 2015, 2014 and 2013, respectively. The increase of NOK 7.5 billion from 2014 to 2015 was mainly due to higher refining margins and solid liquids trading results in addition to negative USD/NOK foreign exchange rate development and net reversal of impairment charges of NOK 3.5 billion, These increases were partially offset by the Sonatrach Arbitration Settlement of NOK 2.8 billion in 2014 in Statoil's favour, and lower margins for the European gas sales.

The increase of NOK 13.6 billion from 2013 to 2014 was mainly due to lower impairment losses in 2014 compared to 2013, the Sonatrach Arbitration Settlement of NOK 2.8 billion in 2014 in Statoil's favour, the onerous contract provision related to Cove Point of NOK 4.1 billion in 2013, and improved margins on gas in Europe including LNG arbitrage and stronger contribution from US gas sales due to an exceptionally cold winter in the North East US.

Further, net operating income increased due to improved refining margins and increased result related to ownership in infrastructure. These increases were partially offset by losses on operational storages in 2014 due to reduced prices.

4.1.7 Other operations

The Other reporting segment includes activities within New Energy Solutions; Global Strategy and Business Development; Technology, Projects and Drilling; and Corporate staffs and support functions.

In 2015, the Other reporting segment recorded a net operating loss of NOK 0.8 billion compared to a net operating loss of NOK 1.5 billion in 2014 and a net operating loss of NOK 1.1 billion in 2013.

4.2 Liquidity and capital resources

We believe that our established liquidity reserves, credit rating and access to capital markets provide us with sufficient working capital for our foreseeable requirements.

4.2.1 Review of cash flows

Statoil`s cash flows in 2015 reflect a high investment level, continued portfolio optimisation and issuance of new debt resulting in a small decrease in cash and cash equivalents and increase in short-term financial investments.

CONSOLIDATED STATEMENT OF CASH FLOWS

(in NOK billion)	Note	2015	2014	Full year 2013
Income before tax		4.3	109.4	138.4
Depreciation, amortisation and net impairment losses	11, 12	133.8	101.4	72.4
Exploration expenditures written off	12	17.1	13.7	3.1
(Gains) losses on foreign currency transactions and balances		(0.4)	(3.1)	4.8
(Gains) losses from dispositions	4	(17.3)	(12.4)	(17.6)
(Increase) decrease in other items related to operating activities		19.8	3.9	6.6
(Increase) decrease in net derivative financial instruments	25	9.2	(2.8)	11.7
Interest received		2.9	2.1	2.1
Interest paid		(3.6)	(3.4)	(2.5)
Cash flows provided by operating activities before taxes paid and working capital items		165.8	208.8	218.8
Taxes paid		(65.7)	(96.6)	(114.2)
(Increase) decrease in working capital		8.9	14.2	(3.3)
Cash flows provided by operating activities		109.0	126.5	101.3
Additions through business combinations	4	(3.5)	0.0	0.0
Capital expenditures and investments		(124.7)	(122.6)	(114.9)
(Increase) decrease in financial investments		(19.8)	(12.7)	(23.2)
(Increase) decrease in other non-current items		(0.3)	0.8	0.6
Proceeds from sale of assets and businesses	4	33.2	22.6	27.1
Cash flows used in investing activities		(115.1)	(112.0)	(110.4)
New finance debt	18	32.2	20.6	62.8
Repayment of finance debt		(11.4)	(9.7)	(7.3)
Dividend paid	17	(22.9)	(33.7)	(21.5)
Net current finance debt and other		(5.5)	(0.3)	(7.3)
Cash flows provided by (used in) financing activities		(7.5)	(23.1)	26.6
Net increase (decrease) in cash and cash equivalents		(13.6)	(8.6)	17.5
Effect of exchange rate changes on cash and cash equivalents		7.1	5.7	2.9
Cash and cash equivalents at the beginning of the period (net of overdraft)	16	82.4	85.3	64.9
Cash and cash equivalents at the end of the period (net of overdraft)	16	75.9	82.4	85.3

Cash flows provided by operations
The most significant drivers of cash flows provided by operations were the level of production and prices for liquids and natural gas that impact revenues, purchases [net of inventory], taxes paid and changes in working capital items.

Cash flows provided by operating activities were NOK 109.0 billion in 2015 compared to NOK 126.5 billion in 2014, which is a decrease of NOK 17.5 billion. Cash flows provided by operating activities before taxes paid and working capital items were reduced by NOK 43.0 billion compared to 2014, driven by a significant reduction in both liquids and gas prices measured in NOK. The decrease was partially offset by positive changes in working capital and lower taxes paid in 2015 compared to 2014.

Cash flows provided by operating activities were NOK 126.5 billion in 2014 compared to NOK 101.3 billion in 2013, an increase of NOK 25.2 billion. Cash flows provided by operating activities before taxes paid and working capital items were reduced by NOK 10.0 billion compared to 2013, driven by decreased profitability mainly caused by lower prices for liquids and European gas. The decrease was more than offset by positive changes in working capital and lower taxes paid in 2014 compared to 2013.

Cash flows used in investing activities
Cash flows used in investing activities were NOK 115.1 billion in 2015 compared to NOK 112.0 billion in 2014, an increase of NOK 3.1 billion mainly due to increased capital expenditures, financial investments and additions through business combinations, partially offset by higher proceeds from sale of assets and businesses. The proceeds from sale of assets in 2015 of NOK 33.2 billion were mainly related to the divestment of the remaining interests in the Shah Deniz field and the South Caucasus pipeline, sale of office buildings, sale of interest in the Marcellus onshore play, sale of interests in Trans Adriatic pipeline AG and the sale of interests in licences on the NCS.

Cash flows used in investing activities were NOK 112.0 billion in 2014 compared to NOK 110.4 billion in 2013, an increase of NOK 1.6 billion mainly due to increased capital expenditures, partly offset by lower investments in deposits with more than three months maturity. The proceeds from sale of assets in 2014 of NOK 22.6 billion were mainly related to the divestment of interests in the Shah Deniz field and the South Caucasus pipeline and the sale of interests in licences on the NCS.

Cash flows provided by (used in) financing activities
Cash flows used in financing activities were NOK 7.5 billion in 2015 and were mainly related to payments of dividends NOK 22.9 and repayments of debt NOK 11.4, partially offset by issuance of new debt of NOK 32.2 billion. Cash flows used in financing activities were NOK 23.1 billion in 2014 and were mainly related to payments of dividends and repayments of debt, partly offset by issuance of new debt in November 2014 of NOK 20.6 billion. The amounts reported in 2013 were influenced by debt issuances of NOK 62.8 billion in total.

4.2.2 Financial assets and debt

Statoil has a strong balance sheet and considerable financial flexibility. The net debt ratio before adjustments was 25.6% at the end of 2015. Net interest-bearing debt before adjustments increased by NOK 32.8 billion in 2015 and was NOK 122.0 billion at the end of 2015.

Financial position and liquidity
Statoil's financial position is strong although its net debt ratio before adjustments at year end increased from 19.0% in 2014 to 25.6% in 2015. Net interest-bearing debt increased from NOK 89.2 billion to NOK 122.0 billion. During 2015 Statoil's total equity decreased from NOK 381.2 billion to NOK 355.1 billion, mainly due to impairments recognised in 2015. Current level of net debt ratio is below levels from previous periods of low prices. Cash flows provided by operating activities were reduced in 2015 mainly due to lower prices and increased cash flows used in investments. Statoil introduced USD as its dividend declaration currency in the second quarter of 2015 announcement and has paid out four quarterly dividends in 2015. For the fourth quarter of 2015 the board of directors will propose to the annual general meeting (AGM) to maintain a dividend of USD 0.2201 per share for the fourth quarter 2015 and to introduce a two-year scrip dividend programme starting from the fourth quarter 2015. For details see section 6.1.1 *Dividends*.

Statoil believes that, given its current liquidity reserves, including committed credit facilities of USD 5.0 billion and its access to various capital markets, Statoil will have sufficient capital available to meet its liquidity needs.

Funding needs arise as a result of Statoil's general business activity. Statoil generally seek to establish financing at the corporate level. Project financing may be used in cases involving joint ventures with other companies. Statoil aims to have access at all times to a variety of funding sources in respect of markets and instruments as well as maintaining relationships with a core group of international banks that provide various kinds of banking services.

Statoil has credit ratings from Moody's and Standard & Poor's (S&P). These ratings ensure necessary predictability when it comes to funding access at attractive terms and conditions. Our current long-term ratings are Aa2 and A+ from Moody's and S&P, respectively. The S&P rating was revised from AA- on credit watch negative to A+ with stable outlook on 22 February 2016. Moody's placed Statoil and its peers on review for downgrade on 22 January 2016. As of the date of this Annual Report on Form 20-F, Moody`s review of Statoil's rating had not yet concluded. Both rating agency reviews have been triggered by low oil prices. The short-term ratings are P-1 from Moody's and A-1 from S&P. In order to maintain financial flexibility going forward, we intend to keep key financial ratios at levels consistent with our objective of maintaining Statoil's long-term credit rating at least within the single A category on a stand-alone basis.

The management of financial assets and liabilities takes into consideration funding sources, the maturity profile of non-current debt, interest rate risk, currency risk and available liquid assets. Statoil's borrowings are denominated in various currencies and normally swapped into USD. In addition, interest rate derivatives, primarily interest rate swaps are used, to manage the interest rate risk of our long-term debt portfolio. The Group's central treasury unit manages the funding and liquidity activities at Group level.

We have diversified our cash investments across a range of financial instruments and counterparties to avoid concentrating risk in any one type of investment or any single country. As of 31 December 2015, approximately 6% of our liquid assets were held in USD-denominated assets, 17% in NOK, 51% in EUR, 7% in DKK, 15% in SEK, and 1% in GBP, before the effect of currency swaps and forward contracts. Approximately 72% of our liquid assets were held in treasury bills and commercial papers, 23% in time deposits, 3% in money market funds and 2% at available bank deposits. As of 31 December 2015, approximately 3% of our liquid assets were classified as restricted cash (including collateral deposits).

Our general policy is to keep a liquidity reserve in the form of cash and cash equivalents or other current financial investments in our balance sheet, as well as committed, unused credit facilities and credit lines in order to ensure that we have sufficient financial resources to meet our short-term requirements.

Long-term funding is raised when we identify a need for such financing based on our business activities, cash flows and required financial flexibility or when market conditions are considered to be favourable. Bond transactions were made in 2015 at very favourable terms, pre-funding longer-term commitments.

The group's borrowing needs are usually covered through the issuing of short-, medium- and long-term securities, including utilisation of a US Commercial Paper Programme (programme limit USD 4.0 billion) and a Shelf Registration Statement (unlimited) filed with the Securities and Exchange Commission (SEC) in the USA as well as through issues under a Euro Medium-Term Note (EMTN) Programme (programme limit updated to EUR 20.0 billion 5 February, 2016) listed on the London Stock Exchange. Committed credit facilities and credit lines may also be utilised. After the effect of currency swaps, the major part of our borrowings is in USD.

During 2015 Statoil issued bonds with maturities from four to 20 years for a total amount of EUR 3.75 billion (NOK 32.1 billion). The bonds were issued in EUR and swapped into USD. All of the bonds are unconditionally guaranteed by Statoil Petroleum AS. For more information see note 18 *Finance debt*.

Statoil issued new debt securities in 2014 equivalent to NOK 20.5 billion and in 2013 equivalent to NOK 62.8 billion.

Financial indicators

Financial indicators (in NOK billion)	For the year ended 31 December 2015	2014	2013
Gross interest-bearing financial liabilities [1]	**284.5**	231.6	182.5
Net interest-bearing liabilities before adjustments	**122.0**	89.2	58.0
Net debt to capital employed ratio [2]	**25.6%**	19.0%	14.0%
Net debt to capital employed ratio adjusted [3]	**26.8%**	20.0%	15.2%
Cash and cash equivalents	**76.0**	83.1	85.3
Current financial investments	**86.5**	59.2	39.2
ROACE [4]	**(8.0%)**	2.7%	11.3%
Ratio of earnings to fixed charges [5]	**1.1**	9.4	7.5

1) Defined as non-current and current finance debt.

2) As calculated according to IFRS. Net debt to capital employed ratio is the net debt divided by capital employed. Net debt is interest-bearing debt less cash and cash equivalents and current financial investments. Capital employed is net debt, shareholders' equity and minority interest.

3) In order to calculate the net debt to capital employed ratio adjusted, Statoil makes adjustments to capital employed as it would be reported under IFRS to adjust for project financing exposure that does not correlate to the underlying exposure and to add into the capital employed measure interest-bearing elements which are classified together with non-interest-bearing elements under IFRS. See section 4.4.2 *Net debt to capital employed ratio* below for a reconciliation of capital employed and a description of why Statoil makes use of this measure.

4) ROACE is equal to net income adjusted for financial items after tax, divided by average capital employed over the last 12 months. See section 4.4.1 *Return on average capital employed (ROACE)* for a reconciliation of ROACE and a description of why Statoil makes use of this measure.

5) Based on IFRS. For the purpose of these ratios, earnings consist of the income before (i) tax, (ii) minority interest, (iii) amortisation of capitalised interest and (iv) fixed charges (which have been adjusted for capitalised interest) and after adjustment for unremitted earnings from equity accounted entities. Fixed charges consist of interest (including capitalised interest) and estimated interest within operating leases.

Gross interest-bearing debt

Gross interest-bearing debt was NOK 284.5, NOK 231.6 billion and NOK 182.5 billion at 31 December 2015, 2014 and 2013, respectively. The NOK 52.9 billion increase from 2014 to 2015 was due to an increase in non-current finance debt of NOK 58.9 billion, offset by a reduction in current finance debt of NOK 6.0 billion. The NOK 49.0 billion increase from 2013 to 2014 was due to an increase in current finance debt of NOK 9.4 billion and an increase in non-current finance debt of NOK 39.6 billion. Our weighted average annual interest rate was 3.39%, 3.78% and 4.06% at 31 December 2015, 2014 and 2013, respectively. Our weighted average maturity on finance debt was nine years at 31 December 2015, compared to nine years at 31 December 2014 and 10 years at 31 December 2013.

Net interest-bearing debt
Net interest-bearing debt before adjustments were NOK 122.0 billion, NOK 89.2 billion and NOK 58.0 billion at 31 December 2015, 2014 and 2013, respectively. The increase of NOK 32.8 billion from 2014 to 2015 was mainly related to an increase in gross interest-bearing debt of NOK 52.9 billion offset in part by an increase in cash and cash equivalents and current financial investments of NOK 20.1 billion mainly due to negative net cash flow in 2015. The increase of NOK 31.2 billion from 2013 to 2014 was mainly related to an increase in gross interest-bearing debt of NOK 49.0 billion offset in part by an increase in cash and cash equivalents and current financial investments of NOK 17.9 billion.

The net debt to capital employed ratio
The net debt to capital employed ratio before adjustments was 25.6%, 19.0% and 14.0% in 2015, 2014 and 2013 respectively.

The net debt to capital employed ratio adjusted (non-GAAP financial measure, see footnote three above) was 26.8%, 20.0% and 15.2% in 2015, 2014, and 2013, respectively. The 6.8 percentage points increase in net debt to capital employed ratio adjusted from 2014 to 2015 was related to the increase in net interest-bearing debt adjusted of NOK 34.4 billion in combination with an increase in capital employed adjusted of NOK 8.3 billion. The 4.8 percentage points increase in net debt to capital employed ratio adjusted from 2013 to 2014 was related to an increase in net interest-bearing debt adjusted of NOK 31.9 billion in combination with an increase in capital employed adjusted of NOK 57.0 billion.

Cash, cash equivalents and current financial investments
Cash and cash equivalents were NOK 76.0 billion, NOK 83.1 billion and NOK 85.3 billion at 31 December 2015, 2014 and 2013 respectively. See note 16 *Cash and cash equivalents* to the Consolidated financial statements for information concerning restricted cash. Current financial investments, which are part of our liquidity management, amounted to NOK 86.5 billion, NOK 59.2 billion and NOK 39.2 billion at 31 December 2015, 2014 and 2013, respectively.

4.2.3 Investments

Organic capital expenditures (excluding acquisitions, capital leases and other investments with significant different cash flow pattern) amounted to USD 14.7 billion, or NOK 118.8 billion, for the year ended 31 December 2015.

Capital expenditures, defined as additions to property, plant and equipment (including capitalised financial leases), capitalised exploration expenditures, intangible assets, long-term share investments and investments in equity accounted companies, amounted to NOK 125.5 billion for the year ended 2015. The capital expenditure level ended below original guidance due to reduced activity level and increased efficiency. This was partly offset by the development in the USDNOK exchange rate.

In 2014, capital expenditures were NOK 125.1 billion compared to NOK 117.4 billion in 2013. The increase was primarily related to higher activity level in Development and Production International.

Organic capital expenditures (excluding acquisitions, capital leases and other investments with significant different cash flow pattern) amounted to NOK 118.8 billion for the year ended 2015, or USD 14.7 billion. In 2014, organic capital expenditures amounted to NOK 121.6 billion, or USD 19.6 billion.

The section describes our estimated organic capital expenditure for 2016 relating to potential capital expenditure requirements for the principal investment opportunities available to us and other capital projects currently under consideration. The figure is based on Statoil developing organically, and it excludes possible expenditures relating to acquisitions. The expenditure estimates and descriptions of investments in the segment descriptions below could therefore differ materially from the actual expenditure. Organic capital expenditures are estimated to be around USD 13 billion in 2016.

Statoil finances its capital expenditures both internally and externally. For more information see section 4.2.2 *Financial assets and debt*.

In Norway a substantial proportion of our 2016 capital expenditures will be spent on ongoing development projects such as Johan Sverdrup, Gina Krog and Aasta Hansteen, in addition to various extensions, modifications and improvements on currently producing fields like Gullfaks, Oseberg and Troll.

Internationally we currently estimate that a substantial proportion of our 2016 capital expenditure will be spent on the following ongoing and planned development projects: Mariner in UK and Julia, Stampede and Bakken in the US.

In midstream and downstream we currently estimate that most of the 2016 capital expenditures will be spent on Polarled and Johan Sverdrup export pipelines, in addition to processing and transportation solutions related to Bakken, Marcellus and Eagle Ford in the US.

As illustrated in the section 4.2.5 *Principal contractual obligations,* Statoil have committed to certain investments in the future. The further into the future, the more flexibility we will have to revise expenditure. This flexibility is partly dependent on the expenditure our partners in joint ventures agree to commit to. A large part of the capital expenditure for 2016 is committed.

Statoil may alter the amount, timing or segmental or project allocation of our capital expenditures in anticipation of or as a result of a number of factors outside our control.

4.2.4 Impact of reduced prices

Our results are affected by the development in the price of raw materials and services that are necessary for the development and operation of oil and gas producing assets.

Cost development in the prices of goods, raw materials and services that are necessary for the development and operation of oil and gas producing assets can vary considerably over time and between each market segment.

The reduction in the oil price has been driving a decrease in commodities prices. Prices in supplier markets have been reduced and in several supplier market segments Statoil has achieved reduced rates compared to the 2013/2014 level. Such savings have been achieved both in new and renegotiated contracts. While some of the cost reductions relates to capitalised expenditures and thus only affects our annual results through decreased depreciation, certain elements of operating expenditures have also been affected by this cost reduction.

See the analysis of profit and loss in section 4.1 *Operating and financial review* as well section 2.3 *Group Outlook*.

4.2.5 Principal contractual obligations

The table summarises our principal contractual obligations and other commercial commitments as of 31 December 2015.

The table includes contractual obligations, but excludes derivatives and other hedging instruments as well as asset retirement obligations, as these obligations for the most part are expected to lead to cash disbursements more than five years in the future. Obligations payable by Statoil to unconsolidated equity affiliates are included gross in the table. Where Statoil includes both an ownership interest and the transport capacity cost for a pipeline in the consolidated accounts, the amounts in the table include the transport commitments that exceed Statoil's ownership share. See section 5.2.3 *Disclosures about market risk* for more information.

Contractual obligations (in NOK billion)	As at 31 December 2015 Payment due by period 1) Less than 1 year	1-3 years	3-5 years	More than 5 years	Total
Undiscounted non-current finance debt	19.0	72.0	81.1	207.5	379.6
Minimum operating lease payments	25.6	28.8	17.6	27.8	99.8
Nominal minimum other long-term commitments 2)	13.5	24.6	23.1	77.9	139.1
Total contractual obligations	58.1	125.4	121.8	313.2	618.5

1) "Less than 1 year" represents 2015; "1-3 years" represents 2016 and 2017, "3-5 years" represents 2018 and 2019, while "More than 5 years" includes amounts for later periods.

2) For further information see note 23 *Other commitments and contingencies* to the Consolidated financial statements.

Non-current finance debt in the table represents principal payment obligations. For information on interest commitments relating to long-term debt, reference is made to note 18 *Finance debt* and note 22 *Leases* to the Consolidated financial statements.

Statoil had contractual commitments of NOK 62.3 billion at 31 December 2015. The contractual commitments reflect Statoil's share and mainly comprise construction and acquisition of property, plant and equipment.

Statoil's projected pension benefit obligation was NOK 60.1 billion, and the fair value of plan assets amounted to NOK 45.2 billion as of 31 December 2015. Company contributions are mainly related to employees in Norway. In 2014 Statoil ASA made a decision to change the company's pension plan in Norway from a defined benefit plan to a defined contribution plan. The actual transitioning to the defined contribution plan took place in 2015, see note 19 *Pensions* to the Consolidated financial statements for more information.

4.2.6 Off balance sheet arrangements

This section describes various agreements that are not recognised in the balance sheet, such as operational leases and transportation and processing capacity contracts.

We have entered into various agreements, such as operational leases and transportation and processing capacity contracts, that are not recognised in the balance sheet. For more information, see section 4.2.5 *Principal contractual obligations* and note 22 *Leases* to the Consolidated financial statements.

Statoil is party to certain guarantees, commitments and contingencies that, pursuant to IFRS, are not necessarily recognised in the balance sheet as liabilities. See note 23 *Other commitments and contingencies* to the Consolidated financial statements for more information.

4.3 Accounting Standards (IFRS)

We prepare our Consolidated financial statements in accordance with International Financial Reporting Standards (IFRS) as adopted by the EU and as issued by the International Accounting Standards Board.

We prepared our first set of Consolidated financial statements pursuant to IFRS for 2007. The IFRS standards have been applied consistently to all periods presented in the Consolidated financial statements and when preparing an opening IFRS balance sheet as of 1 January 2006 (subject to certain exemptions allowed by IFRS 1) for the purpose of the transition to IFRS.

See note 2 *Significant accounting policies* to the Consolidated financial statements for a discussion of key accounting estimates and judgements.

4.4 Non-GAAP measures

This section describes the non-GAAP financial measures that are used in this report.

We are subject to SEC regulations regarding the use of "non-GAAP financial measures" in public disclosures. Non-GAAP financial measures are defined as numerical measures that either exclude or include amounts that are not excluded or included in the comparable measures calculated and presented in accordance with generally accepted accounting principles, which in our case refers to IFRS.

The following financial measures may be considered non-GAAP financial measures:

- Return on average capital employed (ROACE)
- Net debt to capital employed ratio before adjustments
- Net debt to capital employed ratio adjusted
- Organic capital expenditures
- Production cost per boe of entitlement volumes

For information regarding Organic capital expenditures see section 4.2.3 *Investments*.
For information regarding Production cost per barrel of entitlement volumes see note 27 *Supplementary oil and gas information (unaudited)* to the Consolidated financial statements.

4.4.1 Return on average capital employed (ROACE)

We use ROACE to measure the return on capital employed, regardless of whether the financing is through equity or debt.

In the group's view, this measure provides useful information for both the group and investors about performance during the period under evaluation. We make regular use of this measure to evaluate our operations. Our use of ROACE should not be viewed as an alternative to income before financial items, income taxes and minority interest, or to net income, which are measures calculated in accordance with generally accepted accounting principles or ratios based on these figures.

ROACE was negative 8.0% in 2015 compared to 2.7% in 2014 and 11.3% in 2013. The decrease from last year is due to the negative development in net income adjusted for financial items, combined with an increase in average capital employed.

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Calculation of numerator and denominator used in ROACE calculation (in NOK billion, except percentages)	For the year ended 31 December 2015	2014	2013	15-14 change	14-13 change
Net income for the year	(37.3)	22.0	39.2		
-Net financial items	(10.6)	(0.0)			
-Tax on financial items	10.2	9.2			
+Accretion expense net after tax	(1.0)	(1.1)			
+Net financial items adjusted after tax[1]			4.6		
Net income adjusted for financial Items after tax (A1)	(37.9)	11.8	43.9	>(100%)	(73%)
Capital employed before adjustments to net interest-bearing debt: [2]					
Year End 2015	477.1				
Year End 2014	470.4	470.4			
Year End 2013		414.0	414.0		
Year End 2012			359.2		
Sum of capital employed for two years (B1)	947.5	884.4	773.2		
Calculated average capital employed: Average capital employed before adjustments to net interest-bearing debt (B1/2)	473.8	442.2	386.6	7%	14%
Calculated ROACE: Return on average capital employed (A1/(B1/2))	(8.0%)	2.7%	11.3%	>(100%)	(77%)

1) Calculation of financial items is revised for 2015 and 2014 ROACE definition. Net financial items after tax for 2013 includes financial items adjusted of negative NOK 4.6 billion and tax on financial items of NOK 9.2 billion.

2) Capital employed before adjustments for each year is reconciled in the table in the section 4.4.2 *Net debt to capital employed ratio*.

4.4.2 Net debt to capital employed ratio

In the Company's view, the calculated net debt to capital employed ratio gives a more complete picture of the Group's current debt situation than gross interest-bearing financial liabilities.

The calculation uses balance sheet items relating to gross interest bearing financial liabilities and adjusts for cash, cash equivalents and current financial investments. Certain adjustments are made, since different legal entities in the Group lend to projects and others borrow from banks. Project financing through an external bank or similar institution will not be netted in the balance sheet and will over-report the debt stated in the balance sheet in relation to the underlying exposure in the Group. Similarly, certain net interest-bearing debts incurred from activities pursuant to the Owners Instruction from the Norwegian State are set off against receivables on the Norwegian State's direct financial interest (SDFI).

The net interest-bearing debt adjusted for these two items is included in the average capital employed.

The table below reconciles the net interest-bearing liabilities adjusted, capital employed and net debt to capital employed adjusted ratio with the most directly comparable financial measure or measures calculated in accordance with IFRS.

Calculation of capital employed and net debt to capital employed ratio (in NOK billion, except percentages)	2015	For the year ended 31 December 2014	2013
Shareholders' equity	**354.7**	380.8	355.5
Non-controlling interests (Minority interest)	**0.3**	0.4	0.5
Total equity (A)	**355.1**	381.2	356.0
Current bonds, bank loans, commercial papers and collateral liabilities	**20.5**	26.5	17.1
Bonds, bank loans and finance lease liabilities	**264.0**	205.1	165.5
Gross interest-bearing financial liabilities (B)	**284.5**	231.6	182.5
Cash and cash equivalents	**76.0**	83.1	85.3
Current financial investments	**86.5**	59.2	39.2
Cash and cash equivalents and current financial investments (C)	**162.4**	142.3	124.5
Net interest-bearing liabilities before adjustments (B1) (B-C)	**122.0**	89.2	58.0
Other interest-bearing elements [1)]	**9.8**	8.0	7.1
Marketing instruction adjustment [2)]	**(1.9)**	(1.6)	(1.3)
Adjustment for project loan [3)]	**0.0**	(0.1)	(0.2)
Net interest-bearing liabilities adjusted (B2)	**129.9**	95.6	63.6
Calculation of capital employed:			
Capital employed before adjustments to net interest-bearing liabilities (A+B1)	**477.1**	470.4	414.0
Capital employed adjusted (A+B2)	**485.0**	476.7	419.6
Calculated net debt to capital employed:			
Net debt to capital employed before adjustments (B1/(A+B1)	**25.6%**	19.0%	14.0%
Net debt to capital employed adjusted (B2/(A+B2)	**26.8%**	20.0%	15.2%

1) Other interest-bearing elements are cash and cash equivalents adjustments regarding collateral deposits classified as cash and cash equivalents in the Consolidated balance sheet but considered as non-cash in the non-GAAP calculations as well as financial investments in Statoil Forsikring AS classified as current financial investments.

2) Marketing instruction adjustment is an adjustment to gross interest bearing financial debt due to the SDFI part of the financial lease in the Snøhvit vessels that are included in Statoil's Consolidated balance sheet.

3) Adjustment for project loan is adjustment to gross interest-bearing debt due to the BTC project loan structure.

5 Risk review

Statoil's overall risk management includes identifying, evaluating and managing risk in all its activities to ensure safe operations and to achieve Statoil's corporate goals.

5.1 Risk factors

Statoil is exposed to a number of risks that could affect its operational and financial performance. In this section, some of the key risk factors are addressed.

5.1.1 Risks related to our business

This section describes the most significant potential risks relating to Statoil's business:

A prolonged period of low oil and/or natural gas prices would have a material adverse effect on Statoil.
The prices of oil and natural gas have fluctuated greatly in response to changes in many factors. Currently, Statoil is in a situation where oil and natural gas prices have declined substantially compared to levels seen over the last few years. There are several reasons for this decline, but fundamental market forces beyond the control of Statoil or other similar market participants have impacted and can continue to impact oil and natural gas prices in the future.

Generally, Statoil does not and will not have control over the factors that affect the prices of oil and natural gas. These factors include:
- economic and political developments in resource-producing regions
- global and regional supply and demand
- the ability of the Organisation of the Petroleum Exporting Countries (Opec) and/or other producing nations to influence global production levels and prices
- prices of alternative fuels that affect the prices realised under Statoil's long-term gas sales contracts
- government regulations and actions; including changes in energy and climate policies
- global economic conditions
- war or other international conflicts
- changes in population growth and consumer preferences
- the price and availability of new technology and
- weather conditions

It is impossible to predict future price movements for oil and/or natural gas with certainty. A prolonged period of low oil and natural gas prices will adversely affect Statoil's business, the results of operations, financial condition, liquidity and Statoil's ability to finance planned capital expenditure, including possible reductions in capital expenditures which could lead to reduced reserve replacement. In addition to the adverse effect on revenues, margins and profitability from any fall in oil and natural gas prices, a prolonged period of low prices or other indicators could, if deemed to have longer term impact, lead to further reviews for impairment of the group's oil and natural gas properties. Such reviews would reflect the management's view of long-term oil and natural gas prices and could result in a charge for impairment that could have a significant effect on the results of Statoil's operations in the period in which it occurs. Changes in management's view on long-term oil and/or natural gas prices or further material reductions in oil, gas and/or product prices could have an adverse impact on the economic viability of projects that are planned or in development.

Statoil's crude oil and natural gas reserves are only estimates and Statoil's future production, revenues and expenditures with respect to its reserves may differ materially from these estimates.
The reliability of proved reserve estimates depends on:
- the quality and quantity of Statoil's geological, technical and economic data
- the production performance of Statoil's reservoirs
- extensive engineering judgments and
- whether the prevailing tax rules and other government regulations, contracts and oil, gas and other prices will remain the same as on the date estimates are made

Proved reserves are calculated based on the U.S. Securities and Exchange Commission (SEC) requirements and may therefore differ substantially from Statoil's view on expected reserves.

Many of the factors, assumptions and variables involved in estimating reserves are beyond Statoil's control and may prove to be incorrect over time. The results of drilling, testing and production after the date of the estimates may require substantial upward or downward revisions in Statoil's reserve data. The prices used for proved reserves are defined by the SEC and are calculated based on a 12 month un-weighted arithmetic average of the first-day-of-the-month price for each month during the reporting year, leading to a forward price strongly linked to last year's price environment. Fluctuations in oil and gas prices will have a direct impact on Statoil's proved reserves. For fields governed by production sharing agreements (PSAs), a lower price may lead to higher entitlement to the production and increased reserves for those fields. Adversely, a lower price environment may also lead to lower activity resulting in reduced reserves. For PSAs these two effects may to some degree offset each other. In addition a low price environment may result in earlier shutdown due to uneconomic production. This will affect both PSAs and fields with concession types of agreement.

Exploratory drilling involves numerous risks, including the risk that Statoil will encounter no commercially productive oil or natural gas reservoirs. This could materially adversely affect Statoil's results. Statoil's exploration activities include accessing new acreage and maturing resources through high risk exploration drilling activities. These risks include risks associated with the execution of drilling and seismic operations and those associated with maturing unproven resources.

New acreage is primarily acquired through concessions, bidding rounds and acquisitions. Geological interpretations and successful exploration drilling and appraisal work leads to maturing and commercially attractive resources. Additionally, Statoil also needs to be focused on optimising its rig capacity by thoughtful deployment and redeployment. Given these risks and operational requirements, Statoil may not effectively acquire acreage, successfully conduct its drilling and appraisal work or optimise its rig capacity, which could result in a material adverse effect on the results of its operations and financial condition. Exploration activities involve the risk of accidents and environmental incidents. Exploration activities also involve technical challenges related to operating in harsh environments as well as technologically demanding subsurface/geological challenges which Statoil may not effectively manage.

If Statoil fails to acquire or discover and develop additional reserves, its reserves and production will decline materially from their current levels. Successful implementation of Statoil's group strategy for value growth is critically dependent on sustaining its long-term reserve replacement. If upstream resources are not progressed to proved reserves in a timely manner, Statoil's reserve base and thereby future production will gradually decline and future revenue will be reduced.

Statoil's future production is highly dependent on its success in acquiring or finding and developing additional reserves adding value. If unsuccessful, future total proved reserves and production will decline.

If the low price environment continues for a substantial time, this may result in undeveloped acreage not being considered economically viable and consequently discovered resources not being matured to reserves. This may also lead to exploration areas not being explored for new resources and subsequently not being matured for development resulting in less future proved reserves. Successful implementation of Statoil's improvement initiatives may partly offset this effect to some degree making new exploration areas and undeveloped acreage more economically attractive for exploration and development.

In a number of resource-rich countries, national oil companies control a significant proportion of oil and gas reserves that remain to be developed. To the extent that national oil companies choose to develop their oil and gas resources without the participation of international oil companies, or if Statoil is unable to develop partnerships with national oil companies, its ability to find and acquire or develop additional reserves will be more limited.

Statoil is exposed to a wide range of health, safety and environmental risks that could result in significant losses.
Exploration for, and the development, production, processing and transportation of oil and natural gas can be hazardous and technical integrity failures, operational failures, natural disasters or other occurrences can result in: loss of life, oil spills, gas leaks, loss of containment of hazardous materials, water contamination, blowouts, cratering, fires and equipment failure, among other things.

The risks associated with Statoil's activities are affected by the difficult geographies, climate zones and environmentally sensitive regions in which Statoil operates. All modes of transportation of hydrocarbons - including road, rail, sea or pipeline - are particularly susceptible to a loss of containment of hydrocarbons and other hazardous materials, and, given the high volumes involved, these could represent a significant risk to people and the environment. Offshore operations and transportation are subject to marine perils, including severe storms and other adverse weather conditions and vessel collisions. Onshore operations and transportation are subject to adverse weather conditions and accidents. Both onshore and offshore operations and transportation are subject to interruptions, restrictions or termination by government authorities based on safety, environmental or other considerations.

Policy and regulatory change due to rising climate change concerns, and the physical effects of climate change, could impact Statoil's business.
Statoil expects and is preparing for policy and regulatory changes targeted at reducing greenhouse gas emissions of its upstream operations/activities. Statoil expects greenhouse gas emission costs to increase from current levels beyond 2020 and to have a wider geographical range than today. There is continuing uncertainty over these regulatory and policy developments, including the mechanisms that will be employed, and the level of global co-ordination and hence efficiency and uniformity of measures. This in turn leads to uncertainty over the eventual long-term implications to development project cost or operating cost and constraints. As an example, new technological solutions could be required. This could result in increased cost or longer lead times, or have an impact on investment decisions for future projects. Climate related policy changes may also reduce access to prospective geographical areas in the future and affect the demand for and prices of Statoil's products.

Regulatory changes and other factors may encourage the development of low-carbon energy technologies such as renewable energy which could impact the demand for oil and gas, particularly in specific regions. As an example, development of battery technologies could allow more intermittent renewables to be used in the power sector. This could especially impact Statoil's gas sales, particularly if subsidies of renewable energy in Europe were to increase.

Statoil carefully monitors and assesses the potential impact of climate change. Developments in climate change could have a significant impact on Statoil's financial performance, profitability and outlook, whether directly through changes in taxation and regulation, or indirectly through changes in consumer behaviour.

Statoil has assessed the sensitivity of its project portfolio (equity production and expected production from accessed exploration acreage) against the assumptions regarding commodity and carbon prices in the International Energy Agency's (IEA) Current Policies scenario, the IEA New Policies scenario and the IEA 450 scenario, as laid out in their "World Economic Outlook 2015" report. The assessment demonstrated that the IEA's "450 ppm scenario", which is compatible with a global warming of maximum of two degrees Celsius with more than 50% probability, could have a negative impact of approximately 5% on Statoil's net present value compared to Statoil's internal planning assumptions as of December 2015. This assessment is based on Statoil's and the IEA's assumptions which may not be accurate and which are likely to change over time as new information becomes available. Accordingly, there can be no assurance that the assessment, which is presented in Statoil ASA's 2015 Sustainability report, is a reliable indicator of the actual impact of climate change on Statoil.

It is not possible to predict the exact magnitude of the physical impact of climate change on Statoil's operations. However, effects of climate change could result in less stable weather patterns, which would result in more severe storms and other weather conditions that could interfere with Statoil's operations. Changes in physical climate parameters could impact the costs of Statoil's operations, for example through restrained water availability and prolonged droughts, or through increasing frequency of other extreme weather events.

Statoil is exposed to risks as a result of its hydraulic fracturing usage.
Statoil's US operations use hydraulic fracturing which is subject to a range of applicable federal, state and local laws, including those discussed under the heading "Legal and Regulatory Risks". Fracturing is an important and common practice that is used to stimulate production of crude oil and/or natural gas from dense subsurface rock formations. Statoil's hydraulic fracturing and fluid handling operations are designed and operated to minimise the risk, if any, of subsurface migration of hydraulic fracturing fluids and spillage or mishandling of hydraulic fracturing fluids, however, a proven case of subsurface migration of hydraulic fracturing fluids or a case of spillage or mishandling of hydraulic fracturing fluids during these activities could potentially subject Statoil to civil and/or criminal liability and the possibility of substantial costs, including environmental remediation, depending on the circumstances of the underground migration, spillage, or mishandling, the nature and scope of the underground migration, spillage, or mishandling, and the applicable laws and regulations.

In addition, various states and local governments have implemented, or are considering, increased regulatory oversight of hydraulic fracturing through additional permit requirements, operational restrictions, disclosure requirements and temporary or permanent bans. New or further changes in laws and regulations imposing reporting obligations on, or otherwise banning or limiting, the hydraulic fracturing process could make it more difficult to complete oil and natural gas wells in shale formations, cause operational delays, increase costs of regulatory compliance or in exploration and production, which could adversely affect Statoil's US onshore business and the demand for fracturing services.

Statoil is exposed to security threats that could have a materially adverse effect on Statoil's results of operations and financial condition.
Although Statoil has security barriers, policies and risk management processes in places which are designed to protect its assets against a range of security threats, no assurances can be made that such attacks will not occur and adversely impact its operations. Security threats such as acts of terrorism and cyber-attacks against Statoil's production and exploration facilities, offices, pipelines, means of transportation or computer systems or breaches of Statoil's security system, could result in significant losses. Failure to manage the foregoing risks could result in injury or loss of life, damage to the environment, damage to or the destruction of wells and production facilities, pipelines and other property. Statoil could face, among other things, regulatory action, legal liability, damage to its reputation, a significant reduction in revenues, an increase in costs, a shutdown of operations and a loss of its investments in affected areas. Statoil does not purchase cyber risks insurance because the available insurance products do not provide satisfactory coverage.

Statoil's crisis management systems may prove inadequate.
Statoil has crisis management plans and capability to deal with emergencies at every level of its operations. If Statoil does not respond or is perceived not to have responded in an appropriate manner to either an external or internal crisis, its business, operations and reputation could be severely affected. For Statoil's most important activities, it has also developed business continuity plans to carry on or recover operations following a disruption or incident. Inability to restore or replace critical capacity to an agreed level within an agreed time frame could prolong the impact of any disruption and could severely affect Statoil's business and operations.

Statoil encounters competition from other oil and gas companies in all areas of its operations.
Some of Statoil's larger, financially stronger competitors may be able to pay more to gain access to resources, while its smaller competitors may be able to move faster and gain earlier access than Statoil. Gaining access to profitable resources either through the acquisition of licences, exploratory prospects or producing properties is key to ensuring the long-term health and sustainability of the business and Statoil's failure to do so could have an adverse impact on its performance.

Technology is a key competitive advantage in Statoil's industry and a larger company may be able to invest more in developing or acquiring intellectual property rights to technology that Statoil may require. Should Statoil's innovation lag behind the industry, its performance could be impeded.

Statoil's development projects and production activities involve many uncertainties and operating risks that can prevent Statoil from realising profits and cause substantial losses.
Oil and gas projects may be curtailed, delayed or cancelled for many reasons, including equipment shortages or failures, natural hazards, unexpected drilling conditions or reservoir characteristics, irregularities in geological formations, accidents, mechanical and technical difficulties or challenges due to new technology. This is particularly relevant because of the physical environments in which some of Statoil's projects are situated. Many of Statoil's development and production projects are located in deep waters or other harsh environments - such as the Gulf of Mexico in the US, the Flemish Pass in Canada or the Barents Sea in Norway, or have challenging field characteristics such as its heavy oil projects in Brazil (Peregrino), Norway (Grane) and the UK (Mariner). In US onshore, low regional prices may cause certain areas to be unprofitable and the company may curtail production until prices recover. There is therefore a risk that Statoil undertakes development projects that do not yield expected returns, especially in the current environment of decreasing oil and gas prices combined with the relatively high levels of tax and government take in several jurisdictions, including Norway.

Capital expenditures in the oil and gas industry have increased over the last few years due to a high activity level and more complex and capital intensive development projects. This, combined with prolonged low oil and gas prices, could reduce the returns and erode the profitability of some of Statoil's projects and capital programs.

As a response to these challenges, Statoil will need at all times to evaluate profitability and robustness of projects and consider postponing or stopping projects, adjusting strategies and targets or withdrawing from certain geographical areas.

Statoil faces challenges in achieving its strategic objective of successfully exploiting profitable growth opportunities.
An important element of Statoil's strategy is to continue to pursue attractive and profitable growth opportunities available to it by both enhancing and repositioning its asset portfolio and expanding into new markets. The opportunities that Statoil is actively pursuing may involve the acquisition of businesses or properties that complement or expand its existing portfolio. The challenges related to the renewal of Statoil's upstream portfolio is growing due to increasing global competition for access to opportunities.

Statoil's ability to successfully implement this strategy will depend on a variety of factors, including its ability to:

- identify acceptable opportunities
- negotiate favourable terms
- develop new market opportunities or acquire properties or businesses promptly and profitably
- integrate acquired properties or businesses into Statoil's operations
- arrange financing, if necessary and
- comply with legal regulations

As Statoil pursues business opportunities in new and existing markets, it anticipates significant investments and costs in connection with the development of such opportunities. Statoil may incur or assume unanticipated liabilities, losses or costs associated with assets or businesses acquired. Any failure by Statoil to successfully pursue and exploit new business opportunities could result in financial losses and inhibit growth. Any such new projects Statoil acquires will require additional capital expenditure and will increase the cost of its discoveries and development. These projects may also have different risk profiles than Statoil's existing portfolio. These and other effects of such acquisitions could result in Statoil having to revise either or both of Statoil's forecasts with respect to unit production costs and production.

In addition, the pursuit of acquisitions or new business opportunities could divert financial and management resources away from Statoil's day-to-day operations to the integration of acquired operations or properties. Statoil may require additional debt or equity financing to undertake or consummate future acquisitions or projects, and such financing may not be available on terms satisfactory to Statoil, if at all, and it may, in the case of equity, be dilutive to Statoil's earnings per share.

The profitability of Statoil's oil and gas production may be affected by limited transportation infrastructure when a field is in a remote location.
Statoil's ability to exploit economically any discovered petroleum resources beyond its proved reserves will depend, among other factors, on the availability of the infrastructure required to transport oil and gas to potential buyers at a commercially acceptable price. Oil is transported by vessels, rail or pipelines to refineries, and natural gas is usually transported by pipeline or by vessels (for liquid natural gas) to processing plants and end users. Statoil may not be successful in its efforts to secure transportation and markets for all of its potential production.

Statoil is exposed to security threats on its information systems and digital infrastructure that could harm its assets and operations.
Statoil's security barriers protect its information systems and digital infrastructure from being compromised by unauthorised parties. Failure to maintain and develop these barriers may affect the confidentiality, integrity and availability of its information systems and digital infrastructure, including those critical to Statoil's operations. Threats to Statoil's information systems could result in significant financial damage to Statoil. Threats to Statoil's industrial control systems are not limited by geography as Statoil's digital infrastructure is accessible globally, and incidents in the industry in recent years have shown that parties who are able to circumvent barriers aimed at securing industrial control systems are capable and willing to perform attacks that destroy, disrupt or otherwise compromise operations. Such attacks could result in material losses or loss of life with consequent financial implications.

Some of Statoil's international interests are located in regions where political, social and economic instability could adversely impact Statoil's business.
Statoil has assets and operations located in politically, socially and economically diverse regions around the world where potential developments such as expropriation, nationalisation of property, unilateral change of contracts or regulations, civil strife, strikes, political unrest, war, terrorism, border disputes, guerrilla activities, insurrections, piracy and the imposition of international sanctions or other events could occur. Political risks and security threats require continuous monitoring. Adverse and hostile actions against Statoil's staff, its facilities, its transportation systems and its digital infrastructure (cybersecurity) could cause harm to people and disrupt Statoil's operations and further business opportunities in these or other regions, lead to a decline in production and otherwise adversely affect Statoil's business. This could have a materially adverse effect on Statoil's results of operations and its financial condition.

Statoil's operations are subject to dynamic political and legal factors in the countries in which it operates.
Statoil has assets in a number of countries with emerging or transitioning economies that, in part or in whole, lack well-functioning and reliable legal systems, where the enforcement of contractual rights is uncertain or where the governmental and regulatory framework is subject to unexpected change. Statoil's exploration and production activities in these countries are often undertaken together with national oil companies and are subject to a significant degree of state control. In recent years, governments and national oil companies in some regions have begun to exercise greater authority and impose more stringent conditions on companies engaged in exploration and production activities. Intervention by governments in such countries can take a wide variety of forms, including:

- restrictions on exploration, production, imports and exports
- the awarding or denial of exploration and production interests
- the imposition of specific seismic and/or drilling obligations
- price and exchange controls
- tax or royalty increases, including retroactive claims
- nationalisation or expropriation of Statoil's assets
- unilateral cancellation or modification of Statoil's licence or contractual rights
- the renegotiation of contracts
- payment delays and
- currency exchange restrictions or currency devaluation

The likelihood of these occurrences and their overall effect on Statoil vary greatly from country to country and are hard to predict. If such risks materialise, they could cause Statoil to incur material costs and/or cause Statoil's production to decrease, potentially having a materially adverse effect on Statoil's operations or financial condition.

Statoil is exposed to potentially adverse changes in the tax regimes of each jurisdiction in which Statoil operates.
Statoil has business operations in many countries around the world. Changes in the tax laws of the countries in which Statoil operates could have a material adverse effect on its liquidity and results of operations.

Statoil faces foreign exchange risks that could adversely affect the results of Statoil's operations.
Statoil's business faces foreign exchange risks and this is managed with USD as the base currency. Statoil has a large percentage of its revenues and cash receipts denominated in USD and sales of gas and refined products are mainly denominated in EUR and GBP. Further, Statoil pays a large portion of its income taxes, and a share of our operating expenses and capital expenditures, in NOK. The majority of Statoil's long term debt has USD exposure.

Statoil is exposed to risks relating to trading and supply activities.
Statoil is engaged in substantial trading and commercial activities in the physical markets. Statoil also uses financial instruments such as futures, options, over-the-counter (OTC) forward contracts, market swaps and contracts for differences related to crude oil, petroleum products, natural gas and electricity in order to manage price volatility. Statoil also uses financial instruments to manage foreign exchange and interest rate risk. Although Statoil believes it has established appropriate risk management procedures, trading activities involve elements of forecasting, and Statoil bears the risk of market movements, the risk of losses if prices develop contrary to expectations, and the risk of default by counterparties.

Non-compliance with anti-bribery, anti-corruption and other applicable laws, including failure to meet Statoil's ethical requirements, exposes Statoil to legal liability and damage to its reputation, business and shareholder value.
Statoil has activities in countries which present corruption risks and which may have weak legal institutions, lack of control and transparency. In addition, governments play a significant role in the oil and gas sector, through ownership of resources, participation, licensing and local content which leads to a high level of interaction with public officials. Statoil is, through its international activities, subject to anti-corruption and bribery laws in multiple jurisdictions, including the Norwegian Penal code, the US Foreign Corrupt Practices Act and the UK Bribery Act. A violation of any applicable anti-corruption and bribery laws could expose Statoil to investigations from multiple authorities, and any violations of laws may lead to criminal and/or civil liability with substantial fines. Incidents of non-compliance with applicable anti-corruption and bribery laws and regulations and the Statoil Code of Conduct could be damaging to Statoil's reputation, competitiveness and shareholder value.

Statoil's insurance coverage may not provide adequate protection.
Statoil maintains insurance coverage that includes coverage for physical damage to its oil and gas properties, third-party liability, workers' compensation and employers' liability, general liability, sudden pollution and other coverage. Statoil's insurance coverage includes deductibles that must be met prior to recovery. Statoil's external insurance is subject to caps, exclusions and limitations, and there is no assurance that such coverage will adequately protect Statoil against liability from all potential consequences and damages.

Statoil's efficiency change agenda may impact the development of Statoil's business and its financial results.
In 2014, Statoil announced an extensive efficiency change strategy in order to improve efficiency across the organisation in light of the decline in oil and gas prices. Two programmes were launched, the Statoil Technical Efficiency Programme (STEP) and the organisational efficiency programme (OE). There is a risk of Statoil not being able to define and implement the activities related to cost savings without adversely effecting Statoil's business goals or achieving the necessary cost savings and increases in efficiency

Statoil may fail to secure the right level of workforce competence and capacity over the short and medium term
The external uncertainty of the future of the oil industry in light of reduced oil and natural gas prices and climate policy changes, creates a risk in ensuring a robust workforce through industry cycles. The oil industry is a long term business and needs to take a long term perspective on workforce capacity and competence. Given the current extensive change agenda there is a risk that Statoil will fail to secure the right level of workforce competence and capacity.

Statoil's activities in certain countries may be affected by international sanctions.
Statoil, like other major international energy companies, has a geographically diverse portfolio of reserves and operational sites, which may expose its business and financial affairs to political and economic risks, including operations in areas subject to international sanctions or with sanctioned entities.

Russia
Statoil holds a 30% non-operating interest in a production sharing agreement related to the Kharyaga field in the Nenets Autonomous Area in the Russian Federation. The Kharyaga field produces conventional oil from the Timan Pechora basin onshore in North West Russia. Statoil is further engaged in a

strategic cooperation with Rosneft Oil Company (Rosneft) including a joint cooperation project aimed at undertaking seismic surveys and geological exploration, appraisal, development and production of potential hydrocarbons in four licences on the Russian continental shelf - the Magadan 1, Lisyansky and Kashevarovsky licences in the Sea of Okhotsk (south of the Arctic Circle), and the Perseevsky licence in the Barents Sea (north of the Arctic Circle). Additionally there are two joint cooperation projects onshore; pilot drilling and testing of the onshore heavy oil reservoir layer PK1 in the North Komsomolsky discovery, and the Domanik Sediments Difficult-to-Extract Hydrocarbons Project, aimed at pilot drilling and testing of the limestone Domanik formation in the Russian Volga-Urals basin. For each of these projects, Rosneft holds the majority interest, while Statoil holds a minority interest.

Sanctions imposed by Norway, the EU and the USA target, among others, Russia's financial and energy sectors, including certain companies such as Rosneft and various affiliates, and specific activities related to oil exploration and production in the Arctic offshore area, and in deepwater or shale formation projects. Aspects of those measures affect Statoil's business activities in Russia. The continued progress and financing of the joint projects are, in part, dependent on Statoil and the joint ventures securing various governmental authorisations and clarifications from such governmental authorities also going forward. Statoil continues to pursue the above-described projects within the limitations of current sanctions. However, due to current and possible future sanctions, there is no certainty that the projects can be progressed and concluded as initially planned.

Iran
Certain countries, including Iran, have been identified by the US government as state sponsors of terrorism.

Historically, Statoil held interests in the Iranian South Pars offshore phase 6, 7 and 8 gas development project in the Persian Gulf. Statoil was also an owner of a significant interest in the Anaran block and held a 100% interest in the Khorramabad exploration block - both in Iran. Due to the increase of international sanctions against Iran, Statoil in 2009 voluntarily offered officials from the US State Department information about its Iranian business activity. In October 2010 the US State Department announced under the Comprehensive Iran Sanctions, Accountability and Divestment Act of 2010 (CISADA), Statoil to be eligible to avoid retaliatory measures relating to its activities in Iran, due to Statoil's pledge to end its investments in Iran's energy sector.

Following the January 2016 sanctions relief, offered Iran by the US in accordance with the Joint Comprehensive Plan of Action entered into by Iran and the P5+1, secondary US nuclear sanctions on Iran have been scaled back. Despite this, other secondary and primary US sanctions on Iran remain in place. Since 2010, Statoil's activities relating to Iran have consisted of closing its historic projects in an orderly and compliant manner consistent with applicable sanctions. This has also included efforts to settle, to the extent possible, outstanding tax and social security obligations and recovery rights related to the above mentioned projects. Statoil has at regular intervals kept both relevant Norwegian as well as US authorities updated of such continued efforts.

A company found to have violated US sanctions against Iran could become subject to various types of sanctions, including (but not limited to) denial of US bank loans, restrictions on the importation of goods produced by the sanctioned entity, the prohibition on property transactions by the sanctioned entity in which the property is subject to the jurisdiction of the United States and prohibition of transfers of credit or payments via financial institutions in which the sanctioned entity has any interest.

General
The legislation and rules governing sanctions are complex, constantly evolving and may not be consistent across jurisdictions. Changes in any of these laws or policies or the implementation thereof can be unpredictable. Statoil's business is dynamic and the above facts accordingly, may change over time. Moreover, the description does not fully reflect all parts of Statoil's business where a particular focus on sanctions compliance might be warranted. Lastly, it should be understood that Statoil in the future could also decide to take part in additional business activity also involving sanctioned targets in various parts of the world whilst still remaining compliant with applicable sanctions laws. Statoil is committed to doing business in compliance with all applicable laws, however there can be no assurance that Statoil or affiliates of Statoil or their respective officers, directors, employees or agents are not in violation of such laws. Any such violation could result in substantial civil and/or criminal penalties and might materially adversely affect Statoil's business and results of operations or financial condition.

Statoil is also aware of initiatives by certain US states and institutional investors, such as pension funds, to adopt or consider adopting laws, regulations or policies requiring, among other things, divestment from, reporting of interests in, or agreements not to make future investments in, companies that do business with countries that, among other things, are designated as state sponsors of terrorism. These policies could have an adverse impact on investments by certain investors in Statoil's securities.

Disclosure Pursuant to Section 13 (r) of the Exchange Act
The Iran Threat Reduction and Syria Human Rights Act of 2012 ("ITRA") created a new subsection (r) in Section 13 of the Exchange Act which requires a reporting issuer to provide disclosure if the issuer or any of its affiliates engaged in certain enumerated activities relating to Iran, including activities involving the Government of Iran. Statoil is providing the following disclosure pursuant to Section 13(r).

Statoil is a party to agreements with the National Iranian Oil Company (NIOC), namely, a Development Service Contract for South Pars Gas Phases 6, 7 & 8 (offshore part), an Exploration Service Contract for the Anaran Block and an Exploration Service Contract for the Khorramabad Block, which are located in Iran. Statoil's operational obligations under these agreements have terminated and the licenses have been abandoned.

The cost recovery program for these contracts was completed in 2012, except for the recovery of tax and obligations to the Social Security organisation (SSO). Statoil's activity in Iran during 2015 was focused on a final settlement with the Iranian tax authorities and the SSO relating to the above mentioned agreements. During 2015 Statoil paid the equivalent of USD 3.20 million in tax and SSO to Iranian authorities in local currency (Iranian Rials), from which USD 0.04 million has been booked as expenses in 2015 and the rest have been reversed from previous years' accruals. Also during 2015 Statoil paid USD 0.02 million stamp duty to Iran Tax Organisation. The funds utilised for these purposes were held by Statoil in EN Bank (Iran).

During 2015 Statoil also received the equivalent of USD 0.48 million as insurance payment related to its legacy South Pars business. Also this insurance payment has been booked as revenue in 2015.

During 2015 NIOC, on behalf of Statoil, paid a tax obligation of USD 1.6 million equivalent in Iranian Rial to the local tax authorities. The amount was settled towards recoverable costs from NIOC to Statoil. Statoil is not involved in any other activities in Iran.

Since 2009 Statoil has transparently and regularly provided information about its Iran related activity to the US State Department as well as to the Norwegian Ministry of Foreign Affairs. In a letter from the US State Department of 1November 2010, Statoil was informed that the company was not considered to be a company of concern based on its previous Iran-related activities.

Statoil generated no net profit from the aforementioned activity in 2015. Payments of the above mentioned nature are expected to be made also in 2016, in relation to Statoil's continued winding-down efforts.

In addition, Statoil has in the course of 2015 paid four annual patent fees in Iran of in total EUR 347 (appr. USD 420). The payment of these patent fees will be discontinued in 2016.

5.1.2 Legal and regulatory risks

This section discusses potential legal and regulatory risks related to the legal context of our business operations, such as having to comply with new laws and regulations.

Compliance with health, safety and environmental laws and regulations that apply to Statoil's operations could materially increase its costs. The enactment of such laws and regulations in the future is uncertain.

Statoil incurs, and expects to continue to incur, substantial capital, operating, maintenance and remediation costs relating to compliance with increasingly complex laws and regulations for the protection of the environment and human health and safety, including:

- costs as a result of stricter climate regulations and a higher price on greenhouse gas emissions
- costs of preventing, controlling, eliminating or reducing certain types of emissions to air and discharges to the sea, including costs incurred in connection with government action to address the risk of spills and concerns about the impacts of climate change
- remediation of environmental contamination and adverse impacts caused by Statoil's activities or accidents at various facilities owned or previously owned by Statoil and at third-party sites where Statoil's products or waste have been handled or disposed of
- compensation of persons and/or entities claiming damages as a result of Statoil's activities or accidents and
- costs in connection with the decommissioning of drilling platforms and other facilities

For example, under the Norwegian Petroleum Act of 29 November 1996, as a holder of licences on the Norwegian continental shelf (NCS), Statoil is subject to statutory strict liability in respect of losses or damage suffered as a result of pollution caused by spills or discharges of petroleum from petroleum facilities covered by any of Statoil's licences. This means that anyone within the state or the delineation of the NCS who suffers losses or damage as a result of pollution caused by operations in any of Statoil's NCS licence areas can claim compensation from Statoil without having to demonstrate that the damage is due to any fault on Statoil's part.

Furthermore, in countries where Statoil operates or expects to operate in the near future, new laws and regulations, the imposition of stricter requirements on licences, increasingly strict enforcement of or new interpretations of existing laws and regulations, the aftermath of operational catastrophes in which Statoil or members of its industry are involved or the discovery of previously unknown contamination may require future expenditure in order to, among other things:

- modify operations
- install pollution control equipment
- implement additional safety measures
- perform site clean-ups
- curtail or cease certain operations
- temporarily shut down Statoil's facilities
- meet technical requirements
- increase monitoring, training, record-keeping and contingency planning and
- establish credentials in order to be permitted to commence drilling

Compliance with laws, regulations and obligations relating to climate change and other environmental regulations could result in substantial capital expenditure, reduced profitability as a result of changes in operating costs, and adverse effects on revenue generation and strategic growth opportunities. Statoil regularly assesses how changes in regulations, including introduction of stringent climate policies, may impact the oil price, the costs of developing new oil and gas assets, and the demand for oil and gas.

Statoil's operations in Norway are subject to emissions taxes as well as emissions allowances granted for Statoil's larger European operations under the EU Emissions Trading System. The agreed strengthening of the European Union's emission trading scheme may result in a significant reduction in the total emissions from relevant energy and industry installations which includes Statoil's installations at the NCS. The price of the emissions allowances is also expected to increase significantly towards 2030. At the 21st Conference of Parties (COP21) in Paris in December 2015, 195 countries adopted a new universally applicable climate agreement, to be effective from 2020. The Norwegian Parliament decided that Norway should negotiate with the European

Union to develop the terms for a collective delivery of 40% reductions in greenhouse gas emissions by 2030 compared to 1990. Individual countries' climate plans, the so-called 'Intended Nationally Determined Contributions', are to be strengthened every five years. The implications for the industry are not yet clear, however requirements to reduce emissions could imply increased costs.

The EU Fuel Quality Directive 2009/30/EC and its Implementation Directive 2015/652/EU require fuel suppliers to reduce their carbon intensity for transportation fuels by 6% in 2020 compared to the baseline of 2010. Fuel suppliers can use biofuels, low carbon fuels (i.e. natural gas), charging of electric vehicles and upstream emission reductions to achieve the target. Member States may set penalties on fuels suppliers for not achieving the target. The EU Commission will submit a non-legislative guidance document before April 2017 which will propose common principles on verification and accounting of upstream emissions reductions. The regulation could indirectly impact Statoil if it results in incentives for service station companies to increase the share of biofuels on behalf of fossil fuels.

In the US, the Environmental Protection Agency has taken steps to regulate greenhouse gas emissions under the *Clean Air Act* authority by proposing a Clean Power Plan (CPP). The plan aims to reduce emissions from the US power sector by setting performance standards for power plants. The regulation, if approved, could stimulate increased gas demand. In 2015, the EPA also proposed new source performance standards, in addition to those issued in 2012, targeting volatile organic compound emissions, that are intended to further reduce oil and gas methane emissions. This could imply additional costs for oil and gas producers.

Statoil incorporates a cost for carbon in the assessment of all new projects. This guides Statoil's strategy and its investment decisions. For investment decisions pertaining to oil and gas projects in Norway, Statoil includes an internal cost of USD 64 per tonne of CO_2-equivalent (based on the average annual exchange rate in 2015), based on the cost of the Norwegian CO_2 tax. In 2014, Statoil began to apply an internal cost of USD 50 per tonne of CO_2-equivalent in its investment decisions for all new oil and gas projects outside of Norway.

Many of Statoil's mature fields are producing increasing quantities of water with oil and gas. Statoil's ability to dispose of this water in environmentally acceptable ways may have an impact on its oil and gas production. Statoil's investments in North American onshore producing assets will be subject to evolving regulations which are common to all energy companies with investments in this region. This could affect Statoil's operations and profitability with respect to these operations.

If Statoil does not succeed in overcoming the perceived trade-off between global access to energy and the protection or improvement of the natural environment, Statoil could fail to live up to its aspirations of zero or minimal damage to the environment and of contributing to human progress.

Statoil is exposed to risk of supervision, review and sanctions for violations of regulatory laws at the supranational and national level. These include, among others, competition and antitrust laws and financial and trading.
Statoil's products are marketed and traded worldwide and therefore subject to competition and antitrust laws at the supranational and national level in multiple jurisdictions. Statoil is exposed to investigations from competition and antitrust authorities, and violations of the applicable laws and regulations may lead to substantial fines. In December 2015, the European Commission announced that it currently will not pursue its investigation against Statoil and certain other oil and gas producers concerning alleged crude oil price manipulation. The investigation had been on-going since May 2013 when the EFTA Surveillance Authority conducted an unannounced inspection at Statoil's head office in Stavanger, Norway, on behalf of the European Commission. The authorities suspected participation by several companies, including Statoil, in anti-competitive practices and/or market manipulation related to Platts Market-On-Close price assessment process.

Statoil is also exposed to financial review from financial supervisory authorities such as the Norwegian Financial Supervisory Authority (FSA) and the US Securities and Exchange Commission (the SEC). Reviews performed by these authorities could result in changes to previous accounts and future accounting policies. On 10 March 2014, the FSA concluded a review of Statoil's 2012 financial statements. Statoil has accepted two of the FSA's conclusions following this review but has appealed the third to the Norwegian Ministry of Finance.

Statoil is listed on both the Oslo Børs and New York Stock Exchange (NYSE), and is registered with the SEC. Statoil is required to comply with the continuing obligations of these regulatory authorities, and violation of these obligations may result in imposition of fines or other sanctions.

The Norwegian Petroleum Supervisor (Ptil) supervises all aspects of Statoil's operations, from exploration drilling through development and operation, to cessation and removal. Its regulatory authority covers the whole NCS as well as petroleum-related plants on land in Norway. Statoil is exposed to supervision from Ptil, and such supervision could result in audit reports, orders and investigations.

The formation of a competitive internal gas market within the European Union (EU) and the general liberalisation of European gas markets could adversely affect Statoil's business.
The continuing liberalisation of EU gas markets following legislative instruments rolled out in 2011 and the implementation of these legislative instruments by member states, could create new business opportunities for Statoil, but could also affect Statoil's market position or result in a reduction in prices in Statoil's gas sales contracts. Statoil's exposure to hub gas prices has increased and correspondingly increased Statoil's exposure to price volatility. Statoil continually monitors its contractual obligations and makes efforts to negotiate the most competitive pricing and other conditions available in the market.

The EU-wide quantity of carbon allowances issued each year under the Emission Trading Scheme (ETS) for greenhouse gas emission allowances began to decrease in a linear manner in 2013. The ETS can have a positive or negative impact on Statoil, depending on the price of carbon, which will consequently have an impact on the development of gas-fired power generation in the EU. Until now, the carbon price has been too low to replace coal with gas fired generation capacity. This effect has been worsened by heavy subsidising of renewables which has caused gas fired power plants to shut down. Current EU climate and energy policies do not address this problem, but there is a tendency towards more market based subsidies in the new guidelines on environment and energy aid.

Political and economic policies of the Norwegian State could affect Statoil's business.
The Norwegian State plays an active role in the management of NCS hydrocarbon resources. In addition to its direct participation in petroleum activities through the State's direct financial interest (SDFI) and its indirect impact through legislation, such as tax and environmental laws and regulations, the Norwegian State, among other things, awards licences for exploration, production and transportation, approves exploration and development projects and applications for production rates for individual fields and may, if important public interests are at stake, also instruct Statoil and other oil companies to reduce petroleum production. Furthermore, in the production licences in which the SDFI holds an interest, the Norwegian State has the power to direct petroleum licences' actions in certain circumstances.

If the Norwegian State were to take additional action under its activities on the NCS or to change laws, regulations, policies or practices relating to the oil and gas industry, Statoil's NCS exploration, development and production activities and the results of its operations could be affected.

5.1.3 Risks related to state ownership

This section discusses some of the potential risks relating to Statoil's business that could derive from the Norwegian State's majority ownership and from Statoil's involvement in the SDFI.

The interests of Statoil's majority shareholder, the Norwegian State, may not always be aligned with the interests of Statoil's other shareholders, and this may affect Statoil's decisions relating to the NCS.
The Norwegian Parliament, known as the Storting, and the Norwegian State have resolved that the Norwegian State's shares in Statoil and the SDFI's interest in NCS licences must be managed in accordance with a coordinated ownership strategy for the Norwegian State's oil and gas interests. Under this strategy, the Norwegian State has required Statoil to continue to market the Norwegian State's oil and gas together with Statoil's own oil and gas as a single economic unit.

Pursuant to this coordinated ownership strategy, the Norwegian State requires Statoil, in its activities on the NCS, to take account of the Norwegian State's interests in all decisions that may affect the development and marketing of Statoil's own and the Norwegian State's oil and gas.

The Norwegian State directly held 67% of Statoil's ordinary shares as of 31 December 2015. Based on the Norwegian Public Limited Companies Act, the Norwegian State effectively has the power to influence the outcome of any vote of shareholders due to the percentage of Statoil's shares it owns, including amending its articles of association and electing all non-employee members of the corporate assembly. The employees are entitled to be represented by up to one-third of the members of the board of directors and one-third of the corporate assembly.

The corporate assembly is responsible for electing Statoil's board of directors. It also makes recommendations to the general meeting concerning the board of directors' proposals relating to the company's annual accounts, balance sheet, allocation of profit and coverage of loss. The interests of the Norwegian State in deciding these and other matters and the factors it considers when casting its votes, especially under the coordinated ownership strategy for the SDFI and Statoil's shares held by the Norwegian State, could be different from the interests of Statoil's other shareholders.

If the Norwegian State's coordinated ownership strategy is not implemented and pursued in the future, then Statoil's mandate to continue to sell the Norwegian State's oil and gas together with its own oil and gas as a single economic unit is likely to be prejudiced. Loss of the mandate to sell the SDFI's oil and gas could have an adverse effect on Statoil's position in the markets in which it operates.

For further information about the mandate to sell the Norwegian State's oil and gas see section 3.12.4 *SDFI oil and gas marketing and sale.*

5.2 Risk management

Statoil's overall risk management approach includes identifying, evaluating and managing risk in all its activities. In order to achieve optimal corporate solutions, Statoil bases its risk management on an enterprise-wide risk management approach.

Statoil defines risk as a deviation from a specified reference value and the uncertainty associated with it. A positive deviation is defined as an upside risk, while a negative deviation is a downside risk. The reference value is most commonly a forecast, percentile or target. Statoil has an enterprise risk management (ERM) approach, which means that:

- focus is on the value impact for Statoil
- risk is managed to make sure that Statoil's operations are safe and in compliance with Statoils' requirements and
- focus is on risk and reward at all levels in the organisation

Statoil's corporate risk committee (CRC) is headed by the chief financial officer and its members include representatives of the principal business areas. It is an enterprise risk management advisory body that primarily advises the chief financial officer, but also the business areas' management on specific issues. The CRC assesses and advises on measures aimed at managing the overall risk to the group, and it proposes appropriate measures to adjust risk at the corporate level. The CRC is also responsible for reviewing and developing Statoil's risk policies. The committee meets regularly during the year to support Statoil's risk management strategies, including hedging and trading strategies, as well as risk management methodologies. It regularly receives risk information that is relevant to it from Statoil's corporate risk department.

Risk is managed in the business line and is an integrated part of any manager's responsibility. However, some risks are managed at corporate level to avoid suboptimisation. This includes oil and natural gas price risks, interest and currency risks, risk dimension in the strategy work, prioritisation processes and capital structure discussions.

The following section describes in some detail the market risks to which Statoil is exposed and how Statoil manages these risks.

5.2.1 Managing operational risk

Statoil manages risk in order to ensure safe operations and to achieve its corporate goals in compliance with its requirements.

All risks are related to Statoil's value chain, which denotes the value that is added in each step - from access, maturing, project execution and operation to market. In addition to the economic impact these risks could have on Statoil's cash flows, Statoil has have a strong focus on avoiding HSE and integrity-related incidents (such as accidents, fraud and corruption). Most of the risks are managed by the principal business area line managers. Some operational risks are insurable and insured by Statoil's captive insurance company operating in the Norwegian and international insurance markets.

Statoil's risk management process is based on ISO31000 Risk management – principles and guidelines. The process provides a standardised framework and methodology for assessing and managing risk. A standardisation of the process across the entire enterprise allows for comparable risk levels and efficiency in decisions and it enables the organisation to create sustainable value while avoiding incidents. The process ensures that risks are identified, analysed, evaluated and managed. Risk adjusting actions are subject to a cost benefit evaluation (except certain safety related risks which are subject to specific regulations).

5.2.2 Managing financial risk

The results of Statoil's operations depend on a number of factors, most significantly those that affect the price it receives for the products.

Statoil has developed policies aimed at managing the financial volatility inherent in some of the business exposures. In accordance with these policies, Statoil enters into various financial and commodity-based transactions (derivatives). While the policies and mandates are set at the company level, the business areas are responsible for marketing and trading commodities are also responsible for managing commodity-based price risks. Interest, liquidity, liability and credit risks are managed by the company's central finance department.

The factors that influence the results of Statoil's operations include: the level of crude oil and natural gas prices, trends in the exchange rate between the USD, in which the trading price of crude oil is generally stated, EUR and GBP where Statoil has a large share of its natural gas sales, and NOK, in which its accounts are reported and a substantial proportion of the costs are incurred; Statoil's oil and natural gas production volumes, which in turn depend on entitlement volumes under PSAs and available petroleum reserves, and Statoil's own, as well as partners' expertise and cooperation in recovering oil and natural gas from those reserves; and changes in Statoil's portfolio of assets due to acquisitions and disposals.

Statoil's results will also be affected by trends in the international oil industry, including possible actions by governments and other regulatory authorities in the jurisdictions in which Statoil operates, or possible or continued actions by members of the Organization of Petroleum Exporting Countries (Opec) and/or other producing nations that affect price levels and volumes, refining margins, the cost of oilfield services, supplies and equipment, competition for exploration opportunities and operatorships, and deregulation of the natural gas markets, all of which may cause substantial changes to existing market structures and to the overall level and volatility of prices and price differentials.

The following table shows the yearly averages for quoted Brent Blend crude oil prices, natural gas average sales prices, refining reference margins and the USDNOK exchange rates for 2015, 2014 and 2013.

Yearly average	2015	2014	2013
Crude oil (USD/bbl Brent blend)	55.3	98.9	108.7
Average invoiced gas prices - Europe (NOK/scm)	2.16	2.28	2.45
Refining reference margin (USD/bbl)	8.0	4.7	4.1
USDNOK average daily exchange rate	8.07	6.30	5.88

The illustration shows the indicative full-year effect on the financial result for 2016 given certain changes in the crude oil price, natural gas contract prices and the USD/NOK exchange rate. The estimated price sensitivity of Statoil's financial results to each of the factors has been estimated based on the assumption that all other factors remain unchanged.

Significant downward adjustments of Statoil's commodity price assumptions will result in impairment losses on certain producing and development assets in the portfolio. Subsequent to year end 2015, commodity prices have continued to be volatile. See note 11 *Property, plant and equipment* and note 12 *Intangible assets* to the Consolidated financial statements for sensitivity analysis related to impairment losses.

Statoil assesses oil and gas price hedging opportunities on a regular basis as a tool with regard to financial robustness and flexibility.

Fluctuating foreign exchange rates can have a significant impact on the operating results. Statoil's revenues and cash flows are mainly denominated in or driven by USD, while a large portion of the operating expenses, capital expenditures and income taxes payable accrue in NOK. Statoil seeks to manage this currency mismatch by issuing or swapping non-current financial debt in USD. This long-term funding policy is an integrated part of our total risk management programme. Statoil also engages in foreign currency management in order to cover the non-USD needs, which are primarily in NOK. In general, an increase in the value of USD in relation to NOK can be expected to increase Statoil's reported earnings.

Historically, Statoil's revenues have largely been generated by the production of oil and natural gas on the NCS. Norway imposes a 78% marginal tax rate on income from offshore oil and natural gas activities (a symmetrical tax system). For more information see section 3.12.6 *Taxation of Statoil*.

Statoil's earnings volatility is moderated as a result of the significant proportion of its Norwegian offshore income that is subject to a 78% tax rate in profitable periods, and the significant tax assets generated by its Norwegian offshore operations in any loss-making periods. Most of the taxes Statoil pays are paid to the Norwegian State. Dividends received in Norway are 97% exempt from tax, with the remaining 3% taxed at the ordinary rate of 27%. For dividends received from companies in a low-tax jurisdiction within the European Economic Area (EEA), the 97% exemption only applies if real business activities are conducted in that jurisdiction. Dividends received from companies in non-EEA countries are 97% exempt if the Norwegian recipient has held at least 10% of the shares for a minimum of two years and the foreign country is not a low-tax jurisdiction.

Government fiscal policy is an issue in several of the countries in which Statoil operates, such as, but not limited to, Algeria, Angola, Nigeria, Brazil, the USA and Venezuela. However, Statoil's exposure in Venezuela is low. For instance, government fiscal policy could require royalties in cash or in kind, increased tax rates, increased government participation and changes in terms and conditions as defined in various production or income-sharing contracts. Statoil's financial statements are based on currently enacted regulations and on any current claims from tax authorities regarding past events. Developments in government fiscal policy may have a negative effect on future net income.

Financial risk management

Statoil's business activities naturally expose the group to financial risk. The group's approach to risk management includes identifying, evaluating and managing risk in all activities using a top-down approach for the purpose of avoiding sub-optimisation and utilising correlations observed from a group perspective. Summing up the different market risks without including the correlations will overestimate Statoil's total market risk. For this reason, Statoil utilises correlations between all of the most important market risks, such as oil and natural gas prices, product prices, currencies and interest rates, to calculate the overall market risk and thereby utilise the natural hedges embedded in its portfolio. This approach also reduces the number of unnecessary transactions, which reduces transaction costs and avoids sub-optimisation.

In order to achieve the above effects, Statoil has centralised trading mandates (financial positions taken to achieve financial gains, in addition to established policies) so that all major/strategic transactions are coordinated through the CRC. Local trading mandates are therefore relatively small.

Statoil's activities expose the company to the following financial risks: market risks (including commodity price risk, interest rate risk and currency risk), liquidity risk and credit risk. For a discussion of financial risk management see note 5 *Financial risk management* in the Consolidated financial statements.

5.2.3 Disclosures about market risk

Statoil uses financial instruments to manage commodity price risks, interest rate risks, currency risks and liquidity risks. Significant amounts of assets and liabilities are accounted for as financial instruments.

See note 25 *Financial instruments: fair value measurement and sensitivity analysis of market risk* in the Consolidated financial statements, for details of the nature and extent of such positions, and for qualitative and quantitative disclosures of the risks associated with these instruments.

5.3 Legal proceedings

Statoil is involved in a number of proceedings globally concerning matters arising in connection with the conduct of its business.

Statoil is currently not aware of any regulatory, judicial or arbitration proceedings or claims that it believes may have, or have had in the recent past, individually or in the aggregate, significant effects on Statoil's financial position or profitability or on the results of its operations or liquidity. This includes the legal proceedings described hereafter:

Agbami redetermination, Nigeria:
Through its ownership in OML 128 in Nigeria, Statoil is party to an ownership interest redetermination process for the Agbami field. In October 2015 Statoil received the expert's final ruling which implies a reduction of 5.17 percentage points in Statoil's equity interest in the field from 20.21% to 15.04%. In 2013, Statoil initiated arbitration proceedings to set aside interim decisions made by the expert in the redetermination process, but this was declined by the arbitration tribunal in its November 2015 judgment. Statoil has initiated proceedings before the Federal High Court in Lagos to set aside the arbitration award, and also intends to initiate a new arbitration to set aside the expert's final ruling.

As of 31 December 2015 Statoil has made a provision of NOK 9.5 billion, net of tax, which reflects a reduction of 5.17 percentage points in Statoil's equity interest in the Agbami field.

Royalty Litigation, US Onshore:
Statoil is currently defending multiple, but individually immaterial, royalty litigations and arbitrations, some on behalf of large classes of mineral owners, relating to its operated and non-operated positions in the Marcellus and Eagle Ford shale plays. Mineral owners in these proceedings generally allege that Statoil has breached their oil and gas leases by first paying royalty on the basis of an impermissibly-low unit price, and second taking prohibited and/or excessive deductions for post-production costs. The cases are in various procedural stages and are typical disputes for oil companies in the US onshore business. None of the litigations or arbitrations is currently set for trial or final hearing.

In the ordinary course of business, companies in the Statoil group are subject to a number of other loss contingencies arising from litigation and claims raised by governmental and private parties, for instance contractors, tax authorities, land owners for on-shore activities and buyers of Statoil's products.

See also note 9 *Income taxes* and note 23 *Other commitments and contingencies* in Consolidated financial statements.

6 Shareholder information

Statoil is the largest company listed on the Oslo Børs, where it trades under the ticker code STL. Statoil is also listed on the New York Stock Exchange under the ticker code STO.

STATOIL SHARE	2015	2014	2013	2012	2011
Shareprice STL (low) (NOK)	116.30	120.00	147.70	162.40	160.50
Shareprice STL (average) (NOK)	137.59	166.41	123.00	133.80	113.70
Shareprice STL (high) (NOK)	160.80	194.80	136.72	146.97	139.60
Shareprice STL (year-end) (NOK)	123.70	131.20	147.00	139.00	153.50
Market value year-end (NOK billion)	394	418	468	443	490
Daily turnover (million shares)	5.1	3.7	3.0	4.3	8.9
Ordinary earnings per share (EPS) (NOK)	-11.80	6.87	12.50	21.60	24.70
P/E[1)]	-10.48	19.10	11.76	6.44	6.21
Ordinary dividend per share (NOK)[2)]	1.80	7.20	7.00	6.75	6.50
Ordinary dividend per share (USD)[2)]	0.6603				
Growth in ordinary dividend per share[3)]	NA	2.9%	3.7%	3.8%	4.0%
Dividend per share (NOK)[4)]	7.62	7.20	7.00	6.75	6.50
Dividend per share (USD)[4)]	0.86	0.97	1.15	1.21	1.08
Pay-out ratio[5)]	-65%	105%	56%	31%	26%
Dividend yield[6)]	6.2%	5.5%	4.8%	4.9%	4.2%
Ordinary shares outstanding, weighted average	3,179,442,977	3,179,958,780	3,180,683,828	3,181,546,060	3,182,112,843
Ordinary shares outstanding, year-end	3,188,647,103	3,188,647,103	3,188,647,103	3,188,647,103	3,188,647,103

1) Share price at year end divided by EPS.

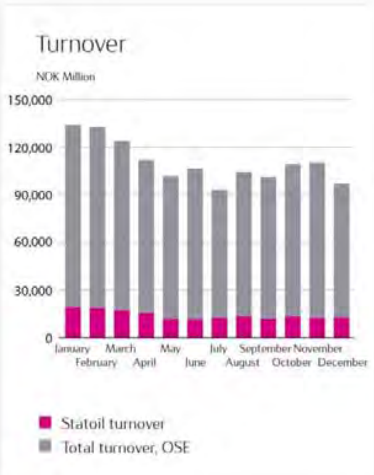
2) Proposed cash dividend for 2015. For 2015, the NOK amount covers first quarter while the USD amount is for second, third and fourth quarter. See section 6.1 *Dividend policy*.

3) Excluding special dividend and share buy-back.

4) Conversions between NOK and USD are conducted by applying the year end exchange rate for the respective year.

5) Total dividend per share in NOK divided by EPS.

6) Total dividend per share in NOK divided by year end share price.



As of 31 December 2015, Statoil represented 14.68% of the total value of all companies registered on the Oslo Børs, with a market value of NOK 394 billion.

Statoil's share price closed at NOK 123.70 at the end of 2015.

Taking into consideration the total dividend paid out in 2015 of NOK 7.20 per share, which includes four quarterly payments of NOK 1.80 per share for the third and fourth quarter of 2014 and first and second quarter of 2015, the total return was negative NOK 0.30 per share. The graph above, "Quote history", shows the development of the Statoil share price compared to the oil price and the Oslo Børs Benchmark Index (OSEBX). The board of directors proposes a dividend of USD 0.2201 per share for the fourth quarter 2015, for approval by the annual general meeting on 11 May 2016. Diluted earnings per share amounted to negative NOK 11.80, compared to positive NOK 6.87 in 2014.

The turnover of shares is a measure of traded volumes. On average, 5.1 million Statoil shares were traded on the Oslo Børs every day in 2015 compared to 3.7 million shares in 2014. In 2015, Statoil shares accounted for 15% of the total market value traded throughout the year (see illustration), compared to 12% in 2014.

Statoil ASA has one class of shares, and each share confers one vote at the general meeting. Statoil ASA had 3,188,647,103 ordinary shares outstanding at year end.

As of 31 December 2015, Statoil had 91,774 shareholders registered in the Norwegian Central Securities Depository (VPS), down from 92,692 shareholders at 31 December 2014.

6.1 Dividend policy

It is Statoil's ambition to grow the annual cash dividend measured in USD per share in line with long-term underlying earnings.

Statoil's board approves first, second and third quarter interim dividends, based on an authorisation from the annual general meeting (AGM), while the AGM approves the fourth quarter dividend and the implicit the total dividend based on a proposal from the board. When deciding the interim dividends and recommending the total annual dividend level, the board will take into consideration expected cash flow, capital expenditure plans, financing requirements and appropriate financial flexibility. In addition to cash dividend, Statoil might buy back shares as part of total distribution of capital to the shareholders. The shareholders at the AGM may vote to reduce, but may not increase, the fourth quarter dividend proposed by the board of directors. It is Statoil's intention to have this authorisation approved at the AGM. Statoil announces dividend payments in connection with quarterly results. Payment of quarterly dividends is expected to take place approximately four months after the announcement of each quarterly dividend.

The board of directors updated the dividend policy in 2015 to reflect USD as the declaration currency.

The board of directors proposes to the AGM a dividend of USD 0.2201 per share for the fourth quarter 2015 and the introduction of a two-year scrip dividend programme for eligible shareholders starting from the fourth quarter 2015. The scrip programme will give shareholders the option to receive quarterly dividends in cash or in newly issued shares in Statoil at a 5% discount for the fourth quarter 2015. The Norwegian Government, as majority shareholder, supports the proposal and will seek the Norwegian Parliament's approval to vote in favour of the proposal at the AGM. The Norwegian government intends to match subscription of shares by minority shareholders, and thereby maintain its ownership share at 67% throughout the programme.

6.1.1 Dividends

In 2014 Statoil implemented quarterly dividend payments and from second quarter 2015 Statoil implemented USD as dividend declaration currency.

Although we currently intend to pay quarterly dividends on our ordinary shares, we cannot give an assurance that dividends will be paid, or predict the amount of any dividends. Future dividends will depend on a number of factors prevailing at the time our board of directors considers any dividend payment. The following table shows the cash dividend amounts to all shareholders since 2010 on a per share basis and in aggregate.

				Ordinary dividend per share						Ordinary dividend per
Fiscal year	Curr.	Q1	Curr.	Q2	Curr.	Q3	Curr.	Q4	Curr.	share
2011									NOK	6.5000
2012									NOK	6.7500
2013									NOK	7.0000
2014	NOK	1.8000	NOK	1.8000	NOK	1.8000	NOK	1.8000	NOK	7.2000
2015	NOK	1.8000							NOK	1.8000
2015			USD	0.2201	USD	0.2201	USD	0.2201	USD	0.6603

Statoil commenced quarterly dividends in 2014. During 2015 Statoil paid four quarterly dividends. The third quarter 2014 dividend was paid out in February 2015, the fourth quarter 2014 dividend was paid out in May 2015, the first quarter 2015 dividend was paid out in August 2015 and the second quarter 2015 dividend was paid out in November 2015. The third quarter 2015 dividend was paid out in February 2016. The proposed fourth quarter 2015 dividend will be considered at the annual general meeting 11 May 2016. The Statoil share will be traded ex dividend 12 May 2016 and if approved, the dividend will be disbursed around late June 2016. For US ADR holders, the ex-dividend date will be 12 May 2016 and expected payment date for ADR holders will be in June 2016.

From the second quarter 2015 Statoil implemented declaring dividends in USD. As from the third quarter 2015 only dividend in USD per share will be announced. Dividends in NOK per share will be communicated four business days after record date for shareholders at Oslo Børs. Since we will declare dividends in USD, exchange rate fluctuations will affect the amounts in NOK received by shareholders on the Oslo Børs.

Share repurchase
In addition to a cash dividend, Statoil may buy back shares as part of its total distribution of capital to its shareholders. For the period 2013-2015, the board of directors was authorised by the annual general meeting of Statoil to repurchase Statoil shares in the market for subsequent annulment. We have not undertaken any share repurchase based on this authorisation.

It is Statoil's intention to renew this authorisation at the annual general meeting. Statoil intends to use share buybacks more actively going forward, based on balance sheet strength considerations.

6.2 Shares purchased by issuer

Shares are acquired in the market for transfer to employees under the share savings scheme in accordance with the limits set by the board of directors. No shares were repurchased in the market for the purpose of subsequent annulment in 2015.

6.2.1 Statoil's share savings plan

Since 2004, Statoil has had a share savings plan for employees of the company. The purpose of this plan is to strengthen the business culture and encourage loyalty through employees becoming part-owners of the company.

Through regular salary deductions, employees can invest up to 5% of their base salary in Statoil shares. In addition, the company contributes 20% of the total share investment made by employees in Norway, up to a maximum of NOK 1,500 per year (approximately USD 170). This company contribution is a tax-free employee benefit under current Norwegian tax legislation. After a lock-in period of two calendar years, one extra share will be awarded for each share purchased. Under current Norwegian tax legislation, the share award is a taxable employee benefit, with a value equal to the value of the shares and taxed at the time of the award.

The board of directors is authorised to acquire Statoil shares in the market on behalf of the company. The authorisation may be used to acquire own shares for a total nominal value of up to NOK 35 million. Shares acquired under this authorisation may only be used for sale and transfer to employees of the Statoil group as part of the company's share savings plan as approved by the board of directors. The minimum and maximum amount that may be paid per share is NOK 50 and 500, respectively.

The authorisation is valid until the next annual general meeting, but not beyond 30 June 2016. This authorisation replaces the previous authorisation to acquire Statoil's own shares for implementation of the share savings plan granted by the annual general meeting 14 May 2014. It is Statoil's intention to renew this authorisation at the annual general meeting. Statoil intends to use share buybacks more actively going forward, based on balance sheet strength considerations.

The nominal value of each share is NOK 2.50. With a maximum overall nominal value of NOK 35 million, the authorisation for the repurchase of shares in connection with the group's share savings plan covers the repurchase of no more than 14 million shares.

Period in which shares were repurchased	Number of shares repurchased	Average price per share in NOK	Total number of shares purchased as part of programme	Maximum number of shares that may yet be purchased under the programme authorisation[1]
Jan-15	713,771	130.6301	4,713,258	6,286,742
Feb-15	628,251	149.5611	5,341,509	5,658,491
Mar-15	700,062	134.5595	6,041,571	4,958,429
Apr-15	598,244	157.0929	6,639,815	4,360,185
May-15	605,625	154.6826	7,245,440	3,754,560
Jun-15	664,037	140.9826	664,037	13,335,963
Jul-15	661,604	141.2402	1,325,641	12,674,359
Aug-15	707,278	132.0766	2,032,919	11,967,081
Sep-15	781,215	119.1604	2,814,134	11,185,866
Oct-15	661,646	140.4563	3,475,780	10,524,220
Nov-15	717,182	129.8833	4,192,962	9,807,038
Dec-15	750,203	123.5585	4,943,165	9,056,835
Jan-16	878,834	102.6997	5,821,999	8,178,001
Feb-16	745,858	117.5826	6,567,857	7,432,143
TOTAL	9,813,810 [2]	132.4013 [3]		

1) The authorisation to repurchase a maximum of 11 million shares with a maximum overall nominal value of NOK 27.5 million for repurchase of shares in connection with the share savings plan was given by the annual general meeting on 14 May 2014. The authorisation was maintained by the annual general meeting on 19 May 2015 at a maximum of 14 million shares with a maximum overall nominal value of 35 million for repurchase of shares, valid until 30 June 2016.

2) All shares repurchased have been purchased in the open market and pursuant to the authorisation mentioned above.

3) Weighted average price per share.

6.3 Information and communications

Updated information about Statoil's financial performance and future prospects forms the basis for assessing the value of the company.

Information provided to the stock market must be transparent and ensure equal treatment of all shareholders, and it must aim to provide shareholders with correct, clear, relevant and timely information that forms the basis for assessing the value of the company.

Statoil shares are listed on the Oslo Børs, and its American Depositary Receipts (ADRs) are listed on the New York Stock Exchange. We distribute share price-sensitive information through the international wire services, the Oslo Børs in Norway, the Securities and Exchange Commission in the US, and our website Statoil.com.

Our registrar manages our shares listed on the Oslo Børs on our behalf and provides the connection to the Norwegian Central Securities Depository (VPS). Important services provided by the registrar are investor services for private shareholders, the disbursement of dividends and assistance at our general meetings. DnB Bank is currently the account registrar for Statoil.

6.3.1 Investor contact

Our investor relations staff function (IR) coordinates the dialogue with our shareholders.

We place great emphasis on ensuring that relevant and timely information is distributed to the capital markets. Given the size and diversity of our shareholder base, the opportunities for direct shareholder interaction are limited. Our "Investor Centre" web pages are therefore specially designed for investors and analysts who wish to follow the company's progress - Statoil.com/IR.

We broadcast our quarterly presentations and other relevant presentations by management directly on the internet, and the related reports are made available together with other relevant information on our website.

Ticker Codes:
Oslo Børs: STL
New York Stock Exchange: STO
Reuters: STL.OL
Bloomberg: STL NO

Financial calendar for 2016

04 February	Fourth quarter results and strategy update
16 February	Q3 2015 ADS trading ex-dividend
17 February	Q3 2015 ordinary share trading ex-dividend
26 February	Q3 2015 ordinary share dividend payment
04 March	Q3 2015 ADS dividend payment
18 March	Publication annual report 2015
27 April	First quarter 2016
11 May	Annual general meeting
12 May	Q4 2015 ADS trading ex-dividend
12 May	Q4 2015 ordinary share trading ex-dividend
June	Q4 2015 ordinary share dividend payment
June	Q4 2015 ADS dividend payment
27 July	Second quarter 2016
end August	Q1 2016 ADS trading ex-dividend
end August	Q1 2016 ordinary share trading ex-dividend
end August	Q1 2016 ordinary share dividend payment
early September	Q1 2016 ADS dividend payment
27 October	Third quarter 2016
end November	Q2 2016 ADS trading ex-dividend
end November	Q2 2016 ordinary share trading ex-dividend
end November	Q2 2016 ordinary share dividend payment
early December	Q2 2016 ADS dividend payment

6.4 Market and market prices

The principal trading market for our ordinary shares is the Oslo Børs. The ordinary shares are also listed on the New York Stock Exchange, trading in the form of American Depositary Shares (ADS).

Statoil's shares have been listed on the Oslo Børst since our initial public offering on 18 June 2001. The ADSs traded on the New York Stock Exchange are evidenced by American Depositary Receipts (ADR), and each ADS represents one ordinary share. Statoil has a sponsored ADR facility with Deutsche Bank Trust Company Americas as depositary.

6.4.1 Share prices

These are the reported high and low quotations at market closing for the ordinary shares on the Oslo Børs and New York Stock Exchange for the periods indicated.

They are derived from the Oslo Børs Daily Official List, and the highest and lowest sales prices of the ADSs as reported on the New York Stock Exchange composite tape.

	NOK per ordinary share		USD per ADS	
Share price	High	Low	High	Low
Year ended 31 December				
2011	160.50	113.70	29.58	20.16
2012	162.40	133.80	28.92	22.15
2013	147.70	123.00	27.00	20.14
2014	194.80	120.00	31.91	15.82
2015	160.80	116.30	21.31	13.42
Quarter ended				
Monday, March 31, 2014	171.30	146.40	28.51	23.37
Monday, June 30, 2014	194.80	164.90	31.91	27.60
Tuesday, September 30, 2014	191.00	171.90	31.01	26.93
Tuesday, December 31, 2014	173.70	120.00	26.79	15.82
Tuesday, March 31, 2015	149.80	125.80	19.62	16.25
Tuesday, June 30, 2015	160.80	140.10	21.31	17.59
Wednesday, September 30, 2015	141.40	116.30	17.56	13.85
Wednesday, December 30, 2015	145.60	118.70	17.74	13.42
March, up until 8 March 2016	133.80	97.90	15.94	11.38
Month of				
September 2015	126.80	116.80	15.31	13.85
October 2015	144.70	126.40	17.74	14.83
November 2015	145.60	129.70	17.06	14.90
December 2015	135.70	118.70	15.70	13.42
January 2016	123.50	97.90	13.96	11.38
February 2016	127.10	108.00	14.56	12.49
March up until 8 March 2016	133.80	127.30	15.94	14.78

6.4.2 Statoil ADR programme fees

Fees and charges payable by a holder of ADSs.

As depositary from 31 January 2013, Deutsche Bank Trust Company Americas collects its fees for the delivery and surrender of ADSs directly from investors depositing shares or surrendering ADSs for the purpose of withdrawal, or from intermediaries acting for them. The depositary collects fees from investors by deducting the fees from the amounts distributed or by selling a portion of distributable property to pay the fees. The depositary may refuse to provide fee-attracting services until its fees for those services are paid.

The charges of the depositary payable by investors are as follows:

Persons depositing or withdrawing shares must pay:	For:
USD 5.00 (or less) per 100 ADSs (or portion of 100 ADSs)	• Issuance of ADSs, including issuances resulting from a distribution of shares or rights or other property • Cancellation of ADSs for the purpose of withdrawal, including if the deposit agreement terminates
USD 0.02(or less) per ADS, subject to the company's consent	• Any cash distribution to ADS registered holders
USD 0.05 (or less) per ADS, subject to the company's consent	• For the operation and maintenance costs in administering the ADR program
A fee equivalent to the fee that would be payable if securities distributed to you had been shares and the shares had been deposited for issuance of ADSs	• Distribution of securities distributed to holders of deposited securities which are distributed by the Depositary to ADS registered holders
Registration or transfer fees	• Transfer and registration of shares on our share register to or from the name of the Depositary or its agent when you deposit or withdraw shares
Expenses of the Depositary	• Cable, telex and facsimile transmissions (as provided in the deposit agreement) • Converting foreign currency to US dollars
Taxes and other governmental charges the Depositary or the custodian have to pay on any ADS or share underlying an ADS, for example, stock transfer taxes, stamp duty or withholding taxes	• As necessary
Any charges incurred by the Depositary or its agents for servicing the deposited securities	• As necessary

Reimbursements and payments made and fee waivers granted by the depositary
The depositary has agreed to reimburse certain company expenses related to the company's ADR programme and incurred by the company in connection with the programme. In the year ended 31 December 2015, the depositary reimbursed approximately USD 1.43 million to the company in relation to certain expenses including investor relations expenses, expenses related to the maintenance of the ADR programme, legal counsel fees, printing and ADR certificates.

The depositary has also agreed to waive fees for costs associated with the administration of the ADR programme, and it has paid certain expenses directly to third parties on behalf of the company. The expenses paid to third parties include expenses relating to reporting services and access charges to its online platform, re-registration costs borne by the custodian. For the year ended 31 December 2015, the depositary paid expenses of approximately USD 69,576 directly to third parties.

6.5 Taxation

This section describes the material Norwegian tax consequences that apply to shareholders resident in Norway and to non-resident shareholders in connection with the acquisition, ownership and disposal of shares and American Depositary Shares (ADS). The term “shareholder” refers to both holders of shares and holders of ADSs, unless otherwise explicitly stated.

Norwegian tax matters

The outline does not provide a complete description of all tax regulations that might be relevant (i.e. for investors to whom special regulations may be applicable), and is based on current law and practice. Shareholders should consult their professional tax adviser for advice about individual tax consequences.

Taxation of dividends

Corporate shareholders (i.e. limited liability companies and similar entities) residing in Norway for tax purposes are generally subject to tax in Norway on dividends received from Norwegian companies. The basis for taxation is 3% of the dividends received, which is subject to the standard income tax rate. The standard income tax rate has been reduced from 27% in 2015 to 25% in 2016.

Individual shareholders resident in Norway for tax purposes are subject to the standard income tax rate (reduced from 27% in 2015 to 25% in 2016) in Norway for dividend income exceeding a basic tax free allowance. However, in 2016 dividend income exceeding the basic tax free allowance is grossed up with a factor of 1.15 before taken to taxation, resulting in an effective tax rate of 28.75% (25% x 1.15). The tax free allowance is computed for each individual share or ADS on the basis of the cost price of that share or ADS multiplied by a risk-free interest rate. The risk-free interest rate will be determined every income year. Any part of the calculated allowance for one year that exceeds the dividend distributed for the share or ADS ("unused allowance") may be carried forward and set off against future dividends received for (or gains upon the realisation of, see below) the same share or ADS. Any unused allowance will also be added to the basis for computation of the allowance for the same share or ADS the following year.

Non-resident shareholders are as a rule subject to withholding tax at a rate of 25% on dividends distributed by Norwegian companies. This withholding tax does not apply to corporate shareholders in the EEA area that document that they are genuinely established and carry on genuine economic business activity within the EEA area, provided that Norway is entitled to receive information from the state of residence pursuant to a tax treaty or other international treaty. If no such treaty exists with the state of residence, the shareholder may instead present confirmation issued by the tax authorities of the state of residence verifying the documentation. Individual shareholders resident for tax purposes in the EEA area may apply to the Norwegian tax authorities for a refund if the tax withheld by the distributing company exceeds the tax that would have been levied on individual shareholders resident in Norway.

The withholding rate of 25% is often reduced in tax treaties between Norway and other countries. Generally, the treaty rate does not exceed 15% and, in cases where a corporate shareholder holds a qualifying percentage of ownership in the distributing company, the withholding tax rate on dividends may be further reduced. The withholding tax rate in the tax treaty between the United States and Norway is currently 15% in all cases. It is the responsibility of the distributing company to deduct the withholding tax when dividends are paid to non-resident shareholders.

The reduced withholding rate will generally only apply to dividends paid on shares held by shareholders who are able to properly demonstrate to the company that they are entitled to the benefits of the tax treaty.

For holders of shares and ADSs deposited with Deutsche Bank Trust Company Americas (Deutsche Bank), documentation establishing that the holder is eligible for the benefits under the tax treaty with Norway, may be provided to Deutsche Bank. Deutsche Bank has been granted permission by the Norwegian tax authorities to receive dividends from us for redistribution to a beneficial owner of shares and ADSs at the applicable treaty withholding rate.

Dividends paid to shareholders (either directly or through a depositary) who have not provided the relevant documentation to the relevant party that they are eligible for the reduced rate, will be subject to withholding tax of 25%. The beneficial owners will in this case have to apply to the Central Office - Foreign Tax Affairs (COFTA) for a refund of the excess amount of tax withheld.

According to information provided by the Central Office of Foreign Tax Affairs (COFTA), an application for a refund of withholding tax from shareholders must contain the following:

1. Full name, address and tax identification number of the claimant.
2. Payment details, including name of account holder, either a Norwegian bank account number or IBAN and SWIFT/BIC code. The IBAN account must be able to receive NOK as the refund will be transferred in NOK.
3. A specification of the Norwegian company(ies) involved, the exact amount of shares, the date of each dividend payment, the dividend per share, the total dividend payment, the Norwegian withholding tax rate, and the reclaimed amount. All amounts must be given in NOK.
4. Documentation that confirms the claimant's residency.
    - A claim according to a tax treaty must contain a Certificate of Residence issued by the competent local tax authorities with reference to the claimant's tax identification number. The certificate of residence must state that the claimant was resident according to the tax treaty with Norway during the year when the decision to distribute the dividend was made. The confirmation must be in original. The Certificate of Residence must mention solely the claimant's name

- A claim according to the tax exemption method cf. tax act section 2-38 must contain confirmation that the claimant is registered and based within the EEA and genuinely established in that country

5. A credit advice, certifying that the claimant has received the dividends and has been subject to Norwegian withholding tax on the dividends. The credit advice must fill the following criteria:
   - It must document the chain of transactions, including information about the foreign custodian/bank/clearing central registered in Norway that initially received the dividends. If the dividends have been paid through a chain of transactions, each transaction must be documented with a credit advice issued to the initial receiver
   - It must be issued by the bank that credits the claimant the dividend payment. It must contain the following details:
     - Name of the payment recipient, i.e. the claimant
     - Name and ISIN of the stock etc
     - The exact amount of shares
     - The gross amount and withholding tax in NOK
     - The ex-date, the record date and the pay-date
     - The dividend per share

   Please note that the credit advice must specify that the dividend payment has been subject to withholding tax, not just tax. This clarification will be a definite requirement on claims made from 1 January 2014 onward.
6. Power of attorney/attestation, a general power of attorney from the beneficial owner to authorise the claimant to claim a refund.
   The power of attorney does not need to mention the specific dividend payments. Still, COFTA requires that the claimant makes a spreadsheet listing the names of the companies from which the dividends were received, with the dates and the amounts of withholding tax. This spreadsheet should accompany the application and has to be approved and signed by the beneficial owner.
   Please note that only one refund claim can be made regarding each dividend payment, and applications for the same claim must not be filed several times, neither directly nor via custodians.
7. A claim should also contain general information about the claimant as regards legal, corporate and taxable aspects. Please note that only the beneficial owner may apply for a refund of withholding tax. An entity that is acting on behalf of someone else as either trustee or investment manager, and who is as such the registered or indirect owner of the dividends, is not entitled to a refund. Neither is an entity that receives the dividend payments and passes them directly on to other entities/persons entitled to a refund.

In some cases COFTA may request further, and more specific, information about the claim for refund and the claimant. An assessment of the entity and of the validity of the claim is made in each individual case.

The application should be sent to the following address: Central Office Foreign Tax Affairs/Sentralskattekontoret for utenlandssaker, Postboks 8031, 4068 Stavanger, NORWAY

Corporate shareholders that carry on business activities in Norway, and whose shares or ADSs are effectively connected with such activities are not subject to withholding tax. For such shareholders, 3% of the received dividends are subject to the standard income tax rate (reduced from 27% in 2015 to 25% in 2016).

Taxation on the realisation of shares and ADSs

Corporate shareholders resident in Norway for tax purposes are not subject to tax in Norway on gains derived from the sale, redemption or other disposal of shares or ADSs in Norwegian companies. Capital losses are not deductible.

Individual shareholders residing in Norway for tax purposes are subject to tax in Norway on the sale, redemption or other disposal of shares or ADSs. Gains or losses in connection with such realisation are included in the individual's ordinary taxable income in the year of disposal, which is subject to the standard income tax rate, being reduced from 27% in 2015 to 25% in 2016. However, in 2016 the taxable gain or deductible loss is grossed up with a factor of 1.15 before included in the ordinary taxable income, resulting in an effective tax rate of 28.75% (25% x 1.15).

The taxable gain or deductible loss (before gross up) is calculated as the sales price adjusted for transaction expenses minus the taxable basis. A shareholder's tax basis is normally equal to the acquisition cost of the shares or ADSs. Any unused allowance pertaining to a share may be deducted from a taxable gain on the same share or ADS, but may not lead to or increase a deductible loss. Furthermore, any unused allowance may not be set off against gains from the realisation of the other shares or ADSs.

If the shareholder disposes of shares or ADSs acquired at different times, the shares or ADSs that were first acquired will be deemed to be first sold (the "FIFO" principle) when calculating the taxable gain or loss.

A corporate shareholder or an individual shareholder who ceases to be tax resident in Norway due to domestic law or tax treaty provisions may, in certain circumstances, become subject to Norwegian exit taxation on capital gains related to shares or ADSs.

Shareholders not residing in Norway are generally not subject to tax in Norway on capital gains, and losses are not deductible on the sale, redemption or other disposal of shares or ADSs in Norwegian companies, unless the shareholder carries on business activities in Norway and such shares or ADSs are or have been effectively connected with such activities.

Wealth tax

The shares or ADSs are included in the basis for the computation of wealth tax imposed on individuals resident in Norway for tax purposes. Norwegian limited companies and certain similar entities are not subject to wealth tax. The current marginal wealth tax rate is 0.85% of the value assessed. The assessment value of listed shares (including ADSs) is 100% of the listed value of such shares or ADSs on 1 January in the assessment year.

Non-resident shareholders are not subject to wealth tax in Norway for shares and ADSs in Norwegian limited companies unless the shareholder is an individual and the shareholding is effectively connected with the individual's business activities in Norway.

Inheritance tax and gift tax
No inheritance or gift tax is imposed in Norway.

Transfer tax
No transfer tax is imposed in Norway in connection with the sale or purchase of shares or ADSs.

United States tax matters
This section describes the material United States federal income tax consequences for US holders (as defined below) of owning shares or ADSs. It only applies to you if you hold your shares or ADSs as capital assets for tax purposes. This section does not apply to you if you are a member of a special class of holders subject to special rules, including:

- dealers in securities
- traders in securities that elect to use a mark-to-market method of accounting for their securities holdings
- tax-exempt organisations
- life insurance companies
- persons liable for alternative minimum tax
- persons that actually or constructively own 10% or more of the voting stock of Statoil
- persons that hold shares or ADSs as part of a straddle or a hedging or conversion transaction
- persons that purchase or sell shares or ADSs as part of a wash sale for tax purposes or
- persons whose functional currency is not USD

This section is based on the Internal Revenue Code of 1986, as amended, its legislative history, existing and proposed regulations, published rulings and court decisions, and the Convention between the United States of America and the Kingdom of Norway for the Avoidance of Double Taxation and the Prevention of Fiscal Evasion with Respect to Taxes on Income and Property (the "Treaty"). These laws are subject to change, possibly on a retroactive basis. In addition, this section is based in part upon the representations of the depositary and the assumption that each obligation in the deposit agreement and any related agreement will be performed in accordance with its terms. For United States federal income tax purposes, if you hold ADRs evidencing ADSs, you will generally be treated as the owner of the ordinary shares represented by those ADRs. Exchanges of shares for ADRs and ADRs for shares will not generally be subject to United States federal income tax.

If a partnership holds the shares or ADSs, the United States federal income tax treatment of a partner will generally depend on the status of the partner and the tax treatment of the partnership. A partner in a partnership holding the shares or ADSs should consult its tax adviser with regard to the United States federal income tax treatment of an investment in the shares or ADSs.

You are a "US holder" if you are a beneficial owner of shares or ADSs and you are for United States federal income tax purposes:

- a citizen or resident of the United States;
- a United States domestic corporation;
- an estate whose income is subject to United States federal income tax regardless of its source; or
- a trust if a United States court can exercise primary supervision over the trust's administration and one or more United States persons are authorised to control all substantial decisions of the trust.

You should consult your own tax adviser regarding the United States federal, state and local and Norwegian and other tax consequences of owning and disposing of shares and ADSs in your particular circumstances.

Taxation of dividends
If you are a US holder, the gross amount of any dividend paid by Statoil out of its current or accumulated earnings and profits (as determined for United States federal income tax purposes) is subject to United States federal income taxation. If you are a non-corporate US holder, dividends paid to you will be eligible to be taxed at the preferential rates applicable to long-term capital gains as long as, in the year that you receive the dividend, the shares or ADSs are readily tradable on an established securities market in the United States or Statoil is eligible for benefits under the Treaty. To qualify for the preferential rates, you must hold the shares or ADSs for more than 60 days during the 121-day period beginning 60 days before the ex-dividend date and meet certain other requirements. Furthermore, these tax consequences would be different if Statoil were to be treated as a PFIC as discussed below.

You must include any Norwegian tax withheld from the dividend payment in this gross amount even though you do not in fact receive the amount withheld as tax. The dividend is taxable for you when you, in the case of shares, or the depositary, in the case of ADSs, receive the dividend, actually or constructively. The dividend will not be eligible for the dividends-received deduction generally allowed to United States corporations in respect of dividends received from other United States corporations.

The amount of the dividend distribution that you must include in your income as a US holder will be the value in USD of the payments made in NOK determined at the spot NOK/USD rate on the date the dividend distribution is includible in your income, regardless of whether or not the payment is in fact converted into USD. Distributions in excess of current and accumulated earnings and profits, as determined for United States federal income tax purposes, will be treated as a non-taxable return of capital to the extent of your tax basis in the shares or ADSs and, to the extent in excess of your tax basis, will be treated as capital gain.

Subject to certain limitations, the 15% Norwegian tax withheld in accordance with the Treaty and paid to Norway will be creditable or deductible against your United States federal income tax liability. Special rules apply when determining the foreign tax credit limitation with respect to dividends that are subject to the preferential rates. To the extent that a refund of the tax withheld is available to you under Norwegian law, the amount of tax withheld that is refundable will not be eligible for credit against your United States federal income tax liability. Dividends will be income from sources outside the United States and will generally, depending on your circumstances, be either "passive" or "general" income for purposes of computing the foreign tax credit allowable to you.

Any gain or loss resulting from currency exchange rate fluctuations during the period from the date you include the dividend payment in income until the date you convert the payment into USD will generally be treated as ordinary income or loss and will not be eligible for the special tax rate. Such gain or loss will generally be income or loss from sources within the United States for foreign tax credit limitation purposes.

Taxation of capital gains

Subject to the PFIC rules discussed below, if you are a US holder and you sell or otherwise dispose of your shares or ADSs, you will generally recognise a capital gain or loss for United States federal income tax purposes equal to the difference between the value in USD of the amount that you realise and your tax basis, determined in USD, in your shares or ADSs. A capital gain of a non-corporate US holder is generally taxed at preferential rates if the property is held for more than one year. The gain or loss will generally be income or loss from sources within the United States for foreign tax credit limitation purposes.

If you receive any foreign currency on the sale of shares or ADSs, you may recognise ordinary income or loss from sources within the United States as a result of currency fluctuations between the date of the sale of the shares or ADSs and the date the sales proceeds are converted into USD. You should consult your own tax adviser regarding how to account for payments made or received in a currency other than USD.

PFIC rules

We believe that the shares and ADSs should not be treated as stock of a PFIC for United States federal income tax purposes, but this conclusion is a factual determination that is made annually and thus may be subject to change. If we were to be treated as a PFIC, unless a US holder elects to be taxed annually on a mark-to-market basis with respect to the shares or ADSs, a gain realised on the sale or other disposition of the shares or ADSs would in general not be treated as a capital gain. Instead, if you are a US holder, you would be treated as if you had realised such gain and certain "excess distributions" ratably over your holding period for the shares or ADSs. Amounts allocated to the year in which the gain is realised or the “excess distribution” is received or to a taxable year before we were classified as a PFIC would be subject to tax at ordinary income tax rates, and amounts allocated to all other years would be taxed at the highest tax rate in effect for each such year to which the gain or distribution was allocated, together with an interest charge in respect of the tax attributable to each such year. With certain exceptions, the shares or ADSs will be treated as stock in a PFIC if we were a PFIC at any time during the period you held the shares or ADSs. Dividends that you receive from us will not be eligible for the preferential tax rates if we are treated as a PFIC with respect to you, either in the taxable year of the distribution or the preceding taxable year, but will instead be taxable at rates applicable to ordinary income.

Tax Filings

You should consult your own advisers regarding any tax filing or reporting obligations that arise out of the acquisition, ownership or disposition of shares or ADSs. Failure to comply with certain US tax filing or reporting obligations can cause you to be subject to significant penalties.

6.6 Exchange controls and limitations

Under Norwegian foreign exchange controls currently in effect, transfers of capital to and from Norway are not subject to prior government approval.

An exception applies to the physical transfer of payments in currency exceeding certain thresholds, which must be declared to the Norwegian custom authorities.

This means that non-Norwegian resident shareholders may receive dividend payments without Norwegian exchange control consent as long as the payment is made through a licensed bank or other licensed payment institution.

There are no restrictions affecting the rights of non-Norwegian residents or foreign owners to hold or vote for our shares.

6.7 Exchange rates

The table below shows the high, low, average and end-of-period exchange rates for the Norwegian krone for USD 1.00 as announced by Norges Bank (Norway's central bank).

The average is computed using the monthly average exchange rates announced by Norges Bank during the period indicated.

For the year ended 31 December	Low	High	Average	End of Period
2011	5.2369	6.0315	5.6059	5.9927
2012	5.5349	6.1471	5.8172	5.5664
2013	5.4438	6.2154	5.8753	6.0837
2014	5.8611	7.6111	6.3011	7.4332
2015	7.3593	8.8090	8.0637	8.8090

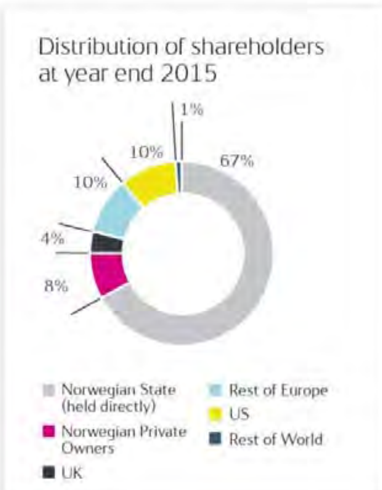
	Low	High
2015		
September	8.0891	8.5783
October	8.0524	8.5700
November	8.4636	8.6929
December	8.4842	8.8090
2016		
January	8.6641	8.9578
February	8.5111	8.7294
March (up to and including 8 March 2016)	8.5441	8.6791

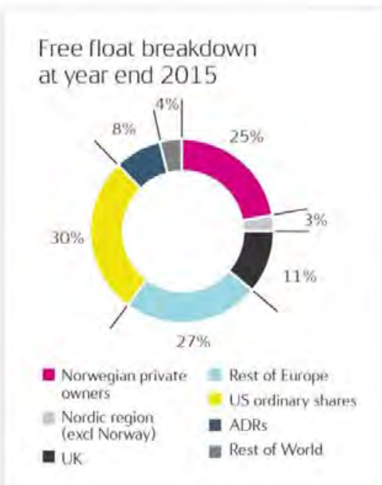
On 8 March 2016, the exchange rate announced by the Norges Bank for the Norwegian krone was USD 1.00 = NOK 8.5496.

Fluctuations in the exchange rate between the Norwegian krone and the US dollar will affect the amounts in US dollars received by holders of American Depositary Shares (ADSs) on the conversion of dividends, if any, paid in Norwegian kroner on the ordinary shares, and they may affect the US dollar price of the ADSs on the New York Stock Exchange.

6.8 Major shareholders

The Norwegian State is the largest shareholder in Statoil, with a direct ownership interest of 67%. Its ownership interest is managed by the Norwegian Ministry of Petroleum and Energy.





Pursuant to the exchange ratio agreed in connection with the merger with Hydro's oil and gas activities, the State's ownership interest in the merged company was 62.5%, or 1,992,959,739 shares, on 1 October 2007. In accordance with the Norwegian parliament's decision of 2001 concerning a minimum state shareholding in Statoil of two-thirds, the Government built up the State's ownership interest in Statoil by buying shares in the market during the period from June 2008 to March 2009. In March 2009, the Government announced that the State's direct ownership interest had reached 67%, and the Government's direct purchase of Statoil shares was completed.

As of 31 December 2015, the Norwegian State had a 67% direct ownership interest in Statoil and a 3.23% indirect interest through the National Insurance Fund (Folketrygdfondet), totaling 70.23%.

The Norwegian State is the only person or entity known to us to own beneficially, directly or indirectly, more than 5% of our outstanding shares. We have not been notified of any other beneficial owner of 5% or more of our ordinary shares as of 31 December 2015.

Statoil has one class of shares, and each share confers one vote at the general meeting. The Norwegian State does not have any voting rights that differ from the rights of other ordinary shareholders. Pursuant to the Norwegian Public Limited Liability Companies Act, a majority of at least two-thirds of the votes cast as well as of the votes represented at a general meeting is required to amend our articles of association. As long as the Norwegian State owns more than one-third of our shares, it will be able to prevent any amendments to our articles of association. Since the Norwegian State, acting through the Norwegian Minister of Petroleum and Energy, has in excess of two-thirds of the shares in the company, it has sole power to amend our articles of association. In addition, as majority shareholder, the Norwegian State has the power to control any decision at general meetings of our shareholders that requires a majority vote, including the election of the majority of the corporate assembly, which has the power to elect our board of directors and approve the dividend proposed by the board of directors.

The Norwegian State endorses the principles set out in "The Norwegian Code of Practice for Corporate Governance", and it has stated that it expects companies in which the State has ownership interests to adhere to the code. The principle of ensuring equal treatment of different groups of shareholders is a key element in the State's own guidelines. In companies in which the State is a shareholder together with others, the State wishes to exercise the same rights and obligations as any other shareholder and not act in a manner that has a detrimental effect on the rights or financial interests of other shareholders. In addition to the principle of equal treatment of shareholders, emphasis is also placed on transparency in relation to the State's ownership and on the general meeting being the correct arena for owner decisions and formal resolutions.

	Shareholders at December 2015	Number of Shares	Ownership in %
1	Government of Norway	2,136,393,559	67.00%
2	Folketrygdfondet	103,124,812	3.20%
3	SAFE Investment Company Limited	32,256,434	1.00%
4	BlackRock Institutional Trust Company, N.A.	31,513,618	1.00%
5	INVESCO Asset Management Limited	26,461,451	0.80%
6	Schroder Investment Management Ltd. (SIM)	23,330,607	0.70%
7	The Vanguard Group, Inc.	19,539,470	0.60%
8	Allianz Global Investors GmbH	18,371,484	0.60%
9	KLP Forsikring	16,642,798	0.50%
10	Storebrand Kapitalforvaltning AS	14,448,698	0.50%
11	BlackRock Investment Management, LLC	13,995,472	0.40%
12	Epoch Investment Partners, Inc.	13,815,430	0.40%
13	State Street Global Advisors (US)	13,670,590	0.40%
14	DNB Asset Management AS	13,641,273	0.40%
15	Fidelity Worldwide Investment (UK) Ltd.	11,886,480	0.40%
16	Acadian Asset Management LLC	11,578,950	0.40%
17	TIAA-CREF	11,231,159	0.40%
18	T. Rowe Price Associates, Inc.	11,003,874	0.30%
19	APG Asset Management	10,436,861	0.30%
20	AXA Investment Managers UK Ltd.	10,075,894	0.30%

Source: Data collected by third party, authorized by Statoil, December 2015

7 Corporate governance

Statoil's objective is to create long-term value for its shareholders through the exploration for and production, transportation, refining and marketing of petroleum and petroleum-derived products and other forms of energy.

In pursuing its corporate objective, Statoil is committed to the highest standard of governance and to cultivating a values-based performance culture that rewards exemplary ethical practices, respect for the environment and personal and corporate integrity. Statoil believes that there is a link between high-quality governance and the creation of shareholder value.

The work of the board of directors is based on the existence of a clearly defined division of roles and responsibilities between the shareholders, the board of directors and the company's management.

Statoil's governing structures and controls help to ensure that Statoil runs its business in a profitable manner for the benefit of shareholders, employees and other stakeholders in the societies in which Statoil operates.

The following principles underline Statoil's approach to corporate governance:
- All shareholders will be treated equally
- Statoil will ensure that all shareholders have access to up-to-date, reliable and relevant information about its activities
- Statoil will have a board of directors that is independent (as defined by Norwegian Standards) of the group's management. The board focuses on preventing conflicts of interest between shareholders, the board of directors and the company's management
- The board of directors will base its work on the principles for good corporate governance applicable at all times

Corporate governance in Statoil is subject to regular review and discussion by the board of directors.

Statoil's board of directors endorses the "Norwegian Code of Practice for Corporate Governance". The company's compliance with, and deviations from, the code's recommendations are commented on in a separate corporate governance statement issued by Statoil's board of directors. This statement, which contains further details on the corporate governance of Statoil, is available at www.statoil.com/cg.

7.1 Articles of association

The articles of association and the Norwegian Public Limited Liability Companies Act form the legal framework for Statoil's operations.

Statoil's current articles of association were adopted at the annual general meeting of shareholders on 14 May 2013.

Summary of Statoil's articles of association:

Name of the company
The registered name is Statoil ASA. Statoil is a Norwegian public limited company.

Registered office
Statoil's registered office is in Stavanger, Norway, registered with the Norwegian Register of Business Enterprises under number 923 609 016.

Object of the company
The object of Statoil is, either by itself or through participation in or together with other companies, to engage in the exploration, production, transportation, refining and marketing of petroleum and petroleum-derived products, and other forms of energy, as well as other business.

Share capital
Statoil's share capital is NOK 7,971,617,757.50 divided into 3,188,647,103 ordinary shares.

Nominal value of shares
The nominal value of each ordinary share is NOK 2.50.

Board of directors
Statoil's articles of association provide that the board of directors shall consist of nine to 11 directors. The board, including the chair and the deputy chair, shall be elected by the corporate assembly for a period of up to two years.

Corporate assembly
Statoil has a corporate assembly comprising 18 members who are normally elected for a term of two years. The general meeting elects 12 members with four deputy members, and six members with deputy members are elected by and from among the employees.

General meetings of shareholders
Statoil's annual general meeting is held no later than 30 June each year.

The meeting will consider the annual report and accounts, including the distribution of any dividend, and any other matters required by law or the articles of association.

Documents relating to matters to be dealt with at general meetings do not need to be sent to all shareholders if the documents are accessible on Statoil's website. A shareholder may nevertheless request that such documents be sent to him/her.

Shareholders may vote in writing, including through electronic communication, for a period before the general meeting. In order to practise advance voting, the board of directors must stipulate applicable guidelines. Statoil's board of directors adopted guidelines for such advance voting in March 2012, and these guidelines are described in the notices of the annual general meetings.

Marketing of petroleum on behalf of the Norwegian State
Statoil's articles of association provide that Statoil is responsible for marketing and selling petroleum produced under the SDFI's shares in production licences on the Norwegian continental shelf (NCS) as well as petroleum received by the Norwegian State paid as royalty together with its own production. Statoil's general meeting adopted an instruction in respect of such marketing on 25 May 2001, as most recently amended by authorisation of the annual general meeting on 19 May 2011.

Nomination committee
The tasks of the nomination committee are to make recommendations to the general meeting regarding the election of and fees for shareholder-elected members and deputy members of the corporate assembly, to make recommendations to the corporate assembly regarding the election of and fees for shareholder-elected members of the board of directors, to make recommendations to the corporate assembly regarding the election of the chair and the deputy chair of the board and to make recommendations to the general meeting regarding the election of and fees for members of the nomination committee.

The general meeting may adopt instructions for the nomination committee.

The full articles of association are available at Statoil.com/articlesofassociation.

7.2 Code of Conduct

Ethics - Statoil's approach
Statoil believes that responsible and ethical behavior is a necessary condition for a sustainable business. Statoil's Code of Conduct (the Code) is based on its values and reflects Statoil's commitment to high ethical standards in all its activities.

Our Code of Conduct
The Code describes Statoil's code of business practice and the requirements to expected behavior in areas such as anti-corruption, fair competition, human rights and non-discrimination working environments with equal opportunity. The Code applies to Statoil's board members, employees and hired personnel.

Statoil seeks to work with others who share its commitment to ethics and compliance, and Statoil manages its risks through in-depth knowledge of suppliers, business partners and markets. Statoil expects its suppliers and business partners to comply with applicable laws, respect internationally recognised human rights and adhere to ethical standards which are consistent with Statoil's ethical requirements when working for or together with Statoil. In joint ventures and entities where Statoil does not have control, Statoil makes good faith efforts to encourage the adoption of ethics and anti-corruption policies and procedures that are consistent with itss standards. Anyone working for Statoil who does not comply with the Code faces disciplinary action, up to and including summery dismissal or termination of their contract.

Training and Certifying the Code
Code of Conduct training and comprehensive trainings on specific issues, including anti-corruption and anti-trust, is carried out to explain how the Code applies and to describe the tools that Statoil has made available to address risk.

All Statoil employees have to annually confirm electronically that they understand and will comply with the Code (Code certification). The Code certification reminds the individuals of their duty to comply with Statoil's values and ethical requirements and creates an environment with open dialog on ethical issues, both internally and externally.

Anti-corruption compliance programme
Statoil is against all forms of corruption including bribery, facilitation payments and trading in influence and has a company-wide anti-corruption compliance programme which implements its zero-tolerance policy. The programme includes mandatory procedures designed to comply with applicable laws and regulations and training on relevant issues such as gifts, hospitality and conflicts of interest. Compliance officers, who are responsible for ensuring that ethics and anti-corruption considerations are integrated into Statoil's business activities, constitute an important part of the programme.

In 2015, Statoil focused on the systematic support and follow up of its compliance officers in the business units and on strengthening the compliance officer network within Statoil. Further, the Statoil Code of Conduct was subject to a comprehensive review, and was updated and made more user-friendly. In 2016 , the new Code will be rolled out and implemented.

Speak Up

Statoil is committed to maintain an open dialog on ethical issues. The Code requires those who have a question or suspect misconduct to raise their concern either through internal channels or through Statoil's external Ethics Helpline. Employees are encouraged to discuss their concerns with their supervisor. Statoil recognises that raising a concern is not always easy so there are have several internal channels for taking concerns forward, including through human resources or the ethics and compliance function in the legal department. Concerns can also be expressed through the externally operated Ethics Helpline which is available 24/7, and allows for anonymous reporting and two-way communication through the use of a pin-code. Statoil has a non-retaliation policy for anyone who reports in good faith.

More information about Statoil's policies and requirements related to the Code of Conduct is available on Statoil.com/ethics.

7.3 General meeting of shareholders

The general meeting of shareholders is Statoil's supreme corporate body. The objective of the general meeting is to ensure shareholder democracy and all shareholders are encouraged to participate in person or by proxy.

The general meeting of shareholders is Statoil's supreme corporate body. The 2016 annual general meeting (AGM) is scheduled for 11 May 2016 in Stavanger, Norway, with simultaneous transmission by webcast through our website. The AGM is conducted in Norwegian, with simultaneous English translation during the webcast.

The main framework for convening and holding Statoil's AGM is as follows:

Pursuant to Statoil's articles of association, the AGM must be held by the end of June each year. Notice of the meeting and documents relating to the AGM are published on Statoil's website and notice is sent to all shareholders with known addresses at least 21 days prior to the meeting. All shareholders who are registered in the Norwegian Central Securities Depository (VPS) will receive an invitation to the AGM. Other documents relating to Statoil's AGMs will be made available on Statoil's website. A shareholder may nevertheless request that documents that relate to matters to be dealt with at the AGM be sent to him/her.

Shareholders are entitled to have their proposals dealt with at the AGM if the proposal has been submitted in writing to the board of directors in sufficient time to enable it to be included in the notice of meeting, i.e. no later than 28 days before the meeting. Shareholders who are unable to attend may vote by proxy.

As described in the notice of the general meeting, shareholders may vote in writing, including through electronic communication, for a period before the general meeting.

The deadline for registration for the AGM in Statoil is the day before the AGM is due to take place.

The AGM is normally opened and chaired by the chair of the corporate assembly. If there is a dispute concerning individual matters and the chair of the corporate assembly belongs to one of the disputing parties, or is for some other reason not perceived as being impartial, another person will be appointed to chair the AGM. This is in order to ensure impartiality in relation to the matters to be considered. As Statoil has a large number of shareholders with a wide geographical distribution, Statoil offers shareholders the opportunity to follow the AGM by webcast.

The following matters are decided at the AGM:
- Approval of the board of directors' report, the financial statements and any dividend proposed by the board of directors and recommended by the corporate assembly
- Election of the shareholders' representatives to the corporate assembly and approval of the corporate assembly's fees
- Election of the nomination committee and approval of the nomination committee's fees
- Election of the external auditor and approval of the auditor's fee
- Any other matters listed in the notice convening the AGM

All shares carry an equal right to vote at general meetings. Resolutions at general meetings are normally passed by simple majority. However, Norwegian company law requires a qualified majority for certain resolutions, including resolutions to waive preferential rights in connection with any share issue, approval of a merger or demerger, amendment of the articles of association or authorisation to increase or reduce the share capital. Such matters require the approval of at least two-thirds of the aggregate number of votes cast as well as two-thirds of the share capital represented at the general meeting.

If shares are registered by a nominee in the Norwegian Central Securities Depositary (VPS), cf. section 4-10 of the Norwegian Public Limited Liability Companies Act, and the beneficial shareholder wants to vote for their shares, the beneficial shareholder must re-register the shares in a separate VPS account in their own name prior to the general meeting. If the holder can prove that such steps have been taken and that the holder has a de facto shareholder interest in the company, the holder may, in the company's opinion, vote for the shares. Decisions regarding voting rights for shareholders and proxy holders are made by the person opening the meeting, whose decisions may be reversed by the general meeting by simple majority vote.

The minutes of the AGM are made available on Statoil's website immediately after the AGM.

As regards to extraordinary general meetings (EGM), an EGM will be held in order to consider and decide a specific matter if demanded by the corporate assembly, the chair of the corporate assembly, the auditor or shareholders representing at least 5% of the share capital. The board must ensure that an EGM is held within a month of such demand being submitted.

In the following, certain types of resolutions by the general meeting of shareholders are outlined:

New share issues
If Statoil issues any new shares, including bonus shares, the articles of association must be amended. This requires the same majority as other amendments to the articles of association. In addition, under Norwegian law, the shareholders have a preferential right to subscribe for new shares issued by Statoil. The preferential right to subscribe for an issue may be waived by a resolution of a general meeting passed by the same percentage majority as required to approve amendments to the articles of association. The general meeting may, with a majority as described above, authorise the board of directors to issue new shares, and to waive the preferential rights of shareholders in connection with such share issues. Such authorisation may be effective for a maximum of two years, and the par value of the shares to be issued may not exceed 50% of the nominal share capital when the authorisation was granted.

The issuing of shares through the exercise of preferential rights to holders who are citizens or residents of the USA may require Statoil to file a registration statement in the USA under US securities laws. If Statoil decides not to file a registration statement, these holders may not be able to exercise their preferential rights.

Right of redemption and repurchase of shares
Statoil's articles of association do not authorise the redemption of shares. In the absence of authorisation, the redemption of shares may nonetheless be decided upon by a general meeting of shareholders by a two-thirds majority on certain conditions. However, such share redemption would, for all practical purposes, depend on the consent of all shareholders whose shares are redeemed.

A Norwegian company may purchase its own shares if authorisation to do so has been granted by a general meeting with the approval of at least two-thirds of the aggregate number of votes cast as well as two-thirds of the share capital represented at the general meeting. The aggregate par value of such treasury shares held by the company must not exceed 10% of the company's share capital, and treasury shares may only be acquired if, according to the most recently adopted balance sheet, the company's distributable equity exceeds the consideration to be paid for the shares. Pursuant to Norwegian law, authorisation by the general meeting cannot be granted for a period exceeding 18 months.

Distribution of assets on liquidation
Under Norwegian law, a company may be wound up by a resolution of the company's shareholders at a general meeting passed by both a two-thirds majority of the aggregate votes cast and a two-thirds majority of the aggregate share capital represented at the general meeting. The shares are ranked equally in the event of a return on capital by the company upon winding up or otherwise.

7.4 Nomination committee

Pursuant to Statoil's articles of association, the nomination committee shall consist of four members who are shareholders or representatives of shareholders.

The committee is independent of both the board of directors and the company's management.

The duties of the nomination committee are to submit recommendations to:
- the annual general meeting for the election of shareholder-elected members and deputy members of the corporate assembly, and the remuneration of members of the corporate assembly
- the annual general meeting for the election and remuneration of members of the nomination committee
- the corporate assembly for the election of shareholder-elected members of the board of directors and remuneration of the members of the board of directors and
- the corporate assembly for the election of the chair and deputy chair of the corporate assembly

Using a form on Statoil's website, shareholders can propose candidates for the board of directors, the corporate assembly and the nomination committee.

The members of the nomination committee are elected by the annual general meeting. The chair of the nomination committee and one other member are elected from among the shareholder-elected members of the corporate assembly. Members of the nomination committee are normally elected for a term of two years.

Personal deputy members for one or more of the nomination committee's members may be elected in accordance with the same criteria as described above. A deputy member only meets for the member if the appointment of that member terminates before the term of office has expired.

The members of the nomination committee are:

- Olaug Svarva (chair), Managing director at Folketrygdfondet
- Tom Rathke, Group executive vice president Wealth Management at DnB
- Elisabeth Berge, Secretary general, Norwegian Ministry of Petroleum and Energy (personal deputy for Elisabeth Berge is Bjørn Ståle Haavik, Director at the Norwegian Ministry of Petroleum and Energy)
- Tone Lunde Bakker, Global head of cash management at Danske Bank

The nomination committee held 19 ordinary meetings and three telephone meetings in 2015.

The instructions for the nomination committee, including the rules of procedure, are available at Statoil.com/nominationcommittee.

7.5 Corporate assembly

Pursuant to the Norwegian Public Limited Liability Companies Act, companies with more than 200 employees must elect a corporate assembly unless otherwise agreed between the company and a majority of its employees.

Name	Occupation	Place of residence	Year of birth	Position	Family relations to corporate executive committee, board or corporate assembly members	Share ownership for members as of 31.12.2015	Share ownership for members as of 08.03.2016	First time elected	Expiration date of current term
Olaug Svarva	Managing director, Folketrygdfondet	Oslo	1957	Chair, Shareholder-elected	No	0	0	2007	2016
Idar Kreutzer	CEO, Finance Norway (FNO)	Oslo	1962	Deputy chair, Shareholder-elected	No	0	0	2007	2016
Karin Aslaksen	Head of HR department, the National Police Directorate of Norway	Hosle	1959	Shareholder-elected	No	0	0	2008	2016
Greger Mannsverk	Managing director, Kimek AS	Kirkenes	1961	Shareholder-elected	No	0	0	2002	2016
Steinar Olsen	CEO, Jemso A/S	Stavanger	1949	Shareholder-elected	No	0	0	2007	2016
Tone Cathrine Lunde Bakker	Global head of cash management at Danske Bank	Oslo	1962	Shareholder-elected	No	0	0	2014	2016
Ingvald Strømmen	Dean at Norwegian University of Science and Technology (NTNU)	Ranheim	1950	Shareholder-elected	No	0	0	2006	2016
Rune Bjerke	President and CEO, DNB ASA	Oslo	1960	Shareholder-elected	No	0	0	2007	2016
Barbro Hætta	Medical doctor, University Hospital of North Norway	Harstad	1972	Shareholder-elected	No	0	0	2010	2016
Siri Kalvig	Associate professor, University of Stavanger	Stavanger	1970	Shareholder-elected	No	0	0	2010	2016
Terje Venold	Independent advisor with various directorships	Bærum	1950	Shareholder-elected	No	500	500	2014	2016
Kjersti Kleven	Co-owner of John Kleven AS	Ulsteinvik	1967	Shareholder-elected	No	0	0	2014	2016
Brit Gunn Ersland	Union representative, Tekna. Specialist Reservoir Tech.	Bergen	1960	Employee-elected	No	1,567	1,802	2011	2017
Steinar Kåre Dale	Union representative, NITO, SR Analyst	Mongstad	1961	Employee-elected	No	2,424	2,710	2013	2017
Per Martin Labråten	Union representative, Industri Energi. Production technician	Brevik	1961	Employee-elected	No	599	803	2007	2017
Anne K.S. Horneland	Union representative, Industri Energi	Hafrsfjord	1956	Employee-elected	No	4,575	4,902	2006	2017
Jan-Eirik Feste	Union representative, YS	Lindås	1952	Employee-elected	No	862	1,088	2008	2017
Hilde Møllerstad	Union representative, Tekna/NITO	Oslo	1966	Employee-elected	No	2,595	3,034	2013	2017
Per Helge Ødegård	Union representative, Lederne. Discipl resp operation process	Porsgrunn	1963	Employee-elected, observer	No	816	1,023	1994	2017
Dag-Rune Dale	Union representative, Industri Energi, Safety officer	Kollsnes	1963	Employee-elected, observer	No	2,787	3,058	2013	2017
Sun Lehmann	Union representative, Tekna	Trondheim	1972	Employee-elected, observer	No	2,867	3,237	2015	2017
Total						19,592	22,157		

An election of the employee-elected members of the corporate assembly was held early 2015. Effective as of 28 April 2015, Brit Gunn Ersland was elected as new member (from the former position as an observer), Sun Lehmann was elected as a new observer and Oddvar Karlsen, Jorunn Birkeland and Sten Atle Jølle were elected as new deputy members of the corporate assembly. Eldfrid Irene Hognestad (member) left the corporate assembly as of the same date. The number of deputy members for the employee-elected members of the corporate assembly was also reduced from 17 to 11 deputy members.

Pursuant to Statoil's articles of association, the corporate assembly normally consists of 18 members. Twelve members with four deputy members are nominated by the nomination committee and elected at the general meeting of shareholders, and six members, three observers and deputy members are elected by and from among the employees. Such employees are non-executive personnel.

Members of the corporate assembly are normally elected for a term of two years. Members of the board of directors and the general manager cannot be members of the corporate assembly, but they are entitled to attend and to speak at meetings of the corporate assembly unless the corporate assembly decides otherwise in individual cases.

The duties of the corporate assembly are defined in section 6-37 of the Norwegian Public Limited Liability Companies Act. The corporate assembly elects the board of directors and the chair of the board. Its responsibilities also include overseeing the board and the CEO's management of the company, making decisions on investments of considerable magnitude in relation to the company's resources and making decisions involving the rationalisation or reorganisation of operations that will entail major changes in or reallocation of the workforce.

Statoil's corporate assembly held four ordinary meetings in 2015.

All members of the corporate assembly live in Norway. Members of the corporate assembly do not have service contracts with the company or its subsidiaries providing for benefits upon termination of office.

7.6 Board of directors

Pursuant to Statoil's articles of association, the board of directors consists of between nine and 11 members. The management is not represented on the board.

At present, Statoil's board of directors consists of 10 members. As required by Norwegian company law, the company's employees are entitled to be represented by three board members. There are no board member service contracts that provide for benefits upon termination of office. Statoil's board of directors has determined that, in its judgment, all of the shareholder representatives on the board, except for Wenche Agerup, are considered independent.

The board of directors of Statoil ASA is responsible for the overall management of the Statoil group, and for supervising the group's activities in general. The board of directors handles matters of major importance or of an extraordinary nature. However, it may require the management to refer any matter to it. The board of directors appoints the president and chief executive officer (CEO), and stipulates the job instructions, powers of attorney and terms and conditions of employment for the president and CEO.

The board of directors has three sub-committees - the "audit committee", "the safety, sustainability and ethics committee", and "the compensation and executive development committee".

The board held eight ordinary board meetings and four extraordinary meetings in 2015. Average attendance at these board meetings was 95.9%.

Members of the board of directors as of 31 December 2015:

Øystein Løseth

Øystein Løseth
Position: Shareholder-elected chair of the board and chair of the board's compensation and executive committee.
Born: 1958
Term of office: Member of the board of directors of Statoil ASA since 1 October 2014, and since 1 July 2015, also chair of the board and chair of the board's compensation and executive development committee. Up for election in 2016.
Independent: Yes
Other directorships: Chair of the board of Eidsiva Energi AS.
Number of shares in Statoil ASA as of 31 December 2015: 1,000
Loans from Statoil: None
Experience: In the period 2010 - 2014, Løseth was the CEO and before that First Senior Executive Vice President (since 2009), of Vattenfall AB. In the period 2003 - 2009, Løseth worked for NUON, a Dutch energy company, first as Division Managing Director, then as a Managing Director and the CEO, from 2006 and 2008 respectively. From 2002 to 2003, Løseth was the Head of Production, Business Development and R&D of Statkraft. In addition, he has other extensive management experience from Statkraft and Statoil, within strategy and business development among others.
Education: Løseth graduated as M.Sc. from the Norwegian University of Science and Technology and has a degree in Economics from BI Norwegian School of Management in Bergen.
Family relations: No family relations to other members of the board, members of the corporate executive committee or the corporate assembly.
Other matters: In 2015, Løseth participated in eight ordinary board meetings, four extraordinary board meetings, three meetings of the compensation and executive development committee, four meetings of the audit committee and one meeting in the safety, sustainability and ethics committee. Løseth is a Norwegian citizen and resident in Norway.

Roy Franklin

Roy Franklin
Born: 1953
Position: Shareholder-elected deputy chair of the board, chair of the board's safety, sustainability and ethics committee and member of the board's audit committee.
Term of office: Deputy chair of the board of Statoil ASA from 1 July 2015. Franklin was also previously a member of the board of StatoilHydro from October 2007 and Statoil from November 2009 until June 2013. Up for election in 2016.
Independent: Yes
Other directorships: Non-executive chair of the board of Keller Group plc, a London-based international engineering company and Cuadrilla Resources Holdings Limited, a privately held UK company focusing on unconventional energy sources. Board member of the Australian oil and gas company Santos Ltd, the private equity firm Kerogen Capital Ltd and the London-based international engineering company Amec Foster Wheeler.
Number of shares in Statoil ASA as of 31 December 2015: None
Loans from Statoil ASA: None
Experience: Franklin has broad experience from management positions in several countries, including positions with BP, Paladin Resources plc and Clyde Petroleum plc.
Education: Franklin has a Bachelor of Science in Geology from the University of Southampton, UK.
Family relations: No family relations to other members of the board, members of the corporate executive committee or the corporate assembly.
Other matters: In 2015, Franklin participated in four ordinary board meetings, three meetings of the audit committee and two meetings of the safety, sustainability and ethics committee. Franklin is a UK citizen and resident in UK.

Bjørn Tore Godal

Bjørn Tore Godal
Born: 1945
Position: Shareholder-elected member of the board, the board's compensation and executive development committee and the board's safety, sustainability and ethics committee.
Term of office: Member of the board of Statoil ASA from 1 September 2010. Up for election in 2016.
Independent: Yes
Other directorships: Chair of the Council of the Norwegian Defence University College (NDUC), and vice chair of the board of the Fridtjof Nansen Institute (FNI).
Number of shares in Statoil ASA as of 31 December 2015: None
Loans from Statoil ASA: None
Experience: Godal was a member of the Norwegian parliament for 15 years during the period 1986-2001. At various times, he served as minister for trade and shipping, minister for defense, and minister of foreign affairs for a total of eight years between 1991 and 2001. From 2007-2010, Godal was special adviser for international energy and climate issues at the Norwegian Ministry of Foreign Affairs. From 2003-2007, Godal was Norway's ambassador to Germany and from 2002-2003 he was senior adviser at the department of political science at the University of Oslo.
Education: Godal has a bachelor of arts degree in political science, history and sociology from the University of Oslo.
Family relations: No family relations to other members of the board, members of the corporate executive committee or the corporate assembly.
Other matters: In 2015, Godal participated in eight ordinary board meetings, three extraordinary board meetings, seven meetings of the compensation and executive development committee and five meetings of the safety, sustainability and ethics committee. Godal is a Norwegian citizen and resident in Norway.

Jakob Stausholm

Jakob Stausholm
Born: 1968
Position: Shareholder-elected member of the board and chair of the board's audit committee.
Term of office: Member of the board of Statoil ASA since July 2009. Up for election in 2016.
Independent: Yes
Other directorships: No
Number of shares in Statoil ASA as of 31 December 2015: 50,000
Loans from Statoil: None
Experience: Chief strategy and transformation officer of Maersk Line, the largest container shipping company in the world and part of A.P. Moller - Maersk Group. From 2008 to 2011, Stausholm was chief financial officer of the global facility services provider ISS A/S. Before joining ISS's corporate executive committee, he was employed by the Shell Group for 19 years and held a number of management positions, including vice president finance for the group's exploration and production in Asia and the Pacific, chief internal auditor and CFO of group subsidiaries.
Education: M.Sc. in economics from the University of Copenhagen.
Family relations: No family relations to other members of the board, members of the corporate executive committee or the corporate assembly.
Other matters: In 2015, Stausholm participated in eight ordinary board meetings, four extraordinary board meetings and six meetings of the audit committee. Stausholm is a Danish citizen and resident in Denmark.

Maria Johanna Oudeman

Maria Johanna Oudeman
Born: 1958
Position: Shareholder-elected member of the board and member of the board's compensation and executive development committee.
Term of office: Member of the board of Statoil ASA since 15 September 2012. Up for election in 2016.
Independent: Yes
Other directorships: Oudeman is a member of the boards of Solvay SA, Het Concertgebouw, Rijksmuseum and SHV Holdings.
Number of shares in Statoil ASA as of 31 December 2015: None
Loans from Statoil: None
Experience: Oudeman is the President of Utrecht University in the Netherlands, one of Europe's leading universities. From 2010 to 2013, Oudeman was a member of the Executive Committee of Akzo Nobel, responsible for HR and Organisational Development. Akzo Nobel is the world's largest paint and coatings company and major producer of specialty chemicals, with operations in more than 80 countries. Before joining Akzo Nobel, she was Executive Director Strip Products Division at Corus Group, now Tata Steel Europe. Oudeman has extensive experience as a line manager in the steel industry and considerable international business experience.
Education: Oudeman has a law degree from Rijksuniversiteit Groningen in the Netherlands and an MBA in business administration from the University of Rochester, New York, USA and Erasmus University, Rotterdam, the Netherlands.
Family relations: No family relations to other members of the board, members of the corporate executive committee or the corporate assembly.
Other matters: In 2015, Oudeman participated in eight ordinary board meetings, four extraordinary board meetings, six meetings of the compensation and executive development committee and one meeting of the board's safety, sustainability and ethics committee. Oudeman is a Dutch citizen and resident in the Netherlands.

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Rebekka Glasser Herlofsen

Rebekka Glasser Herlofsen
Born: 1970
Position: Shareholder-elected member of the board and the board's audit committee.
Term of office: Member of the board of Statoil ASA since 19 March 2015 Up for election in 2016.
Independent: Yes
Other directorships: Member of the board of directors of DNV holding, DNV Foundation, DNV GL and member of the committee for tax and capital in the Norwegian Shipowners' Association.
Number of shares in Statoil ASA as of 31 December 2015: None
Loans from Statoil: None
Experience: Since 2012, Herlofsen has been the Chief Financial Officer in the Norwegian shipping company Torvald Klaveness. She has broad financial and strategic experience from several corporations and board directorships. Herlofsen's professional career began in the leading Nordic Investment Bank, Enskilda Securities, where she worked with corporate finance from 1995 to 1999 in Oslo and London. During the next ten years Herlofsen worked in the Norwegian shipping comp any Bergesen d.y. ASA (later BW Group). During her period with Bergesen d.y. ASA/BW Group Herlofsen held leading positions within M&A, strategy and corporate planning and was part of the group management team.
Education: MSc in Economics and Business Administration (Siviløkonom) and Certified Financial Analyst Program, the Norwegian School of Economics (NHH). Breakthrough Program for Top Executives at IMD business school, Switzerland.
Family relations: No family relations to other members of the board, members of the corporate executive committee or the corporate assembly.
Other matters: In 2015, Herlofsen participated in six ordinary board meetings, one extraordinary board meeting and four meetings of the audit committee. Herlofsen is a Norwegian citizen and resident in Norway.

Wenche Agerup

Wenche Agerup
Born: 1964
Position: Shareholder-elected member of the board, the board's compensation and executive development committee and the board's safety, sustainability and ethics committee.
Term of office: Member of the board of Statoil ASA since 21 August 2015. Up for election in 2016.
Independent: No.
Pursuant to the NYSE rules, a director will not be considered independent under the NYSE rules if the director is, or was within the past three years, an executive officer of another company at which any of the listed company's current executive officers are, or were within the past three years, members of the compensation committee. This rule also applies to foreign listed companies. Agerup was a member of Norsk Hydro ASA's management team while Irene Rummelhoff, Executive Vice President of New Energy Solutions in Statoil, was member of the board's compensation committee in Norsk Hydro. Agerup is therefore deemed as a non-independent board member in Statoil for a period of three years from 31 December 2014, i.e. until 31 December 2017.
Other directorships: Agerup is a member of the board of the seismic company TGS ASA.
Number of shares in Statoil ASA as of 31 December 2015: 2,423
Loans from Statoil: None
Experience: Agerup is an Executive Vice President and the Chief Corporate Affairs Officer in Telenor ASA. Agerup was the Executive Vice President for Corporate Staffs and the General Counsel of Norsk Hydro ASA from 2010 to 31 December 2014. She has held various executive roles in Hydro since 1997, including within the company's M&A-activities, the business area Alumina, Bauxite and Energy, as a plant manager at Hydro's metal plant in Årdal and as a project director for a Joint Venture in Australia where Hydro cooperated with the Australian listed company UMC.
Education: MA in Law from the University of Oslo, Norway (1989) and a Master of Business Administration from Babson College, USA (1991).
Family relations: No family relations to other members of the board, members of the corporate executive committee or the corporate assembly.
Other matters: In 2015, Agerup participated in three ordinary board meetings, three meetings of the compensation and executive development committee and two meetings of the safety, sustainability and ethics committee. Agerup is a Norwegian citizen and resident in Norway.

Lill-Heidi Bakkerud

Lill-Heidi Bakkerud
Born: 1963
Position: Employee-elected member of the board and member of the board's safety, sustainability and ethics committee.
Term of office: Member of the board of Statoil ASA from 1998 to 2002, and again since 2004. Up for election in 2017.
Independent: No
Other directorships: Bakkerud is a member of the executive committee of the Industry Energy (IE) trade union and holds a number of offices as a result of this.
Number of shares in Statoil ASA as of 31 December 2015: 330
Loans from Statoil: None
Experience: Bakkerud has worked as a process technician at the petrochemical plant in Bamble and on the Gullfaks field in the North Sea. She is now a full-time employee representative as the leader of the union Industri Energi's Statoil branch.
Education: Bakkerud has a craft certificate as a process/chemistry worker.
Family relations: No family relations to other members of the board, members of the corporate executive committee or the corporate assembly.
Other matters: In 2015, Bakkerud participated in eight ordinary board meetings, four extraordinary board meetings and five meetings of the safety, sustainability and ethics committee. Bakkerud is a Norwegian citizen and resident in Norway.

Ingrid Elisabeth di Valerio

Ingrid Elisabeth di Valerio
Born: 1964
Position: Employee-elected member of the board and member of the board's audit committee.
Term of office: Member of board of directors of Statoil ASA from 1 July 2013. Up for election in 2017.
Independent: No
Other directorships: Board member of First Scandinavia, Montanus AS and member of Tekna's central nomination committee.
Number of shares held in Statoil ASA as of 31 December 2015: 2,845
Loans from Statoil: None
Experience: Di Valerio has been employed by Statoil since 2005, and works within materials discipline for Technology, Projects & Drilling. Di Valerio was the union Tekna's main representative in Statoil from 2008 to 2013. She also sat on Tekna's central committee from 2005 to 2013.
Education: Chartered engineer (mathematics and physics) from the Norwegian University of Science and Technology in Trondheim (NTNU).
Familiy relations: No family relationships to other board members, members of the corporate executive committee or the corporate assembly.
Other: In 2015, di Valerio participated in eight ordinary board meetings, four extraordinary board meetings and six meetings of the audit committee. Di Valerio is a Norwegian citizen and resident in Norway.

Stig Lægreid

Stig Lægreid
Born: 1963
Position: Employee-elected member of the board and member of the board's safety, sustainability and ethics committee.
Term of office: Member of the board of directors of Statoil ASA from 1 July 2013. Up for election in 2017.
Independent: No
Other directorships: Member of The Norwegian society for Engineers and Technologists' (NITO) negotiation committee for private sector.
Number of shares held in Statoil ASA as of 31 December 2015: 1,519
Loans from Statoil: None
Experience: Employed in ÅSV and Norsk Hydro since 1985. Mainly occupied as project engineer and constructor for production of primary metals until 2005 and from 2005 as weight estimator for platform design. He is now a full-time employee representative as the leader of the union NITO, Statoil.
Education: Bachelor degree, mechanical construction from OIH.
Family relations: No family relationships to other board members, members of the corporate executive committee or the corporate assembly.
Other: In 2015, Lægreid participated in eight ordinary board meetings, four extraordinary board meetings and five meetings of the safety, sustainability and ethics committee. Lægreid is a Norwegian citizen and resident in Norway.

In addition, there are four employee-elected deputy members of the board who attend board meetings in the event an employee-elected member of the board is unable to attend.

7.6.1 Audit committee

The board of directors elects at least three of its members to serve on the board of directors' audit committee and appoints one of them to act as chair. The employee-elected members of the board of directors may nominate one audit committee member.

At year-end 2015, the audit committee members were Jakob Stausholm (chair), Roy Franklin, Rebekka Herlofsen and Ingrid di Valerio (employee-elected board member).

The audit committee is a sub-committee of the board of directors, and its objective is to act as a preparatory body in connection with the board's supervisory roles with respect to financial reporting and the effectiveness of the company's internal control system. It also attends to other tasks assigned to it in accordance with the instructions for the audit committee adopted by the board of directors. The audit committee is instructed to assist the board of directors in its supervising of matters such as:

- Monitoring the financial reporting process, including oil and gas reserves, fraudulent issues and reviewing the implementation of accounting principles and policies
- Monitoring the effectiveness of the company's internal control, internal audit and risk management systems
- Maintaining continuous contact with the statutory auditor regarding the annual and consolidated accounts
- Reviewing and monitoring the independence of the company's internal auditor and the independence of the statutory auditor, reference is made to the Norwegian Auditors Act chapter 4, and, in particular, whether services other than audits provided by the statutory auditor or the audit firm are a threat to the statutory auditor's independence

The audit committee supervises implementation of and compliance with the group's Code of Conduct in relation to financial reporting.

The internal audit function reports directly to the board of directors and to the chief executive officer.

Under Norwegian law, the external auditor is appointed by the shareholders at the annual general meeting based on a proposal from the corporate assembly. The audit committee issues a statement to the annual general meeting relating to the proposal.

The audit committee meets at least five times a year, and it meets separately with the internal auditor and the external auditor on a regular basis.

The audit committee is also charged with reviewing the scope of the audit and the nature of any non-audit services provided by external auditors. The external auditors report directly to the audit committee on a regular basis.

The audit committee is tasked with ensuring that the company has procedures in place for receiving and dealing with complaints received by the company regarding accounting, internal control or auditing matters, and procedures for the confidential and anonymous submission, via the group's ethics helpline, by company employees of concerns regarding accounting or auditing matters, as well as other matters regarded as being in breach of the group's Code of Conduct, a material violation of an applicable US federal or state securities law, a material breach of fiduciary duties or a similar material violation of any other US or Norwegian statutory provision. The audit committee is designated as the company's qualified legal compliance committee for the purposes of section 307 of the Sarbanes-Oxley Act of 2002.

In the execution of its tasks, the audit committee may examine all activities and circumstances relating to the operations of the company. In this regard, the audit committee may request the chief executive officer or any other employee to grant it access to information, facilities and personnel and such assistance as it requests. The audit committee is authorised to carry out or instigate such investigations as it deems necessary in order to carry out its tasks and it may use the company's internal audit or investigation unit, the external auditor or other external advice and assistance. The costs of such work will be covered by the company.

The audit committee is only responsible to the board of directors for the execution of its tasks. The work of the audit committee in no way alters the responsibility of the board of directors and its individual members, and the board of directors retains full responsibility for the audit committee's tasks.

The audit committee held six meetings in 2015. There was 96.3% attendance at the committee's meetings.

The board of directors has decided that a member of the audit committee, Jakob Stausholm, qualifies as an "audit committee financial expert", as defined in Item 16A of Form 20-F. The board of directors has also concluded that Jakob Stausholm, Roy Franklin and Rebekka Herlofsen are independent within the meaning of Rule 10A-3 under the Securities Exchange Act.

The committee's mandate is available at Statoil.com/auditcommittee.

7.6.2 Compensation and executive development committee

The compensation and executive development committee is a sub-committee of the board of directors that assists the board in matters relating to management compensation and leadership development.

The main responsibilities of the compensation and executive development committee are:

(1) as a preparatory body for the board, to make recommendations to the board in all matters relating to principles and the framework for executive rewards, remuneration strategies and concepts, the CEO's contract and terms of employment, and leadership development, assessments and succession planning;

(2) to be informed about and advise the company's management in its work on Statoil's remuneration strategy for senior executive and in drawing up appropriate remuneration policies for senior executives; and

(3) to review Statoil's remuneration policies in order to safeguard the owners' long-term interests.

The committee consists of up to four board members. At year-end 2015, the committee members were Øystein Løseth (chair), Bjørn Tore Godal, Maria Johanna Oudeman and Wenche Agerup. All of the committee members are non-executive directors. All members, except for Wenche Agerup, are independent.

The committee held seven meetings in 2015 and attendance was 96%.

For a more detailed description of the objective and duties of the compensation committee, please see the instructions for the compensation committee available at Statoil.com/compensationcommittee.

7.6.3 Safety, sustainability and ethics committee

The safety, sustainability and ethics committee is a sub-committee of the board of directors that assists the board in matters relating to safety, sustainability and ethics.

The safety, sustainability and ethics committee (the committee) is chaired by Roy Franklin and the other members are Bjørn Tore Godal, Wenche Agerup, Stig Lægreid (employee-elected board member) and Lill-Heidi Bakkerud (employee-elected board member).

In its business activities, Statoil is committed to comply with applicable laws and regulations and to act in an ethical, environmental, safe and socially responsible manner. The committee has been established to support our commitment in this regard, and it assists the board of directors in its supervision of the company's safety, sustainability and ethics policies, systems and principles with the exception of aspects related to "financial matters".

Establishing and maintaining a committee dedicated to safety, sustainability and ethics is intended to ensure that the board of directors has a strong focus on and knowledge of these complex, important and constantly evolving areas. The committee acts as a preparatory body for the board of directors and, among other things, monitors and assesses the effectiveness, development and implementation of policies, systems and principles in the areas of safety, sustainability and ethics, with the exception of aspects related to "financial matters".

The committee held five meetings in 2015, and attendance was 100%.

For a more detailed description of the objective, duties and composition of the committee, please see the instructions for the committee available at Statoil.com/ssecommittee.

7.7 Compliance with NYSE listing rules

Statoil's primary listing is on the Oslo Børs, but Statoil is also registered as a foreign private issuer with the US Securities and Exchange Commission and listed on the New York Stock Exchange.

American Depositary Shares represent the company's ordinary shares listed on the New York Stock Exchange (NYSE). While Statoil's corporate governance practices follow the requirements of Norwegian law, Statoil is also subject to the NYSE's listing rules.

As a foreign private issuer, Statoil is exempted from most of the NYSE corporate governance standards that domestic US companies must comply with. However, Statoil is required to disclose any significant ways in which its corporate governance practices differ from those applicable to domestic US companies under the NYSE rules. A statement of differences is set out below:

Corporate governance guidelines

The NYSE rules require domestic US companies to adopt and disclose corporate governance guidelines. Statoil's corporate governance principles are developed by the management and the board of directors, in accordance with the Norwegian Code of Practice for Corporate Governance and applicable law. Oversight of the board of directors and management is exercised by the corporate assembly.

Director independence

The NYSE rules require domestic US companies to have a majority of "independent directors". The NYSE definition of an "independent director" sets out five specific tests of independence and also requires an affirmative determination by the board of directors that the director has no material relationship with the company.

Pursuant to Norwegian company law, Statoil's board of directors consists of members elected by shareholders and employees. Statoil's board of directors has determined that, in its judgment, all of the shareholder-elected directors, except one, are independent. In making its determinations of independence, the board focuses inter alia on there not being any conflicts of interest between shareholders, the board of directors and the company's management, but it does not explicitly make its determination based on the NYSE's five specific tests. The directors elected from among Statoil's employees would not be considered independent under the NYSE rules because they are employees of Statoil. None of the employee-elected directors is an executive officer of the company.

For further information about the board of directors see section 7.6 *Board of directors*.

Board committees

Pursuant to Norwegian company law, managing the company is the responsibility of the board of directors. Statoil has an audit committee, a safety, sustainability and ethics committee and a compensation and executive development committee. They are responsible for preparing certain matters for the board of directors. The audit committee and the compensation and executive development committee operate pursuant to charters that are broadly comparable to the form required by the NYSE rules. They report on a regular basis to, and are subject to, continuous oversight by the board of directors. For further information about the board's sub-committees, see sections 7.6.1 *Audit Committee,* 7.6.2 *Compensation and executive development committee and 7.6.3 Safety, sustainability and ethics committee.*

Statoil complies with the NYSE rule regarding the obligation to have an audit committee that meets the requirements of Rule 10A-3 of the US Securities Exchange Act of 1934.

As required by Norwegian company legislation, the members of Statoil's audit committee include an employee-elected director. Statoil relies on the exemption provided for in Rule 10A-3(b)(1)(iv)(C) from the independence requirements of the US Securities Exchange Act of 1934 with respect to the employee-elected director. Statoil does not believe that its reliance on this exemption will materially adversely affect the ability of the audit committee to act independently or to satisfy the other requirements of Rule 10A-3 relating to audit committees. The other members of the audit committee meet the independence requirements under Rule 10A-3.

Among other things, the audit committee evaluates the qualifications and independence of the company's external auditor. However, in accordance with Norwegian law, the auditor is elected by the annual general meeting of the company's shareholders.

Statoil does not have a nominating/corporate governance sub-committee formed from its board of directors. Instead, the roles prescribed for a nominating/corporate governance committee under the NYSE rules are principally carried out by the corporate assembly and the nomination committee which is elected by the general meeting of shareholders. NYSE rules require the compensation committee of US companies to comprise independent directors under the NYSE rules, recommend senior management remuneration and make a determination on the independence of advisors when engaging them. Statoil, as foreign private issuer, is exempt from complying with these rules and is permitted to follow its home country regulations. Statoil considers all its compensation committee members to be independent, cf. the discussion on director independence above. Statoil's compensation committee makes recommendations to the board about management remuneration, including that of the CEO. The compensation committee assesses its own performance and has the authority to hire external advisors. The nomination committee, which is elected by the general meeting of shareholders, recommends to the corporate assembly the candidates and remuneration of the board of directors. Also, the nomination committee recommends to the general meeting of shareholders the candidates and remuneration of the corporate assembly and the nomination committee.

Shareholder approval of equity compensation plans

The NYSE rules require that, with limited exemptions, all equity compensation plans must be subject to a shareholder vote. Under Norwegian company law, although the issuance of shares and authority to buy back company shares must be approved by Statoil's annual general meeting of shareholders, the approval of equity compensation plans is normally reserved for the board of directors.

7.8 Management

The president and CEO has overall responsibility for day-to-day operations in Statoil and appoints the corporate executive committee (CEC). Each of the members of the CEC is head of a separate business area or staff function.

The president and CEO has overall responsibility for day-to-day operations in Statoil. The president and CEO is responsible for developing Statoil's business strategy and presenting it to the board of directors for decision, for the execution of the business strategy and for cultivating a performance-driven, value-based culture.

The president and CEO appoints the corporate executive committee. Members of the CEC have a collective duty to safeguard and promote Statoil's corporate interests and to provide the president and CEO with the best possible basis for deciding the company's direction, making decisions and executing and following up business activities. In addition, each of the CEC members is head of a separate business area or staff function.

Members of Statoil's corporate executive committee as of 31 December 2015:

Eldar Sætre, President and CEO

Eldar Sætre
Born: 1956
Position: President and chief executive officer of Statoil ASA since 15 October 2014.
External offices: Member of the board of Strømberg Gruppen AS and Trucknor AS.
Number of shares in Statoil ASA as of 31 December 2015: 39,130
Loans from Statoil: None
Experience: Sætre joined Statoil in 1980. Executive vice president and CFO from October 2003 until December 2010. Executive vice president for Marketing, Midstream and Processing (MMP) from 2011 until 2014.
Education: MA in business economics from the Norwegian School of Economics and Business Administration (NHH) in Bergen.
Family relations: No family relations to other members of the CEC, members of the board or the corporate assembly.
Other matters: Sætre is a Norwegian citizen and resident in Norway.

Hans Jakob Hegge, Chief financial officer (CFO)

Hans Jakob Hegge
Born: 1969
Position: Executive vice president and chief financial officer (CFO) of Statoil ASA since 1 August 2015.
External offices: None
Number of shares in Statoil ASA as of 31 December 2015: 22,854
Loans from Statoil: None
Experience: Hegge has held several managerial positions in Statoil, including Senior Vice President (SVP) for Operations North in Development and Production Norway (DPN) (2013-2015), SVP for Operations East (2011-2013) in DPN, SVP for Operational Development in DPN (2009-2011) and SVP for Global Business Services in Chief Financial Officer area (CFO) (2005-2009). From 1995 to 2004 he held various positions in DPN, Natural Gas business area and corporate functions in Statoil.
Education: Master of Science degree from the Norwegian School of Economics and Business Administration (NHH).
Family relations: No family relations to other members of the CEC, members of the board or the corporate assembly.
Other matters: Hegge is a Norwegian citizen and resident in Norway.

Anders Opedal, Chief operating officer (COO)

Anders Opedal
Born: 1968
Position: Executive vice president and chief operating officer (COO) of Statoil ASA since 1 April 2015.
External offices: None
Number of shares in Statoil ASA as of 31 December 2015: 14,511
Loans from Statoil: None
Experience: Opedal joined Statoil in 1997 as a petroleum engineer in the Statfjord operations. He has held a range of positions in Drilling and well, Procurement and projects. In 2011 Opedal took on the role as Senior Vice President for Projects in Technology, Projects and Drilling (TPD) responsible for Statoil's approximately NOK 300 billion project portfolio. Before joining Statoil, Opedal worked for Schlumberger and Baker Hughes.
Education: MBA from Heriot-Watt University and an engineering degree from NTH.
Family relations: No family relations to other members of the CEC, members of the board or the corporate assembly.
Other matters: Opedal is a Norwegian citizen and resident in Norway.


Lars Christian Bacher, Executive vice president Development and Production International (DPI)

Lars Christian Bacher
Born: 1964
Position: Executive vice president of Statoil ASA since 1 September 2012.
External offices: None
Number of shares in Statoil ASA as of 31 December 2015: 21,116
Loans from Statoil ASA: None
Experience: Bacher joined Statoil in 1991 and has held a number of leading positions in Statoil, including that of platform manager on the Norne and Statfjord fields on the Norwegian continental shelf. He was in charge of the merger process involving the offshore installations of Norsk Hydro and Statoil. Bacher has also been senior vice president for Gullfaks operations and subsequently for the Tampen area. His most recent position, which he held from September 2009, was as senior vice president for Statoil's Canadian operations in Development & Production USA (DPUSA).
Education: Master of science in chemical engineering from the Norwegian Institute of Technology (NTH). He also holds a master's degree in finance from the Norwegian School of Economics and Business Administration (NHH).
Family relations: No family relations to other members of the corporate executive committee, the board of directors or the corporate assembly.
Other matters: Bacher is a Norwegian citizen and resident in Norway.


Torgrim Reitan, Executive vice president Development and Production USA (DPUSA)

Torgrim Reitan
Born: 1969
Position: Executive vice president of Statoil ASA since 1 January 2011.
External offices: None
Number of shares in Statoil ASA as of 31 December 2015: 28,482
Loans from Statoil: None
Experience: From 1 January 2011 to 1 August 2015 Reitan held the position as executive vice president and chief financial officer of Statoil (CFO). He has held several managerial positions in Statoil, including senior vice president (SVP) in trading and operations in the Natural Gas business area (2009 - 2010), SVP in performance management and analysis (2007 - 2009) and SVP in performance management, tax and M&A (2005 - 2007). From 1995 to 2004, Reitan held various positions in the Natural Gas business area and corporate functions in Statoil.
Education: Master of science degree from the Norwegian School of Economics and Business Administration (NHH).
Family relations: No family relations to other members of the CEC, members of the board or the corporate assembly.
Other matters: Reitan is a Norwegian citizen and resident in the United States.


John Knight, Executive vice president Global Strategy and Business Development (GSB)

John Knight
Born: 1958
Position: Executive vice president of Statoil ASA since 1 January 2011.
External offices: Member on the advisory board of the Columbia University Center on Global Energy Policy in New York. Chair of ONS16 Conference Committee in Stavanger, Norway and member on the advisory board of Imperial College Business School MsC Climate Change Management and Finance in London.
Numbers of shares in Statoil ASA as of 31 December 2015: 85,731
Loans from Statoil ASA: None
Experience: Knight held several central managerial positions in International Operations in Statoil since 2002, mainly in business development. Between 1987 and 2002, Knight held various positions in energy investment banking. From 1977 to 1987, he qualified and worked as a barrister/lawyer, and was employed by Shell Petroleum in London during the period 1985-1987.
Education: Knight has first and post-graduate degrees in law from Cambridge University and the Inns of Court School of Law in London.
Family relations: No family relations to other members of the CEC, members of the board or the corporate assembly.
Other matters: Knight is a British citizen and resident in England.


Tim Dodson. Executive vice president, Exploration (EXP)

Tim Dodson
Born: 1959
Position: Executive vice president of Statoil ASA since 1 January 2011.
External offices: None
Number of shares in Statoil ASA as of 31 December 2015: 28,614
Loans from Statoil ASA: None
Experience: Dodson has worked in Statoil since 1985 and held central management positions in the company, including the positions of senior vice president for global exploration, Exploration & Production Norway and the technology arena.
Education: Master of science in geology and geography from the University of Keele.
Family relations: No family relations to other members of the CEC, members of the board or the corporate assembly.
Other matters: Dodson is a British citizen and resident in Norway.

Margareth Øvrum. Executive vice president Technology, Projects and Drilling (TPD)

Margareth Øvrum
Born: 1958
Position: Executive vice president of Statoil ASA since September 2004.
External offices: Member of the board of Atlas Copco AB (Sweden) and Alfa Laval (Sweden).
Number of shares in Statoil ASA as of 31 December 2015: 42,621
Loans from Statoil: None
Experience: Øvrum has worked for Statoil since 1982 and has held central management positions in the company, including the position of executive vice president for health, safety and the environment and executive vice president for Technology & Projects. Øvrum was the company's first female platform manager, on the Gullfaks field. She was senior vice president for operations for Veslefrikk and vice president of operations support for the Norwegian continental shelf.
Education: Master's degree in engineering (sivilingeniør) from the Norwegian Institute of Technology (NTH) in Trondheim, specialising in technical physics.
Family relations: No family relations to other members of the CEC, members of the board or the corporate assembly.
Other matters: Øvrum is a Norwegian citizen and resident in Norway.

Arne Sigve Nylund, Executive vice president Development and production Norway (DPN)

Arne Sigve Nylund
Born: 1960
Position: Executive vice president of Statoil ASA since 1 January 2014.
External offices: Member of the board of directors of The Norwegian Oil & Gas Association (Norsk Olje & Gass).
Number of shares in Statoil ASA as of 31 December 2015: 9,261
Loans from Statoil: None
Experience: Employed by Mobil Exploration Inc. from 1983-1987. Since 1987, Nylund has held several central management positions in Statoil ASA.
Education: Mechanical engineer from Stavanger College of Engineering with further qualifications in operational technology from Rogaland Regional College/University of Stavanger (UiS). Business graduate of the Norwegian School of Business and Management (NHH).
Family relations: No family relations to other members of the CEC, members of the board or the corporate assembly.
Other matters: Nylund is a Norwegian citizen and is resident in Norway.

Jens Økland, executive vice president Marketing, Midstream and Processing (MMP)

Jens Økland
Born: 1969
Position: Executive vice president of Statoil ASA since 1 June 2015.
External offices: None
Number of shares in Statoil ASA as of 31 December 2015: 10,735
Loans from Statoil ASA: None
Experience: Økland joined Statoil in 1994 and has mainly worked in the midstream and downstream sectors. Before becoming executive vice president of MMP, Økland worked as vice president of operations for the Åsgard area in Development and Production Norway. Åsgard ranks among the largest developments on the Norwegian continental shelf, supplying about 11 billion cubic metres of gas annually to Europe. Previously Økland was senior vice president of Statoil's natural gas portfolio and supply business in North America, marketing and developing infrastructure solutions for equity and non-equity production. Before heading up Statoil's downstream gas division in North America, he had senior marketing and business development positions within natural gas in Europe mainly focusing on Germany, Statoil's largest gas market.
Education: MSc in business from BI Norwegian Business School.
Family relations: No family relations to other members of the CEC, members of the board or the corporate assembly.
Other matters: Økland is a Norwegian citizen and resident in Norway.

Irene Rummelhoff, executive vice president New Energy Solutions (NES)

Irene Rummelhoff
Born: 1967
Position: Executive vice president of Statoil ASA since 1 June 2015.
External offices: Member of the board of directors of Norsk Hydro ASA.
Number of shares in Statoil ASA as of 31 December 2015: 17,082
Loans from Statoil ASA: None
Experience: Rummehoff joined Statoil in 1991. She has held a number of management positions within international business development, exploration, and the downstream business in Statoil.
Education: Master's degree in petroleum geosciences from the Norwegian Institute of Technology (NTH).
Family relations: No family relations to other members of the CEC, members of the board or the corporate assembly.
Other matters: Rummehoff is a Norwegian citizen and resident in Norway.

Statoil has granted loans to the Statoil-employed spouse of certain of the Executive Vice Presidents as part of its general loan arrangement for Statoil employees. Employees in salary grade 12 or higher may take out a car loan from Statoil in accordance with standardised provisions set by the company. The standard maximum car loan is limited to the cost of the car, including registration fees, but not exceeding NOK 300,000. Employees outside the collective labour area are entitled to a car loan up to NOK 575,000 (vice presidents and senior vice presidents) or NOK 475,000 (other positions). The car loan is interest-free, but the tax value, "interest advantage", must be reported as salary. Permanent employees in Statoil ASA may also apply for a consumer loan up to NOK 300.000. The interest rate on consumer loans is corresponding to the standard rate in effect at any time for "reasonable loans" from employer as decided by the Norwegian Ministry of Finance, i.e. the lowest rate an employer may offer without triggering taxation of the advantage for the employee.

7.9 Compensation to governing bodies

This section describes the compensation to the board of directors, the corporate executive committee and the corporate assembly.

In 2015, the aggregate compensation to the corporate assembly was NOK 1,047,143, to the members of the board of directors NOK 5,950,035 and to the members of the corporate executive committee NOK 87,763,000 (all in rounded figures).

The members of the corporate assembly and the board of directors have an annual, fixed remuneration, except for deputy members who receive remuneration per meeting. In addition, board members resident outside of Scandinavia or outside of Europe receive additional travel fees (based on two different travel fee rates) per board meeting attended. The shareholder-elected and employee-elected members of the corporate assembly and the board are entitled to the same remuneration rates.

Detailed information about the individual compensation to the members of the board of directors and members of the corporate executive committee in 2015 is provided in the tables below.

Members of the board (figures in NOK thousand)	Board of directors	Audit committee	Compensation and executive development committee	SSE committee	Total remuneration
Øystein Løseth[1)]	557	65	65	-	687
Svein Rennemo[2)]	357	-	53	-	410
Grace Reksten Skaugen[3)]	98	-	27	-	125
Jakob Stausholm	373	207	-	-	580
Bjørn Tore Godal	373	-	84	93	550
Lill Heidi Bakkerud	373	-	-	84	457
Maria Johanna Oudeman	503	-	84	-	587
Catherine Hughes[4)]	198	-	-	37	235
James Mulva[5)]	307	65	-	-	373
Stig Lægreid	373	-	-	84	457
Ingrid Elisabeth di Valerio	373	134	-	-	507
Roy Franklin[6)]	261	68	-	65	394
Wenche Agerup[7)]	138	-	31	31	200
Rebekka Glasser Herlofsen[8)]	296	91	-	-	387
Total	4,580	631	344	395	5,950

1) Chair of the board from 1 July 2015
2) Chair of the board until and including 30 June 2015 (resigned)
3) Deputy chair until and including 18 March 2015 (resigned)
4) Member until and including 15 April 2015 (resigned)
5) Member until and including 30 June 2015 (resigned)
6) Deputy chair from 1 July 2015
7) Member from 21 August 2015
8) Member from 19 March 2015

Members of corporate executive committee in 2015 (figures in NOK thousand)[1]	Fixed remuneration			Annual variable pay[5]	Taxable benefits	Taxable compensatio n	Non-taxable benefits in kind	Estimated pension cost[6]	Estimated present value of pension obligation[7, 8]
	Fixed pay[2]	Cash allowance[3]	LTI[4]						
Eldar Sætre[9, 11]	7,748	0	2,492	3,504	421	14,165	0	0	79,699
Hans Jakob Hegge[9]	1,349	44	302	324	7	2,025	0	273	7,753
Torgrim Reitan[9, 10]	1,881	0	0	1,022	337	3,239	0	979	12,727
Torgrim Reitan - CFO[9]	1,890	0	761	0	117	2,769	0	0	0
Lars Christian Bacher	3,266	0	739	843	377	5,226	437	872	14,191
Timothy Dodson	3,695	0	803	789	148	5,435	321	1,109	33,022
Margareth Øvrum	3,805	0	867	1,241	152	6,066	127	0	48,435
Arne Sigve Nylund	3,345	0	725	1,352	146	5,568	0	833	28,586
Jens Økland[9]	1,684	41	394	526	11	2,655	0	354	5,669
Tor Martin Anfinnsen[9]	1,298	0	281	584	104	2,266	0	390	22,576
Irene Rummelhoff[9]	1,563	38	365	395	11	2,371	0	386	7,585
Anders Opedal[9]	2,323	44	544	761	11	3,682	0	547	7,540
William Maloney[8, 9]	3,933	0	4,625	4,625	1,226	14,410	138	698	0
John Knight[2, 8]	8,695	0	3,468	3,468	1,231	16,863	0	0	0

1) All figures in the table are presented on accrual basis.
2) Fixed pay consists of base salary, holiday allowance and other administrative benefits. John Knight's fixed pay also includes a cash supplement that replaces his defined contribution pension plan.
3) Cash allowance in lieu of pension accrual above 12 G (the base amount in the national insurance scheme).
4) The fixed long-term incentive (LTI) element implies an obligation to invest the net amount in Statoil shares. A lock-in period of 3 years applies for the investment. The LTI element is presented the year it is granted for the members of the corporate executive committee employed by Statoil ASA. Members of the corporate executive committee employed by non-Norwegian subsidiaries have a LTI scheme deviating from the model used in the parent company. A net amount equivalent to the annual variable pay is used for purchasing Statoil shares.
5) Annual variable pay includes holiday allowance for corporate executive committee (CEC) members resident in Norway.
6) Estimated pension cost for CEC members under defined benefit plans (Eldar Sætre, Timothy Dodson, Margareth Øvrum, Arne Sigve Nylund and Tor Martin Anfinnsen) is calculated based on actuarial assumptions and pensionable salary (mainly base salary) at 31 December 2014 and is recognised as pension cost in the statement of income for 2015. The other CEC members have defined contribution plans including notional contribution plans and the contributions in the reporting period are recognised as pension cost in the statement of income. Payroll tax is not included. For further information, see note 19 *Pensions*.
7) Torgrim Reitan, Lars Christian Bacher, Hans Jakob Hegge, Jens Økland, Irene Rummelhoff and Anders Opedal were transferred to a defined contribution plan from 1 April 2015. Paid-up policies and rights letters issued in 2015 related to the defined benefit plans as well as the notional contribution plans are included in the present value of pension obligation at 31 December 2015. Estimated present value of pension obligation for the rest of the members of CEC employed by Statoil ASA, are presented with the defined benefit obligation.
8) William Maloney and John Knight's remuneration is in local currency US Dollar and British Pound, respectively. For John Knight the figures in the table are presented in NOK, using average currency rates in 2015. For William Maloney the average currency rates for the period 1 January to 30 September 2015 are used. The change in currency rates during the year, such as strengthening of USD and GBP versus NOK, impacts the development from 2014 to 2015. William Maloney's variable compensation is paid in 2015.
9) Eldar Sætre resumed role as acting chief executive officer (CEO) from 15 October 2014 until 3 February 2015. The 4 February Eldar Sætre was appointed as CEO on a permanent basis. Tor Martin Anfinnsen acted as executive vice president for Marketing, Midstream and Processing (MMP) from 15 October 2014 until 31 May 2015. Jens Økland was appointed executive vice president for MMP from 1 June 2015. William Maloney resigned as executive vice president for Development and Production North America (DPNA) July 31 and was followed by Torgrim Reitan who started as executive vice president for Development and Production USA (DPUSA) 1 August 2015. Hans Jakob Hegge was appointed executive vice president and chief financial officer from 1. August 2015. Irene Rummelhoff was appointed executive vice president for the newly established business area New Energy Solutions (NES) on 1 June 2015. Anders Opedal was appointed on 1 April 2015 in the new position chief operating officer (COO).
10) Compensation and benefit including standard international assignment terms for Torgrim Reitan during his tenure as executive vice president in DPUSA, commencing 1 August 2015.
11) Fixed pay for Eldar Sætre includes fixed remuneration element of NOK 1 815 000 not included in pensionable salary

There are no loans from the company to members of the corporate executive committee.

Former chief executive officer Helge Lund has in 2015 paid back NOK 5 033 491 in LTI bonus received in 2012, 2013 and 2014. He has received compensations and benefits that amount to NOK 2.7 million in 2015. The amount is related to base salary for the period 1 January to 8 February 2015 and final settlement payments such as holiday allowance earned in 2014 and 2015.

	Fixed remuneration							
Members of corporate executive committee in 2014 (figures in NOK thousand)[1)]	Fixed pay[3)]	LTI[6)]	Annual variable pay[7)]	Taxable benefits in kind	Taxable compensation	Non-taxable benefits in kind	Estimated pension cost[8)]	Estimated present value of pension obligation[4), 9)]
Helge Lund[4), 5), 9)]	5,640	2,165	-	249	8,054	199	6,008	73,944
Torgrim Reitan[9)]	3,283	761	1,066	126	5,237	-	879	16,339
Lars Christian Bacher[9)]	3,256	739	1,034	363	5,393	428	685	15,879
Timothy Dodson	3,496	803	1,124	175	5,597	313	1,343	32,689
Margareth Øvrum	3,779	867	1,457	250	6,352	98	1,349	48,701
Arne Sigve Nylund[5)]	2,984	725	1,421	108	5,239	-	773	26,646
Eldar Sætre - CEO[5)]	1,370	-	689	35	2,094	-	989	46,769
Eldar Sætre - MMP	2,685	858	901	143	4,588	-	-	-
Tor Martin Anfinnsen[5)]	817	-	239	90	1,147	-	234	22,196
William Maloney[2), 8)]	4,333	2,167	2,167	960	9,627	166	713	-
John Knight[2), 3)]	7,132	2,845	2,845	1,133	13,955	-	-	-

1) All figures in the table are presented on accrual basis.

2) William Maloney and John Knight's remuneration is in local currency US Dollar and British Pound, respectively. The figures in the table are presented in NOK, using average currency rates in 2014.

3) Fixed pay consist of base salary, holiday allowance and any other administrative benefits. The figures are presented on accrual basis. John Knight's fixed pay also includes a cash supplement that replaces his defined contribution pension plan in 2014.

4) Helge Lund resigned from his position as CEO of Statoil 15 October 2014. Helge Lund has received salary and benefits that amounts to NOK 1.8 million in 2014 after his resignation as chief executive officer, not included in the table above. The pension liability listed in the table above represents the estimated present value of his pension obligation as of 31 December 2014. In line with the company's LTI policy, resignation during the lock-in period is regarded as a non-fulfilment of the LTI obligations. Following his resignation Helge Lund was obliged to pay back to Statoil a total of NOK 5 033 491, calculated based on the value of the locked shares acquired under the LTI program.

5) Following Helge Lund's resignation, Eldar Sætre resumed role as acting CEO with immediate effect on 15 October 2014, and Tor Martin Anfinnsen replaced Eldar Sætre as acting executive vice president for Marketing, Midstream and Processing (MMP). Arne Sigve Nylund replaced Øystein Michelsen from January 2014.

6) The fixed long-term incentive (LTI) element implies an obligation to invest the net amount in Statoil shares. A lock-in period of 3 years applies for the investment. The LTI element is presented the year it is granted for the members of the corporate executive committee employed by Statoil ASA. Members of the corporate executive committee employed by non-Norwegian subsidiaries have a LTI scheme deviating from the model used in the parent company. A net amount equivalent to the annual variable pay is used for purchasing Statoil shares, and the figures are presented on accrual basis.

7) Annual variable pay includes holiday allowance, and is presented on accrual basis.

8) Estimated pension cost is calculated based on actuarial assumptions and pensionable salary (mainly base salary) at 31 December 2013 and is recognised as pension cost in the statement of income for 2014. Payroll tax is not included. William Maloney is employed by a non-Norwegian entity and his pension cost reflects the payment under the entity's defined contribution plan made in 2014.

9) Torgrim Reitan and Lars Christian Bacher was transferred to a defined contribution plan from 1 April 2015, and the Estimated present value of pension obligation per 31 December 2014 reflects this change. Estimated present value of pension obligation related to Helge Lund, Torgrim Reitan and Lars Christian Bacher, are based on the estimated value of paid-up policies and rights letters to be issued in 2015, related to Helge Lund's resignation and the termination of Torgrim Reitan and Lars Christian Bacher's defined benefit pension plan. Estimated present value of pension obligation for the rest of the members of the corporate executive committee employed by Statoil ASA, are presented with the defined benefit obligation.

1 Remuneration policy and concept for the accounting year 2016

Reference is made to the document "Statement on remuneration for Statoil's Corporate Executive Committee", which is available at www.statoil.com, for a detailed description of the remuneration and remuneration policy for executive management applicable for the years 2015 and 2016. The main elements of Statoil's executive remuneration are described in the paragraphs below.

1.1 Policy and principles

The board of directors has in 2015 decided to introduce several new elements to the company's executive remuneration concept. The revised governmental guidelines on executive remuneration as of 13 February 2015 ("2015 governmental guidelines") entailed adjustments with impact on the company's executive remuneration concept. Changes to the pension system and the long-term incentive scheme are implemented to align with the 2015 governmental guidelines on executive remuneration. In addition the company has initiated improvements to strengthen the link between executive remuneration and the company's overall performance and results.

The changes include:

- a cap on pension contribution at the maximum limit in the tax-favoured joint pension schemes in Norway (currently 12 G[2])
- adjustment to the long-term incentive scheme (LTI)
- a company performance modifier
- a threshold for variable pay

These changes are described in section 1.2-1.5 below.
The company performance modifier is subject to approval by the 2016 annual general meeting (AGM) cf. section 5.

Other than described in this section, the company's established remuneration principles and concepts as described in previous years Statements on remuneration and other employment terms for Statoil's corporate executive committee will be continued in the accounting year 2016.

The remuneration concept is an integrated part of our values based performance framework. It has been designed to:

- reflect our global competitive market strategy and local market conditions
- strengthen the common interests of employees in the Statoil group and its shareholders
- be in accordance with statutory regulations and good corporate governance
- be fair, transparent and non-discriminatory
- equally reward and recognise "what" we deliver and "how" we deliver
- differentiate on the basis of responsibilities and performance
- reward both short- and long-term contributions and results

1.2 Cap on pension contribution at the maximum limit in the tax-favoured joint pension schemes in Norway

In the White Paper no. 27 (2013- 2014) the Government announced changes to its policy relating to pension contribution in companies where the State has majority ownership. The State would no longer support pension contribution above 12 G. This policy change was manifested in 2015 governmental guidelines on executive remuneration. In order to align with the 2015 governmental guidelines, Statoil ASA has introduced a cap at 12 G for pension contribution for new members of the corporate executive committee appointed after the effective date of the 2015 governmental guidelines.

In lieu of pension contribution for income above 12 G, new internal members of the corporate executive committee will be eligible for compensation. The compensation level will be dependent on the candidate's pension terms and base salary level and will be in the range of 15 - 20% of his/her base salary.

1.3 Adjustments to the long-term incentive scheme in Statoil ASA

According to the 2015 governmental guidelines, the long-term incentive (LTI) scheme is defined as variable remuneration. Earlier this was part of the fixed remuneration and included in the basis for calculating the participants' annual variable pay. This practice will be discontinued with the effect from earning year 2016. The LTI scheme as variable remuneration will have a maximum annual grant at 30% of the participants' fixed remuneration c.f. section 1.6 below.

1.4 Threshold

The board of directors has decided to introduce a threshold in the reward concept as a pre-requisite for the payment of variable pay and grant of long-term incentive (LTI). The threshold will have effect on the long-term incentive grant in 2016 provided this is not impeded by obligations in individual agreements. From the earning year 2016 the threshold will be applied on annual variable pay payments in 2017 and onwards. The threshold is based on Statoil group's full-year adjusted earnings after tax, requiring that a minimum level of earnings must be achieved for any payments to be made. This minimum level has been set at USD 2 billion. Earnings between USD 2 and 3.3 will result in bonus payments reduced by 50%. Above USD 3.3 billion the threshold is fully achieved and variable pay payments are not affected. Prior to application of the threshold an assessment of the company's overall performance in relation to the adjusted earnings results shall be made by the board of directors based on recommendations by the board compensation and executive development committee.

1.5 Company performance modifier

Subject to approval by the 2016 annual general meeting, a company performance modifier is introduced in the calculations for variable pay schemes from 2016 with subsequent impact on variable pay from 2017 onwards. The company performance modifier determines the proportion of the bonus factor that

[2] *The base amount in the Norwegian national insurance scheme, currently NOK 90,068*

will be paid, ranging from 50% to 150%. Company performance is assessed against two equally weighted measures: relative total shareholder return (TSR) and relative return on average capital employed (RoACE).

1.6 The remuneration concept for the corporate executive committee

Statoil's remuneration concept for the corporate executive committee consists of the following main elements:

- Fixed remuneration (base salary) and as applicable cash compensation
- Variable pay (annual variable pay (AVP) and long-term Incentive (LTI))
- Benefits (primarily pension, insurance and share savings plan)

Fixed remuneration consists of base salary, and as applicable cash compensation. The cash compensation is applied in lieu of pension contribution above 12 G as described in section 1.2 above or as a fixed remuneration to be competitive in the market.

The variable pay elements for members of the corporate executive committee in the parent company are:

- annual variable pay scheme which has a maximum potential of 50% of fixed remuneration
- LTI scheme with a maximum grant of 30% of fixed remuneration. The LTI grant level is differentiated related to position level. The obligation to invest the net LTI amount in Statoil shares and keep for a lock in period of 3 years will be continued.

The annual variable pay will be subject to the company performance modifier ref. section 1.5 above. Irrespective of the performance modifier results, the annual variable pay will have a maximum at 50% of the fixed remuneration.

The main benefit programmes applicable to senior executives are the general pension scheme, the insurance scheme and the employee share savings plan. In 2015 Statoil implemented a defined contribution scheme as the new general pension scheme. With the exception of employees who were 15 years or less from regular retirement age at 31th December 2014, all employees have been transferred to the new scheme. The employees exempted from transfer will retain the defined benefit scheme.

Deviations from the general principles outlined below pertaining to one current member and one former member of the corporate executive committee, implemented with effect as of 1 January 2011, are described in the statement on executive remuneration. These deviations have also been described in previous statements on remuneration and other employment terms for Statoil's corporate executive committee.

The main elements of Statoil's executive remuneration are described in more detail in the table below.

Main Elements - Statoil Executive Remuneration			
Remuneration Element	**Objective**	**Award level**	**Performance criteria**
Base Salary	Attract and retain the right high-performing individuals providing competitive but not market-leading terms.	We offer base salary levels which are aligned with the individual's responsibility and performance at a level which is competitive in the markets in which we operate.	The evaluation of performance is based on the fulfilment of pre-defined goals; see element Annual Variable Pay below. The base salary is normally subject to annual review.
Long-Term Incentive (LTI)	Strengthen the alignment of top management and shareholder interests and retention of key employees.	The LTI system is a, monetary compensation calculated as a portion of the participant's base salary; with a maximum annual grant at 30% of fixed remuneration. On behalf of the participant, the company acquires shares equivalent to the net annual amount. The grant is subject to a three year lock-in period and then released for the participant's disposal. Deviations applicable for executive vice presidents employed outside the parent company are described in the statement on executive remuneration. The threshold principles will apply for the annual grant.	In Statoil ASA, LTI is a variable remuneration element, Participation in the LTI scheme and the size of the annual LTI element are reflective of the level and impact of the position and not directly linked to the incumbent's performance.
Annual Variable Pay	Drive and reward individuals for annual achievement of business objectives and how results are delivered. Ensure link between individual variable pay and company's overall financial performance.	Members of the corporate executive committee are entitled to an annual variable pay ranging from 0-50% of their fixed remuneration. Target value is 25% (target value reflects fully satisfactory goal achievement). Deviations applicable for members of the corporate executive committee employed outside the parent company are described in the statement on executive remuneration. The deviation will in 2016 apply for one executive vice president employed by Statoil Global Employment Company Ltd. in London. The threshold principles and the company modifier (subject to AGM approval) will apply.	Achievement of annual performance goals (how and what to deliver), in order to create long-term and sustainable shareholder value. Assessment of goals related to selected KPI's from the balanced scorecard will impact the variable remuneration for the members of the corporate executive committee.
Pension & Insurance Schemes	Provide competitive postemployment and other benefits.	The general occupational pension plan is a defined contribution scheme with a contribution level of 7%/22% below/above 7,1 G. The defined benefit scheme will be retained by a grandfathered group of employees. The benefit scheme has a pension level amounting to 66 per cent of the pensionable salary conditional on a minimum of 30 years of service. Pension from the national insurance scheme is taken into account when estimating the pension. In order to draw a full pension from Statoil's defined benefit scheme the employment with the company needs to be maintained until the pensionable age. For new internal members of the corporate executive committee a cap for pension contribution at 12 G is established.	N/A
Employee Share Savings Plan	Align and strengthen employee and shareholder interests and remunerate for long term commitment and value creation.	Offer to purchase Statoil shares in the market limited to 5% of annual base salary.	If shares are kept for two calendar years of continued employment, the participants will be allocated bonus shares proportionate to their purchase.

1.7. Base salary and remuneration mix 2016

Due to the current challenges facing our industry with falling oil and gas prices, decreasing margins and unsustainable cost levels, a salary freeze will be implemented for members of the corporate executive committee and other leaders and senior professionals in 2016.

The graphs below illustrate the chief executive officer's remuneration mix for 2016 and a typical remuneration mix for executive vice presidents. The chief executive officer's total remuneration package includes an additional fixed remuneration element compared to the executive vice presidents, and the executive vice presidents remuneration package includes, as applicable, a cash compensation in lieu of pension contribution above 12 G due to the implemented cap, see section 1.2 *Cap on pension contribution at the maximum limit in the tax-favoured joint pension schemes in Norway* above; please see further details of the chief executive officer's terms and conditions in section 1.11 *Terms and conditions for president and chief executive officer, Eldar*

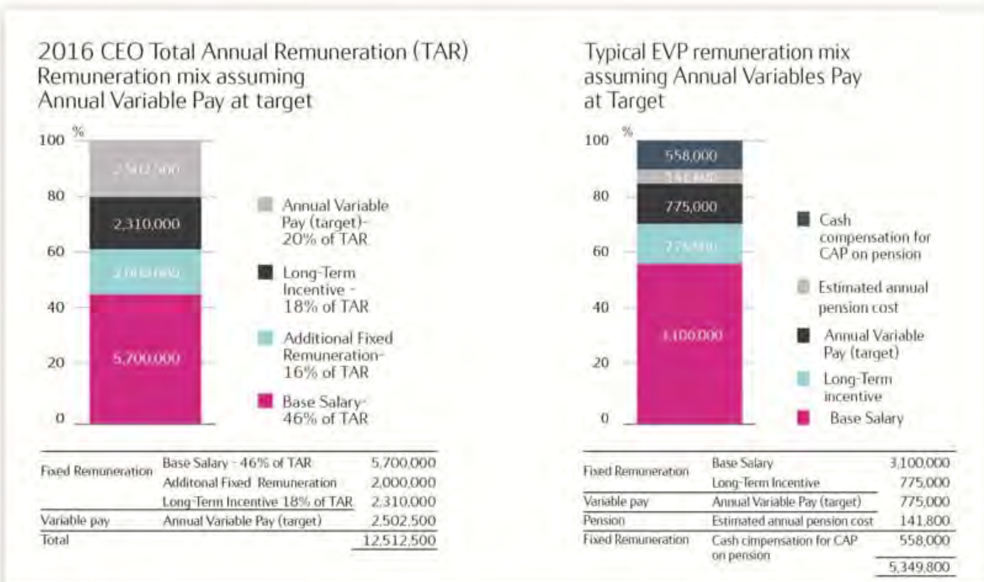

Figure 1: Illustrates chief executive officer remuneration mix for 2016. CEO's pension was fully accrued by 31 December 2014.
Figure 2: Illustrates an example of a typical remuneration mix for an executive vice president in Statoil with a cap on pension contribution.

1.8. Pension and insurance schemes

Members of the corporate executive committee are part of the general pension scheme in Statoil ASA. The chief executive officer and three executive vice presidents have individual early retirement pension agreement with the company.

The chief executive officer and one of the executive vice presidents have individual pension terms according to a previous standard arrangement implemented in October 2006. Subject to specific terms those executives are entitled to a pension amounting to 66 per cent of pensionable salary and a retirement age of 62. When calculating the number of years of membership in Statoil's general pension plan, these agreements grant the right to an extra contribution time corresponding to half a year of extra membership for each year the individual has served as executive vice president.

In addition, two members of the corporate executive committee have individually agreed retirement age of 65 and an early retirement pension level amounting to 66% of pensionable salary.

The individual pension terms for executive vice presidents outlined above are results of commitments according to previous established agreements.

Following a board decision 7 February 2012, the company's standard pension arrangements for executive vice presidents deviating from Statoil ASA's general pension plan have been discontinued and have not been applied for new appointments to the corporate executive committee.

As described in section 1.2, a cap on pension contribution for income above 12 G was in 2015 implemented for new members of the Corporate Executive Committee. The cap is applied to four executives vice presidents appointed after 13 February 2015.

Members of the corporate executive committee appointed before 13 February 2015, will maintain their pension contribution above 12 G based on obligations in established agreements.

Pension accruals for pensionable salary above 12 G are recognised as an unfunded defined benefit pension plan, i.e. not funded in a separate legal entity.

In addition to the pension benefits outlined above, the executive vice presidents in the parent company are offered disability and dependents' benefits in accordance with Statoil's general pension plan. Members of the corporate executive committee are covered by the general insurance schemes applicable within Statoil.

1.9. Severance pay arrangements

The chief executive officer and the executive vice presidents are entitled to a severance payment equivalent to six months' salary, commencing at the time of expiry of a six months' notice period, when the resignation is at the request from the company. The same amount of severance payment is also payable if the parties agree that the employment should be discontinued and the executive vice president gives notice pursuant to a written agreement with the company. Any other payment earned by the executive vice president during the period of severance payment will be fully deducted. This relates to earnings from any employment or business activity where the executive vice president has active ownership.

The entitlement to severance payment is conditional on the chief executive officer or the executive vice president not being guilty of gross misconduct, gross negligence, disloyalty or other material breach of his/her duties.

As a general rule, the chief executive officer's/executive vice president's own notice will not instigate any severance payment.

1.10. Other benefits

Statoil has a share savings plan available to all employees including members of the corporate executive committee. The share savings plan entails an offer to purchase Statoil shares in the market limited to five per cent of annual gross salary. If the shares are kept for two full calendar years of continued employment the employees will be allocated bonus shares proportionate to their purchase. Shares to be used for sale and transfer to employees are acquired by Statoil in the market, in accordance with the authorisation from the annual general meeting.

The members of the corporate executive committee have benefits in kind such as company car and electronic communication.

1.11. Terms and conditions for president and chief executive officer, Eldar Sætre

Effective 4 February 2015 Statoil's board of directors appointed Eldar Sætre as president and chief executive officer of Statoil, following an acting period since 15 October 2014. The chief executive officer's annual base salary is NOK 5,700,000. Furthermore, the CEO is entitled to an additional fixed remuneration element of NOK 2,000,000 not included in the pensionable income.

The chief executive officer will participate in an annual variable pay scheme with a target level of 25%, and participation to the Company's 2016 LTI scheme with a value of 30% (gross) of base salary. The pension terms remain unchanged according to previously established pension agreement, as described in section 1.8 above.

2. Performance management, assessment and results essential for variable pay

2.1. Performance management, assessment and results essential for variable pay for 2015

Individual salary and annual variable pay reviews are based on the performance evaluation in our performance management system.

Performance is evaluated in two dimensions; "What" we deliver and "How" we deliver. Goals on "How" we deliver are based on our core values and leadership principles and address the behaviour required and expected in order to achieve our delivery goals.

"What" we deliver (business delivery) is defined through the company's performance framework "Ambition to Action", which addresses strategic objectives, key performance Indicators (KPIs) and actions across the five perspectives; Safety, Security and Sustainability, People and Leadership, Operations, Market and Results. Generally, Statoil believes in setting ambitious targets to inspire and drive strong performance.

In 2015, the main objectives and KPIs for each perspective were as outlined below. Each perspective was in addition supported by comprehensive plans and actions. It is only the KPI's for Results that will affect variable remuneration for members of the corporate executive committee.

Strategic objectives		2015 assessment
Safety, Security and Sustainability	The strategic objectives and actions address security and sustainability (Safety - see the Results perspective below)	There were no serious well incidents, whereas the number of oil and gas leakages was above target. Total CO_2 reduction was better than targeted and future ambitions have been increased.
People and organisation	The strategic objectives and actions address high performing leaders and teams, and global and cost-effective capabilities	Employee engagement increased from 2014, during a time with extensive organisational efficiency programmes. Leadership renewal across the organisation was better than targeted.
Operations	The strategic objectives and actions address reliable and cost-efficient operations, and value-driven technology development.	Production came in well above target, partly driven by continued improvements in production efficiency and optimised gas production from our flexible gas fields. Unit production cost is now the lowest among industry peers. Unit finding cost increased due to lower than expected exploration results.
Market	The strategic objectives and actions address stakeholder trust, value chain optimisation and portfolio and project management.	The organic Reserve Replacement Ratio (RRR) ended somewhat below the target of 1, while total RRR was well below due to divestments and a number of projects being postponed to maintain financial flexibility and improve project profitability. Project cost efficiency versus peers continued to improve.
Results	The strategic objectives and actions address shareholder return, financial robustness, value creation from exploration, cost & capital discipline and for 2015 also Safety.	Relative Total Shareholder Return (TSR) improved and ended on 6th against an industry peer group of 12. Relative RoACE also ended 6th but fell as a result of high exposure to upstream margins. Capex ended well below initially guided levels. The cash flow improvement programme delivered well above target. The serious incident frequency of 0,6 was unchanged from 2014.

Board assessment of the chief executive officer's performance
In its assessment of the chief executive officer's performance, and consequently his merit and annual pay for 2015, the board has put emphasis on the solid delivery on the cashflow improvement programme as well as CAPEX reductions and TSR. Serious incident frequency also continues to improve from 2014.

Before final conclusions of the performance assessments are drawn, sound judgement and hindsight information are applied. Measured KPI results are reviewed against their strategic contribution, sustainability and significant changes in assumptions.

This balanced approach, which involves a broad set of goals defined in relation to both "What" and "How" dimensions and an overall performance evaluation, is viewed to significantly reduce the likelihood that remuneration policies may stimulate excessive risk-taking or have other material adverse effects.

2.2 Key performance indicators for the chief executive officer for 2016

For the accounting year 2016 the CEO's variable remuneration for 2016 and base salary merit increase as of 1 January 2017 will be based on assessment of results on the following KIPs:

Safety, Security and Sustainability
- CO_2 intensity for the upstream portfolio
- Serious Incident Frequency (actual)

Market
- Capex (capital expenditure)

Results
- Relative Total Shareholder Return
- Relative RoACE
- Cash flow improvement programme

3. Execution of the remuneration policy and principles in 2015

3.1 Deviations from the governmental guidelines on variable compensation 2015

Two members of the executive committee had in 2015 variable pay schemes deviating from the description in section 1.6 above. One of the executives was employed by Statoil Gulf Services LLC in Houston and resigned from the company 31 July 2015. He was entitled to a variable pay scheme with a maximum of 100% for AVP and LTI, respectively. The other is still employed by Statoil Global Employment Company Ltd. in London and his variable pay scheme entail a framework for variable pay of 75% of his base salary for each of the elements annual variable pay and LTI, and is performance based. His contract also includes a provision for severance payment of 12 months' base salary.

The board's overall assessment is that the extended framework implemented with effect from 1 January 2011 for the variable pay schemes for these executives is necessary due to local market conditions, but not market leading for positions at this level at the respective locations.

3.2 Changes to the Corporate Executive Committee in 2015

In addition to the appointment of Eldar Sætre as president and chief executive officer, several changes have in 2015 been implemented to the organisational structure and the composition of the corporate executive committee. A new corporate staff and support function, chief operating officer (COO), was established from 1 April 2015, and Anders Opedal was appointed as executive vice president and COO.

New energy Solution (NES) was established as a new business area 1 June 2015 with Irene Rummelhoff as the executive vice president. Jens Økland was appointed executive vice president in MMP from 1 June 2015 succeeding Tor Martin Anfinnsen's acting period.

William Maloney, executive vice president Development and Production North America (DPNA), resigned from the company 31 July 2015. An adjustment to the DPNA organisation is implemented and this business area is renamed to Development and Production USA (DPUSA) [3]. Torgrim Reitan assumed responsibility as executive vice president in DPUSA as of 1 August 2015. Hans Jakob Hegge succeeded Torgrim Reitan as CFO from 1 august 2015.

3.3 Changes to individual terms in 2015

Following former president and chief executive officer Helge Lund's resignation a termination agreement was entered into. Helge Lund's termination date was 9 February 2015. Helge Lund received base salary and benefits compensation up until this date. He did not receive variable pay for the performance year 2014. The LTI scheme and share savings plan was closed in accordance with the company policy, and a repayment of NOK 5,033,491 was made by Helge Lund to Statoil ASA according to the LTI agreement. The company issued a paid-up policy and pension right letters for his pension accruals, in accordance with his individual pension agreement.

4. The decision-making process

The decision-making process for implementing or changing remuneration policies and concepts, and the determination of salaries and other remuneration for corporate executive committee, are in accordance with the provisions of the Norwegian public limited liability companies act sections 5-6 and 6-16 a and the board's rules of procedure. The board's rules of procedure are available at www.statoil.com/board.

The board of directors has appointed a designated compensation and executive development committee. The compensation and executive development committee is a preparatory body for the board. The committee's main objective is to assist the board of directors in its work relating to the terms of employment for Statoil's chief executive officer and the main principles and strategy for the remuneration and leadership development of our senior executives. The board of directors determines the chief executive officer's salary and other terms of employment.

The compensation and executive development committee answers to the board of Statoil ASA for the performance of its duties. The work of the committee in no way alters the responsibilities of the board of directors or the individual board members.

For further details about the roles and responsibilities of the compensation and executive development committee, please refer to the committee's instructions available at www.statoil.com/compensationcommittee.

5. Company performance modifier

Introduction

It is recommended to introduce a company performance modifier to be applied in calculation of variable pay. The relative total shareholder return is recommended as one of the criteria in the company modifier. Thus, the case is submitted to the annual general meeting for approval, pursuant to the provisions in the Public Limited Companies Act § 5-6 third paragraph last sentence ref. § 6-16 a, first paragraph third sentence number 3.

Background

Statoil has implemented annual variable pay schemes (AVP) for members of the corporate executive committee. The schemes are described in section 1.6 of this statement. Other executives, managers and employees in defined professional positions are also eligible for individual variable pay according to the company's guidelines.

The company's current annual variable pay scheme is entirely based on the individual participants' performance. Statoil has not implemented a company performance modifier for the variable pay schemes. The prevalent trend in the market is to ensure that variable remuneration is aligned with the company's performance. The governmental guidelines on executive remuneration also underline that "there shall be a clear connection between the variable salary and the performance of the company."

Proposal

Based on this, it is proposed to strengthen the link between the company's overall financial results and the individual variable pay by introducing a company performance modifier. The company performance is planned to be assessed against two equally weighted measures: relative total shareholder return (TSR) and relative return on average capital employed (RoACE). TSR and RoACE have historically constituted important performance indicators at the company's scorecard and are currently also applied in the corporate performance management system.

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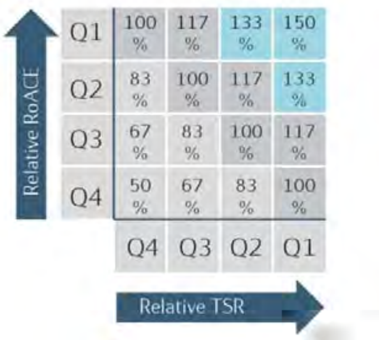
[3] *Transfer of responsibility for the company's business in Canada from Development and Production North America (DPNA) to Development and Production International (DPI)*

The results of both of these corporate performance measures are compared to our peers and our relative position determined. A position of first quartile means that Statoil is amongst the top scoring quartile of peer companies. A position of fourth quartile means Statoil is in the bottom performing quartile. In years with strong deliveries on relative TSR and RoACE, the matrix will result in the variable pay being modified with a factor higher than one and, correspondingly, lower than one in weak years. By applying relative numbers, the effect of fluctuating oil price will be reduced.

The combination of ratings for both measures, will act as a 'multiplier' according to the matrix displayed below.



The plan is to introduce the company performance modifier in calculation of annual variable pay for members of Statoil's corporate executive committee. Further application of the company performance modifier in Long-term incentive schemes will also be assessed and decided if deemed appropriate. In Long-term incentive schemes a three years average result for the modifier will typically be applied. The company also plan to implement the modifier in variable pay schemes for employees in positions below the corporate executive level.

The annual variable pay for members of the corporate executive committee will be within a framework of 50% of the fixed remuneration irrespective of the result of the modifier. Any deviations from this framework for members of the corporate executive committee will be explicitly explained in the board's annual Statements on remuneration and other employment terms for Statoil's corporate executive committee.

A complete statement on remuneration and other employment terms for Statoil's corporate executive committee is available at www.statoil.com.

7.10 Share ownership

This section describes the number of Statoil shares owned by the members of the board of directors, the corporate assembly and the corporate executive committee.

The number of Statoil shares owned by the members of the board of directors and the executive committee and/or owned by their close associates is shown below. Individually, each member of the board of directors and the corporate executive committee owned less than 1% of the outstanding Statoil shares.

Ownership of Statoil shares (including share ownership of «close associates»)	As of 31 December 2015	As of 8 March 2016
Members of the corporate executive committee		
Eldar Sætre	39,130	40,024
Hans Jakob Hegge	22,854	23,908
Anders Opedal	14,511	14,511
Lars Christian Bacher	21,116	22,308
Torgrim Reitan	28,482	29,435
John Knight	85,731	87,565
Tim Dodson	28,614	29,438
Margareth Øvrum	42,621	44,033
Arne Sigve Nylund	9,261	9,261
Jens Økland	10,735	11,386
Irene Rummelhoff	17,082	17,639
Members of the board of directors		
Øystein Løseth	1,000	1,000
Roy Franklin	0	0
Bjørn Tore Godal	0	0
Jakob Stausholm	50,000	50,000
Maria Johanna Oudeman	0	0
Rebekka Glasser Herlofsen	0	0
Wenche Agerup	2,423	2,423
Lill-Heidi Bakkerud	330	330
Ingrid Elisabeth di Valerio	2,845	3,165
Stig Lægreid	1,519	1,807

Individually, each member of the corporate assembly owned less than 1% of the outstanding Statoil shares as of 31 December 2015 and as of 8 March 2016. In aggregate, members of the corporate assembly owned a total of 19,592 shares as of 31 December 2015 and a total of 22,157 shares as of 8 March 2016. Information about the individual share ownership of the members of the corporate assembly is presented in the section *Corporate governance - Corporate assembly*.

The voting rights of members of the board of directors, the corporate executive committee and the corporate assembly do not differ from those of ordinary shareholders.

7.11 Independent auditor

This section provides details about the independent auditor, the remuneration of the auditor and policies and procedures relating to the auditor.

Our independent registered public accounting firm (independent auditor) is independent in relation to Statoil and is elected by the general meeting of shareholders. The independent auditor's fee must be approved by the general meeting of shareholders.

Pursuant to the instructions for the board's audit committee approved by the board of directors, the audit committee is responsible for ensuring that the company is subject to an independent and effective external and internal audit.

Every year, the independent auditor presents a plan to the audit committee for the execution of the independent auditor's work.

The independent auditor attends the meeting of the board of directors that deals with the preparation of the annual accounts.

The independent auditor participates in meetings of the audit committee.

When evaluating the independent auditor, emphasis is placed on the firm's qualifications, capacity, local and international availability and the size of the fee.

The audit committee evaluates and makes a recommendation to the board of directors, the corporate assembly and the general meeting of shareholders regarding the choice of independent auditor. The committee is responsible for ensuring that the independent auditor meets the requirements in Norway and in the countries where Statoil is listed. The independent auditor is subject to the provisions of US securities legislation, which stipulates that a responsible partner may not lead the engagement for more than five consecutive years.

The audit committee considers all reports from the independent auditor before they are considered by the board of directors. The audit committee holds regular meetings with the independent auditor without the company's management being present.

The audit committee's policies and procedures for pre-approval

In its instructions for the audit committee, the board of directors has delegated authority to the audit committee to pre-approve assignments to be performed by the independent auditor. Within this pre-approval, the audit committee has issued further guidelines. The audit committee has issued guidelines for the management's pre-approval of assignments to be performed by the independent auditor.

All audit-related and other services provided by the independent auditor must be pre-approved by the audit committee. Provided that the types of services proposed are permissible under SEC guidelines, pre-approval is usually granted at a regular audit committee meeting. The chair of the audit committee has been authorised to pre-approve services that are in accordance with policies established by the audit committee that specify in detail the types of services that qualify. It is a condition that any services pre-approved in this manner are presented to the full audit committee at its next meeting. Some pre-approvals can therefore be granted by the chair of the audit committee if an urgent reply is deemed necessary.

Remuneration of the independent auditor in 2015

In the annual Consolidated financial statements and in the parent company's financial statements, the independent auditor's remuneration is split between the audit fee and the fee for audit-related and other services. The chair presents the breakdown between the audit fee and the fee for audit-related and other services to the annual general meeting of shareholders.

The following table sets out the aggregate fees related to professional services rendered by Statoil's principal accountant KPMG AS, for the fiscal year 2015, 2014 and 2013.

Auditor's remuneration (in NOK million, excluding VAT)	For the year ended 31 December 2015	2014	2013
Audit fee	49	45	38
Audit related fee	14	8	8
Tax fee	0	0	0
Other service fee	0	0	0
Total	63	53	46

All fees included in the table were approved by the board's audit committee.

Audit fee is defined as the fee for standard audit work that must be performed every year in order to issue an opinion on Statoil's Consolidated financial statements, on Statoil's internal control over annual reporting and to issue reports on the statutory financial statements. It also includes other audit services, which are services that only the independent auditor can reasonably provide, such as the auditing of non-recurring transactions and the application of new accounting policies, audits of significant and newly implemented system controls and limited reviews of quarterly financial results.

Audit-related fees include other assurance and related services provided by auditors, but not limited to those that can only reasonably be provided by the external auditor who signs the audit report, that are reasonably related to the performance of the audit or review of the company's financial statements, such as acquisition due diligence, audits of pension and benefit plans, consultations concerning financial accounting and reporting standards.

Other services fees include services provided by the auditors within the framework of the Sarbanes-Oxley Act, i.e. certain agreed procedures.

Of total increase in audit and audit related fees, NOK 3.2 million is due to currency effects, equivalent to 5%.

In addition to the figures in the table above, the audit fees and audit-related fees relating to Statoil operated licences paid to KPMG for the years 2015, 2014 and 2013 amounted to NOK 7 million, NOK 6 million and NOK 6 million, respectively.

7.12 Controls and procedures

This section describes controls and procedures relating to our financial reporting.

Evaluation of disclosure controls and procedures

The management, with the participation of our chief executive officer and chief financial officer, has evaluated the effectiveness of the design and operation of our disclosure controls and procedures pursuant to Exchange Act Rule 13a-15(b) as of the end of the period covered by the Form 20-F. Based on that evaluation, the chief executive officer and chief financial officer have concluded that these disclosure controls and procedures are effective at a reasonable level of assurance.

In order to facilitate the evaluation, the disclosure committee reviews material disclosures made by Statoil for any errors, misstatements and omissions. The disclosure committee is chaired by the chief financial officer. It consists of the heads of investor relations, accounting and financial compliance, performance management and risk, tax and the general counsel and it may be supplemented by other internal and external personnel. The head of the internal audit is an observer at the committee's meetings.

In designing and evaluating our disclosure controls and procedures, our management, with the participation of the chief executive officer and chief financial officer, recognised that any controls and procedures, no matter how well designed and operated, can only provide reasonable assurance that the desired control objectives will be achieved, and that the management must necessarily exercise judgment when evaluating the cost-benefit aspects of possible controls and procedures. Because of the limitations inherent in all control systems, no evaluation of controls can provide absolute assurance that all control issues and any instances of fraud in the company have been detected.

The management's report on internal control over financial reporting

The management of Statoil ASA is responsible for establishing and maintaining adequate internal control over financial reporting. Our internal control over financial reporting is a process designed, under the supervision of the chief executive officer and chief financial officer, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of Statoil's financial statements for external reporting purposes in accordance with International Financial Reporting Standards (IFRS) as adopted by the European Union (EU). The accounting policies applied by the group also comply with IFRS as issued by the International Accounting Standards Board (IASB).

The management has assessed the effectiveness of internal control over financial reporting based on the Internal Control - Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Based on this assessment, the management has concluded that Statoil's internal control over financial reporting as of 31 December 2015 was effective.

Statoil's internal control over financial reporting includes policies and procedures that pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect transactions and dispositions of assets, provide reasonable assurance that transactions are recorded in the manner necessary to permit the preparation of financial statements in accordance with IFRS, and that receipts and expenditures are only carried out in accordance with the authorisation of the management and directors of Statoil; and provide reasonable assurance regarding the prevention or timely detection of any unauthorised acquisition, use or disposition of Statoil's assets that could have a material effect on our financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect all misstatements. Moreover, projections of any evaluation of the effectiveness of internal control to future periods are subject to a risk that controls may become inadequate because of changes in conditions and that the degree of compliance with the policies or procedures may deteriorate.

The effectiveness of internal control over financial reporting as of 31 December 2015 has been audited by KPMG AS, an independent registered public accounting firm that also audits the Consolidated financial statements included in this annual report. Their audit report on the internal control over financial reporting is included in section 8 in the Consolidated financial statements in this report.

No changes occurred in our internal control over financial reporting during the period covered by Form 20-F that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

We continuously make improvement to our internal control environment.

8 Consolidated financial statements Statoil

CONSOLIDATED STATEMENT OF INCOME

(in NOK billion)	Note	2015	2014	Full year 2013
Revenues		465.3	606.8	616.6
Net income from equity accounted investments		(0.3)	(0.3)	0.1
Other income	4	17.8	16.1	17.8
Total revenues and other income	3	482.8	622.7	634.5
Purchases [net of inventory variation]		(211.2)	(301.3)	(306.9)
Operating expenses		(84.5)	(72.9)	(74.1)
Selling, general and administrative expenses		(7.5)	(7.3)	(7.8)
Depreciation, amortisation and net impairment losses	11, 12	(133.8)	(101.4)	(72.4)
Exploration expenses	12	(31.0)	(30.3)	(18.0)
Net operating income	3	14.9	109.5	155.5
Net financial items	8	(10.6)	(0.0)	(17.0)
Income before tax		4.3	109.4	138.4
Income tax	9	(41.6)	(87.4)	(99.2)
Net income		(37.3)	22.0	39.2
Attributable to equity holders of the company		(37.5)	21.9	39.9
Attributable to non-controlling interests		0.2	0.1	(0.6)
Basic earnings per share (in NOK)	10	(11.80)	6.89	12.53
Diluted earnings per share (in NOK)	10	(11.80)	6.87	12.50

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CONSOLIDATED STATEMENT OF COMPREHENSIVE INCOME

(in NOK billion)	Note	2015	2014	Full year 2013
Net income		(37.3)	22.0	39.2
Actuarial gains (losses) on defined benefit pension plans	19	10.1	(0.0)	(5.9)
Income tax effect on income and expense recognised in OCI		(2.8)	0.9	1.5
Items that will not be reclassified to the Consolidated statement of income		7.3	0.9	(4.4)
Currency translation adjustments[1)]		27.4	41.6	22.9
Items that may be subsequently reclassified to the Consolidated statement of income		27.4	41.6	22.9
Other comprehensive income		34.7	42.5	18.5
Total comprehensive income		(2.6)	64.5	57.7
Attributable to the equity holders of the company		(2.8)	64.4	58.3
Attributable to non-controlling interests		0.2	0.1	(0.6)

1) Currency translation adjustments of NOK 27.4 billion in 2015 are net of accumulated currency translation gains of NOK 3.3 billion reclassified to the Consolidated statement of income related to the sale of interests in the Shah Deniz project, the South Caucasus Pipeline and the Trans Adriatic Pipeline AG. See note 4 *Acquisitions and dispositions*.

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CONSOLIDATED BALANCE SHEET

(in NOK billion)	Note	At 31 December 2015	2014
ASSETS			
Property, plant and equipment	11	**546.2**	562.1
Intangible assets	12	**83.3**	85.2
Equity accounted investments		**7.3**	8.4
Deferred tax assets	9	**17.8**	12.9
Pension assets	19	**11.3**	8.0
Derivative financial instruments	25	**23.8**	29.9
Financial investments	13	**20.6**	19.6
Prepayments and financial receivables	13	**8.5**	5.7
Total non-current assets		**718.7**	731.7
Inventories	14	**22.0**	23.7
Trade and other receivables	15	**58.8**	83.3
Derivative financial instruments	25	**4.8**	5.3
Financial investments	13	**86.5**	59.2
Cash and cash equivalents	16	**76.0**	83.1
Total current assets		**248.0**	254.8
Total assets		**966.7**	986.4
EQUITY AND LIABILITIES			
Shareholders' equity		**354.7**	380.8
Non-controlling interests		**0.3**	0.4
Total equity	17	**355.1**	381.2
Finance debt	18, 22	**264.0**	205.1
Deferred tax liabilities	9	**65.4**	71.5
Pension liabilities	19	**26.2**	27.9
Provisions	20	**109.4**	117.2
Derivative financial instruments	25	**11.3**	4.5
Total non-current liabilities		**476.3**	426.2
Trade and other payables	21	**82.2**	100.7
Current tax payable		**24.1**	39.6
Finance debt	18	**20.5**	26.5
Dividends payable	17	**6.2**	5.7
Derivative financial instruments	25	**2.3**	6.6
Total current liabilities		**135.3**	179.0
Total liabilities		**611.7**	605.2
Total equity and liabilities		**966.7**	986.4

CONSOLIDATED STATEMENT OF CHANGES IN EQUITY

(in NOK billion)	Share capital	Additional paid-in capital	Retained earnings	Currency translation adjustments	Shareholders' equity	Non-controlling interests	Total equity
At 31 December 2012	8.0	40.6	270.8	(0.2)	319.2	0.7	319.9
Net income for the period			39.9		39.9	(0.6)	39.2
Other comprehensive income			(4.4)	22.9	18.5		18.5
Total comprehensive income							57.7
Dividends			(21.5)		(21.5)		(21.5)
Other equity transactions		(0.3)	(0.3)		(0.6)	0.4	(0.2)
At 31 December 2013	8.0	40.3	284.5	22.7	355.5	0.5	356.0
Net income for the period			21.9		21.9	0.1	22.0
Other comprehensive income			0.9	41.6	42.5		42.5
Total comprehensive income							64.5
Dividends			(39.4)		(39.4)		(39.4)
Other equity transactions		(0.1)	0.4		0.3	(0.2)	0.1
At 31 December 2014	8.0	40.2	268.4	64.3	380.8	0.4	381.2
Net income for the period			(37.5)		(37.5)	0.2	(37.3)
Other comprehensive income[1)]			7.3	27.4	34.7		34.7
Total comprehensive income							(2.6)
Dividends			(23.1)		(23.1)		(23.1)
Other equity transactions		(0.1)	(0.0)		(0.1)	(0.3)	(0.4)
At 31 December 2015	8.0	40.1	215.1	91.6	354.7	0.3	355.1

1) Currency translation adjustments of NOK 27.4 billion in 2015 are net of accumulated currency translation gains of NOK 3.3 billion reclassified to the Consolidated statement of income related to the sale of interests in the Shah Deniz project, the South Caucasus Pipeline and the Trans Adriatic Pipeline AG. See note 4 *Acquisitions and dispositions*.

Refer to note 17 *Shareholders' equity*.

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CONSOLIDATED STATEMENT OF CASH FLOWS

(in NOK billion)	Note	2015	2014	Full year 2013
Income before tax		**4.3**	109.4	138.4
Depreciation, amortisation and net impairment losses	11, 12	**133.8**	101.4	72.4
Exploration expenditures written off	12	**17.1**	13.7	3.1
(Gains) losses on foreign currency transactions and balances		**(0.4)**	(3.1)	4.8
(Gains) losses from dispositions	4	**(17.3)**	(12.4)	(17.6)
(Increase) decrease in other items related to operating activities		**19.8**	3.9	6.6
(Increase) decrease in net derivative financial instruments	25	**9.2**	(2.8)	11.7
Interest received		**2.9**	2.1	2.1
Interest paid		**(3.6)**	(3.4)	(2.5)
Cash flows provided by operating activities before taxes paid and working capital items		**165.8**	208.8	218.8
Taxes paid		**(65.7)**	(96.6)	(114.2)
(Increase) decrease in working capital		**8.9**	14.2	(3.3)
Cash flows provided by operating activities		**109.0**	126.5	101.3
Additions through business combinations	4	**(3.5)**	0.0	0.0
Capital expenditures and investments		**(124.7)**	(122.6)	(114.9)
(Increase) decrease in financial investments		**(19.8)**	(12.7)	(23.2)
(Increase) decrease in other non-current items		**(0.3)**	0.8	0.6
Proceeds from sale of assets and businesses	4	**33.2**	22.6	27.1
Cash flows used in investing activities		**(115.1)**	(112.0)	(110.4)
New finance debt	18	**32.2**	20.6	62.8
Repayment of finance debt		**(11.4)**	(9.7)	(7.3)
Dividend paid	17	**(22.9)**	(33.7)	(21.5)
Net current finance debt and other		**(5.5)**	(0.3)	(7.3)
Cash flows provided by (used in) financing activities		**(7.5)**	(23.1)	26.6
Net increase (decrease) in cash and cash equivalents		**(13.6)**	(8.6)	17.5
Effect of exchange rate changes on cash and cash equivalents		**7.1**	5.7	2.9
Cash and cash equivalents at the beginning of the period (net of overdraft)	16	**82.4**	85.3	64.9
Cash and cash equivalents at the end of the period (net of overdraft)	16	**75.9**	82.4	85.3

Cash and cash equivalents included a bank overdraft of NOK 0.1 billion at 31 December 2015, a bank overdraft of NOK 0.7 billion at 31 December 2014 and a bank overdraft that was rounded to zero at 31 December 2013.

Interest paid in cash flows provided by operating activities is excluding capitalised interest of NOK 3.2 billion at 31 December 2015, NOK 1.6 billion at 31 December 2014 and NOK 1.1 billion at 31 December 2013. Capitalised interest is included in *Capital expenditures and investments* in cash flows used in investing activities.

8.1 Notes to the Consolidated financial statements

1 Organisation

Statoil ASA, originally Den Norske Stats Oljeselskap AS, was founded in 1972 and is incorporated and domiciled in Norway. The address of its registered office is Forusbeen 50, N-4035 Stavanger, Norway.

Statoil ASA is listed on the Oslo Børs (Norway) and the New York Stock Exchange (USA).

The Statoil group's business consists principally of the exploration, production, transportation, refining and marketing of petroleum and petroleum-derived products and other forms of energy.

All the Statoil group's oil and gas activities and net assets on the Norwegian continental shelf are owned by Statoil Petroleum AS, a 100% owned operating subsidiary. Statoil Petroleum AS is co-obligor or guarantor of certain debt obligations of Statoil ASA.

The Consolidated financial statements of Statoil for the full year 2015 were authorised for issue in accordance with a resolution of the board of directors on 9 March 2016.

2 Significant accounting policies

Statement of compliance
The Consolidated financial statements of Statoil ASA and its subsidiaries (Statoil) have been prepared in accordance with International Financial Reporting Standards (IFRSs) as adopted by the European Union (EU) and also comply with IFRSs as issued by the International Accounting Standards Board (IASB), effective at 31 December 2015.

Basis of preparation
The financial statements are prepared on the historical cost basis with some exceptions, as detailed in the accounting policies set out below. These policies have been applied consistently to all periods presented in these Consolidated financial statements. Certain amounts in the comparable years have been restated to conform to current year presentation. The subtotals and totals in some of the tables may not equal the sum of the amounts shown due to rounding.

Operating related expenses in the Consolidated statement of income are presented as a combination of function and nature in conformity with industry practice. *Purchases [net of inventory variation]* and *Depreciation, amortisation and net impairment losses* are presented in separate lines by their nature, while *Operating expenses* and *Selling, general and administrative expenses* as well as *Exploration expenses* are presented on a functional basis. Significant expenses such as salaries, pensions, etc. are presented by their nature in the notes to the Consolidated financial statements.

Standards and amendments to standards, issued but not yet adopted
At the date of these Consolidated financial statements, the following standards and amendments to standards applicable to Statoil have been issued, but were not yet effective:

- IFRS 15 *Revenue from Contracts with Customers*, issued in May 2014 and, following an amendment to the standard issued in September 2015, effective from 1 January 2018, covers the recognition of such revenue in the financial statements and related disclosure and will replace IAS 18 *Revenue*. The standard requires identification of the performance obligations for the transfer of goods and services in each contract with customers. Revenue will be recognised upon satisfaction of the performance obligations in the amounts that reflect the consideration to which the company expects to be entitled in exchange for those goods and services. The standard requires adoption either on a retrospective basis or on the basis of the cumulative effect on retained earnings. Statoil is still in the process of evaluating the potential impact of IFRS 15, and has not yet determined its adoption date or its implementation method for the standard

- The amendment to IFRS 11 *Accounting for Acquisitions of Interests in Joint Operations*, issued in May 2014 and effective from 1 January 2016, establishes requirements for the accounting for acquisitions of interests in joint operations in which the activity constitutes a business. The amendment is to be applied prospectively. Statoil has adopted the amendment on the effective date

- IFRS 9 *Financial Instruments*, issued in its final form in July 2014 and effective from 1 January 2018, will replace IAS *39 Financial Instruments: Recognition and Measurement*. IFRS 9 introduces a new model for classification and measurement of financial assets and financial liabilities, a reformed approach to hedge accounting, and a more forward-looking impairment model. The standard's transition provisions partly require retrospective adoption, and partly prospective adoption. Statoil is in the process of evaluating the potential impact of IFRS 9, and has not yet determined its adoption date for the standard

- The amendments to IFRS 10 *Consolidated Financial Statements* and IAS 28 *Investments in Associates and Joint Ventures*, issued in September 2014 and, following an amendment issued in December 2015, effective from a future date to be determined by the IASB, establish requirements for the accounting for sales or contributions of assets between an investor and its associate or joint venture. Whether or not the assets are housed in a subsidiary, a full gain or loss will be recognised in the statement of income when the transaction involves assets that constitute a business, whereas a partial gain or loss will be recognised when the transaction involves assets that do not constitute a business. The amendments are to be applied prospectively. Statoil has not determined an adoption date for the amendments

- IFRS 16 *Leases*, issued in January 2016 and effective from 1 January 2019, covers the recognition of leases and related disclosure in the financial statements, and will replace IAS 17 *Leases*. In the financial statement of lessees, the new standard requires recognition of all contracts that qualify under its definition of a lease as right-of-use assets and lease liabilities in the balance sheet, while lease payments are to be reflected as interest expense and reduction of lease liabilities. The right-of-use assets are to be depreciated in accordance with IAS 16 *Property, Plant and Equipment* over the shorter of each contract's term and the assets' useful life. The standard consequently implies a significant change in lessees' accounting for leases currently defined as operating leases under IAS 17, both as regards impact on the balance sheet and the statement of income. IFRS 16 defines a lease as a contract that conveys the right to control the use of an identified asset for a period of time in exchange for consideration. While this definition is not dissimilar to that of IAS 17, it would have required further evaluation of each contract to determine whether all leases included in Note 22 *Leases* of these financial statements, or contracts currently not defined as leases, would qualify as leases under the new standard. The standard introduces new requirements both as regards establishing the term of a lease and the related discounted cash flows that determine the amount of a lease liability to be recognised. The standard requires adoption either on a full retrospective basis, or retrospectively with the cumulative effect of initially recognising the standard as an adjustment to retained earnings at the date of initial application, and if so with a number of practical expedients in transitioning existing leases at the time of initial application. Statoil is in the early phase of evaluating the impact of IFRS 16, and has not yet determined its adoption date, its implementation method, or the expected impact of the standard on the Consolidated financial statements

- The disclosure initiative amendments to *IAS 7 Statement of Cash Flows,* issued in January 2016 and effective from 1 January 2017, establishes certain additional requirements as to disclosure of changes in financing liabilities. Statoil will implement the amendments on the effective date

Other standards and amendments to standards, issued but not yet effective, are either not expected to impact Statoil's Consolidated financial statements materially, or are not expected to be relevant to Statoil's Consolidated financial statements upon adoption.

Basis of consolidation

The Consolidated financial statements include the accounts of Statoil ASA and its subsidiaries and include Statoil's interest in jointly controlled and equity accounted investments.

Subsidiaries

Entities are determined to be controlled by Statoil, and consolidated in Statoil's financial statements, when Statoil has power over the entity, ability to use that power to affect the entity's returns, and exposure to, or rights to, variable returns from its involvement with the entity.

All intercompany balances and transactions, including unrealised profits and losses arising from Statoil's internal transactions, have been eliminated in full. Non-controlling interests are presented separately within equity in the balance sheet.

Joint operations and similar arrangements, joint ventures and associates

A joint arrangement is present where Statoil holds a long-term interest which is jointly controlled by Statoil and one or more other venturers under a contractual arrangement in which decisions about the relevant activities require the unanimous consent of the parties sharing control. Such joint arrangements are classified as either joint operations or joint ventures.

The parties to a joint operation have rights to the assets and obligations for the liabilities, relating to their respective share of the joint arrangement. In determining whether the terms of contractual arrangements and other facts and circumstances lead to a classification as joint operations, Statoil in particular considers the nature of products and markets of the arrangement and whether the substance of their agreements is that the parties involved have rights to substantially all the arrangement's assets. Statoil accounts for the assets, liabilities, revenues and expenses relating to its interests in joint operations in accordance with the principles applicable to those particular assets, liabilities, revenues and expenses. Normally this leads to accounting for the joint operation in a manner similar to the previous proportionate consolidation method.

Those of Statoil's exploration and production licence activities that are within the scope of IFRS 11 *Joint Arrangements* have been classified as joint operations. A considerable number of Statoil's unincorporated joint exploration and production activities are conducted through arrangements that are not jointly controlled, either because unanimous consent is not required among all parties involved, or no single group of parties has joint control over the activity. Licence activities where control can be achieved through agreement between more than one combination of involved parties are considered to be outside the scope of IFRS 11, and these activities are accounted for on a pro-rata basis using Statoil's ownership share. In determining whether each separate arrangement related to Statoil's unincorporated joint exploration and production licence activities is within or outside the scope of IFRS 11, Statoil considers the terms of relevant licence agreements, governmental concessions and other legal arrangements impacting how and by whom each arrangement is controlled. Subsequent changes in the ownership shares and number of licence participants, transactions involving licence shares, or changes in the terms of relevant agreements may lead to changes in Statoil's evaluation of control and impact a licence arrangement's classification in relation to IFRS 11 in Statoil's Consolidated financial statements. Currently there are no significant differences in Statoil's accounting for unincorporated licence arrangements whether in scope of IFRS 11 or not.

Joint ventures, in which Statoil has rights to the net assets, are accounted for using the equity method.

Investments in companies in which Statoil has neither control nor joint control, but has the ability to exercise significant influence over operating and financial policies, are classified as associates and are accounted for using the equity method.

Statoil as operator of joint operations and similar arrangements

Indirect operating expenses such as personnel expenses are accumulated in cost pools. These costs are allocated on an hours incurred basis to operating segments and Statoil operated joint operations under IFRS 11 and to similar arrangements (licences) outside the scope of IFRS 11. Costs allocated to the other partners' share of operated joint operations and similar arrangements reduce the costs in the Consolidated statement of income. Only Statoil's share of the statement of income and balance sheet items related to Statoil operated joint operations and similar arrangements are reflected in the Consolidated statement of income and the Consolidated balance sheet.

Reportable segments

Statoil identifies its operating segments on the basis of those components of Statoil that are regularly reviewed by the chief operating decision maker, Statoil's corporate executive committee (CEC). Statoil combines operating segments when these satisfy relevant aggregation criteria.

Statoil's accounting policies as described in this note also apply to the specific financial information included in reportable segments related disclosure in these Consolidated financial statements.

Foreign currency translation

In preparing the financial statements of the individual entities, transactions in foreign currencies (those other than functional currency) are translated at the foreign exchange rate at the dates of the transactions. Monetary assets and liabilities denominated in foreign currencies are translated to the functional currency at the foreign exchange rate at the balance sheet date. Foreign exchange differences arising on translation are recognised in the Consolidated statement of income as foreign exchange gains or losses within *Net financial items*. Foreign exchange differences arising from the translation of estimate-based provisions, however, generally are accounted for as part of the change in the underlying estimate and as such may be included within the relevant operating expense or income tax sections of the Consolidated statement of income depending on the nature of the provision. Non-monetary assets that are measured at historical cost in a foreign currency are translated using the exchange rate at the date of the transactions.

Presentation currency

For the purpose of the Consolidated financial statements, the statement of income, the balance sheet and the cash flows of each entity are translated from the functional currency into the presentation currency, Norwegian kroner (NOK). The assets and liabilities of entities whose functional currencies are other than NOK, including Statoil's parent company Statoil ASA whose functional currency is United States dollar (USD), are translated into NOK at the foreign exchange rate at the balance sheet date. The revenues and expenses of such entities are translated using the foreign exchange rates on the dates of the transactions. Foreign exchange differences arising on translation from functional currency to presentation currency are recognised separately in Other comprehensive income (OCI). The cumulative amount of such translation differences relating to an entity and previously recognised in OCI, is reclassified to the Consolidated statement of income and reflected as a part of the gain or loss on disposal of that entity.

Business combinations

Determining whether an acquisition meets the definition of a business combination requires judgement to be applied on a case by case basis. Acquisitions are assessed under the relevant IFRS criteria to establish whether the transaction represents a business combination or an asset purchase. Depending on the specific facts, acquisitions of exploration and evaluation licences for which a development decision has not yet been made, have largely been concluded to represent asset purchases.

Business combinations, except for transactions between entities under common control, are accounted for using the acquisition method of accounting. The acquired identifiable tangible and intangible assets, liabilities and contingent liabilities are measured at their fair values at the date of the acquisition. Acquisition costs incurred are expensed under *Selling, general and administrative expenses*.

Revenue recognition

Revenues associated with sale and transportation of crude oil, natural gas, petroleum products and other merchandise are recognised when risk passes to the customer, which is normally when title passes at the point of delivery of the goods, based on the contractual terms of the agreements.

Revenues from the production of oil and gas properties in which Statoil shares an interest with other companies are recognised on the basis of volumes lifted and sold to customers during the period (the sales method). Where Statoil has lifted and sold more than the ownership interest, an accrual is recognised for the cost of the overlift. Where Statoil has lifted and sold less than the ownership interest, costs are deferred for the underlift.

Revenue is presented net of customs, excise taxes and royalties paid in-kind on petroleum products. Revenue is presented gross of in-kind payments of amounts representing income tax.

Sales and purchases of physical commodities, which are not settled net, are presented on a gross basis as *Revenues* and *Purchases [net of inventory variation]* in the statement of income. Activities related to trading and commodity-based derivative instruments are reported on a net basis, with the margin included in *Revenues*.

Transactions with the Norwegian State

Statoil markets and sells the Norwegian State's share of oil and gas production from the Norwegian continental shelf (NCS). The Norwegian State's participation in petroleum activities is organised through the State's direct financial interest (SDFI). All purchases and sales of the SDFI's oil production are classified as *Purchases [net of inventory variation]* and *Revenues*, respectively. Statoil sells, in its own name, but for the Norwegian State's account and risk, the State's production of natural gas. These sales and related expenditures refunded by the Norwegian State are presented net in the Consolidated financial statements.

Employee benefits
Wages, salaries, bonuses, social security contributions, paid annual leave and sick leave are accrued in the period in which the associated services are rendered by employees of Statoil.

Research and development
Statoil undertakes research and development both on a funded basis for licence holders and on an unfunded basis for projects at its own risk. Statoil's own share of the licence holders' funding and the total costs of the unfunded projects are considered for capitalisation under the applicable IFRS requirements. Subsequent to initial recognition, any capitalised development costs are reported at cost less accumulated amortisation and accumulated impairment losses.

Income tax
Income tax in the Consolidated statement of income comprises current and deferred tax expense. *Income tax* is recognised in the Consolidated statement of income except when it relates to items recognised in OCI.

Current tax consists of the expected tax payable on the taxable income for the year and any adjustment to tax payable for previous years. Uncertain tax positions and potential tax exposures are analysed individually, and the best estimate of the probable amount for liabilities to be paid (unpaid potential tax exposure amounts, including penalties) and for assets to be received (disputed tax positions for which payment has already been made) in each case is recognised within current tax or deferred tax as appropriate. Interest income and interest expenses relating to tax issues are estimated and recognised in the period in which they are earned or incurred, and are presented within *Net financial items* in the Consolidated statement of income. Uplift benefit on the NCS is recognised when the deduction is included in the current year tax return and impacts taxes payable.

Deferred tax assets and liabilities are recognised for the future tax consequences attributable to differences between the carrying amounts of existing assets and liabilities and their respective tax bases, subject to the initial recognition exemption. The amount of deferred tax is based on the expected manner of realisation or settlement of the carrying amount of assets and liabilities, using tax rates enacted or substantively enacted at the balance sheet date. A deferred tax asset is recognised only to the extent that it is probable that future taxable income will be available against which the asset can be utilised. In order for a deferred tax asset to be recognised based on future taxable income, convincing evidence is required, taking into account the existence of contracts, production of oil or gas in the near future based on volumes of proved reserves, observable prices in active markets, expected volatility of trading profits, expected currency rate movements and similar facts and circumstances.

Oil and gas exploration, evaluation and development expenditures
Statoil uses the successful efforts method of accounting for oil and gas exploration costs. Expenditures to acquire mineral interests in oil and gas properties and to drill and equip exploratory wells are capitalised as exploration and evaluation expenditures within *Intangible assets* until the well is complete and the results have been evaluated, or there is any other indicator of a potential impairment. Exploration wells that discover potentially economic quantities of oil and natural gas remain capitalised as intangible assets during the evaluation phase of the find. This evaluation is normally finalised within one year after well completion. If, following the evaluation, the exploratory well has not found potentially commercial quantities of hydrocarbons, the previously capitalised costs are evaluated for derecognition or tested for impairment. Geological and geophysical costs and other exploration and evaluation expenditures are expensed as incurred.

Capitalised exploration and evaluation expenditures, including expenditures to acquire mineral interests in oil and gas properties, related to offshore wells that find proved reserves are transferred from exploration expenditures and acquisition costs - oil and gas prospects (*Intangible assets*) to *Property, plant and equipment* at the time of sanctioning of the development project. For onshore wells where no sanction is required, the transfer of acquisition cost - oil and gas prospects (*Intangible assets*) to *Property, plant and equipment* occurs at the time when a well is ready for production.

For exploration and evaluation asset acquisitions (farm-in arrangements) in which Statoil has made arrangements to fund a portion of the selling partner's (farmor's) exploration and/or future development expenditures (carried interests), these expenditures are reflected in the Consolidated financial statements as and when the exploration and development work progresses. Statoil reflects exploration and evaluation asset dispositions (farm-out arrangements) on a historical cost basis with no gain or loss recognition.

A gain or loss related to a post-tax based disposition of assets on the NCS includes the release of tax liabilities previously computed and recognised related to the assets in question. The resulting gross gain or loss is recognised in full in *Other income* in the Consolidated statement of income.

Consideration from the sale of an undeveloped part of an onshore asset reduces the carrying amount of the asset. The part of the consideration that exceeds the carrying amount of the asset, if any, is reflected in the Consolidated statement of income under *Other income*.

Exchanges (swaps) of exploration and evaluation assets are accounted for at the carrying amounts of the assets given up with no gain or loss recognition.

Property, plant and equipment
Property, plant and equipment is reflected at cost, less accumulated depreciation and accumulated impairment losses. The initial cost of an asset comprises its purchase price or construction cost, any costs directly attributable to bringing the asset into operation, the initial estimate of an asset retirement obligation, if any, exploration costs transferred from intangible assets and, for qualifying assets, borrowing costs. Property, plant and equipment include costs relating to expenditures incurred under the terms of profit sharing agreements (PSAs) in certain countries, and which qualify for recognition as assets of Statoil. State-owned entities in the respective countries, however, normally hold the legal title to such PSA-based property, plant and equipment.

Exchanges of assets are measured at the fair value of the asset given up, unless the fair value of neither the asset received nor the asset given up is measurable with sufficient reliability.

Expenditure on major maintenance refits or repairs comprises the cost of replacement assets or parts of assets, inspection costs and overhaul costs. Where an asset or part of an asset is replaced and it is probable that future economic benefits associated with the item will flow to Statoil, the expenditure is capitalised. Inspection and overhaul costs, associated with regularly scheduled major maintenance programs planned and carried out at recurring intervals exceeding one year, are capitalised and amortised over the period to the next scheduled inspection and overhaul. All other maintenance costs are expensed as incurred.

Capitalised exploration and evaluation expenditures, development expenditure on the construction, installation or completion of infrastructure facilities such as platforms, pipelines and the drilling of production wells, and field-dedicated transport systems for oil and gas are capitalised as producing oil and gas properties within *Property, plant and equipment.* Such capitalised costs, when designed for significantly larger volumes than the reserves from already developed and producing wells, are depreciated using the unit of production method based on proved reserves expected to be recovered from the area during the concession or contract period. Depreciation of production wells uses the unit of production method based on proved developed reserves, and capitalised acquisition costs of proved properties are depreciated using the unit of production method based on total proved reserves. In the rare circumstances where the use of proved reserves fails to provide an appropriate measure of depreciation, a more appropriate reserve estimate is used. Depreciation of other assets and transport systems used by several fields is calculated on the basis of their estimated useful lives, normally using the straight-line method. Each part of an item of property, plant and equipment with a cost that is significant in relation to the total cost of the item is depreciated separately. For exploration and production assets, Statoil has established separate depreciation categories which as a minimum distinguish between platforms, pipelines and wells.

The estimated useful lives of property, plant and equipment are reviewed on an annual basis, and changes in useful lives are accounted for prospectively. An item of property, plant and equipment is derecognised upon disposal or when no future economic benefits are expected to arise from the continued use of the asset. Any gain or loss arising on derecognition of the asset (calculated as the difference between the net disposal proceeds and the carrying amount of the item) is included in *Other income* or *Operating expenses*, respectively, in the period the item is derecognised.

Leases

Leases for which Statoil assumes substantially all the risks and rewards of ownership are reflected as finance leases. When an asset leased by a joint operation or similar arrangement to which Statoil is a party qualifies as a finance lease, Statoil reflects its proportionate share of the leased asset and related obligations. Finance leases are classified in the Consolidated balance sheet within *Property, plant and equipment* and *Finance debt*. All other leases are classified as operating leases, and the costs are charged to the relevant operating expense related caption on a straight line basis over the lease term, unless another basis is more representative of the benefits of the lease to Statoil.

Statoil distinguishes between lease and capacity contracts. Lease contracts provide the right to use a specific asset for a period of time, while capacity contracts confer on Statoil the right to and the obligation to pay for certain volume capacity availability related to transport, terminal use, storage, etc. Such capacity contracts that do not involve specified assets or that do not involve substantially all the capacity of an undivided interest in a specific asset are not considered by Statoil to qualify as leases for accounting purposes. Capacity payments are reflected as *Operating expenses* in the Consolidated statement of income in the period for which the capacity contractually is available to Statoil.

Intangible assets including goodwill

Intangible assets are stated at cost, less accumulated amortisation and accumulated impairment losses. Intangible assets include acquisition cost for oil and gas prospects, expenditures on the exploration for and evaluation of oil and natural gas resources, goodwill and other intangible assets.

Intangible assets relating to expenditures on the exploration for and evaluation of oil and natural gas resources are not amortised. When the decision to develop a particular area is made, its intangible exploration and evaluation assets are reclassified to *Property, plant and equipment*.

Goodwill is initially measured at the excess of the aggregate of the consideration transferred and the amount recognised for any non-controlling interest over the fair value of the identifiable assets acquired and liabilities assumed in a business combination at the acquisition date. Goodwill acquired is allocated to each cash generating unit, or group of units, expected to benefit from the combination's synergies. Following initial recognition, goodwill is measured at cost less any accumulated impairment losses.

Financial assets

Financial assets are initially recognised at fair value when Statoil becomes a party to the contractual provisions of the asset. For additional information on fair value methods, refer to the Measurement of fair values section below. The subsequent measurement of the financial assets depends on which category they have been classified into at inception.

At initial recognition, Statoil classifies its financial assets into the following three main categories: Financial investments at fair value through profit or loss, loans and receivables, and available-for-sale (AFS) financial assets. The first main category, financial investments at fair value through profit or loss, further consists of two sub-categories: Financial assets held for trading and financial assets that on initial recognition are designated as fair value through profit and loss. The latter approach may also be referred to as the fair value option.

Cash and cash equivalents include cash in hand, current balances with banks and similar institutions, and short-term highly liquid investments that are readily convertible to known amounts of cash, are subject to an insignificant risk of changes in fair value and have a maturity of three months or less from the acquisition date.

Trade receivables are carried at the original invoice amount less a provision for doubtful receivables which is made when there is objective evidence that Statoil will be unable to recover the balances in full.

A significant part of Statoil's investments in treasury bills, commercial papers, bonds and listed equity securities is managed together as an investment portfolio of Statoil's captive insurance company and is held in order to comply with specific regulations for capital retention. The investment portfolio is managed and evaluated on a fair value basis in accordance with an investment strategy and is accounted for using the fair value option with changes in fair value recognised through profit or loss.

Financial assets are presented as current if they contractually will expire or otherwise are expected to be recovered within 12 months after the balance sheet date, or if they are held for the purpose of being traded. Financial assets and financial liabilities are shown separately in the Consolidated balance sheet, unless Statoil has both a legal right and a demonstrable intention to net settle certain balances payable to and receivable from the same counterparty, in which case they are shown net in the balance sheet.

Inventories

Inventories are stated at the lower of cost and net realisable value. Cost is determined by the first-in first-out method and comprises direct purchase costs, cost of production, transportation and manufacturing expenses.

Impairment

Impairment of property, plant and equipment and intangible assets other than goodwill

Statoil assesses individual assets or groups of assets for impairment whenever events or changes in circumstances indicate that the carrying value of an asset may not be recoverable. Assets are grouped into cash generating units (CGUs) which are the smallest identifiable groups of assets that generate cash inflows that are largely independent of the cash inflows from other groups of assets. Normally, separate CGUs are individual oil and gas fields or plants. Each unconventional asset play is considered a single CGU when no cash inflows from parts of the play can be reliably identified as being largely independent of the cash inflows from other parts of the play. In impairment evaluations, the carrying amounts of CGUs are determined on a basis consistent with that of the recoverable amount. In Statoil's line of business, judgement is involved in determining what constitutes a CGU. Development in production, infrastructure solutions, markets, product pricing, management actions and other factors may over time lead to changes in CGUs such as the division of one original CGU into several.

In assessing whether a write-down of the carrying amount of a potentially impaired asset is required, the asset's carrying amount is compared to the recoverable amount. The recoverable amount of an asset is the higher of its fair value less cost of disposal and its value in use. Fair value less cost of disposal is determined based on comparable recent arm's length market transactions, or based on Statoil's estimate of the price that would be received for the asset in an orderly transaction between market participants. Value in use is determined using a discounted cash flow model. The estimated future cash flows applied are based on reasonable and supportable assumptions and represent management's best estimates of the range of economic conditions that will exist over the remaining useful life of the assets, as set down in Statoil's most recently approved long-term forecasts. Statoil uses an approach of regular updates of assumptions and economic conditions in establishing the long-term forecasts which are reviewed by corporate management and updated at least annually. For assets and CGUs with an expected useful life or timeline for production of expected reserves extending beyond 5 years, the forecasts reflect expected production volumes for oil and natural gas, and the related cash flows include project or asset specific estimates reflecting the relevant period. Such estimates are established on the basis of Statoil's principles and assumptions consistently applied.

In performing a value-in-use-based impairment test, the estimated future cash flows are adjusted for risks specific to the asset and discounted using a real post-tax discount rate which is based on Statoil's post-tax weighted average cost of capital (WACC). The use of post-tax discount rates in determining value in use does not result in a materially different determination of the need for, or the amount of, impairment that would be required if pre-tax discount rates had been used.

Unproved oil and gas properties are assessed for impairment when facts and circumstances suggest that the carrying amount of the asset may exceed its recoverable amount, and at least once a year. Exploratory wells that have found reserves, but where classification of those reserves as proved depends on whether major capital expenditure can be justified or where the economic viability of that major capital expenditure depends on the successful completion of further exploration work, will remain capitalised during the evaluation phase for the exploratory finds. Thereafter it will be considered a trigger for impairment evaluation of the well if no development decision is planned for the near future and there are no concrete plans for future drilling in the licence.

An assessment is made at each reporting date as to whether there is any indication that previously recognised impairment losses may no longer be relevant or may have decreased. If such an indication exists, the recoverable amount is estimated. A previously recognised impairment loss is reversed only if there has been a change in the estimates used to determine the asset's recoverable amount since the last impairment loss was recognised. If that is the case, the carrying amount of the asset is increased to its recoverable amount. That increased amount cannot exceed the carrying amount that would have been determined, net of depreciation, had no impairment loss been recognised for the asset in prior years.

Impairment losses and reversals of impairment losses are presented in the Consolidated statement of income as *Exploration expenses* or *Depreciation, amortisation and net impairment losses*, on the basis of their nature as either exploration assets (intangible exploration assets) or development and producing assets (property, plant and equipment and other intangible assets), respectively.

Impairment of goodwill

Goodwill is reviewed for impairment annually or more frequently if events or changes in circumstances indicate that the carrying value may be impaired. Impairment is determined by assessing the recoverable amount of the CGU, or group of units, to which the goodwill relates. Where the recoverable amount of the CGU, or group of units, is less than the carrying amount, an impairment loss is recognised. Once recognised, impairments of goodwill are not reversed in future periods.

Financial liabilities

Financial liabilities are initially recognised at fair value when Statoil becomes a party to the contractual provisions of the liability. The subsequent measurement of financial liabilities depends on which category they have been classified into. The categories applicable for Statoil are either financial liabilities at fair value through profit or loss or financial liabilities measured at amortised cost using the effective interest method. The latter applies to Statoil's non-current bank loans and bonds.

Financial liabilities are presented as current if the liability is due to be settled within 12 months after the balance sheet date, or if they are held for the purpose of being traded. Financial liabilities are derecognised when the contractual obligations expire, are discharged or cancelled. Gains and losses arising on the repurchase, settlement or cancellation of liabilities are recognised either in interest income and other financial items or in interest and other finance expenses within *Net financial items*.

Derivative financial instruments

Statoil uses derivative financial instruments to manage certain exposures to fluctuations in foreign currency exchange rates, interest rates and commodity prices. Such derivative financial instruments are initially recognised at fair value on the date on which a derivative contract is entered into and are subsequently re-measured at fair value through profit and loss. The impact of commodity-based derivative financial instruments is recognised in the Consolidated statement of income under *Revenues*, as such derivative instruments are related to sales contracts or revenue-related risk management for all significant purposes. The impact of other financial instruments is reflected under *Net financial items*.

Derivatives are carried as assets when the fair value is positive and as liabilities when the fair value is negative. Derivative assets or liabilities expected to be recovered, or with the legal right to be settled more than 12 months after the balance sheet date are classified as non-current, with the exception of derivative financial instruments held for the purpose of being traded.

Contracts to buy or sell a non-financial item that can be settled net in cash or another financial instrument, or by exchanging financial instruments, as if the contracts were financial instruments, are accounted for as financial instruments. However, contracts that are entered into and continue to be held for the purpose of the receipt or delivery of a non-financial item in accordance with Statoil's expected purchase, sale or usage requirements, also referred to as own-use, are not accounted for as financial instruments. This is applicable to a significant number of contracts for the purchase or sale of crude oil and natural gas, which are recognised upon delivery.

Derivatives embedded in other financial instruments or in non-financial host contracts are recognised as separate derivatives and are reflected at fair value with subsequent changes through profit and loss, when their risks and economic characteristics are not closely related to those of the host contracts, and the host contracts are not carried at fair value. Where there is an active market for a commodity or other non-financial item referenced in a purchase or sale contract, a pricing formula will, for instance, be considered to be closely related to the host purchase or sales contract if the price formula is based on the active market in question. A price formula with indexation to other markets or products will however result in the recognition of a separate derivative. Where there is no active market for the commodity or other non-financial item in question, Statoil assesses the characteristics of such a price related embedded derivative to be closely related to the host contract if the price formula is based on relevant indexations commonly used by other market participants. This applies to a number of Statoil's long-term natural gas sales agreements.

Pension liabilities

Statoil has pension plans for employees that either provide a defined pension benefit upon retirement or a pension dependent on defined contributions and related returns. A portion of the contributions are provided for as notional contributions, for which the liability increases with a promised notional return, set equal to the actual return of assets invested through the ordinary defined contribution plan. For defined benefit plans, the benefit to be received by employees generally depends on many factors including length of service, retirement date and future salary levels.

Statoil's proportionate share of multi-employer defined benefit plans are recognised as liabilities in the balance sheet to the extent that sufficient information is available and a reliable estimate of the obligation can be made.

Statoil's net obligation in respect of defined benefit pension plans is calculated separately for each plan by estimating the amount of future benefit that employees have earned in return for their services in the current and prior periods. That benefit is discounted to determine its present value, and the fair value of any plan assets is deducted. The discount rate is the yield at the balance sheet date, reflecting the maturity dates approximating the terms of Statoil's obligations. The discount rate for the main part of the pension obligations has been established on the basis of Norwegian mortgage covered bonds, which are considered high quality corporate bonds. The cost of pension benefit plans is expensed over the period that the employees render services and become eligible to receive benefits. The calculation is performed by an external actuary.

The net interest related to defined benefit plans is calculated by applying the discount rate to the opening present value of the benefit obligation and opening present value of the plan assets, adjusted for material changes during the year. The resulting net interest element is presented in the statement of income as part of net pension cost within *Net operating income*. The difference between estimated interest income and actual return is recognised in the Consolidated statement of comprehensive income.

Past service cost is recognised when a plan amendment (the introduction or withdrawal of, or changes to, a defined benefit plan) or curtailment (a significant reduction by the entity in the number of employees covered by a plan) occurs, or when recognising related restructuring costs or termination benefits. The obligation and related plan assets are re-measured using current actuarial assumptions, and the gain or loss is recognised in the statement of income.

Actuarial gains and losses are recognised in full in the Consolidated statement of comprehensive income in the period in which they occur, while actuarial gains and losses related to provision for termination benefits are recognised in the Consolidated statement of income in the period in which they occur. Due to the parent company Statoil ASA's functional currency being USD, the significant part of Statoil's pension obligations will be payable in a foreign currency (i.e. NOK). As a consequence, actuarial gains and losses related to the parent company's pension obligation include the impact of exchange rate fluctuations.

Contributions to defined contribution schemes are recognised in the statement of income in the period in which the contribution amounts are earned by the employees.

Notional contribution plans, reported in the parent company Statoil ASA, are recognised as pension liabilities with the actual value of the notional contributions and promised return at reporting date. Notional contributions and changes in fair value of notional assets are recognised in the statement of income as periodic pension cost.

Periodic pension cost is accumulated in cost pools and allocated to operating segments and Statoil operated joint operations (licences) on an hours incurred basis and recognised in the statement of income based on the function of the cost.

Onerous contracts

Statoil recognises as provisions the net obligation under contracts defined as onerous. Contracts are deemed to be onerous if the unavoidable cost of meeting the obligations under the contract exceeds the economic benefits expected to be received in relation to the contract. A contract which forms an integral part of the operations of a CGU whose assets are dedicated to that contract, and for which the economic benefits cannot be reliably separated from those of the CGU, is included in impairment considerations for the applicable CGU.

Asset retirement obligations (ARO)

Provisions for ARO costs are recognised when Statoil has an obligation (legal or constructive) to dismantle and remove a facility or an item of property, plant and equipment and to restore the site on which it is located, and when a reliable estimate of that liability can be made. The amount recognised is the present value of the estimated future expenditures determined in accordance with local conditions and requirements. Cost is estimated based on current regulations and technology, considering relevant risks and uncertainties. The discount rate used in the calculation of the ARO is a risk-free rate based on the applicable currency and time horizon of the underlying cash flows, adjusted for a credit premium which reflects Statoil's own credit risk. Normally an obligation arises for a new facility, such as an oil and natural gas production or transportation facility, upon construction or installation. An obligation may also crystallise during the period of operation of a facility through a change in legislation or through a decision to terminate operations, or be based on commitments associated with Statoil's ongoing use of pipeline transport systems where removal obligations rest with the volume shippers. The provisions are classified under *Provisions* in the Consolidated balance sheet. Some of the refining and process operations are deemed to have indefinite lives, and in consequence, no ARO has been recognised for their plants.

When a provision for ARO cost is recognised, a corresponding amount is recognised to increase the related property, plant and equipment and is subsequently depreciated as part of the costs of the facility or item of property, plant and equipment. Any change in the present value of the estimated expenditure is reflected as an adjustment to the provision and the corresponding property, plant and equipment. When a decrease in the ARO provision related to a producing asset exceeds the carrying amount of the asset, the excess is recognised as a reduction of *Depreciation, amortisation and net impairment losses* in the Consolidated statement of income. When an asset has reached the end of its useful life, all subsequent changes to the ARO provision are recognised as they occur in *Operating expenses* in the Consolidated statement of income. Removal provisions associated with Statoil's role as shipper of volumes through third party transport systems are expensed as incurred.

Measurement of fair values

Quoted prices in active markets represent the best evidence of fair value and are used by Statoil in determining the fair values of assets and liabilities to the extent possible. Financial instruments quoted in active markets will typically include commercial papers, bonds and equity instruments with quoted market prices obtained from the relevant exchanges or clearing houses. The fair values of quoted financial assets, financial liabilities and derivative instruments are determined by reference to mid-market prices, at the close of business on the balance sheet date.

Where there is no active market, fair value is determined using valuation techniques. These include using recent arm's-length market transactions, reference to other instruments that are substantially the same, discounted cash flow analysis, and pricing models and related internal assumptions. In the valuation techniques, Statoil also takes into consideration the counterparty and its own credit risk. This is either reflected in the discount rate used or through direct adjustments to the calculated cash flows. Consequently, where Statoil reflects elements of long-term physical delivery commodity contracts at fair value, such fair value estimates to the extent possible are based on quoted forward prices in the market and underlying indexes in the contracts, as well as assumptions of forward prices and margins where observable market prices are not available. Similarly, the fair values of interest and currency swaps are estimated based on relevant quotes from active markets, quotes of comparable instruments, and other appropriate valuation techniques.

Critical accounting judgements and key sources of estimation uncertainty

Critical judgements in applying accounting policies

The following are the critical judgements, apart from those involving estimations (see below), that Statoil has made in the process of applying the accounting policies and that have the most significant effect on the amounts recognised in the financial statements:

Revenue recognition - gross versus net presentation of traded SDFI volumes of oil and gas production

As described under Transactions with the Norwegian State above, Statoil markets and sells the Norwegian State's share of oil and gas production from the NCS. Statoil includes the costs of purchase and proceeds from the sale of the SDFI oil production in *Purchases [net of inventory variation]* and *Revenues*, respectively. In making the judgement, Statoil considered the detailed criteria for the recognition of revenue from the sale of goods and, in particular, concluded that the risk and reward of the ownership of the oil had been transferred from the SDFI to Statoil.

Statoil sells, in its own name, but for the Norwegian State's account and risk, the State's production of natural gas. These gas sales, and related expenditures refunded by the State, are shown net in Statoil's Consolidated financial statements. In making the judgement, Statoil considered the same criteria as for the oil production and concluded that the risk and reward of the ownership of the gas had not been transferred from the SDFI to Statoil.

Key sources of estimation uncertainty

The preparation of the Consolidated financial statements requires that management make estimates and assumptions that affect reported amounts of assets, liabilities, income and expenses. The estimates and associated assumptions are based on historical experience and various other factors that are believed to be reasonable under the circumstances, the result of which form the basis of making the judgements about carrying values of assets and liabilities that are not readily apparent from other sources. Actual results may differ from these estimates. The estimates and underlying assumptions are reviewed on an on-going basis considering the current and expected future market conditions.

Statoil is exposed to a number of underlying economic factors which affect the overall results, such as liquids prices, natural gas prices, refining margins, foreign exchange rates and interest rates as well as financial instruments with fair values derived from changes in these factors. In addition, Statoil's results are influenced by the level of production, which in the short term may be influenced by, for instance, maintenance programmes. In the long term, the results are impacted by the success of exploration and field development activities.

The matters described below are considered to be the most important in understanding the key sources of estimation uncertainty that are involved in preparing these Consolidated financial statements and the uncertainties that could most significantly impact the amounts reported on the results of operations, financial position and cash flows.

Proved oil and gas reserves

Proved oil and gas reserves may materially impact the Consolidated financial statements, as changes in the proved reserves, for instance as a result of changes in prices, will impact the unit of production rates used for depreciation and amortisation. Proved oil and gas reserves have been estimated by internal qualified professionals on the basis of industry standards and governed by criteria established by regulations of the U.S. Securities Exchange Commission (SEC), which require the use of a price based on a 12-month average for reserve estimation, and which are to be based on existing economic conditions and operating methods and with a high degree of confidence (at least 90% probability) that the quantities will be recovered. The Financial Accounting Standards Board (FASB) requirements for supplemental oil and gas disclosures align with the SEC regulations. Reserves estimates are based on subjective judgements involving geological and engineering assessments of in-place hydrocarbon volumes, the production, historical recovery and processing yield factors and installed plant operating capacity. For future development projects, proved reserves estimates are included only where there is a significant commitment to project funding and execution and when relevant governmental and regulatory approvals have been secured or are reasonably certain to be secured. The reliability of these estimates at any point in time depends on both the quality and quantity of the technical and economic data and the efficiency of extracting and processing the hydrocarbons. An independent third party has evaluated Statoil's proved reserves estimates, and the results of this evaluation do not differ materially from Statoil's estimates. Proved oil and gas reserves are those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward, from known reservoirs, and under existing economic conditions, operating methods and government regulations. Unless evidence indicates that renewal is reasonably certain, estimates of economically producible reserves only reflect the period before the contracts providing the right to operate expire. The project to extract the hydrocarbons must have commenced, or the operator must be reasonably certain that it will commence within a reasonable time.

Expected oil and gas reserves

Expected oil and gas reserves may materially impact the Consolidated financial statements, as changes in the expected reserves, for instance as a result of changes in prices, will impact asset retirement obligations and impairment testing of upstream assets, which in turn may lead to changes in impairment charges affecting operating income. Expected oil and gas reserves are the estimated remaining, commercially recoverable quantities, based on Statoil's judgement of future economic conditions, from projects in operation or justified for development. Recoverable oil and gas quantities are always uncertain, and the expected value is the weighted average, or statistical mean, of the possible outcomes. Expected reserves are therefore typically larger than proved reserves as defined by the SEC rules. Expected oil and gas reserves have been estimated by internal qualified professionals on the basis of industry standards and are used for impairment testing purposes and for calculation of asset retirement obligations. Reserves estimates are based on subjective judgements involving geological and engineering assessments of in-place hydrocarbon volumes, the production, historical recovery and processing yield factors, installed plant operating capacity and operating approval limits. The reliability of these estimates at any point in time depends on both the quality and quantity of the technical and economic data and the efficiency of extracting and processing the hydrocarbons.

Exploration and leasehold acquisition costs

Statoil capitalises the costs of drilling exploratory wells pending determination of whether the wells have found proved oil and gas reserves. Statoil also capitalises leasehold acquisition costs and signature bonuses paid to obtain access to undeveloped oil and gas acreage. Judgements as to whether these expenditures should remain capitalised or written down due to impairment losses in the period may materially affect the operating income for the period.

Impairment/reversal of impairment

Statoil has significant investments in property, plant and equipment and intangible assets. Changes in the circumstances or expectations of future performance of an individual asset may be an indicator that the asset is impaired, requiring the carrying amount to be written down to its recoverable amount. Impairments are reversed if conditions for impairment are no longer present. Evaluating whether an asset is impaired or if an impairment should be reversed requires a high degree of judgement and may to a large extent depend upon the selection of key assumptions about the future.

Unproved oil and gas properties are assessed for impairment when facts and circumstances suggest that the carrying amount of the asset may exceed its recoverable amount, and at least annually. If, following evaluation, an exploratory well has not found proved reserves, the previously capitalised costs are tested for impairment. Subsequent to the initial evaluation phase for a well, it will be considered a trigger for impairment testing of a well if no development decision is planned for the near future and there is no concrete plan for future drilling in the licence.

Impairment of unsuccessful wells is reversed, as applicable, to the extent that conditions for impairment are no longer present.

Estimating recoverable amounts involves complexity in estimating relevant future cash flows, based on assumptions about the future, discounted to their present value. Impairment testing requires long-term assumptions to be made concerning a number of often volatile economic factors such as future market prices, refinery margins, currency exchange rates and future output, discount rates and political and country risk among others, in order to establish relevant future cash flows. Impairment testing frequently also requires judgement regarding probabilities and probability distributions as well as levels of sensitivity inherent in the establishment of recoverable amount estimates. Long-term assumptions for major economic factors are made at a group level, and there is a high degree of reasoned judgement involved in establishing these assumptions, in determining other relevant factors such as forward price curves, in estimating production outputs and in determining the ultimate terminal value of an asset.

Employee retirement plans
When estimating the present value of defined benefit pension obligations that represent a long-term liability in the Consolidated balance sheet, and indirectly, the period's net pension expense in the Consolidated statement of income, management make a number of critical assumptions affecting these estimates. Most notably, assumptions made about the discount rate to be applied to future benefit payments and plan assets, the expected rate of pension increase and the annual rate of compensation increase, have a direct and potentially material impact on the amounts presented. Significant changes in these assumptions between periods can have a material effect on the Consolidated financial statements.

Asset retirement obligations
Statoil has significant obligations to decommission and remove offshore installations at the end of the production period. It is difficult to estimate the costs of these decommissioning and removal activities, which are based on current regulations and technology, and consider relevant risks and uncertainties. Most of the removal activities are many years into the future, and the removal technology and costs are constantly changing. The estimates include assumptions of the time required and the day rates for rigs, marine operations and heavy lift vessels that can vary considerably depending on the assumed removal complexity. As a result, the initial recognition of the liability and the capitalised cost associated with decommissioning and removal obligations, and the subsequent adjustment of these balance sheet items, involve the application of significant judgement.

Derivative financial instruments
When not directly observable in active markets, the fair value of derivative contracts must be computed internally based on internal assumptions as well as directly observable market information, including forward and yield curves for commodities, currencies and interest rates. Changes in internal assumptions, forward and yield curves could materially impact the internally computed fair value of derivative contracts, particularly long-term contracts, resulting in a corresponding impact on income or loss in the Consolidated statement of income.

Income tax
Every year Statoil incurs significant amounts of income taxes payable to various jurisdictions around the world and recognises significant changes to deferred tax assets and deferred tax liabilities, all of which are based on management's interpretations of applicable laws, regulations and relevant court decisions. The quality of these estimates is highly dependent upon management's ability to properly apply at times very complex sets of rules, to recognise changes in applicable rules and, in the case of deferred tax assets, management's ability to project future earnings from activities that may apply loss carry forward positions against future income taxes.

3 Segments

With effect from the third quarter of 2015 Statoil implemented a new corporate structure. Statoil's operations are now managed through the following operating segments: Development and Production Norway (DPN), Development and Production USA (DPUSA), Development and Production International (DPI), Marketing, Midstream and Processing (MMP), New Energy Solutions (NES) and Other.

The development and production operating segments are responsible for the commercial development of the oil and gas portfolios within their respective geographical areas: DPN on the Norwegian continental shelf, DPUSA including offshore and onshore activities in the USA and Mexico, and DPI worldwide outside of DPN and DPUSA.

Exploration activities are managed by a separate business unit, which has the global responsibility across the group for discovery and appraisal of new resources. Exploration activities are allocated to and presented in the respective development and production operating segments.

The MMP segment is responsible for marketing and trading of oil and gas commodities (crude, condensate, gas liquids, products, natural gas and liquefied natural gas), electricity and emission rights, as well as transportation, processing and manufacturing of the above mentioned commodities, operations of refineries, terminals, processing and power plants.

The NES segment is responsible for wind parks, carbon capture and storage as well as other renewable energy and low-carbon energy solutions.

Statoil reports its business through reporting segments which correspond to the operating segments, except for the operating segments DPI and DPUSA which have been aggregated into one reporting segment, Development and Production International. This aggregation has its basis in similar economic characteristics, the nature of products, services and production processes, the type and class of customers, the methods of distribution and regulatory environment. The new operating segment NES is reported in the segment Other in 2015 due to its immateriality.

The Other reporting segment includes activities within New Energy Solutions, Global Strategy and Business Development, Technology, Projects and Drilling and Corporate Staffs and Services.

The eliminations section includes the elimination of inter-segment sales and related unrealised profits, mainly from the sale of crude oil and products. Inter-segment revenues are based upon estimated market prices.

Segment data for the years ended 31 December 2015, 2014 and 2013 is presented below. The measurement basis of segment profit is *Net operating income*. In the tables below, deferred tax assets, pension assets and non-current financial assets are not allocated to the segments. Also, the line additions to PP&E, intangibles and equity accounted investments is excluding movements due to changes in asset retirement obligations.

(in NOK billion)	Development and Production Norway	Development and Production International	Marketing, Midstream and Processing	Other	Eliminations	Total
Full year 2015						
Revenues third party and other income	(0.9)	15.3	465.5	3.1	-	483.1
Revenues inter-segment	140.4	53.9	1.5	0.0	(195.7)	(0.0)
Net income (loss) from equity accounted investments	0.0	(0.8)	0.4	0.0	-	(0.3)
Total revenues and other income	139.5	68.4	467.4	3.2	(195.7)	482.8
Purchases [net of inventory variation]	(0.0)	(0.1)	(406.5)	(0.0)	195.4	(211.2)
Operating and SG&A expenses	(25.8)	(27.3)	(37.6)	(2.8)	1.5	(91.9)
Depreciation, amortisation and net impairment losses	(51.4)	(81.6)	0.4	(1.1)	0.0	(133.8)
Exploration expenses	(4.6)	(26.3)	0.0	0.0	0.0	(31.0)
Net operating income	57.6	(66.9)	23.7	(0.8)	1.2	14.9
Additions to PP&E, intangibles and equity accounted investments	50.6	65.4	7.3	2.2	0.0	125.5
Balance sheet information						
Equity accounted investments	0.0	2.9	1.9	2.4	-	7.3
Non-current segment assets	244.1	330.1	49.2	6.1	-	629.5
Non-current assets, not allocated to segments						82.0
Total non-current assets						718.7

(in NOK billion)	Development and Production Norway	Development and Production International	Marketing, Midstream and Processing	Other	Eliminations	Total
Full year 2014						
Revenues third party and other income	9.0	18.6	595.0	0.4	-	622.9
Revenues inter-segment	173.2	67.3	1.8	0.0	(242.3)	(0.0)
Net income (loss) from equity accounted investments	0.1	(0.8)	0.5	(0.0)	-	(0.3)
Total revenues and other income	182.2	85.2	597.3	0.3	(242.3)	622.7
Purchases [net of inventory variation]	(0.0)	(0.0)	(544.2)	(0.0)	242.9	(301.3)
Operating and SG&A expenses	(25.2)	(22.9)	(33.2)	(0.9)	2.0	(80.2)
Depreciation, amortisation and net impairment losses	(40.0)	(56.8)	(3.6)	(1.0)	-	(101.4)
Exploration expenses	(5.4)	(25.0)	(0.0)	0.0	-	(30.3)
Net operating income	111.7	(19.5)	16.2	(1.5)	2.6	109.5
Additions to PP&E, intangibles and equity accounted investments	55.1	61.4	7.8	0.8	-	125.1
Balance sheet information						
Equity accounted investments	0.2	4.8	3.2	0.2	-	8.4
Non-current segment assets	262.0	333.8	46.3	5.1	-	647.3
Non-current assets, not allocated to segments						76.0
Total non-current assets						731.7

(in NOK billion)	Development and Production Norway	Development and Production International	Marketing, Midstream and Processing	Other	Eliminations	Total
Full year 2013						
Revenues third party and other income	9.4	16.5	607.5	1.0	-	634.4
Revenues inter-segment	192.7	65.4	1.0	0.1	(259.1)	0.0
Net income (loss) from equity accounted investments	0.1	(0.0)	0.1	(0.0)	-	0.1
Total revenues and other income	202.2	81.9	608.6	1.0	(259.1)	634.5
Purchases [net of inventory variation]	0.0	(0.1)	(565.2)	(0.0)	258.4	(306.9)
Operating and SG&A expenses	(27.4)	(21.0)	(33.7)	(0.8)	1.1	(81.9)
Depreciation, amortisation and net impairment losses	(32.2)	(31.9)	(7.0)	(1.3)	0.0	(72.4)
Exploration expenses	(5.5)	(12.5)	(0.0)	(0.0)	0.0	(18.0)
Net operating income	137.1	16.4	2.6	(1.1)	0.4	155.5
Additions to PP&E, intangibles and equity accounted investments	57.3	52.9	5.9	1.3	-	117.4
Balance sheet information						
Equity accounted investments	0.2	4.8	2.3	0.2	-	7.4
Non-current segment assets	247.6	286.5	39.3	5.6	-	578.9
Non-current assets, not allocated to segments						60.5
Total non-current assets						646.8

See note 4 *Acquisitions and dispositions* for information on transactions that affect the different segments.

See note 11 *Property, plant and equipment* for information on impairment losses that affected the different segments.

See note 12 *Intangible assets* for information on impairment losses that affected primarily the DPI segment.

See note 23 *Other commitments, contingent liabilities and contingent assets* for information on contingencies that have influenced the DPI and MMP segments.

Revenues by geographical areas

Statoil has business operations in more than 30 countries. When attributing revenues third party and other income to the country of the legal entity executing the sale, Norway constitutes 76% and the USA constitutes 13%.

Non-current assets by country

(in NOK billion)	2015	2014	At 31 December 2013
Norway	277.4	289.6	269.6
USA	180.9	182.9	159.2
Angola	47.1	51.3	45.9
Brazil	30.6	29.5	24.5
UK	25.4	19.7	13.6
Canada	20.0	17.6	19.9
Algeria	12.6	11.8	9.0
Azerbaijan	12.5	23.6	19.0
Other countries	30.3	29.5	25.6
Total non-current assets[1)]	636.7	655.6	586.3

1) Excluding deferred tax assets, pension assets and non-current financial assets.

Revenues by product type

(in NOK billion)	2015	2014	2013
Crude oil	223.1	324.6	321.5
Natural gas	99.6	99.3	110.4
Refined products	86.5	104.8	118.9
Natural gas liquids	44.2	59.5	64.5
Other	12.0	18.6	1.3
Total revenues	465.3	606.8	616.6

4 Acquisitions and disposals

2015

Sale of interests in the Marcellus onshore play

In January 2015 Statoil closed an agreement with Southwestern Energy, entered into in the fourth quarter 2014, reducing Statoil's average working interest in the non-operated southern Marcellus onshore play from 29% to 23%. The transaction was recognised in the Development and Production International (DPI) segment with no impact on the Consolidated statement of income. Proceeds from the sale were NOK 2.8 billion.

Sale of interests in the Shah Deniz project and the South Caucasus Pipeline

In April 2015 Statoil closed an agreement with Petronas, entered into in October 2014, to sell its remaining 15.5% interest in the Shah Deniz project and the South Caucasus Pipeline. Statoil recognised a total gain of NOK 12.4 billion. The gain was presented in the line item *Other income* in the Consolidated statement of income. In the segment reporting, the gain was recognised in the DPI and the Marketing, Midstream and Processing (MMP) segments, with NOK 12.3 billion and NOK 0.1 billion, respectively. The part of the transaction recognised in the DPI segment was tax exempt under the rules in Norway and Azerbaijan. Total proceeds from the sale were NOK 20.3 billion, of which NOK 0.7 billion was received in 2014 and NOK 19.6 billion in 2015.

Sale of head office building

In June 2015 Statoil closed a transaction with Colony Capital, Inc. for the sale of the company's head office building in Stavanger through the sale of shares in the company Forusbeen 50 AS. At the same time, Statoil entered into a 15 year operating lease agreement for the building. A gain of NOK 1.5 billion was recognised in the Other segment. The gain was presented in the line item *Other income* in the Consolidated statement of income. Proceeds from the sale were NOK 2.3 billion.

Sale of office buildings

In December 2015 Statoil closed a transaction with TRD Campus AS for the sale of the company's office buildings in Trondheim and Stjørdal through the sale of shares in the companies Strandveien 4 AS and Arkitekt Ebbelsvei 10 AS. At the same time Statoil entered into 15 year operating lease agreements for the buildings. A gain of NOK 0.6 billion was recognised in the Other segment. The gain was presented in the line item *Other income* in the Consolidated statement of income. Proceeds from the sale were NOK 1.7 billion.

Sale of interests in the Trans Adriatic Pipeline AG

In December 2015 Statoil closed an agreement with Italian gas structure company Snam SpA to sell its 20% interest in Trans Adriatic Pipeline AG. A gain of NOK 1.4 billion was recognised in the MMP segment. The gain was tax exempt and presented in the line item *Other income* in the Consolidated statement of income. Total proceeds from the sale were NOK 2.0 billion.

Sale of interests in the Gudrun field and acquisition of interests in Eagle Ford
In December 2015 Statoil closed an agreement with Repsol to sell a 15% interest in the Gudrun field on the Norwegian continental shelf (NCS). Statoil remains the operator and largest equity holder with a 36% interest. Statoil recognised a total gain of NOK 1.2 billion in the Development and Production Norway (DPN) segment. The gain was presented in the line item *Other income* in the Consolidated statement of income. The transaction was tax exempt under the Norwegian petroleum tax legislation. Proceeds from the sale were NOK 1.9 billion.

Simultaneously Statoil closed an agreement to acquire an additional 13% interest in the Eagle Ford formation with the same party. Statoil's total interest in the Eagle Ford shale play after the acquisition is 63%, and Statoil also became the sole operator. The acquisition was accounted for as a business combination using the acquisition method. The acquisition and valuation date for the purchase price allocation was 30 December 2015. The fair value of net identifiable assets was NOK 3.5 billion. The acquisition was recognised in the DPI and MMP reporting segments with the fair value of net identifiable assets of NOK 2.4 billion and NOK 1.1 billion, respectively. The total purchase price of the business combination was NOK 3.5 billion. No goodwill was recognised.

2014

Sale of interests in the Shah Deniz project and the South Caucasus Pipeline
In March 2014 Statoil closed an agreement with BP and in May 2014 Statoil closed an agreement with SOCAR, both entered into in December 2013, to divest a 3.33% working interest and a 6.67% working interest, respectively, in the Shah Deniz project and the South Caucasus Pipeline. Statoil recognised a total gain of NOK 5.4 billion, presented in the line item *Other income* in the Consolidated statement of income. In the segment reporting, the gain has been presented in the DPI segment and the MMP segment with NOK 5.2 billion and NOK 0.2 billion, respectively. The part of the transaction recognised in the DPI segment was tax exempt under the rules in Norway and Azerbaijan. Proceeds from the sale were NOK 8.2 billion.

Kai Kos Dehseh oil sands swap agreement
In May 2014 Statoil and its partner PTTEP closed an agreement to swap the two parties' respective interests in the Kai Kos Dehseh oil sands project in Alberta, Canada. Statoil paid a balancing cash consideration of NOK 2.5 billion and assumed a net liability of NOK 0.3 billion. Subsequent to the closing, Statoil continues as 100% owner of the Leismer and Corner projects, while PTTEP owns 100% of the Thornbury, Hangingstone and South Leismer areas. The transaction has been recognised in the DPI segment resulting in an increase in *Property, plant and equipment* of NOK 4.6 billion, including a transfer from *Intangible assets* of NOK 1.8 billion, and with no impact on the Consolidated statement of income.

Sale of interests in licences on the Norwegian continental shelf
In December 2014 Statoil closed an agreement with Wintershall to sell certain ownership interests in licences on the NCS. A gain of NOK 5.9 billion has been recognised in the DPN segment. The gain has been presented in the line item *Other income* in the Consolidated statement of income. The transaction was tax exempt under the rules in the Norwegian petroleum tax legislation, and the gain included a release of related deferred tax liabilities. Proceeds from the sale were NOK 8.7 billion (USD 1.25 billion).

2013

Sale of interests in exploration and production licences on the Norwegian continental shelf to Wintershall
In July 2013 a sales transaction with Wintershall of certain ownership interests in licences on the NCS was closed. Statoil recognised a gain of NOK 6.4 billion. The gain has been presented in the line item *Other income* in the Consolidated statement of income. In the segment reporting, the gain has been presented in the DPN segment in revenues third party and other income. The transaction was tax exempt under the rules in the Norwegian petroleum tax legislation. Proceeds from the sale were NOK 4.7 billion.

Sale of interests in exploration and production licences on the Norwegian continental shelf and the United Kingdom continental shelf to OMV
In October 2013 a sales transaction with OMV to sell certain ownership interests in licences on the NCS and United Kingdom continental shelf was closed. Statoil recognised a gain of NOK 10.1 billion. The gain has been presented in the line item *Other income* in the Consolidated statement of income. In the segment reporting, the gain has been presented in the DPN segment and in the DPI segment in revenues third party and other income with NOK 6.6 billion and NOK 3.5 billion, respectively. The part of the transaction covering assets on the NCS was tax exempt under the rules in the Norwegian petroleum tax legislation. Proceeds from the sale were NOK 15.9 billion.

5 Financial risk management

General information relevant to financial risks
Statoil's business activities naturally expose Statoil to financial risk. Statoil's approach to risk management includes assessing and managing risk in all activities using a holistic risk approach. Statoil utilises correlations between the most important market risks, such as oil and natural gas prices, refined oil product prices, currencies, and interest rates, to calculate the overall market risk and thereby take into account the natural hedges inherent in Statoil's portfolio. Adding the different market risks without considering these correlations would overestimate Statoil's total market risk. This approach allows Statoil to reduce the number of risk management transactions and thereby reduce transaction costs and avoid sub-optimisation.

An important element in risk management is the use of centralised trading mandates. All major strategic transactions are required to be coordinated through Statoil's corporate risk committee. Mandates delegated to the trading organisations within crude oil, refined products, natural gas and electricity are relatively small compared to the total market risk of Statoil.

The corporate risk committee, which is headed by the chief financial officer and includes representatives from the principal business segments, is responsible for defining, developing and reviewing Statoil's risk policies. The chief financial officer, assisted by the committee, is also responsible for overseeing and developing Statoil's Enterprise Risk Management and proposing appropriate measures to adjust risk at the corporate level. The committee meets at least six times per year and regularly reviews risk information relevant to Statoil.

Financial risks

Statoil's activities expose Statoil to the following financial risks:

- Market risk (including commodity price risk, currency risk and interest rate risk)
- Liquidity risk
- Credit risk

Market risk

Statoil operates in the worldwide crude oil, refined products, natural gas, and electricity markets and is exposed to market risks including fluctuations in hydrocarbon prices, foreign currency rates, interest rates, and electricity prices that can affect the revenues and costs of operating, investing and financing. These risks are managed primarily on a short-term basis with a focus on achieving the highest risk-adjusted returns for Statoil within the given mandate. Long-term exposures are managed at the corporate level, while short-term exposures are managed according to trading strategies and mandates approved by Statoil's corporate risk committee.

In the marketing of commodities Statoil has established guidelines for entering into derivative contracts in order to manage commodity price, foreign currency rate, and interest rate risks. Statoil uses both financial and commodity-based derivatives to manage the risks in revenues, financial items and the present value of future cash flows.

For more information on sensitivity analysis of market risk see note 25 *Financial instruments: fair value measurement and sensitivity analysis of market risk*.

Commodity price risk

Statoil's most important long term commodity risk (oil and natural gas) is related to future market prices as Statoil's risk policy is to be exposed to both upside and downside price movements. To manage short-term commodity risk, Statoil enters into commodity- based derivative contracts, including futures, options, over-the-counter (OTC) forward contracts, market swaps and contracts for differences related to crude oil, petroleum products, natural gas and electricity.

Derivatives associated with crude oil and refined oil products are traded mainly on the Inter Continental Exchange (ICE) in London, the New York Mercantile Exchange (NYMEX), the OTC Brent market, and crude and refined products swap markets. Derivatives associated with natural gas and electricity are mainly OTC physical forwards and options, NASDAQ OMX Oslo forwards and futures traded on the NYMEX and ICE.

The term of crude oil and refined oil products derivatives is usually less than one year, and the term for natural gas and electricity derivatives is usually three years or less. For more detailed information about Statoil's commodity based derivative financial instruments, see note 25 *Financial instruments: fair value measurement and sensitivity analysis of market risk*.

Currency risk

Statoil's operating results and cash flows are affected by foreign currency fluctuations and the most significant currency is Norwegian Krone (NOK) against United States Dollar (USD). Statoil manages its currency risk from operating activities with USD as the base currency. Foreign exchange risk is managed at corporate level in accordance with established policies and mandates.

Statoil's cash flows from operating activities deriving from oil and gas sales, operating expenses and capital expenditures are mainly in USD, but taxes and dividends to shareholders on the Oslo Stock Exchange are in NOK. Accordingly, Statoil's currency management is primarily linked to mitigate currency risk related to tax and dividend payments in NOK. This means that Statoil regularly purchases substantial NOK amounts on a forward basis using conventional derivative instruments.

Interest rate risk

Bonds are normally issued at fixed rates in a variety of local currencies (among others USD, Euro and Great Britain Pound). Bonds may be converted to floating USD bonds by using interest rate and currency swaps. Statoil manages its interest rates exposure on its bond debt based on risk and reward considerations from an enterprise risk management perspective. This means that the fix/floating mix on interest rate exposure may vary from time to time. For more detailed information about Statoil's long-term debt portfolio see note 18 *Finance debt*.

Liquidity risk

Liquidity risk is the risk that Statoil will not be able to meet obligations of financial liabilities when they become due. The purpose of liquidity management is to make certain that Statoil has sufficient funds available at all times to cover its financial obligations.

Statoil manages liquidity and funding at the corporate level, ensuring adequate liquidity to cover Statoil's operational requirements. Statoil has a high focus and attention on credit and liquidity risk. In order to secure necessary financial flexibility, which includes meeting the financial obligations, Statoil maintains a conservative liquidity management policy. To identify future long-term financing needs, Statoil carries out three-year cash forecasts at least monthly.

The main cash outflows are the quarterly dividend payments and Norwegian petroleum tax payments paid six times per year. If the monthly cash flow forecast shows that the liquid assets one month after tax and dividend payments will fall below the defined policy level, new long-term funding will be considered.

Short-term funding needs will normally be covered by the USD 4.0 billion US Commercial Papers Programme (CP) which is backed by a revolving credit facility of USD 5.0 billion, supported by 21 core banks, maturing in 2020. The facility supports secure access to funding, supported by the best available short-term rating. As at 31 December 2015 it has not been drawn.

Statoil raises debt in all major capital markets (USA, Europe and Asia) for long-term funding purposes. The policy is to have a smooth maturity profile with repayments not exceeding five percent of capital employed in any year for the nearest five years. Statoil's non-current financial liabilities have a weighted average maturity of approximately nine years.

For more information about Statoil's non-current financial liabilities, see note 18 *Finance debt*.

The table below shows a maturity profile, based on undiscounted contractual cash flows, for Statoil's financial liabilities.

	At 31 December	
(in NOK billion)	2015	2014
Due within 1 year	104.9	131.4
Due between 1 and 2 years	73.7	43.3
Due between 3 and 4 years	86.9	81.3
Due between 5 and 10 years	93.8	90.5
Due after 10 years	115.5	84.3
Total specified	474.7	430.8

Credit risk

Credit risk is the risk that Statoil's customers or counterparties will cause Statoil financial loss by failing to honour their obligations. Credit risk arises from credit exposures with customer accounts receivables as well as from financial investments, derivative financial instruments and deposits with financial institutions.

Key elements of the credit risk management approach include:
- A global credit risk policy
- Credit mandates
- An internal credit rating process
- Credit risk mitigation tools
- A continuous monitoring and managing of credit exposures

Prior to entering into transactions with new counterparties, Statoil's credit policy requires all counterparties to be formally identified and approved. In addition, all sales, trading and financial counterparties are assigned internal credit ratings as well as exposure limits. Once established, all counterparties are re-assessed regularly and continuously monitored. Counterparty risk assessments are based on a quantitative and qualitative analysis of recent financial statements and other relevant business information like past payment performance, the counterparties' size and business diversification. The internal credit ratings reflect Statoil's assessment of the counterparties' credit risk. Exposure limits are determined based on assigned internal credit ratings combined with other factors, such as expected transaction and industry characteristics. Credit mandates define acceptable credit risk thresholds and are endorsed by management.

Statoil uses risk mitigation tools to reduce or control credit risk both on a counterparty and portfolio level. The main tools include bank and parental guarantees, prepayments and cash collateral.

Statoil has pre-defined limits for the absolute credit risk level allowed at any given time on Statoil's portfolio as well as maximum credit exposures for individual counterparties. Statoil monitors the portfolio on a regular basis and individual exposures against limits on a daily basis. The total credit exposure portfolio of Statoil is geographically diversified among a number of counterparties within the oil and energy sector, as well as larger oil and gas consumers and financial counterparties. The majority of Statoil's credit exposure is with investment grade counterparties.

The following table contains the carrying amount of Statoil's financial receivables and derivative financial instruments split by Statoil's assessment of the counterparty's credit risk. There are no significant receivables that are past due or impaired. Only non-exchange traded instruments are included in derivative financial instruments.

(in NOK billion)	Non-current financial receivables	Trade and other receivables	Non-current derivative financial instruments	Current derivative financial instruments
At 31 December 2015				
Investment grade, rated A or above	0.0	14.6	11.9	2.0
Other investment grade	3.3	27.5	11.9	2.4
Non-investment grade or not rated	2.4	9.3	0.0	0.3
Total financial asset	5.8	51.4	23.8	4.8
At 31 December 2014				
Investment grade, rated A or above	0.0	20.1	15.2	2.4
Other investment grade	0.0	36.5	11.8	2.7
Non-investment grade or not rated	2.7	17.2	2.9	0.2
Total financial asset	2.7	73.7	29.9	5.3

At 31 December 2015, NOK 10.2 billion of cash was held as collateral to mitigate a portion of Statoil's credit exposure. At 31 December 2014 NOK 12.9 billion was held as collateral. The collateral cash is received as a security to mitigate credit exposure related to positive fair values on interest rate swaps, cross currency swaps and foreign exchange swaps. Cash is called as collateral in accordance with the master agreements with the different counterparties when the positive fair values for the different swap agreements are above an agreed threshold.

Under the terms of various master netting agreements for derivative financial instruments as of 31 December 2015, NOK 7.0 billion presented as liabilities do not meet the criteria for offsetting. At 31 December 2014, NOK 5.2 billion was not offset. The collateral received and the amounts not offset from derivative financial instrument liabilities, reduce the credit exposure in the derivative financial instruments presented in the table above as they will offset each other in a potential default situation for the counterparty.

6 Remuneration

(in NOK billion, except average number of employees)	2015	2014	Full year 2013
Salaries[1)]	22.5	23.3	23.5
Pension costs	6.8	3.4	4.6
Payroll tax	3.4	3.5	3.4
Other compensations and social costs	2.5	2.4	2.5
Total payroll costs	35.2	32.5	34.0
Average number of employees[2)]	22,300	23,300	23,600

1) Salaries include bonuses, severance packages and expatriate costs in addition to base pay.
2) Part time employees amount to 3%, 2% and 3% for the years 2015, 2014 and 2013 respectively.

Total payroll expenses are accumulated in cost-pools and partly charged to partners of Statoil operated licences on an hours incurred basis.

For further information on pension costs, see note 19 *Pensions*.

Compensation to the board of directors (BoD) and the corporate executive committee (CEC)
Remuneration to members of the BoD and the CEC during the year was as follows:

(in NOK million)[1]	2015	2014	Full year 2013
Current employee benefits	92.2	73.2	74.5
Post-employment benefits	6.4	13.0	13.0
Other non-current benefits	0.1	0.0	0.1
Share based payment benefits	1.3	1.1	1.1
Total	100.2	87.3	88.7

1) All figures in the table are presented on accrual basis.

At 31 December 2015, 2014 and 2013 there are no loans to the members of the BoD or the CEC.

Share-based compensation
Statoil's share saving plan provides employees with the opportunity to purchase Statoil shares through monthly salary deductions and a contribution by Statoil. If the shares are kept for two full calendar years of continued employment, following the year of purchase, the employees will be allocated one bonus share for each one they have purchased.

Estimated compensation expense including the contribution by Statoil for purchased shares, amounts vested for bonus shares granted and related social security tax was NOK 0.5 billion, NOK 0.6 billion and NOK 0.6 billion related to the 2015, 2014 and 2013 programs, respectively. For the 2016 program (granted in 2015) the estimated compensation expense is NOK 0.5 billion. At 31 December 2015 the amount of compensation cost yet to be expensed throughout the vesting period is NOK 1.2 billion.

7 Other expenses

Auditor's remuneration

(in NOK million, excluding VAT)	2015	2014	Full year 2013
Audit fee	49	45	38
Audit related fee	14	8	8
Tax fee	0	0	0
Other service fee	0	0	0
Total	63	53	46

Of total increase in audit and audit related fees, NOK 3.2 million is due to currency effects, equivalent to 5%.

In addition to the figures in the table above, the audit fees and audit related fees related to Statoil operated licences amount to NOK 7 million, NOK 6 million and NOK 6 million for 2015, 2014 and 2013, respectively.

Research and development expenditures
Research and development (R&D) expenditures were NOK 2.7 billion, NOK 3.0 billion and NOK 3.2 billion in 2015, 2014 and 2013, respectively. R&D expenditures are partly financed by partners of Statoil operated licences. Statoil's share of the expenditures has been recognised as expense in the Consolidated statement of income.

8 Financial items

(in NOK billion)	2015	2014	Full year 2013
Foreign exchange gains (losses) derivative financial instruments	4.4	(1.5)	(4.1)
Other foreign exchange gains (losses)	(6.5)	(0.7)	(4.5)
Net foreign exchange gains (losses)	(2.1)	(2.2)	(8.6)
Dividends received	0.3	0.3	0.1
Gains (losses) financial investments	0.4	1.1	1.9
Interest income financial investments	0.6	0.7	0.6
Interest income non-current financial receivables	0.2	0.1	0.1
Interest income current financial assets and other financial items	1.7	1.8	0.9
Interest income and other financial items	3.2	4.0	3.6
Interest expense bonds and bank loans and net interest on related derivatives	(5.7)	(4.3)	(1.5)
Interest expense finance lease liabilities	(0.2)	(0.3)	(0.2)
Capitalised borrowing costs	3.2	1.6	1.1
Accretion expense asset retirement obligations	(3.9)	(3.7)	(3.2)
Gains (losses) derivative financial instruments	(3.8)	5.8	(7.4)
Interest expense current financial liabilities and other finance expense	(1.2)	(0.8)	(0.8)
Interest and other finance expenses	(11.7)	(1.8)	(12.0)
Net financial items	(10.6)	(0.0)	(17.0)

Statoil's main financial items relate to assets and liabilities categorised in the held for trading category and the amortised cost category. For more information about financial instruments by category see note 25 *Financial instruments: fair value measurement and sensitivity analysis of market risk.*

The line item interest expense bonds and bank loans and net interest on related derivatives primarily includes interest expenses of NOK 8.6 billion, NOK 6.8 billion and NOK 5.4 billion from the financial liabilities at amortised cost category. This was partly offset by net interest on related derivatives from the held for trading category, NOK 2.6 billion, NOK 2.5 billion and NOK 3.9 billion for 2015, 2014 and 2013, respectively.

The line item gains (losses) derivative financial instruments primarily includes fair value loss from the held for trading category of NOK 4.0 billion, a gain of NOK 5.7 billion and a loss of NOK 7.6 billion for 2015, 2014 and 2013, respectively.

Foreign exchange gains (losses) derivative financial instruments include fair value changes of currency derivatives related to liquidity and currency risk. The line item foreign exchange gains (losses) includes a net foreign exchange loss of NOK 9.7 billion, a loss of NOK 13.4 billion and a loss of NOK 4.3 billion from the held for trading category for 2015, 2014 and 2013, respectively.

9 Income taxes

Significant components of income tax expense

(in NOK billion)	2015	2014	Full year 2013
Current income tax expense in respect of current year	52.0	89.6	111.6
Prior period adjustments	0.7	(1.9)	1.3
Current income tax expense	52.7	87.6	112.9
Origination and reversal of temporary differences	(12.3)	(0.6)	(13.4)
Change in tax regulations	0.7	0.1	0.1
Prior period adjustments	0.4	0.3	(0.4)
Deferred tax expense	(11.1)	(0.2)	(13.7)
Income tax expense	41.6	87.4	99.2

During the normal course of its business, Statoil files tax returns in many different tax regimes. There may be differing interpretation of applicable tax laws and regulations regarding some of the matters in the tax returns. It may in certain cases take several years to complete the discussions with the relevant tax authorities or to reach a resolution of the tax positions through litigations. Statoil has provided for probable income tax related assets and liabilities based on best estimates reflecting consistent interpretations of the applicable laws and regulations.

Reconciliation of nominal statutory tax rate to effective tax rate

(in NOK billion)	2015	2014	Full year 2013
Income before tax	4.3	109.4	138.4
Calculated income tax at statutory rate[1)]	(8.5)	31.2	42.4
Calculated Norwegian Petroleum tax[2)]	33.4	62.8	71.7
Tax effect uplift[2)]	(6.8)	(6.4)	(5.2)
Tax effect of permanent differences regarding divestments	(3.7)	(6.2)	(12.0)
Tax effect of permanent differences caused by functional currency different from tax currency	(5.8)	(5.1)	(0.4)
Tax effect of other permanent differences	(0.2)	2.2	(3.7)
Change in unrecognised deferred tax assets	28.2	8.7	3.9
Change in tax regulations[3)]	0.7	0.1	0.1
Prior period adjustments	1.1	(1.7)	0.9
Other items including currency effects	3.2	1.7	1.5
Income tax expense	41.6	87.4	99.2
Effective tax rate	969.3%	79.9%	71.7%

1) The weighted average of statutory tax rates was -198.9% in 2015, 28.5% in 2014 and 30.7% in 2013. The negative weighted average of statutory tax rates for 2015 (198.9%) and the decrease in weighted average tax rates from 2014 to 2015 is mainly caused by losses, impairments and provisions in entities with higher than average statutory tax rates. The decrease from 2013 to 2014 was due to changes in the geographic mix of income, and a decrease in the Norwegian statutory tax rate from 28% to 27%.

2) When computing the petroleum tax of 51% (53% from 2016) on income from the Norwegian continental shelf, an additional tax-free allowance, or uplift, is granted at a rate of 5.5% per year on the basis of the original capitalised cost of offshore production installations. For investments made prior to 5 May 2013, the rate is 7.5% per year. Transitional rules apply to investments from 5 May 2013 covered by among others Plans for development and operation (PDOs) or Plans for installation and operation (PIOs) submitted to the Ministry of Oil and Energy prior to 5 May 2013. The uplift may be deducted from taxable income for a period of four years, starting in the year in which the capital expenditure is incurred. Unused uplift may be carried forward indefinitely. At year end 2015 and 2014, unrecognised uplift credits amounted to NOK 20.6 billion and NOK 21.1 billion, respectively.

3) The increase from 2014 to 2015 is mainly related to change in deferred taxes caused by a reduction in Norwegian statutory tax rate from 27% to 25% effective from 2016.

Deferred tax assets and liabilities comprise

(in NOK billion)	Tax losses carried forward	Property, plant and equipment and Intangible assets	Asset removal obligation	Pensions	Derivatives	Other	Total
Deferred tax at 31 December 2015							
Deferred tax assets	41.8	1.6	61.5	5.1	0.1	7.0	117.1
Deferred tax liabilities	(0.0)	(147.4)	0.0	(0.0)	(8.2)	(9.1)	(164.6)
Net asset (liability) at 31 December 2015	41.8	(145.7)	61.5	5.1	(8.1)	(2.1)	(47.6)
Deferred tax at 31 December 2014							
Deferred tax assets	36.7	4.6	73.3	7.0	0.2	13.4	135.3
Deferred tax liabilities	(0.0)	(172.6)	0.0	0.0	(12.9)	(8.4)	(193.8)
Net asset (liability) at 31 December 2014	36.7	(167.9)	73.3	7.0	(12.7)	4.9	(58.6)

Changes in net deferred tax liability during the year were as follows:

(in NOK billion)	2015	2014	2013
Net deferred tax liability at 1 January	58.6	62.8	77.3
Charged (credited) to the Consolidated statement of income	(11.1)	(0.2)	(13.7)
Other comprehensive income	2.8	(0.9)	(1.5)
Translation differences and other	(2.7)	(3.0)	0.7
Net deferred tax liability at 31 December	47.6	58.6	62.8

Deferred tax assets and liabilities are offset to the extent that the deferred taxes relate to the same fiscal authority, and there is a legally enforceable right to offset current tax assets against current tax liabilities. After netting deferred tax assets and liabilities by fiscal entity, deferred taxes are presented on the balance sheet as follows:

		At 31 December
(in NOK billion)	2015	2014
Deferred tax assets	17.8	12.9
Deferred tax liabilities	65.4	71.5

Deferred tax assets are recognised based on the expectation that sufficient taxable income will be available through reversal of taxable temporary differences or future taxable income. At year end 2015 and 2014 the deferred tax assets of NOK 17.8 billion and NOK 12.9 billion, respectively, were primarily recognised in Norway, Angola and the UK.

Unrecognised deferred tax assets

				At 31 December
		2015		2014
(in NOK billion)	Basis	Tax	Basis	Tax
Deductible temporary differences	21.6	8.9	11.0	3.2
Tax losses carried forward	126.2	46.7	52.5	18.0
Total	147.8	55.6	63.5	21.2

The movement in tax value of unrecognised deferred tax assets in the table above compared to reported change in unrecognised deferred tax assets in the table Reconciliation of nominal statutory tax rate to effective tax rate is mainly caused by currency effects.

Approximately 11% of the unrecognised carry forward tax losses can be carried forward indefinitely. The majority of the remaining part of the unrecognised tax losses expire after 2026. The unrecognised deductible temporary differences do not expire under the current tax legislation. Deferred tax assets have not been recognised in respect of these items because currently there is insufficient evidence to support that future taxable profits will be available to secure utilisation of the benefits.

Total unrecognised deferred tax assets relates to:

(in NOK billion)	2015	At 31 December 2014
US	39.3	12.3
Angola	5.7	0.0
Ireland	2.5	1.8
Canada	2.4	1.9
Netherlands	1.7	1.4
Other	4.0	3.8
Total	55.6	21.2

10 Earnings per share

The weighted average number of ordinary shares is the basis for computing the basic and diluted earnings per share as disclosed in the Consolidated statement of income. The dilutive effect relates to treasury shares.

(in millions)	2015	2014	At 31 December 2013
Weighted average number of ordinary shares	3,179.4	3,180.0	3,180.7
Weighted average number of ordinary shares, diluted	3,188.8	3,188.9	3,188.9
Earnings per share for income attributable to equity holders of the company:			
Basic (NOK)	-11.80	6.89	12.53
Diluted (NOK)	-11.80	6.87	12.50

11 Property, plant and equipment

(in NOK billion)	Machinery, equipment and transportation equipment, including vessels	Production plants and oil and gas assets	Refining and manufacturing plants	Buildings and land	Assets under development	Total
Cost at 31 December 2014	26.1	1,037.5	64.6	10.1	164.7	1,303.0
Additions and transfers	0.4	79.3	5.0	0.6	10.1	95.5
Disposals at cost[2)]	(0.2)	(13.2)	(8.0)	(3.5)	(9.3)	(34.2)
Effect of changes in foreign exchange	4.2	70.3	4.1	1.0	13.2	92.8
Cost at 31 December 2015	30.5	1,174.0	65.7	8.2	178.7	1,457.1
Accumulated depreciation and impairment losses at 31 December 2014	(20.1)	(656.7)	(48.2)	(4.8)	(11.1)	(740.9)
Depreciation	(1.4)	(81.9)	(2.2)	(0.4)	0.0	(85.9)
Impairment losses and transfers	0.0	(27.5)	(0.5)	(0.0)	(20.8)	(48.7)
Reversal of impairment losses	0.0	0.8	4.0	0.1	0.2	5.0
Accumulated depreciation and impairment disposed assets[2)]	0.0	6.6	2.6	1.5	(0.0)	10.8
Effect of changes in foreign exchange	(3.4)	(40.9)	(3.1)	(0.5)	(3.2)	(51.1)
Accumulated depreciation and impairment losses at 31 December 2015	(24.9)	(799.5)	(47.4)	(4.1)	(34.9)	(910.8)
Carrying amount at 31 December 2015	5.6	374.4	18.3	4.0	143.8	546.2
Estimated useful lives (years)	3-20	[1)]	15 - 20	20 - 33		

(in NOK billion)	Machinery, equipment and transportation equipment, including vessels	Production plants and oil and gas assets	Refining and manufacturing plants	Buildings and land	Assets under development	Total
Cost at 31 December 2013	21.1	869.9	60.2	8.4	135.5	1,095.1
Additions and transfers	1.0	108.4	2.0	0.7	23.8	135.9
Disposals at cost	(0.1)	(8.5)	(1.4)	(0.0)	(8.9)	(18.9)
Effect of changes in foreign exchange	4.1	67.7	3.8	1.1	14.3	91.0
Cost at 31 December 2014	26.1	1,037.5	64.6	10.1	164.7	1,303.0
Accumulated depreciation and impairment losses at 31 December 2013	(15.5)	(540.1)	(44.9)	(3.8)	(3.3)	(607.7)
Depreciation	(1.2)	(71.0)	(1.8)	(0.3)	(0.0)	(74.4)
Impairment losses	(0.3)	(16.1)	(1.2)	(0.2)	(7.1)	(24.8)
Reversal of impairment losses	0.0	0.3	1.8	0.0	0.2	2.3
Accumulated depreciation and impairment disposed assets	0.1	5.7	(0.2)	0.0	(0.0)	5.7
Effect of changes in foreign exchange	(3.2)	(35.4)	(2.0)	(0.5)	(1.0)	(42.0)
Accumulated depreciation and impairment losses at 31 December 2014	(20.1)	(656.7)	(48.2)	(4.8)	(11.1)	(740.9)
Carrying amount at 31 December 2014	6.0	380.8	16.4	5.3	153.6	562.1
Estimated useful lives (years)	3-20	1)	15 - 20	20 - 33		

1) Depreciation according to unit of production method, see note 2 *Significant accounting policies*.

2) Includes NOK 5.8 billion related to a change in the classification of Statoil's investment in the Sheringham Shoal Windfarm (Scira Offshore Energy Ltd) from joint operation (pro-rata line by line consolidation) to joint venture (equity method) following changes in the joint operating agreements.

The carrying amount of assets transferred to *Property, plant and equipment* from *Intangible assets* in 2015 and 2014 amounted to NOK 2.7 billion and NOK 9.5 billion, respectively.

Impairments

During 2015 and 2014, Statoil recognised total net impairment losses of NOK 63.3 billion and NOK 38.2 billion respectively on *Property, plant and equipment* and *Intangible assets*.

(in NOK billion)	Property, plant and equipment	Intangible assets[3]	Total
At 31 December 2015			
Producing and development assets[1]	43.8	9.8	53.5
Goodwill[1]	0.0	4.2	4.2
Acquisition costs related to oil and gas prospects[2]	0.0	5.6	5.6
Total net impairment losses recognised	43.8	19.6	63.3
At 31 December 2014			
Producing and development assets[1]	22.5	6.0	28.5
Goodwill[1]	0.0	4.2	4.2
Acquisition costs related to oil and gas prospects[2]	0.0	5.5	5.5
Total net impairment losses recognised	22.5	15.7	38.2

1) Producing and development assets and goodwill are subject to impairment assessment under IAS 36. The total net impairment losses recognised under IAS 36 in 2015 and 2014 amount to NOK 57.7 billion and NOK 32.7 billion, respectively, including impairment of acquisition costs - oil and gas prospects (intangible assets).

2) Acquisition costs related to exploration activities, subject to impairment assessment under the successful efforts method.

3) See note 12 *Intangible assets*.

In assessing the need for impairment of the carrying amount of a potentially impaired asset, the asset's carrying amount is compared to its recoverable amount. The recoverable amount is the higher of fair value less cost of disposal (FVLCOD) and estimated value in use (VIU).

The base discount rate for VIU calculations is 6.5% real after tax. The discount rate is derived from Statoil's weighted average cost of capital. A derived pre-tax discount rate would generally be in the range of 8-12%, depending on asset specific characteristics, such as specific tax treatments, cash flow profiles and economic life. The rates are not changed from last year. For certain assets a pre-tax discount rate could be outside this range, mainly due to special tax elements (for example permanent differences) affecting the pre-tax equivalent. See note 2 *Significant accounting policies* for further information regarding impairment on property, plant and equipment.

(in NOK billion)	Impairment method	Carrying amount before impairment	Carrying amount after impairment	Net impairment loss
At 31 December 2015				
Development and Production Norway	VIU	14.5	11.0	3.5
Development and Production International	VIU	219.5	171.2	48.3
Marketing, Midstream and Processing	VIU	5.2	8.7	(3.5)
Development and Production Norway	FVLCOD	22.9	17.7	5.2
Development and Production International	FVLCOD	4.2	0.0	4.2
Marketing, Midstream and Processing	FVLCOD	0.0	0.0	0.0
Total		266.3	208.6	57.7
At 31 December 2014				
Development and Production Norway	VIU	5.2	2.9	2.3
Development and Production International	VIU	187.9	168.4	19.5
Marketing, Midstream and Processing	VIU	8.8	7.9	0.9
Development and Production Norway	FVLCOD	18.3	18.3	0.0
Development and Production International	FVLCOD	25.4	15.4	10.0
Marketing, Midstream and Processing	FVLCOD	0.0	0.0	0.0
Total		245.6	212.9	32.7

During 2015 net impairment losses of NOK 57.7 billion were recognised, on producing and development assets and goodwill, primarily due to declining commodity price forecasts (primarily oil). The recoverable amount of assets tested for impairment was mainly based on VIU estimates on the basis of internal forecasts on costs, production profiles and commodity prices. For short term commodity prices, observed forward oil and gas price curves for the first two to three years have been used. Long term commodity price forecasts are based on internal price forecasts. The FVLCOD have partly been established through comparisons with observed market transactions and bids, and partly through internally prepared net present value estimates using assumed market participant assumptions. During 2014 impairment losses of NOK 32.7 billion were recognised on producing and development assets and goodwill.

Development and Production Norway (DPN)
In the DPN segment net impairment losses of NOK 8.7 billion were recognised in 2015, which were mainly related to conventional offshore assets in the development phase. The net impairment losses were triggered by reduction in commodity price reductions and project delays. In 2014 impairment losses of NOK 2.3 billion were recognised.

Development and Production International (DPI)
In the DPI segment net impairment losses of NOK 52.5 billion were recognised in 2015 of which NOK 28.3 billion related to unconventional onshore assets in USA, including NOK 4.2 billion of goodwill allocated to these assets. NOK 24.1 billion related to other conventional assets which were not considered significant on an individual cash generating unit level. Impairment losses of NOK 42.7 billion were recognised as *Depreciation, amortisation and net impairment losses* and NOK 9.8 billion as *Exploration expenses*, based on the impaired asset's nature. In 2014 impairment losses of NOK 29.5 billion were recognised.

The net impairment losses related to the unconventional onshore assets in North America, were mainly a result from reduced long term commodity price assumptions partly offset by operational performance improvements and cost reductions. The net impairment losses related to other conventional assets were primarily related to reduced commodity price assumptions, but also included an impairment loss related to an asset under development in the Gulf of Mexico due to installation damages and a consequential start-up delay.

Marketing, Midstream and Processing (MMP)
The MMP segment recognised a net impairment reversal of NOK 3.5 in 2015 mainly related to a refinery. The reversal of impairment was triggered by increased refinery margins and operational improvements. In 2014 net impairment losses of NOK 0.9 billion were recognised.

Sensitivities

Throughout 2015 and subsequent to year end, commodity prices have continued to be volatile. Significant downward adjustments of Statoil's commodity price assumptions would result in impairment losses on certain producing and development assets in Statoil's portfolio. The table below presents an estimate of the carrying amount of producing and development assets, that would be subject to impairment assessment if a further decline in commodity price forecasts over the lifetime of the assets were 20%. The sensitivity has been established on the assumption that all other factors would remain unchanged.

Carrying amount of producing and development assets which would be subject to impairment assessment assuming an additional decline in commodity price forecasts of 20%:

(in NOK billion)	Development and Production Norway	Development and Production International	Marketing, Midstream and Processing	Total
Carrying amount subject to impairment assessment in 2015 (after impairment)[1)]	48	230	9	287
Sensitivity: commodity price decline by 20%[2)]	52	253	N/A	305

1) Relates to assets subject to impairment assessment under IAS 36. As a result of these impairment assessments, Statoil recognised a net impairment loss of NOK 57.7 billion and 32.7 billion in 2015 and 2014 respectively, as described above.

2) The sensitivity which is reflected in this line, relates to the carrying amount of assets subject to impairment assessment under IAS 36. Exploration and evaluation assets accounted for under IFRS 6 are not included.

The information in the table above is for indicative purposes only. A significant and prolonged decline in commodity prices would affect other assumptions, e.g. cost level, currency etc. A general decline in commodity price assumptions of 20% would result in mitigating actions by Statoil by optimising the respective business plans in order to reduce the exposure to changes in the macro environment. Considering the substantial uncertainties related to other relevant assumptions that would be triggered by a significant and prolonged decline in commodity price forecasts, Statoil does not disclose the expected impairment amount.

12 Intangible assets

(in NOK billion)	Exploration expenses	Acquisition costs - oil and gas prospects	Goodwill	Other	Total
Cost at 31 December 2014	22.9	53.4	12.1	3.4	91.8
Additions	9.5	4.5	0.0	(0.2)	13.8
Disposals at cost	(0.5)	(2.3)	(0.1)	(0.2)	(3.0)
Transfers	(0.7)	(2.0)	0.0	(0.0)	(2.7)
Expensed exploration expenditures previously capitalised	(1.7)	(15.4)	0.0	0.0	(17.1)
Effect of changes in foreign exchange	3.1	7.7	1.7	0.5	13.0
Cost at 31 December 2015	32.6	45.9	13.8	3.6	95.8
Accumulated depreciation and impairment losses at 31 December 2014			(5.2)	(1.4)	(6.6)
Amortisation and impairments for the year			(4.2)	(0.0)	(4.2)
Effect of changes in foreign exchange			(1.5)	(0.2)	(1.8)
Accumulated depreciation and impairment losses at 31 December 2015			(10.9)	(1.6)	(12.5)
Carrying amount at 31 December 2015	32.6	45.9	2.8	2.0	83.3

(in NOK billion)	Exploration expenses	Acquisition costs - oil and gas prospects	Goodwill	Other	Total
Cost at 31 December 2013	20.3	58.6	10.5	3.1	92.4
Additions	7.1	1.5	0.0	(0.0)	8.7
Disposals at cost	(0.9)	(0.7)	(0.0)	(0.3)	(1.8)
Transfers	(4.1)	(5.5)	0.0	0.0	(9.5)
Expensed exploration expenditures previously capitalised	(2.7)	(11.1)	0.0	0.0	(13.7)
Effect of changes in foreign exchange	3.1	10.5	1.7	0.6	15.7
Cost at 31 December 2014	22.9	53.4	12.1	3.4	91.8
Accumulated depreciation and impairment losses at 31 December 2013			0.0	(0.9)	(0.9)
Amortisation and impairments for the year			(4.2)	(0.3)	(4.5)
Effect of changes in foreign exchange			(1.0)	(0.2)	(1.2)
Accumulated depreciation and impairment losses at 31 December 2014			(5.2)	(1.4)	(6.6)
Carrying amount at 31 December 2014	22.9	53.4	6.9	2.0	85.2

The useful lives of intangible assets are assessed to be either finite or indefinite. Intangible assets with finite useful lives are amortised systematically over their estimated economic lives, ranging between 10-20 years.

During 2015, intangible assets were impacted by impairments of acquisition costs related to exploration activities of NOK 5.6 billion primarily as a result from dry wells and uncommercial discoveries in Angola and the Gulf of Mexico. Additionally, Statoil recognised impairments of NOK 9.8 billion primarily related to unconventional onshore assets in USA and goodwill related to US onshore assets of NOK 4.2 billion.

Impairment losses and reversals of impairment losses are presented as *Exploration expenses* and *Depreciation, amortisation and net impairment losses* on the basis of their nature as exploration assets (intangible assets) and other intangible assets, respectively. The impairment losses and reversal of impairment losses are based on recoverable amount estimates triggered by changes in reserve estimates, cost estimates and market conditions. See note 11 *Property, plant and equipment* for more information on the basis for impairment assessments.

The table below shows the aging of capitalised exploration expenditures.

(in NOK billion)	2015	2014
Less than one year	12.8	9.2
Between one and five years	16.9	11.4
More than five years	2.9	2.3
Total	32.6	22.9

The table below shows the components of the exploration expenses.

(in NOK billion)	2015	2014	Full year 2013
Exploration expenditures	23.1	23.9	21.8
Expensed exploration expenditures previously capitalised	17.1	13.7	3.1
Capitalised exploration	(9.2)	(7.3)	(6.9)
Exploration expenses	31.0	30.3	18.0

13 Financial investments and non-current prepayments

Non-current financial investments

(in NOK billion)	2015	At 31 December 2014
Bonds	12.4	11.6
Listed equity securities	6.3	6.6
Non-listed equity securities	1.8	1.4
Financial investments	20.6	19.6

Bonds and listed equity securities relate to investment portfolios which are held by Statoil's captive insurance company and accounted for using the fair value option.

Non-current prepayments and financial receivables

(in NOK billion)	2015	At 31 December 2014
Financial receivables interest bearing	6.7	3.7
Prepayments and other non-interest bearing receivables	1.8	2.0
Prepayments and financial receivables	8.5	5.7

Financial receivables interest bearing primarily relate to project financing of equity accounted company and loans to employees.

Current financial investments

(in NOK billion)	2015	At 31 December 2014
Time deposits	19.1	9.8
Interest bearing securities	67.4	49.4
Financial investments	86.5	59.2

At 31 December 2015 current *Financial investments* include NOK 6.0 billion investment portfolios which are held by Statoil's captive insurance company and accounted for using the fair value option. The corresponding balance at 31 December 2014 was NOK 6.0 billion.

For information about financial instruments by category, see note 25 *Financial instruments: fair value measurement and sensitivity analysis of market risk.*

14 Inventories

(in NOK billion)	2015	At 31 December 2014
Crude oil	10.7	10.1
Petroleum products	5.1	6.0
Other	6.3	7.7
Inventories	22.0	23.7

Other inventory consists of natural gas, spare parts and operational materials, including drilling and well equipment.

The write-down of inventories from cost to net realisable value amounted to an expense of NOK 3.9 billion and NOK 4.0 billion in 2015 and 2014, respectively.

15 Trade and other receivables

(in NOK billion)	2015	At 31 December 2014
Trade receivables	39.3	57.8
Current financial receivables	6.5	6.9
Joint venture receivables	5.1	8.5
Equity accounted investments and other related party receivables	0.5	0.5
Total financial trade and other receivables	51.4	73.7
Non-financial trade and other receivables	7.4	9.6
Trade and other receivables	58.8	83.3

For more information about the credit quality of Statoil's counterparties, see note 5 *Financial risk management*. For currency sensitivities, see note 25 *Financial instruments: fair value measurement and sensitivity analysis of market risk*.

16 Cash and cash equivalents

(in NOK billion)	2015	At 31 December 2014
Cash at bank available	9.2	13.5
Time deposits	13.2	32.5
Money market funds	4.0	3.6
Interest bearing securities	44.8	30.6
Restricted cash, including margin deposits	4.8	2.9
Cash and cash equivalents	76.0	83.1

Restricted cash at 31 December 2015 and 2014 includes collateral deposits related to trading activities of NOK 3.6 billion and NOK 2.0 billion, respectively. Collateral deposits are related to certain requirements set out by exchanges where Statoil is participating. The terms and conditions related to these requirements are determined by the respective exchanges.

17 Shareholders' equity

At 31 December 2015 and 2014, Statoil's share capital of NOK 7,971,617,757.50 comprised 3,188,647,103 shares at a nominal value of NOK 2.50.

Statoil ASA has only one class of shares and all shares have voting rights. The holders of shares are entitled to receive dividends as and when declared and are entitled to one vote per share at general meetings of the company.

Dividends declared and paid per share were NOK 1.80 for each of the first two quarters of 2015. From and including the third quarter of 2015, dividend is declared in USD. Interim dividends of USD 0.2201 per share for the third quarter of 2015 were declared in the fourth quarter of 2015 and have been recognised as a liability in the Consolidated financial statements. This amount will be paid in the first quarter of 2016.

The board of directors will propose to the annual general meeting to maintain a dividend of USD 0.2201 per share for the fourth quarter 2015 and the introduction of a two-year scrip dividend programme starting from the fourth quarter 2015. The scrip programme will give shareholders the option to receive quarterly dividends in cash or in newly issued shares in Statoil, at a 5% discount for the fourth quarter 2015.

In 2014 dividends of NOK 7.20 were paid and NOK 7.00 for 2013.

During 2015 a total of 4,057,902 treasury shares were purchased for NOK 0.6 billion and 3,203,968 treasury shares were allocated to employees participating in the share saving plan. In 2014 a total of 3,381,488 treasury shares were purchased for NOK 0.6 billion and 2,960,972 treasury shares were allocated to employees participating in the share saving plan. At 31 December 2015 Statoil had 11,009,183 treasury shares and at 31 December 2014 10,155,249 treasury shares, all of which are related to Statoil's share saving plan. For further information, see note 6 *Remuneration*.

18 Finance debt

Capital management

The main objectives of Statoil's capital management policy are to maintain a strong financial position and to ensure sufficient financial flexibility. One of the key ratios in the assessment of Statoil's financial robustness is net interest-bearing debt adjusted (ND) to capital employed adjusted (CE).

(in NOK billion)	At 31 December 2015	2014
Net interest-bearing debt adjusted (ND)	129.9	95.6
Capital employed adjusted (CE)	485.0	476.7
Net debt to capital employed adjusted (ND/CE)	26.8%	20.0%

ND is defined as Statoil's interest bearing financial liabilities less cash and cash equivalents and current financial investments, adjusted for collateral deposits and balances held by Statoil's captive insurance company (an increase of NOK 9.6 billion and NOK 8.0 billion for 2015 and 2014, respectively), balances related to the SDFI (a decrease of NOK 1.9 billion and NOK 1.6 billion for 2015 and 2014, respectively) and project financing exposure that does not correlate to the underlying exposure (unchanged and decrease of NOK 0.1 billion for 2015 and 2014, respectively). CE is defined as Statoil's total equity (including non-controlling interests) and ND.

Non-current finance debt

Finance debt measured at amortised cost

	Weighted average interest rates in %[1]		Carrying amount in NOK billion at 31 December		Fair value in NOK billion at 31 December[2]	
	2015	2014	2015	2014	2015	2014
Unsecured bonds						
United States Dollar (USD)	3.51	3.50	182.9	154.4	190.5	165.0
Euro (EUR)	2.28	3.99	63.4	37.6	66.0	43.8
Great Britain Pound (GBP)	6.08	6.08	18.0	15.9	23.8	22.3
Norwegian kroner (NOK)	4.18	4.18	3.0	3.0	3.3	3.5
Total			267.3	210.9	283.7	234.7
Unsecured loans						
Japanese yen (JPY)	4.30	4.30	0.7	0.6	0.8	0.9
Secured bank loans						
United States Dollar (USD)	-	4.20	-	0.1	-	0.1
Norwegian kroner (NOK)	3.11	3.11	0.5	0.3	0.5	0.3
Finance lease liabilities			5.1	5.4	5.0	5.6
Total			6.3	6.5	6.3	6.9
Total finance debt			273.6	217.4	289.9	241.6
Less current portion			9.7	12.3	9.7	12.3
Non-current finance debt			264.0	205.1	280.2	229.3

1) Weighted average interest rates are calculated based on the contractual rates on the loans per currency at 31 December and do not include the effect of swap agreements.
2) The fair value of the non-current financial liabilities is determined using a discounted cash flow model and is classified at level 2 in the fair value hierarchy. Interest rates used in the model are derived from the LIBOR and EURIBOR forward curves and will vary based on the time to maturity for the non-current financial liabilities. The credit premium used is based on indicative pricing from external financial institutions.

Unsecured bonds amounting to NOK 182.9 billion are denominated in USD and unsecured bonds amounting to NOK 70.1 billion are swapped into USD. Two bonds denominated in EUR amounting to NOK 14.3 billion are not swapped. The table does not include the effects of agreements entered into to swap the various currencies into USD. For further information see note 25 *Financial instruments: fair value measurement and sensitivity analysis of market risk*.

Substantially all unsecured bond and unsecured bank loan agreements contain provisions restricting future pledging of assets to secure borrowings without granting a similar secured status to the existing bondholders and lenders.

The secured bank loan in NOK has been secured by real estate and land with a total book value of NOK 0.6 billion.

In 2015 Statoil issued the following bonds:

Issuance date	Amount in EUR billion	Interest rate in %	Maturity date
17 February 2015	1.00	1.625	February 2035
17 February 2015	1.25	1.250	February 2027
17 February 2015	1.00	0.875	February 2023
17 February 2015	0.50	floating	August 2019

Out of Statoil's total outstanding unsecured bond portfolio, 48 bond agreements contain provisions allowing Statoil to call the debt prior to its final redemption at par or at certain specified premiums if there are changes to the Norwegian tax laws. The carrying amount of these agreements is NOK 264 billion at the 31 December 2015 closing exchange rate.

For more information about the revolving credit facility, maturity profile for undiscounted cash flows and interest rate risk management, see note 5 *Financial risk management*.

Non-current finance debt maturity profile

(in NOK billion)	2015	At 31 December 2014
Year 2 and 3	54.9	27.3
Year 4 and 5	43.0	44.2
After 5 years	166.1	133.5
Total repayment of non-current finance debt	264.0	205.1
Weighted average maturity (years)	9	9
Weighted average annual interest rate (%)	3.39	3.78

More information regarding finance lease liabilities is provided in note 22 *Leases*.

Current finance debt

(in NOK billion)	2015	At 31 December 2014
Collateral liabilities	10.2	12.9
Non-current finance debt due within one year	9.7	12.3
Other including bank overdraft	0.6	1.3
Total current finance debt	20.5	26.5
Weighted average interest rate (%)	1.90	2.12

Collateral liabilities relate mainly to cash received as security for a portion of Statoil's credit exposure.

19 Pensions

The Norwegian companies in the group are subject to the requirements of the Mandatory Company Pensions Act, and the company's pension scheme follows the requirements of the Act.

Statoil ASA and a number of its subsidiaries have defined contribution plans. The period's contributions are recognised in the Consolidated statement of income as pension cost for the period.

In 2014 Statoil ASA made a decision to change the company's main pension plan in Norway from a defined benefit plan to a defined contribution plan. The actual transitioning to the defined contribution plan took place in 2015. At the same time paid-up policies for the rights vested in the defined benefit plan were issued. Employees with less than 15 years of future service before their regular retirement age retained the existing defined benefit plans. For onshore employees between 37 and 51 years of age and offshore employees between 35 and 49 years of age a compensation plan has been established. The defined contribution plan in Norway is managed by an insurance company (Storebrand).

The new pension plans in Statoil ASA includes unfunded elements. These notional contribution plans are regulated equal to the return on asset for the main contribution plan and are valued at fair value and recognised as pension liabilities. See note 2 *Significant accounting policies* for more information about the accounting treatment of the notional contribution plans reported in Statoil ASA.

In addition to the closed pension plans in Statoil ASA, some of its subsidiaries have defined benefit plans. The defined benefit plans in Norway are managed and financed through Statoil Pensjon (Statoil's pension fund - hereafter "Statoil Pension"). Statoil Pension is an independent pension fund that covers the employees in Statoil's Norwegian companies. The purpose of Statoil Pension is to provide retirement and disability pension to members and survivor's pension to spouses, registered partners, cohabitants and children. The pension fund's assets are kept separate from the company's and group companies' assets. Statoil Pension is supervised by the Financial Supervisory Authority of Norway ("Finanstilsynet") and is licensed to operate as a pension fund.

The Norwegian National Insurance Scheme ("Folketrygden") provides pension payments (social security) to all retired Norwegian citizens. Such payments are calculated by references to a base amount ("Grunnbeløpet" or "G") annually approved by the Norwegian Parliament. Statoil's plan benefits are generally based on a minimum of 30 years of service and 66% of the final salary level, including an assumed benefit from the Norwegian National Insurance Scheme.

Due to national agreements in Norway, Statoil is a member of both the previous agreement-based early retirement plan ("AFP") and the AFP scheme applicable from 1 January 2011. Statoil paid a premium for both AFP schemes until 31 December 2015. After that date, premiums are only due on the latest AFP scheme. The premium in the latest scheme is calculated on the basis of the employees' income between 1 and 7.1 G. The premium is payable for all employees until age 62. Pension from the latest AFP scheme will be paid from the AFP plan administrator to employees for their full lifetime. Statoil has determined that its obligations under this multi-employer defined benefit plan can be estimated with sufficient reliability for recognition purposes. Accordingly, the estimated proportionate share of the latest AFP plan has been recognised as a defined benefit obligation.

The present values of the defined benefit obligation, except for the notional contribution plan, and the related current service cost and past service cost are measured using the projected unit credit method. The assumptions for salary increases, increases in pension payments and social security base amount are based on agreed regulation in the plans, historical observations, future expectations of the assumptions and the relationship between these assumptions. At 31 December 2015 the discount rate for the defined benefit plans in Norway was established on the basis of seven years' mortgage covered bonds interest rate extrapolated on a yield curve which matches the duration of Statoil's payment portfolio for earned benefits.

Social security tax is calculated based on a pension plan's net funded status and is included in the defined benefit obligation.

Statoil has more than one defined benefit plan, but the disclosure is made in total since the plans are not subject to materially different risks. Pension plans outside Norway are not material and as such not disclosed separately.

Net pension cost

(in NOK billion)	2015	2014	2013
Current service cost	3.0	4.7	4.0
Interest cost	1.5	3.1	2.5
Interest (income) on plan asset	(1.2)	(2.6)	(2.1)
Losses (gains) from curtailment, settlement or plan amendment	2.0	(1.9)	0.0[1)]
Actuarial (gains) losses related to termination benefits	(0.0)	(0.2)	0.0
Notional contributions	0.3	0.0	0.0
Defined benefit plans	5.7	3.2	4.4
Defined contribution plans	1.1	0.2	0.2
Total net pension cost	6.8	3.4	4.6

1) In 2015 and 2014 Statoil ASA offered early retirement (termination benefits) to a defined group of employees above the age of 58 years. The expenses of NOK 1.4 billion and NOK 1.6 billion respectively were recognised in the Consolidated statement of income. In addition, a plan amendment effect related to the changed pension scheme in Norway resulted in a recognition in the Consolidated statement of income of a loss of NOK 0.6 billion in 2015 and a gain of NOK 3.5 billion in 2014. The plan amendment effect was recalculated in 2015 due to actual transitioning from a defined benefit to a defined contribution plan took place in 2015 and all information was not available when calculating the effect in 2014.

Pension cost includes associated social security tax and is partly charged to partners of Statoil operated licences.

(in NOK billion)	2015	2014
Defined benefit obligations (DBO)		
Defined benefit obligations at 1 January	65.0	79.4
Current service cost	3.0	4.7
Interest cost	1.5	3.1
Actuarial (gains) losses - Demographic assumptions	0.0	(0.1)
Actuarial (gains) losses - Financial assumptions	(6.0)	4.8
Actuarial (gains) losses - Experience	(3.1)	(2.1)
Benefits paid	(1.9)	(2.0)
Losses (gains) from curtailment, settlement or plan amendment[1)]	2.2	(2.9)
Paid-up policies	(1.2)	(20.4)
Foreign currency translation	0.3	0.3
Changes in notional contribution liability	0.3	0.0
Defined benefit obligations at 31 December	60.1	65.0
Fair value of plan assets		
Fair value of plan assets at 1 January	45.1	62.3
Interest income	1.2	2.6
Return on plan assets (excluding interest income)	0.6	0.9
Company contributions	0.3	0.1
Benefits paid	(0.6)	(0.7)
Paid-up policies and personal insurance	(1.7)	(20.4)
Foreign currency translation	0.3	0.3
Fair value of plan assets at 31 December	45.2	45.1
Net pension liability at 31 December	(14.9)	(19.9)
Represented by:		
Asset recognised as non-current pension assets (funded plan)	11.3	8.0
Liability recognised as non-current pension liabilities (unfunded plans)	(26.2)	(27.9)
DBO specified by funded and unfunded pension plans	60.1	65.0
Funded	33.9	37.2
Unfunded	26.2	27.9
Actual return on assets	1.8	3.5

1) A loss of NOK 0.1 billion in 2015 and a gain of NOK 0.9 billion in 2014, related to the plan amendment, has been recognised against *Property, plant and equipment*.

As part of the change of Statoil ASA's main pension plan in Norway the estimated assets related to paid-up policies and personal insurance (new disability pension and children pension from 2015) and liabilities related to paid-up policies have been excluded from the amounts in the table above.

Actuarial losses and gains recognised directly in Other comprehensive income (OCI)

(in NOK billion)	2015	2014	2013
Net actuarial (losses) gains recognised in OCI during the year	9.7	0.2	(5.5)
Actuarial (losses) gains related to currency effects on net obligation and foreign exchange translation	0.4	(0.2)	(0.4)
Tax effects of actuarial (losses) gains recognised in OCI	(2.8)	0.9	1.2
Recognised directly in OCI during the year net of tax	7.3	0.9	(4.7)
Cumulative actuarial (losses) gains recognised directly in OCI net of tax	(7.2)	(14.5)	(15.4)

The net actuarial gain in 2015 is mainly related to an updated assessment of the discount rate and expected rate of pension increase to be used for pension obligations in Norway.

The line item net actuarial (losses) gains recognised in OCI during the year in 2014 includes actuarial loss charged to partners of Statoil operated licences.

The line item actuarial (losses) gains related to currency effects on net obligation and foreign exchange translation includes the translation of the net pension obligation in NOK to the functional currency USD for the parent company, Statoil ASA, and the translation of the net pension obligation from the functional currency USD to Statoil's presentation currency NOK.

Actuarial assumptions

	Assumptions used to determine benefit costs in %		Assumptions used to determine benefit obligations in %	
	2015	2014	2015	2014
Discount rate	2.50	4.00	2.75	2.50
Rate of compensation increase	2.25	3.50	2.25	2.25
Expected rate of pension increase	1.50	2.50	1.00	1.50
Expected increase of social security base amount (G-amount)	2.25	3.25	2.25	2.25
Weighted-average duration of the defined benefit obligation			17.1	19.1

The assumptions presented are for the Norwegian companies in Statoil which are members of Statoil's pension fund. The defined benefit plans of other subsidiaries are immaterial to the consolidated pension assets and liabilities.

Expected attrition at 31 December 2015 was 0.4% and 0.1% for employees between 50-59 years and 60-67 years, respectively. Expected attrition at 31 December 2014 was 2.1%, 2.2%, 1.3%, 0.5% and 0.2% for the employees under 30 years, 30-39 years, 40-49 years, 50-59 years and 60-67 years, respectively.

For population in Norway, the mortality table K2013, issued by The Financial Supervisory Authority of Norway, is used as the best mortality estimate.

Disability tables for plans in Norway developed by the actuary were implemented in 2013 and represent the best estimate to use for plans in Norway.

Sensitivity analysis

The table below presents an estimate of the potential effects of changes in the key assumptions for the defined benefit plans. The following estimates are based on facts and circumstances as of 31 December 2015. Actual results may materially deviate from these estimates.

	Discount rate		Expected rate of compensation increase		Expected rate of pension increase		Mortality assumption	
(in NOK billion)	0.50%	-0.50%	0.50%	-0.50%	0.50%	-0.50%	+ 1 year	- 1 year
Changes in:								
Defined benefit obligation at 31 December 2015	(4.3)	5.0	1.1	(1.0)	3.5	(3.1)	2.0	(2.2)
Service cost 2016	(0.2)	0.2	0.1	(0.0)	0.1	(0.1)	0.1	(0.1)

The sensitivity of the financial results to each of the key assumptions has been estimated based on the assumption that all other factors would remain unchanged. The estimated effects on the financial result would differ from those that would actually appear in the Consolidated financial statements because the Consolidated financial statements would also reflect the relationship between these assumptions.

Pension assets
The plan assets related to the defined benefit plans were measured at fair value. Statoil Pension invests in both financial assets and real estate.

Real estate properties owned by Statoil Pension amounted to NOK 3.4 billion and NOK 3.2 billion of total pension assets at 31 December 2015 and 2014, respectively, and are rented to Statoil companies.

The table below presents the portfolio weighting as approved by the board of Statoil Pension for 2015. The portfolio weight during a year will depend on the risk capacity.

(in %)	Pension assets on investments classes 2015	2014	Target portfolio weight
Equity securities	38.3	40.1	31 - 43
Bonds	40.3	38.7	36 - 48
Money market instruments	14.9	13.4	0 - 29
Real estate	5.0	4.8	5 - 10
Other assets	1.5	3.0	
Total	100.0	100.0	

In 2015 100% of the equity securities, 38% of bonds and 100% of money market instruments had quoted market prices in an active market (level 1). In 2014 100% of the equity securities, 38% of bonds and 86% of money market instruments had quoted market prices in an active market. Statoil does not have any equity securities, bonds or money market instruments classified in level 3. Real Estate is classified as level 3. For definition of the various levels, see note 25 *Financial instruments: fair value measurement and sensitivity analysis of market risk*.

No company contribution is expected to be paid to Statoil Pension in 2016.

20 Provisions

(in NOK billion)	Asset retirement obligations	Claims and litigations	Other provisions	Total
Non-current portion at 31 December 2014	107.4	3.5	6.3	117.2
Current portion at 31 December 2014 reported as trade and other payables	1.4	13.6	2.1	17.0
Provisions at 31 December 2014	108.8	17.1	8.4	134.2
New or increased provisions	4.2	6.1	4.4	14.8
Decrease in the estimates	(16.2)	(2.2)	(3.3)	(21.7)
Amounts charged against provisions	(2.2)	(4.6)	(0.9)	(7.7)
Effects of change in the discount rate	(6.8)	0.0	(0.1)	(7.0)
Reduction due to divestments	(1.0)	0.0	(0.1)	(1.1)
Accretion expenses	3.9	0.0	0.0	3.9
Reclassification and transfer	(0.6)	0.0	(0.3)	(0.8)
Currency translation	4.8	2.7	0.9	8.4
Provisions at 31 December 2015	95.0	19.1	9.0	123.0
Current portion at 31 December 2015 reported as trade and other payables	1.3	9.2	2.8	13.4
Long term interest bearing provisions at 31 December 2015 reported as finance debt	0.0	0.0	0.2	0.2
Non-current portion at 31 December 2015	93.7	9.8	6.0	109.4

Expected timing of cash outflows

(in NOK billion)	Asset retirement obligations	Other provisions, including claims and litigations	Total
2016 - 2020	12.2	24.7	36.9
2021 - 2025	16.9	0.8	17.7
2026 - 2030	16.1	0.2	16.3
2031 - 2035	25.5	0.7	26.3
Thereafter	24.2	1.6	25.8
At 31 December 2015	95.0	28.1	123.0

Statoil's estimated asset retirement obligations (ARO) have reduced mainly due to a reduction in cost estimates for plugging and abandonment. Changes in ARO are reflected within *Property, plant and equipment* and *Provisions* in the Consolidated balance sheet. The timing of cash outflows related to ARO primarily depends on when the production ceases at the various facilities.

The claims and litigations category mainly relates to expected payments on unresolved claims. The timing and amounts of potential settlements in respect of these are uncertain and dependent on various factors that are outside management's control.

See also comments on provisions in note 23 *Other commitments, contingent liabilities and contingent assets.*

The other provisions category relates to expected payments on onerous contracts, cancellation fees and other.

For further information of methods applied and estimates required, see note 2 *Significant accounting policies*.

21 Trade and other payables

(in NOK billion)	2015	At 31 December 2014
Trade payables	18.1	21.8
Non-trade payables and accrued expenses	20.8	25.2
Joint venture payables	22.8	28.9
Equity accounted investments and other related party payables	5.5	6.6
Total financial trade and other payables	67.2	82.5
Current portion of provisions and other payables	15.0	18.1
Trade and other payables	82.2	100.7

Included in current portion of provisions and other payables are certain provisions that are further described in note 23 *Other commitments, contingent liabilities and contingent assets.* For information regarding currency sensitivities, see note 25 *Financial instruments: fair value measurement and sensitivity analysis of market risk*. For further information on payables to equity accounted investments and other related parties, see note 24 *Related parties*.

22 Leases

Statoil leases certain assets, notably drilling rigs, vessels and office buildings.

In 2015, net rental expenditures were NOK 27.7 billion (NOK 22.9 billion in 2014 and NOK 17.4 billion in 2013) consisting of minimum lease payments of NOK 32.6 billion (NOK 28.4 billion in 2014 and NOK 21.2 billion in 2013) reduced with sublease payments received of NOK 4.9 billion (NOK 5.5 billion in 2014 and NOK 3.8 billion in 2013). Net rental expenditures in 2015 include rig cancellation payments of NOK 1.6 billion. No material contingent rent payments have been expensed in 2015, 2014 or 2013.

The information in the table below shows future minimum lease payments due and receivable under non-cancellable operating leases at 31 December 2015:

	Operating leases					
(in NOK billion)	Rigs	Vessels	Other	Total	Sublease	Net total
2016	18.2	5.0	2.4	25.6	(2.6)	23.0
2017	11.1	3.8	1.8	16.7	(0.9)	15.8
2018	7.3	3.2	1.6	12.1	(0.7)	11.3
2019	6.1	2.5	1.3	9.9	(0.7)	9.2
2020	4.2	2.2	1.3	7.8	(0.7)	7.0
Thereafter	9.0	6.6	12.2	27.8	(1.4)	26.4
Total future minimum lease payments	55.9	23.3	20.6	99.8	(7.1)	92.7

Statoil had certain operating lease contracts for drilling rigs at 31 December 2015. The remaining significant contracts' terms range from one month to eight years. Certain contracts contain renewal options. Rig lease agreements are for the most part based on fixed day rates. Certain rigs have been subleased in whole or for part of the lease term mainly to Statoil operated licenses on the Norwegian continental shelf. These leases are shown gross as operating leases in the table above.

Statoil has a long-term time charter agreement with Teekay for offshore loading and transportation in the North Sea. The contract covers the lifetime of applicable producing fields and at year end 2015 includes three crude tankers. The contract's estimated nominal amount was approximately NOK 7.0 billion at year end 2015, and it is included in the category vessels in the table above.

The category other includes future minimum lease payments to related parties of NOK 4.3 billion regarding the lease of one office building located in Bergen and owned by Statoil`s pension fund ("Statoil Pension"). These operating lease commitments extend to the year 2034. NOK 3.2 billion of the total is payable after 2020.

Statoil had finance lease liabilities of NOK 4.9 billion at 31 December 2015. The nominal minimum lease payments related to these finance leases amount to NOK 6.5 billion. *Property, plant and equipment* includes NOK 6.8 billion for finance leases that have been capitalised at year end (NOK 5.7 billion in 2014), mainly presented in the category machinery, equipment and transportation equipment, including vessels in note 11 *Property, plant and equipment*.

23 Other commitments, contingent liabilities and contingent assets

Contractual commitments

Statoil had contractual commitments of NOK 62.3 billion at 31 December 2015. The contractual commitments reflect Statoil's share and mainly comprise construction and acquisition of property, plant and equipment.

As a condition for being awarded oil and gas exploration and production licences, participants may be committed to drill a certain number of wells. At the end of 2015, Statoil was committed to participate in 32 offshore wells, with an average ownership interest of approximately 33%. Statoil's share of estimated expenditures to drill these wells amounts to NOK 7.7 billion. Additional wells that Statoil may become committed to participating in depending on future discoveries in certain licences are not included in these numbers.

Other long-term commitments

Statoil has entered into various long-term agreements for pipeline transportation as well as terminal use, processing, storage and entry/exit capacity commitments and commitments related to specific purchase agreements. The agreements ensure the rights to the capacity or volumes in question, but also impose on Statoil the obligation to pay for the agreed-upon service or commodity, irrespective of actual use. The contracts' terms vary, with durations of up to 30 years.

Take-or-pay contracts for the purchase of commodity quantities are only included in the table below if their contractually agreed pricing is of a nature that will or may deviate from the obtainable market prices for the commodity at the time of delivery.

Obligations payable by Statoil to entities accounted for as associates and joint ventures are included gross in the table below. Obligations payable by Statoil to entities accounted for as joint operations (for example pipelines) are included net (i.e. gross commitment less Statoil's ownership share).

Nominal minimum other long-term commitments at 31 December 2015:

(in NOK billion)	
2016	13.5
2017	12.8
2018	11.8
2019	12.2
2020	10.9
Thereafter	77.9
Total	139.1

Of the reported other long-term commitments, NOK 17.5 billion relates to pipeline commitments where the construction of these pipelines is pending governmental approval.

Contingent liabilities and contingent assets

During the annual audits of Statoil's participation in Block 4, Block 15, Block 17 and Block 31 offshore Angola, the Angolan Ministry of Finance has assessed additional profit oil and taxes due on the basis of activities that currently include the years 2002 up to and including 2012. Statoil disputes the assessments and is pursuing these matters in accordance with relevant Angolan legal and administrative procedures. On the basis of the assessments and continued activity on the four blocks up to and including 2015, the exposure for Statoil at year end 2015 is estimated to NOK 11.6 billion (USD 1.3 billion), the most significant part of which relates to profit oil elements. Statoil has provided in the Consolidated financial statements for its best estimate related to the assessments, reflected in the Consolidated statement of income mainly as a revenue reduction, with additional amounts reflected as interest expenses and tax expenses, respectively.

Through its ownership in OML 128 in Nigeria, Statoil is party to an ownership interest redetermination process for the Agbami field. In October 2015, Statoil received the Expert's final ruling which implies a reduction of 5.17 percentage points in Statoil's equity interest in the field. Statoil had previously initiated arbitration proceedings to set aside interim decisions made by the Expert, but this was declined by the arbitration tribunal in its November 2015 judgment. Statoil has initiated proceedings before the Federal High Court in Lagos to set aside the arbitration award and also intends to initiate a new arbitration to set aside the Expert's final ruling. As of 31 December 2015, Statoil has recognised a provision of NOK 9.5 billion (USD 1.1 billion), net of tax, which reflects a reduction of 5.17 percentage points in Statoil's equity interest in the Agbami field. The provision is reflected within *Provisions* in the Consolidated balance sheet.

Some long-term gas sales agreements contain price review clauses. Certain counterparties have requested arbitration in connection with price review claims. The related exposure for Statoil has been estimated to an amount equivalent to approximately NOK 3.6 billion for gas delivered prior to year end 2015. Statoil has provided for its best estimate related to these contractual gas price disputes in the Consolidated financial statements, with the impact to the Consolidated statement of income reflected as revenue adjustments.

There is a dispute between the Nigerian National Petroleum Corporation (NNPC) and the partners (Contractor) in Oil Mining Lease (OML) 128 of the unitised Agbami field concerning interpretation of the terms of the OML 128 Production Sharing Contract (PSC). The dispute relates to the allocation between NNPC and Contractor of cost oil, tax oil and profit oil volumes. NNPC has claimed that since the start of production from Agbami, Contractor has lifted excess volumes compared to the PSC terms, and consequently NNPC has increased its lifting of oil. The Contractor disputed NNPC's position and initiated arbitration in the matter in accordance with the terms of the PSC. In 2015 the Arbitral Tribunal ruled in favour of Contractor's interpretation of the PSC on the main points. The Contractor is currently proceeding to enforce the favourable decision by the means available in the Nigerian legal system, while NNPC on its hand has initiated litigation concerning certain objections to the arbitration award. The Nigerian Federal Inland Revenue Service is also contesting the legality of the arbitration process as far as resolving tax related disputes goes, and is actively pursuing this view through the channels of the Nigerian legal system. Statoil's stake in the dispute at year end 2015 is mainly related to oil volumes previously lifted by NNPC contrary to the PSC terms. NNPC has so far kept on its overlifting contrary to the award. Following the arbitration award, Statoil's previous provision related to NNPC's claim has been reversed with the effect mainly reflected as revenue in the Consolidated statement of income.

In 2014, following a regular review process of Statoil's 2012 Consolidated financial statements, the Financial Supervisory Authority of Norway (the FSA) ordered Statoil to: "*Change its future accounting practices for redetermination of CGUs containing onerous contracts. Correct the described error by establishing a separate onerous contract provision for the Cove Point capacity contract in a financial period prior to Q1 2013. The correction shall be presented in the next periodic financial report. Information about the circumstances shall be given in notes to the accounts*." Statoil appealed the order and has been granted a stay in carrying out the FSA's order pending the final outcome of the appeal. The appeal is currently being assessed by the Norwegian Ministry of Finance and not yet concluded. If the outcome of the appeal would require implementing the FSA's order, a provision would be recognised against *Net operating income* in an earlier reporting period than 2013. As the contracts were fully provided for in 2013, there would be no impact on equity at 31 December 2013 or thereafter. The actual amount to be provided in an earlier period would depend on the period in which the provision would be recorded. The FSA order does not specify which period prior to the first quarter 2013 would be relevant for the provision to be recognised. Statoil's reading is that 2011 would be most relevant. There would be no impact on the 2015 and 2014 financial statements, however, the comparative amounts included therein for 2013 *Net operating income* and *Net income* would be NOK 5.6 billion and NOK 5.0 billion higher, respectively.

During the normal course of its business, Statoil is involved in legal proceedings, and several other unresolved claims are currently outstanding. The ultimate liability or asset, in respect of such litigation and claims cannot be determined at this time. Statoil has provided in its Consolidated financial statements for probable liabilities related to litigation and claims based on its best estimate. Statoil does not expect that its financial position, results of operations or cash flows will be materially affected by the resolution of these legal proceedings.

Statoil is actively pursuing the above disputes through the contractual and legal means available in each case, but the timing of the ultimate resolutions and related cash flows, if any, cannot at present be determined with sufficient reliability.

Provisions related to claims are reflected within note 20 *Provisions*.

24 Related parties

Transactions with the Norwegian State
The Norwegian State is the majority shareholder of Statoil and also holds major investments in other Norwegian companies. As of 31 December 2015 the Norwegian State had an ownership interest in Statoil of 67.0% (excluding Folketrygdfondet, the Norwegian national insurance fund, of 3.2%). This ownership structure means that Statoil participates in transactions with many parties that are under a common ownership structure and therefore meet the definition of a related party. All transactions are considered to be on an arm's length basis.

Total purchases of oil and natural gas liquids from the Norwegian State amounted to NOK 60.0 billion, NOK 86.4 billion and NOK 92.5 billion in 2015, 2014 and 2013, respectively. Total purchases of natural gas regarding the Tjeldbergodden methanol plant from the Norwegian State amounted to NOK 0.6 billion, NOK 0.5 billion and NOK 0.5 billion in 2015, 2014 and 2013, respectively. In addition, Statoil ASA sells in its own name, but for the Norwegian State's account and risk, the Norwegian State's gas production. These transactions are presented net. For further information please see note 2 *Significant accounting policies*. The most significant items included in the line item equity accounted investments and other related party payables in note 21 *Trade and other payables*, are amounts payable to the Norwegian State for these purchases.

Other transactions
In relation to its ordinary business operations Statoil enters into contracts such as pipeline transport, gas storage and processing of petroleum products, with companies in which Statoil has ownership interests. Such transactions are carried out on an arm's length basis and are included within the applicable captions in the Consolidated statement of income. Gassled and certain other infrastructure assets are operated by Gassco AS, which is an entity under common control by the Norwegian Ministry of Petroleum and Energy. Gassco's activities are performed on behalf of and for the risk and reward of pipeline and terminal owners, and capacity payments flow through Gassco to the respective owners. Statoil payments that flowed through Gassco in this respect amounted to NOK 7.2 billion, NOK 7.4 billion and NOK 7.3 billion in 2015, 2014 and 2013, respectively.

For information concerning certain lease arrangements with Statoil Pension, see note 22 *Leases*.

Related party transactions with management are presented in note 6 *Remuneration.* Management remuneration for 2015 is presented in note 5 *Remuneration* in the financial statements of the parent company, Statoil ASA.

25 Financial instruments: fair value measurement and sensitivity analysis of market risk

Financial instruments by category

The following tables present Statoil's classes of financial instruments and their carrying amounts by the categories as they are defined in IAS 39 *Financial Instruments: Recognition and Measurement*. All financial instruments' carrying amounts are measured at fair value or their carrying amounts reasonably approximate fair value except non-current financial liabilities. See note 18 *Finance debt* for fair value information of non-current bonds, bank loans and finance lease liabilities.

See note 2 *Significant accounting policies* for further information regarding measurement of fair values.

				Fair value through profit or loss			
(in NOK billion)	Note	Loans and receivables	Available for sale	Held for trading	Fair value option	Non-financial assets	Total carrying amount
At 31 December 2015							
Assets							
Non-current derivative financial instruments		0.0	0.0	23.8	0.0	0.0	23.8
Non-current financial investments	13	0.0	1.8	0.0	18.7	0.0	20.6
Prepayments and financial receivables	13	5.8	0.0	0.0	0.0	2.8	8.5
Trade and other receivables	15	51.4	0.0	0.0	0.0	7.4	58.8
Current derivative financial instruments		0.0	0.0	4.8	0.0	0.0	4.8
Current financial investments	13	19.1	0.0	61.4	6.0	0.0	86.5
Cash and cash equivalents	16	27.1	0.0	48.8	0.0	0.0	76.0
Total		103.4	1.9	138.8	24.7	10.1	278.8

				Fair value through profit or loss			
(in NOK billion)	Note	Loans and receivables	Available for sale	Held for trading	Fair value option	Non-financial assets	Total carrying amount
At 31 December 2014							
Assets							
Non-current derivative financial instruments		0.0	0.0	29.9	0.0	0.0	29.9
Non-current financial investments	13	0.0	1.4	0.0	18.2	0.0	19.6
Prepayments and financial receivables	13	2.7	0.0	0.0	0.0	2.9	5.7
Trade and other receivables	15	73.7	0.0	0.0	0.0	9.6	83.3
Current derivative financial instruments		0.0	0.0	5.3	0.0	0.0	5.3
Current financial investments	13	9.8	0.0	43.4	6.0	0.0	59.2
Cash and cash equivalents	16	48.9	0.0	34.2	0.0	0.0	83.1
Total		135.2	1.4	112.8	24.2	12.6	286.2

(in NOK billion)	Note	Amortised cost	Fair value through profit or loss	Non-financial liabilities	Total carrying amount
At 31 December 2015					
Liabilities					
Non-current finance debt	18	264.0	0.0	0.0	264.0
Non-current derivative financial instruments		0.0	11.3	0.0	11.3
Trade and other payables	21	66.8	0.0	15.4	82.2
Current finance debt	18	20.5	0.0	0.0	20.5
Dividend payable		6.2	0.0	0.0	6.2
Current derivative financial instruments		0.0	2.3	0.0	2.3
Total		357.5	13.6	15.4	386.5

(in NOK billion)	Note	Amortised cost	Fair value through profit or loss	Non-financial liabilities	Total carrying amount
At 31 December 2014					
Liabilities					
Non-current finance debt	18	205.1	0.0	0.0	205.1
Non-current derivative financial instruments		0.0	4.5	0.0	4.5
Trade and other payables	21	82.5	0.0	18.1	100.7
Current finance debt	18	26.5	0.0	0.0	26.5
Dividend payable		5.7	0.0	0.0	5.7
Current derivative financial instruments		0.0	6.6	0.0	6.6
Total		319.8	11.1	18.1	349.1

Fair value hierarchy

The following table summarises each class of financial instruments which are recognised in the Consolidated balance sheet at fair value, split by Statoil's basis for fair value measurement.

(in NOK billion)	Non-current financial investments	Non-current derivative financial instruments - assets	Current financial investments	Current derivative financial instruments - assets	Cash equivalents	Non-current derivative financial instruments - liabilities	Current derivative financial instruments - liabilities	Net fair value
At 31 December 2015								
Level 1	10.5	0.0	4.8	0.0	0.0	0.0	0.0	15.3
Level 2	8.2	15.5	62.6	4.3	48.8	(10.8)	(2.3)	126.3
Level 3	1.8	8.3	0.0	0.4	0.0	(0.5)	0.0	10.1
Total fair value	20.6	23.8	67.4	4.8	48.8	(11.3)	(2.3)	151.7
At 31 December 2014								
Level 1	11.1	0.0	4.0	0.0	0.0	0.0	0.0	15.1
Level 2	7.0	17.2	45.5	4.7	34.2	(4.5)	(6.6)	97.4
Level 3	1.4	12.7	0.0	0.6	0.0	0.0	(0.0)	14.7
Total fair value	19.6	29.9	49.4	5.3	34.2	(4.5)	(6.6)	127.3

Level 1, fair value based on prices quoted in an active market for identical assets or liabilities, includes financial instruments actively traded and for which the values recognised in the Consolidated balance sheet are determined based on observable prices on identical instruments. For Statoil this category will, in most cases, only be relevant for investments in listed equity securities and government bonds.

Level 2, fair value based on inputs other than quoted prices included within level 1, which are derived from observable market transactions, includes Statoil's non-standardised contracts for which fair values are determined on the basis of price inputs from observable market transactions. This will typically be when

Statoil uses forward prices on crude oil, natural gas, interest rates and foreign exchange rates as inputs to the valuation models to determining the fair value of its derivative financial instruments.

Level 3, fair value based on unobservable inputs, includes financial instruments for which fair values are determined on the basis of input and assumptions that are not from observable market transactions. The fair values presented in this category are mainly based on internal assumptions. The internal assumptions are only used in the absence of quoted prices from an active market or other observable price inputs for the financial instruments subject to the valuation.

The fair value of certain earn-out agreements and embedded derivative contracts are determined by the use of valuation techniques with price inputs from observable market transactions as well as internally generated price assumptions and volume profiles. The discount rate used in the valuation is a risk-free rate based on the applicable currency and time horizon of the underlying cash flows adjusted for a credit premium to reflect either Statoil's credit premium, if the value is a liability, or an estimated counterparty credit premium if the value is an asset. In addition a risk premium for risk elements not adjusted for in the cash flow may be included when applicable. The fair values of these derivative financial instruments have been classified in their entirety in the third category within current derivative financial instruments and non-current derivative financial instruments - assets in the table above. Another reasonable assumption, that could have been applied when determining the fair value of these contracts, would be to extrapolate the last observed forward prices with inflation. If Statoil had applied this assumption, the fair value of the contracts included would have decreased by approximately NOK 4.6 billion at end of 2015 and decreased by NOK 3.5 billion at end of 2014 and impacted the Consolidated statement of income with corresponding amounts.

The reconciliation of the changes in fair value during 2015 and 2014 for all financial assets classified in the third level in the hierarchy are presented in the following table.

(in NOK billion)	Non-current financial investments	Non-current derivative financial instruments - assets	Current derivative financial instruments - assets	Non-current derivative financial instruments liabilities	Total amount
Full year 2015					
Opening balance	1.4	12.7	0.6	0.0	14.8
Total gains and losses recognised					
- in statement of income	(0.0)	(3.6)	0.4	(0.5)	(3.6)
- in other comprehensive income	0.0	0.0	0.0	0.0	0.0
Purchases	0.2	0.0	0.0	0.0	0.2
Settlement	(0.0)	(0.9)	(0.6)	0.0	(1.5)
Foreign currency translation differences	0.2	0.1	(0.0)	(0.0)	0.2
Closing balance	1.8	8.3	0.4	(0.5)	10.1
Full year 2014					
Opening balance	0.9	12.0	1.3	0.0	14.2
Total gains and losses recognised					
- in statement of income	(0.0)	0.3	0.6	0.0	0.9
- in other comprehensive income	0.0	0.0	0.0	0.0	0.0
Purchases	0.3	0.0	0.0	0.0	0.3
Sales	0.0	0.4	0.0	0.0	0.4
Settlement	(0.0)	0.0	(1.3)	0.0	(1.3)
Foreign currency translation differences	0.2	0.1	(0.0)	0.0	0.3
Closing balance	1.4	12.7	0.6	0.0	14.8

The assets within level 3 during 2015 have had a net decrease in the fair value of NOK 4.7 billion. Of the NOK 3.1 billion recognised in the Consolidated statement of income during 2015, NOK 2.8 billion is related to changes in fair value of certain earn-out agreements. Related to the same earn-out agreements, NOK 1.5 billion included in the opening balance for 2015 has been fully realised as the underlying volumes have been delivered during 2015 and the amount is presented as settled in the above table.

Substantially all gains and losses recognised in the Consolidated statement of income during 2015 are related to assets held at the end of 2015.

Sensitivity analysis of market risk

Commodity price risk

The table below contains the fair value and related commodity price risk sensitivities of Statoil's commodity based derivatives contracts. For further information related to the type of commodity risks and how Statoil manages these risks, see note 5 *Financial risk management*.

Statoil's assets and liabilities resulting from commodity based derivatives contracts consist of both exchange traded and non-exchange traded instruments, including embedded derivatives that have been bifurcated and recognised at fair value in the Consolidated balance sheet.

Price risk sensitivities at the end of 2015 have been calculated assuming a reasonably possible change of 30% in crude oil, refined products, electricity and natural gas prices. At the end of 2014 an assumption of 40% was used in the calculation and viewed as reasonable possible changes.

Since none of the derivative financial instruments included in the table below are part of hedging relationships, any changes in the fair value would be recognised in the Consolidated statement of income.

(in NOK billion)	- 30% sensitivity	30% sensitivity
At 31 December 2015		
Crude oil and refined products net gains (losses)	1.0	(0.6)
Natural gas and electricity net gains (losses)	3.0	(3.0)

(in NOK billion)	- 40% sensitivity	40% sensitivity
At 31 December 2014		
Crude oil and refined products net gains (losses)	(1.7)	1.8
Natural gas and electricity net gains (losses)	0.7	(0.7)

Currency risk

Currency risk constitutes significant financial risk for Statoil. In accordance with approved strategies and mandates total exposure is managed at a portfolio level on a regular basis. For further information related to the currency risk and how Statoil manages these risks, see note 5 *Financial risk management*.

The following currency risk sensitivity has been calculated by assuming an 11% reasonably possible change in the main foreign exchange rates that Statoil is exposed to. At the end of 2014 a change of 9% in the foreign exchange rates were viewed as reasonably possible changes. An increase in the foreign exchange rates means that the transaction currency has strengthened in value. The estimated gains and the estimated losses following from a change in the foreign exchange rates would impact the Consolidated statement of income.

(in NOK billion)	- 11% sensitivity	11% sensitivity
At 31 December 2015		
USD net gains (losses)	15.4	(15.4)
NOK net gains (losses)	(14.8)	14.8

(in NOK billion)	- 9% sensitivity	9% sensitivity
At 31 December 2014		
USD net gains (losses)	8.1	(8.1)
NOK net gains (losses)	(8.3)	8.3

Interest rate risk

Interest rate risk constitutes significant financial risk for Statoil. In accordance with approved strategies and mandates total exposure is managed at a portfolio level on a regular basis. For further information related to the interest risks and how Statoil manages these risks, see note 5 *Financial risk management*.

The following interest rate risk sensitivity has been calculated by assuming a change of 0.9 percentage points as reasonably possible changes in the interest rates at the end of 2015. At the end of 2014 a change of 0.8 percentage points in the interest rates was viewed as reasonably possible changes. The estimated gains following from a decrease in the interest rates and the estimated losses following from an interest rate increase would impact the Consolidated statement of income.

(in NOK billion)	- 0.9 percentage points sensitivity	0.9 percentage points sensitivity
At 31 December 2015		
Interest rate net gains (losses)	10.7	(10.7)

(in NOK billion)	- 0.8 percentage points sensitivity	0.8 percentage points sensitivity
At 31 December 2014		
Interest rate net gains (losses)	7.1	(7.1)

26 Condensed consolidated financial information related to guaranteed debt securities

Statoil Petroleum AS, a 100% owned subsidiary of Statoil ASA, is the co-obligor of certain existing debt securities of Statoil ASA that are registered under the US Securities Act of 1933 ("US registered debt securities"). As co-obligor, Statoil Petroleum AS fully, unconditionally and irrevocably assumes and agrees to perform, jointly and severally with Statoil ASA, the payment and covenant obligations for these US registered debt securities. In addition, Statoil ASA is also the co-obligor of a US registered debt security of Statoil Petroleum AS. As co-obligor, Statoil ASA fully, unconditionally and irrevocably assumes and agrees to perform, jointly and severally with Statoil Petroleum AS, the payment and covenant obligations of that security. In the future, Statoil ASA may from time to time issue future US registered debt securities for which Statoil Petroleum AS will be the co-obligor or guarantor.

The following financial information on a condensed consolidated basis provides financial information about Statoil ASA, as issuer and co-obligor, Statoil Petroleum AS, as co-obligor and guarantor, and all other subsidiaries as required by SEC Rule 3-10 of Regulation S-X. The condensed consolidated information is prepared in accordance with Statoil's IFRS accounting policies as described in note 2 *Significant accounting policies*, except that investments in subsidiaries and jointly controlled entities are accounted for using the equity method as required by Rule 3-10.

The following is condensed consolidated financial information for the full year 2015, 2014 and 2013, and as of 31 December 2015 and 2014.

CONDENSED CONSOLIDATED STATEMENT OF INCOME AND OTHER COMPREHENSIVE INCOME

Full year 2015 (in NOK billion)	Statoil ASA	Statoil Petroleum AS	Non-guarantor subsidiaries	Consolidation adjustments	The Statoil group
Revenues and other income	316.0	165.6	165.6	(164.1)	483.1
Net income from equity accounted companies	(33.7)	(66.1)	(0.4)	99.9	(0.3)
Total revenues and other income	282.3	99.5	165.2	(64.2)	482.8
Total operating expenses	(316.4)	(101.0)	(215.7)	165.2	(467.9)
Net operating income	(34.1)	(1.5)	(50.5)	101.0	14.9
Net financial items	(22.5)	(0.8)	1.1	11.6	(10.6)
Income before tax	(56.6)	(2.3)	(49.3)	112.6	4.3
Income tax	7.5	(42.7)	(6.4)	(0.1)	(41.6)
Net income	(49.1)	(45.0)	(55.7)	112.5	(37.3)
Other comprehensive income	46.3	18.3	56.4	(86.3)	34.7
Total comprehensive income	(2.8)	(26.7)	0.7	26.2	(2.6)

CONDENSED CONSOLIDATED STATEMENT OF INCOME AND OTHER COMPREHENSIVE INCOME

Full year 2014 (in NOK billion)	Statoil ASA	Statoil Petroleum AS	Non-guarantor subsidiaries	Consolidation adjustments	The Statoil group
Revenues and other income	411.1	210.8	213.7	(212.7)	622.9
Net income from equity accounted companies	21.6	(32.7)	(0.2)	11.0	(0.3)
Total revenues and other income	432.8	178.1	213.4	(201.6)	622.7
Total operating expenses	(417.8)	(89.1)	(222.4)	216.0	(513.2)
Net operating income	15.0	89.0	(8.9)	14.4	109.5
Net financial items	(12.6)	0.0	(0.4)	12.9	(0.0)
Income before tax	2.4	89.0	(9.3)	27.3	109.4
Income tax	6.6	(81.3)	(11.5)	(1.2)	(87.4)
Net income	9.0	7.7	(20.8)	26.0	22.0
Other comprehensive income	55.4	26.0	70.5	(109.3)	42.5
Total comprehensive income	64.4	33.7	49.7	(83.3)	64.5

CONDENSED CONSOLIDATED STATEMENT OF INCOME AND OTHER COMPREHENSIVE INCOME

Full year 2013 (in NOK billion)	Statoil ASA	Statoil Petroleum AS	Non-guarantor subsidiaries	Consolidation adjustments	The Statoil group
Revenues and other income	416.7	228.8	212.1	(223.2)	634.4
Net income from equity accounted companies	55.0	(8.0)	(0.2)	(46.6)	0.1
Total revenues and other income	471.7	220.8	211.9	(269.8)	634.5
Total operating expenses	(418.3)	(85.5)	(199.0)	223.6	(479.1)
Net operating income	53.5	135.3	12.9	(46.2)	155.5
Net financial items	(27.7)	(1.0)	5.9	5.7	(17.0)
Income before tax	25.8	134.3	18.8	(40.5)	138.4
Income tax	8.1	(95.3)	(11.7)	(0.2)	(99.2)
Net income	33.9	39.0	7.1	(40.7)	39.2
Other comprehensive income	24.2	5.0	27.6	(38.2)	18.5
Total comprehensive income	58.1	44.0	34.7	(78.9)	57.7

CONDENSED CONSOLIDATED BALANCE SHEET

At 31 December 2015 (in NOK billion)	Statoil ASA	Statoil Petroleum AS	Non-guarantor subsidiaries	Consolidation adjustments	The Statoil group
ASSETS					
Property, plant, equipment and intangible assets	5.6	261.2	363.0	(0.3)	629.5
Equity accounted companies	472.5	181.0	3.8	(650.1)	7.3
Other non-current assets	38.4	8.9	34.7	0.0	82.0
Non-current receivables from subsidiaries	123.1	0.0	0.2	(123.3)	0.0
Total non-current assets	639.6	451.1	401.7	(773.8)	718.7
Current receivables from subsidiaries	10.9	20.4	120.1	(151.4)	(0.0)
Other current assets	130.8	8.9	36.3	(3.9)	172.1
Cash and cash equivalents	65.8	0.8	9.4	0.0	76.0
Total current assets	207.5	30.1	165.7	(155.3)	248.0
Total assets	847.2	481.2	567.4	(929.1)	966.7
EQUITY AND LIABILITIES					
Total equity	354.7	184.1	463.4	(647.2)	355.1
Non-current liabilities to subsidiaries	0.1	120.9	2.3	(123.3)	0.0
Other non-current liabilities	303.2	126.5	47.9	(1.2)	476.3
Total non-current liabilities	303.3	247.4	50.1	(124.5)	476.3
Other current liabilities	52.5	38.6	50.3	(6.0)	135.3
Current liabilities to subsidiaries	136.7	11.1	3.6	(151.4)	0.0
Total current liabilities	189.1	49.7	53.9	(157.4)	135.3
Total liabilities	492.4	297.1	104.0	(281.9)	611.7
Total equity and liabilities	847.2	481.2	567.4	(929.1)	966.7

CONDENSED CONSOLIDATED BALANCE SHEET

At 31 December 2014 (in NOK billion)	Statoil ASA	Statoil Petroleum AS	Non-guarantor subsidiaries	Consolidation adjustments	The Statoil group
ASSETS					
Property, plant, equipment and intangible assets	5.9	276.4	365.3	(0.4)	647.3
Equity accounted companies	490.0	140.5	7.5	(629.6)	8.4
Other non-current assets	34.8	13.0	28.2	0.0	76.0
Non-current receivables from subsidiaries	68.6	0.4	0.2	(69.2)	0.0
Total non-current assets	599.3	430.3	401.2	(699.2)	731.7
Current receivables from subsidiaries	16.1	50.3	89.0	(155.4)	0.0
Other current assets	116.7	14.2	46.8	(6.0)	171.6
Cash and cash equivalents	71.5	0.6	11.0	0.0	83.1
Total current assets	204.4	65.0	146.7	(161.4)	254.8
Total assets	803.8	495.4	547.9	(860.6)	986.4
EQUITY AND LIABILITIES					
Total equity	380.8	215.1	412.4	(627.1)	381.2
Non-current liabilities to subsidiaries	0.1	66.3	2.7	(69.2)	0.0
Other non-current liabilities	238.2	144.9	45.3	(2.3)	426.2
Total non-current liabilities	238.4	211.2	48.0	(71.4)	426.2
Other current liabilities	68.1	60.0	57.6	(6.7)	179.0
Current liabilities to subsidiaries	116.5	9.1	29.8	(155.4)	0.0
Total current liabilities	184.6	69.1	87.4	(162.1)	179.0
Total liabilities	423.0	280.3	135.5	(233.5)	605.2
Total equity and liabilities	803.8	495.4	547.9	(860.6)	986.4

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CONDENSED CONSOLIDATED CASH FLOW STATEMENT

Full year 2015 (in NOK billion)	Statoil ASA	Statoil Petroleum AS	Non-guarantor subsidiaries	Consolidation adjustments	The Statoil group
Cash flows provided by (used in) operating activities	23.5	64.7	37.4	(16.6)	109.0
Cash flows provided by (used in) investing activities	(44.8)	(141.3)	(46.9)	117.9	(115.1)
Cash flows provided by (used in) financing activities	9.9	76.7	7.2	(101.3)	(7.5)
Net increase (decrease) in cash and cash equivalents	(11.5)	0.1	(2.3)	0.0	(13.6)
Effect of exchange rate changes on cash and cash equivalents	5.7	0.1	1.3	0.0	7.1
Cash and cash equivalents at the beginning of the period (net of overdraft)	71.5	0.6	10.3	0.0	82.4
Cash and cash equivalents at the end of the period (net of overdraft)	65.8	0.8	9.3	0.0	75.9

Full year 2014 (in NOK billion)	Statoil ASA	Statoil Petroleum AS	Non-guarantor subsidiaries	Consolidation adjustments	The Statoil group
Cash flows provided by (used in) operating activities	18.6	73.2	56.9	(22.2)	126.5
Cash flows provided by (used in) investing activities	(16.9)	(59.4)	(55.5)	19.8	(112.0)
Cash flows provided by (used in) financing activities	(11.0)	(13.2)	(1.3)	2.4	(23.1)
Net increase (decrease) in cash and cash equivalents	(9.3)	0.6	0.1	0.0	(8.6)
Effect of exchange rate changes on cash and cash equivalents	3.8	0.1	1.9	0.0	5.8
Cash and cash equivalents at the beginning of the period (net of overdraft)	77.0	0.0	8.3	0.0	85.3
Cash and cash equivalents at the end of the period (net of overdraft)	71.5	0.7	10.3	0.0	82.5

Full year 2013 (in NOK billion)	Statoil ASA	Statoil Petroleum AS	Non-guarantor subsidiaries	Consolidation adjustments	The Statoil group
Cash flows provided by (used in) operating activities	64.3	69.9	39.6	(72.6)	101.3
Cash flows provided by (used in) investing activities	(46.9)	(46.0)	(87.4)	69.9	(110.4)
Cash flows provided by (used in) financing activities	(0.6)	(23.9)	48.5	2.7	26.6
Net increase (decrease) in cash and cash equivalents	16.8	0.0	0.7	0.0	17.5
Effect of exchange rate changes on cash and cash equivalents	2.7	0.0	0.2	0.0	2.9
Cash and cash equivalents at the beginning of the period (net of overdraft)	57.4	0.0	7.5	0.0	64.9
Cash and cash equivalents at the end of the period (net of overdraft)	77.0	0.0	8.3	0.0	85.3

27 Supplementary oil and gas information (unaudited)

In accordance with Financial Accounting Standards Board Accounting Standards Codification "Extractive Activities - Oil and Gas" (Topic 932), Statoil is reporting certain supplemental disclosures about oil and gas exploration and production operations. While this information is developed with reasonable care and disclosed in good faith, it is emphasised that some of the data is necessarily imprecise and represents only approximate amounts because of the subjective judgement involved in developing such information. Accordingly, this information may not necessarily represent the present financial condition of Statoil or its expected future results.

For further information regarding the reserves estimation requirement, see note 2 *Significant accounting policies* - Critical accounting judgements and key sources of estimation uncertainty - Proved oil and gas reserves.

No new events have occurred since 31 December 2015 that would result in a significant change in the estimated proved reserves or other figures reported as of that date.

The disputed equity determination at Agbami will potentially alter Statoil's equity share in this field. The effect on the proved reserves will be included once the redetermination is finalised and the effect is known.

Oil and gas reserve quantities
Statoil's oil and gas reserves have been estimated by its qualified professionals in accordance with industry standards under the requirements of the U.S. Securities and Exchange Commission (SEC), Rule 4-10 of Regulation S-X. Statements of reserves are forward-looking statements.

The determination of these reserves is part of an ongoing process subject to continual revision as additional information becomes available. Estimates of proved reserve quantities are imprecise and change over time as new information becomes available. Moreover, identified reserves and contingent resources that may become proved in the future are excluded from the calculations.

Statoil's proved reserves are recognised under various forms of contractual agreements, including production sharing agreements (PSAs) where Statoil's share of reserves can vary due to commodity prices or other factors. Reserves from agreements such as PSAs and buy back agreements are based on the volumes to which Statoil has access (cost oil and profit oil), limited to available market access. At 31 December 2015, 9% of total proved reserves were related to such agreements (15% of total oil, condensate and natural gas liquids (NGL) reserves and 3% of total gas reserves). This compares with 12% and 14% of total proved reserves for 2014 and 2013, respectively. Net entitlement oil and gas production from fields with such agreements was 104 million boe during 2015 (95 million boe for 2014 and 93 million boe for 2013). Statoil participates in such agreements in Algeria, Angola, Azerbaijan, Libya, Nigeria and Russia.

Statoil is recording, as proved reserves, volumes equivalent to our tax liabilities under negotiated fiscal arrangements (PSAs) where the tax is paid on behalf of Statoil. Reserves are net of royalty oil paid in kind and quantities consumed during production.

Rule 4-10 of Regulation S-X requires that the appraisal of reserves is based on existing economic conditions, including a 12-month average price prior to the end of the reporting period, unless prices are defined by contractual arrangements. The proved reserves at year end 2015 have been determined based on a Brent blend price equivalent of USD 54.17/bbl, compared to USD 101.27/bbl and USD 108.02/bbl for 2014 and 2013 respectively. The volume weighted average gas price for proved reserves at year end 2015 was 1.76 NOK/Sm3. The comparable gas price used to determine gas reserves at year end 2014 and 2013 was 1.90 NOK/Sm3 and 2.13 NOK/Sm3. The volume weighted average NGL price for proved reserves at year end 2015 was USD 30.56/boe. The corresponding NGL price used to determine NGL reserves at year end 2014 and 2013 was USD 57.03/boe and USD 62.32/boe. The significant decrease in commodity prices affects the profitable reserves to be recovered from accumulations resulting in reduced reserves. The negative revisions due to price are in general a result of earlier economic cut-off. For fields with a production-sharing type of agreement this is to some degree offset by higher entitlement to the reserves. These changes are all included in the revision category in the tables below, giving a net reduction of Statoil's proved reserves at year end.

From the Norwegian continental shelf (NCS), Statoil is responsible for managing, transporting and selling the Norwegian State's oil and gas on behalf of the Norwegian State's direct financial interest (SDFI). These reserves are sold in conjunction with the Statoil reserves. As part of this arrangement, Statoil delivers and sells gas to customers in accordance with various types of sales contracts on behalf of the SDFI. In order to fulfil the commitments, Statoil utilises a field supply schedule which provides the highest possible total value for the joint portfolio of oil and gas between Statoil and the SDFI.

Statoil and the SDFI receive income from the joint natural gas sales portfolio based upon their respective share in the supplied volumes. For sales of the SDFI natural gas, to Statoil and to third parties, the payment to the Norwegian State is based on achieved prices, a net back formula calculated price or market value. All of the Norwegian State's oil and NGL is acquired by Statoil. The price Statoil pays to the SDFI for the crude oil is based on market reflective prices. The prices for NGL are either based on achieved prices, market value or market reflective prices.

The regulations of the owner's instruction, as described above, may be changed or withdrawn by the Statoil ASA's general meeting. Due to this uncertainty and the Norwegian State's estimate of proved reserves not being available to Statoil, it is not possible to determine the total quantities to be purchased by Statoil under the owner's instruction.

Topic 932 requires the presentation of reserves and certain other supplemental oil and gas disclosures by geographical area, defined as country or continent containing 15% or more of total proved reserves. Norway contains 75% of total proved reserves at 31 December 2015 and no other country contains reserves approaching 15% of total proved reserves. Accordingly, management has determined that the most meaningful presentation of geographical areas would be Norway and the continents of Eurasia (excluding Norway), Africa and Americas.

The following tables reflect the estimated proved reserves of oil and gas at 31 December 2012 through 2015, and the changes therein.

	Consolidated companies					Equity accounted	Total
	Norway	Eurasia excluding Norway	Africa	Americas	Subtotal	Americas	Total
Net proved oil and condensate reserves in million barrels oil equivalent							
At 31 December 2012	968	193	281	395	1,837	82	1,919
Revisions and improved recovery	133	16	40	18	207	(16)	191
Extensions and discoveries	19	47	8	34	108	0	108
Purchase of reserves-in-place	13	0	0	0	13	0	13
Sales of reserves-in-place	(40)	(15)	0	(2)	(57)	0	(57)
Production	(174)	(15)	(58)	(46)	(294)	(4)	(298)
At 31 December 2013	918	227	271	399	1,815	63	1,877
Revisions and improved recovery	143	10	85	(4)	235	(3)	232
Extensions and discoveries	3	0	5	145	153	0	153
Purchase of reserves-in-place	0	0	0	20	20	0	20
Sales of reserves-in-place	(5)	(27)	(2)	0	(34)	0	(34)
Production	(173)	(14)	(64)	(51)	(301)	(4)	(306)
At 31 December 2014	886	196	296	508	1,887	55	1,942
Revisions and improved recovery	71	(68)	57	(54)	5	(5)	0
Extensions and discoveries	437	0	0	74	511	0	511
Purchase of reserves-in-place	0	0	0	4	4	0	4
Sales of reserves-in-place	(4)	(38)	0	(1)	(43)	0	(43)
Production	(174)	(13)	(75)	(57)	(319)	(4)	(324)
At 31 December 2015	1,216	76	278	474	2,045	46	2,091

Proved reserves of bitumen in Americas, representing less than 2% of Statoil's proved reserves, is included as oil in the table above.

	Consolidated companies					Equity accounted	Total
	Norway	Eurasia excluding Norway	Africa	Americas	Subtotal	Americas	Total
Net proved NGL reserves in million barrels oil equivalent							
At 31 December 2012	405	0	18	47	469	0	469
Revisions and improved recovery	25	0	(0)	4	28	0	28
Extensions and discoveries	1	0	0	10	11	0	11
Purchase of reserves-in-place	0	0	0	0	0	0	0
Sales of reserves-in-place	(21)	0	0	0	(21)	0	(21)
Production	(42)	0	(1)	(4)	(47)	0	(47)
At 31 December 2013	368	0	16	56	441	0	441
Revisions and improved recovery	(2)	0	1	5	4	0	4
Extensions and discoveries	3	0	0	18	21	0	21
Purchase of reserves-in-place	0	0	0	0	0	0	0
Sales of reserves-in-place	(10)	0	0	(2)	(12)	0	(12)
Production	(42)	0	(2)	(7)	(51)	0	(51)
At 31 December 2014	318	0	15	69	403	0	403
Revisions and improved recovery	7	0	3	(20)	(10)	0	(10)
Extensions and discoveries	11	0	0	16	27	0	27
Purchase of reserves-in-place	0	0	0	4	4	0	4
Sales of reserves-in-place	(1)	0	0	(5)	(5)	0	(5)
Production	(44)	0	(3)	(7)	(54)	0	(54)
At 31 December 2015	291	0	15	57	364	0	364

	Consolidated companies					Equity accounted	Total
	Norway	Eurasia excluding Norway	Africa	Americas	Subtotal	Americas	Total
Net proved gas reserves in billion standard cubic feet							
At 31 December 2012	15,003	575	341	1,107	17,027	0	17,027
Revisions and improved recovery	391	187	27	382	987	0	987
Extensions and discoveries	920	1,236	0	112	2,268	0	2,268
Purchase of reserves-in-place	5	0	0	0	5	0	5
Sales of reserves-in-place	(295)	(3)	0	(2)	(300)	0	(300)
Production	(1,264)	(72)	(40)	(196)	(1,571)	0	(1,571)
At 31 December 2013	14,761	1,923	328	1,404	18,416	0	18,416
Revisions and improved recovery	439	32	8	197	676	0	676
Extensions and discoveries	79	0	0	364	443	0	443
Purchase of reserves-in-place	0	0	0	0	0	0	0
Sales of reserves-in-place	(355)	(681)	0	(15)	(1,051)	0	(1,051)
Production	(1,229)	(56)	(38)	(242)	(1,565)	0	(1,565)
At 31 December 2014	13,694	1,218	299	1,708	16,919	0	16,919
Revisions and improved recovery	385	(18)	129	(676)	(180)	0	(180)
Extensions and discoveries	179	0	0	318	497	0	497
Purchase of reserves-in-place	0	0	0	31	31	0	31
Sales of reserves-in-place	(10)	(991)	0	(42)	(1,043)	0	(1,043)
Production	(1,306)	(16)	(63)	(215)	(1,600)	0	(1,600)
At 31 December 2015	12,942	193	366	1,123	14,624	0	14,624

	Consolidated companies					Equity accounted	Total
	Norway	Eurasia excluding Norway	Africa	Americas	Subtotal	Americas	Total
Net proved reserves in million barrels oil equivalent							
At 31 December 2012	4,046	296	360	639	5,340	82	5,422
Revisions and improved recovery	227	49	44	90	411	(16)	395
Extensions and discoveries	183	268	8	64	523	0	523
Purchase of reserves-in-place	14	0	0	0	14	0	14
Sales of reserves-in-place	(113)	(15)	0	(2)	(131)	0	(131)
Production	(441)	(28)	(66)	(85)	(621)	(4)	(625)
At 31 December 2013	3,916	569	346	705	5,537	63	5,600
Revisions and improved recovery	219	16	87	36	359	(3)	356
Extensions and discoveries	20	0	5	227	253	0	253
Purchase of reserves-in-place	0	0	0	20	20	0	20
Sales of reserves-in-place	(78)	(148)	(2)	(5)	(233)	0	(233)
Production	(434)	(24)	(72)	(102)	(631)	(4)	(635)
At 31 December 2014	3,644	413	364	882	5,304	55	5,359
Revisions and improved recovery	146	(72)	83	(194)	(37)	(5)	(42)
Extensions and discoveries	480	0	0	146	627	0	627
Purchase of reserves-in-place	0	0	0	13	13	0	13
Sales of reserves-in-place	(6)	(215)	0	(13)	(235)	0	(235)
Production	(450)	(16)	(88)	(103)	(658)	(4)	(662)
At 31 December 2015	3,814	111	358	731	5,014	46	5,060

Proved reserves of bitumen in Americas, representing less than 2% of Statoil's proved reserves, is included as oil in the table above.

	Consolidated companies					Equity accounted	Total
	Norway	Eurasia excluding Norway	Africa	Americas	Subtotal	Americas	Total
Net proved oil and condensate reserves in million barrels oil equivalent							
At 31 December 2012							
Developed	547	79	221	164	1,010	38	1,049
Undeveloped	421	114	61	231	827	44	870
At 31 December 2013							
Developed	548	63	197	212	1,020	32	1,052
Undeveloped	370	164	74	187	795	30	826
At 31 December 2014							
Developed	559	63	243	267	1,133	24	1,156
Undeveloped	327	133	52	242	754	32	786
At 31 December 2015							
Developed	505	48	248	282	1,083	21	1,104
Undeveloped	711	29	30	192	962	25	987
Net proved NGL reserves in million barrels oil equivalent							
At 31 December 2012							
Developed	296	0	11	27	334	0	334
Undeveloped	109	0	7	20	135	0	135
At 31 December 2013							
Developed	287	0	10	34	330	0	330
Undeveloped	82	0	7	22	111	0	111
At 31 December 2014							
Developed	258	0	9	42	310	0	310
Undeveloped	60	0	6	27	93	0	93
At 31 December 2015							
Developed	235	0	9	45	290	0	290
Undeveloped	56	0	6	12	74	0	74
Net proved gas reserves in billion standard cubic feet							
At 31 December 2012							
Developed	12,073	343	226	567	13,210	0	13,210
Undeveloped	2,931	232	115	540	3,817	0	3,817
At 31 December 2013							
Developed	11,580	467	209	817	13,073	0	13,073
Undeveloped	3,181	1,455	120	586	5,343	0	5,343
At 31 December 2014							
Developed	11,227	312	191	946	12,677	0	12,677
Undeveloped	2,467	906	108	762	4,242	0	4,242
At 31 December 2015							
Developed	10,664	32	206	999	11,901	0	11,901
Undeveloped	2,278	161	160	124	2,723	0	2,723
Net proved oil, condensate, NGL and gas reserves in million barrels oil equivalent							
At 31 December 2012							
Developed	2,994	140	272	292	3,698	38	3,737
Undeveloped	1,052	155	88	347	1,642	44	1,686
At 31 December 2013							
Developed	2,898	146	244	392	3,679	32	3,711
Undeveloped	1,018	423	103	314	1,858	30	1,888
At 31 December 2014							
Developed	2,818	119	287	477	3,701	24	3,725
Undeveloped	826	295	78	405	1,603	32	1,635
At 31 December 2015							
Developed	2,641	53	294	505	3,494	21	3,515
Undeveloped	1,173	57	64	226	1,521	25	1,546

The conversion rates used are 1 standard cubic meter = 35.3 standard cubic feet, 1 standard cubic meter oil equivalent = 6.29 barrels of oil equivalent (boe) and 1,000 standard cubic meter gas = 1 standard cubic meter oil equivalent.

Capitalised cost related to oil and gas producing activities

Consolidated companies

(in NOK billion)	2015	2014	At 31 December 2013
Unproved properties	117.5	97.5	83.8
Proved properties, wells, plants and other equipment	1,327.1	1,178.8	984.1
Total capitalised cost	1,444.6	1,276.3	1,068.0
Accumulated depreciation, impairment and amortisation	(873.1)	(687.2)	(543.7)
Net capitalised cost	571.5	589.1	524.3

Net capitalised cost related to equity accounted investments as of 31 December 2015 was NOK 8.8 billion, NOK 7.2 billion in 2014 and NOK 5.9 billion in 2013. The reported figures are based on capitalised costs within the upstream segments in Statoil, in line with the description below for result of operations for oil and gas producing activities.

Expenditures incurred in oil and gas property acquisition, exploration and development activities

These expenditures include both amounts capitalised and expensed.

Consolidated companies

(in NOK billion)	Norway	Eurasia excluding Norway	Africa	Americas	Total
Full year 2015					
Exploration expenditures	6.4	1.7	3.0	12.0	23.1
Development costs	47.1	11.4	10.5	29.0	98.1
Acquired proved properties	0.0	0.0	0.0	0.7	0.7
Acquired unproved properties	0.0	0.7	0.7	3.1	4.5
Total	53.5	13.7	14.3	44.8	126.3
Full year 2014					
Exploration expenditures	7.0	2.5	7.3	7.1	23.9
Development costs	52.2	13.4	13.3	22.7	101.7
Acquired proved properties	0.0	0.0	0.0	4.7	4.7
Acquired unproved properties	0.0	0.0	0.0	2.3	2.3
Total	59.3	15.9	20.6	36.8	132.5
Full year 2013					
Exploration expenditures	7.9	3.8	2.7	7.4	21.8
Development costs	51.8	8.5	11.6	26.4	98.3
Acquired proved properties	2.2	0.0	0.0	0.0	2.2
Acquired unproved properties	0.0	0.4	0.0	1.8	2.2
Total	61.9	12.7	14.3	35.6	124.5

Expenditures incurred in development activities related to equity accounted investments was NOK 0.4 billion in 2015, NOK 1.6 billion in 2014 and NOK 0.4 billion in 2013.

Results of operation for oil and gas producing activities
As required by Topic 932, the revenues and expenses included in the following table reflect only those relating to the oil and gas producing operations of Statoil.

The result of operations for oil and gas producing activities contains the two upstream reporting segments Development and Production Norway (DPN) and Development and Production International (DPI) as presented in note 3 *Segments*. Production cost is based on operating expenses related to production of oil and gas. From the operating expenses certain expenses such as; transportation costs, accruals for over/underlift position, royalty payments and diluent costs are excluded. These expenses and mainly upstream business administration are included as other expenses in the tables below. Other revenues mainly consist of gains and losses from sales of oil and gas interests and gains and losses from commodity based derivatives within the upstream segments.

Income tax expense is calculated on the basis of statutory tax rates adjusted for uplift and tax credits. No deductions are made for interest or other elements not included in the table below.

Consolidated companies

(in NOK billion)	Norway	Eurasia excluding Norway	Africa	Americas	Total
Full year 2015					
Sales	0.4	2.0	(0.6)	1.6	3.5
Transfers	140.1	3.8	27.7	22.2	193.9
Other revenues	(1.0)	12.3	0.0	0.1	11.4
Total revenues	139.5	18.2	27.2	23.9	208.7
Exploration expenses	(4.6)	(1.7)	(5.1)	(19.5)	(31.0)
Production costs	(21.1)	(1.3)	(5.4)	(6.4)	(34.2)
Depreciation, amortisation and net impairment losses	(51.4)	(6.4)	(20.1)	(55.1)	(133.0)
Other expenses	(4.7)	(1.3)	(1.9)	(11.1)	(19.0)
Total costs	(81.9)	(10.7)	(32.6)	(92.0)	(217.2)
Results of operations before tax	57.6	7.4	(5.4)	(68.2)	(8.5)
Tax expense	(38.8)	1.8	(5.4)	(0.2)	(42.6)
Results of operations	18.8	9.2	(10.8)	(68.3)	(51.1)
Net income from equity accounted investments	0.0	0.3	0.0	(1.0)	(0.8)

Consolidated companies

(in NOK billion)	Norway	Eurasia excluding Norway	Africa	Americas	Total
Full year 2014					
Sales	1.8	4.3	5.0	3.9	15.0
Transfers	172.6	6.1	32.6	28.6	239.9
Other revenues	7.7	5.7	0.7	(1.0)	13.1
Total revenues	182.1	16.1	38.3	31.4	268.1
Exploration expenses	(5.4)	(2.6)	(9.2)	(13.2)	(30.3)
Production costs	(23.0)	(1.5)	(4.6)	(5.3)	(34.4)
Depreciation, amortisation and net impairment losses	(40.0)	(4.9)	(14.1)	(37.9)	(96.9)
Other expenses	(2.2)	(1.2)	0.4	(10.6)	(13.6)
Total costs	(70.5)	(10.1)	(27.5)	(67.0)	(175.2)
Results of operations before tax	111.6	6.0	10.9	(35.6)	92.9
Tax expense	(74.8)	(0.5)	(8.4)	(0.4)	(84.0)
Results of operations	36.8	5.5	2.5	(36.0)	8.8
Net income from equity accounted investments	(0.0)	1.0	0.0	(1.7)	(0.7)

Consolidated companies

(in NOK billion)	Norway	Eurasia excluding Norway	Africa	Americas	Total
Full year 2013					
Sales	0.3	4.0	3.9	4.1	12.3
Transfers	192.5	7.4	30.9	27.1	257.9
Other revenues	9.3	3.9	0.2	0.4	13.8
Total revenues	202.1	15.3	35.0	31.6	284.0
Exploration expenses	(5.5)	(3.4)	(1.6)	(7.5)	(18.0)
Production costs	(22.1)	(1.5)	(3.9)	(3.9)	(31.4)
Depreciation, amortisation and net impairment losses	(32.2)	(2.4)	(13.3)	(16.2)	(64.1)
Other expenses	(5.3)	(1.6)	(0.5)	(9.7)	(17.1)
Total costs	(65.1)	(8.9)	(19.3)	(37.3)	(130.6)
Results of operations before tax	137.0	6.4	15.7	(5.7)	153.4
Tax expense	(90.9)	(2.0)	(8.1)	(1.0)	(102.0)
Results of operations	46.1	4.4	7.6	(6.7)	51.4
Net income from equity accounted investments	0.1	0.3	0.0	(0.3)	0.1

Average production cost in NOK per boe based on entitlement volumes	Norway	Eurasia excluding Norway	Africa	Americas	Total
2015	47	79	61	62	52
2014	53	64	64	52	55
2013	50	53	59	46	51

Production cost per boe is calculated as the production costs in the result of operations table, divided by the produced entitlement volumes (mboe) for the corresponding period.

Standardised measure of discounted future net cash flows relating to proved oil and gas reserves

The table below shows the standardised measure of future net cash flows relating to proved reserves. The analysis is computed in accordance with Topic 932, by applying average market prices as defined by the SEC, year end costs, year end statutory tax rates and a discount factor of 10% to year end quantities of net proved reserves. The standardised measure of discounted future net cash flows is a forward-looking statement.

Future price changes are limited to those provided by existing contractual arrangements at the end of each reporting year. Future development and production costs are those estimated future expenditures necessary to develop and produce year-end estimated proved reserves based on year-end cost indices, assuming continuation of year-end economic conditions. Pre-tax future net cash flow is net of decommissioning and removal costs. Estimated future income taxes are calculated by applying the appropriate year-end statutory tax rates. These rates reflect allowable deductions and tax credits and are applied to estimated future pretax net cash flows, less the tax basis of related assets. Discounted future net cash flows are calculated using a discount rate of 10% per year. Discounting requires a year-by-year estimate of when future expenditures will be incurred and when reserves will be produced. The standardised measure of discounted future net cash flows prescribed under Topic 932 requires assumptions as to the timing and amount of future development and production costs and income from the production of proved reserves. The information does not represent management's estimate or Statoil's expected future cash flows or the value of its proved reserves and therefore should not be relied upon as an indication of Statoil's future cash flow or value of its proved reserves.

(in NOK billion)	Norway	Eurasia excluding Norway	Africa	Americas	Total
At 31 December 2015					
Consolidated companies					
Future net cash inflows	1,288.7	43.9	137.3	189.7	1,659.5
Future development costs	(156.1)	(10.8)	(10.7)	(41.5)	(219.0)
Future production costs	(441.5)	(22.2)	(54.9)	(102.6)	(621.3)
Future income tax expenses	(455.7)	(0.9)	(25.3)	(6.4)	(488.4)
Future net cash flows	235.4	9.9	46.3	39.2	330.8
10% annual discount for estimated timing of cash flows	(96.6)	(3.3)	(11.1)	(15.8)	(126.8)
Standardised measure of discounted future net cash flows	138.8	6.6	35.2	23.4	203.9
Equity accounted investments					
Standardised measure of discounted future net cash flows	0,0	0,0	0,0	1.1	1.1
Total standardised measure of discounted future net cash flows including equity accounted investments	138.8	6.6	35.2	24.5	205.1

(in NOK billion)	Norway	Eurasia excluding Norway	Africa	Americas	Total
At 31 December 2014					
Consolidated companies					
Future net cash inflows	1,467.9	203.4	213.6	323.0	2,207.9
Future development costs	(166.8)	(59.9)	(12.3)	(51.7)	(290.8)
Future production costs	(439.8)	(91.6)	(58.3)	(142.7)	(732.4)
Future income tax expenses	(606.8)	(8.1)	(48.6)	(34.0)	(697.5)
Future net cash flows	254.5	43.8	94.4	94.6	487.3
10% annual discount for estimated timing of cash flows	(99.7)	(27.8)	(28.1)	(41.9)	(197.6)
Standardised measure of discounted future net cash flows	154.7	16.0	66.3	52.7	289.8
Equity accounted investments					
Standardised measure of discounted future net cash flows	0,0	0,0	0,0	5.1	5.1
Total standardised measure of discounted future net cash flows including equity accounted investments	154.7	16.0	66.3	57.8	294.8

(in NOK billion)	Norway	Eurasia excluding Norway	Africa	Americas	Total
At 31 December 2013					
Consolidated companies					
Future net cash inflows	1,700.2	273.7	205.2	257.5	2,436.6
Future development costs	(200.0)	(80.8)	(16.0)	(38.9)	(335.7)
Future production costs	(471.3)	(125.4)	(54.8)	(104.3)	(755.8)
Future income tax expenses	(740.9)	(12.2)	(50.0)	(24.0)	(827.1)
Future net cash flows	288.0	55.3	84.4	90.3	518.0
10% annual discount for estimated timing of cash flows	(120.8)	(39.7)	(27.6)	(41.3)	(229.4)
Standardised measure of discounted future net cash flows	167.2	15.6	56.8	49.0	288.6
Equity accounted investments					
Standardised measure of discounted future net cash flows	0,0	0,0	0,0	4.8	4.8
Total standardised measure of discounted future net cash flows including equity accounted investments	167.2	15.6	56.8	53.8	293.4

Changes in the standardised measure of discounted future net cash flows from proved reserves

(in NOK billion)	2015	2014	2013
Consolidated companies			
Standardised measure at beginning of year	289.8	288.6	252.8
Net change in sales and transfer prices and in production (lifting) costs related to future production	(313.7)	(98.3)	(24.0)
Changes in estimated future development costs	(4.5)	(32.3)	(54.9)
Sales and transfers of oil and gas produced during the period, net of production cost	(168.0)	(232.6)	(243.2)
Net change due to extensions, discoveries, and improved recovery	30.1	23.1	10.6
Net change due to purchases and sales of minerals in place	(7.4)	(25.1)	(33.9)
Net change due to revisions in quantity estimates	76.4	126.1	126.5
Previously estimated development costs incurred during the period	84.6	99.6	95.1
Accretion of discount	71.0	77.3	81.4
Net change in income taxes	145.7	63.3	78.2
Total change in the standardised measure during the year	(85.8)	1.2	35.8
Standardised measure at end of year	203.9	289.8	288.6
Equity accounted investments			
Standardised measure at end of year	1.1	5.1	4.8
Standardised measure at end of year including equity accounted investments	205.1	294.8	293.4

In the table above, each line item presents the sources of changes in the standardised measure value on a discounted basis, with the accretion of discount line item reflecting the increase in the net discounted value of the proved oil and gas reserves due to the fact that the future cash flows are now one year closer in time.

28 Subsequent events

In the first quarter of 2016 Statoil acquired 11.93% of the shares and votes in Lundin Petroleum AB for a total purchase price of SEK 4.6 billion. The shares will be accounted for as a non-current financial investment (available-for-sale) at fair value.

8.2 Report of Independent Registered Public Accounting firm

8.2.1 Report of Independent Registered Public Accounting firm

Report of Independent Registered Public Accounting Firm

To the board of directors and shareholders of Statoil ASA

We have audited the accompanying consolidated balance sheets of Statoil ASA and subsidiaries as of 31 December 2015 and 2014 and the related consolidated statements of income, comprehensive income, changes in equity and cash flows for each of the years in the three-year period ended 31 December 2015. These consolidated financial statements are the responsibility of Statoil ASA's management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the consolidated financial position of Statoil ASA and subsidiaries as of 31 December 2015 and 2014, and the results of their operations and their cash flows for each of the years in the three-year period ended 31 December 2015, in conformity with International Financial Reporting Standards as issued by the International Accounting Standards Board and International Financial Reporting Standards as adopted by the European Union.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), Statoil ASA's internal control over financial reporting as of 31 December 2015, based on criteria established in Internal Control - Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO), and our report dated 9 March 2016 expressed an unqualified opinion on the effectiveness of Statoil ASA's internal control over financial reporting.

/s/ KPMG AS

Trondheim, Norway
9 March 2016

8.2.2 Report of KPMG on Statoil's internal control over financial reporting

Report of Independent Registered Public Accounting Firm

To the board of directors and shareholders of Statoil ASA

We have audited Statoil ASA's internal control over financial reporting as of 31 December 2015, based on criteria established in *Internal Control — Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Statoil ASA's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying *Management's Report on Internal Control over Financial Reporting*. Our responsibility is to express an opinion on Statoil ASA's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audit also included performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, Statoil ASA maintained, in all material respects, effective internal control over financial reporting as of 31 December 2015, based on criteria established in *Internal Control — Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of Statoil ASA and subsidiaries as of 31 December 2015 and 2014 and the related consolidated statements of income, comprehensive income, changes in equity and cash flows for each of the years in the three-year period ended 31 December 2015, and our report dated 9 March 2016 expressed an unqualified opinion on those consolidated financial statements.

/s/ KPMG AS

Trondheim, Norway
9 March 2016

9 Terms and definitions

Organisational abbreviations

- ACG - Azeri-Chirag-GunashliX
- ACQ - Annual contract quantity
- AFP - Agreement-based early retirement plan
- AGM - Annual general meeting
- ÅTS - Åsgard transport system
- APA - Awards in pre-defined areas
- ARO - Asset retirement obligation
- BTC - Baku-Tbilisi-Ceyhan pipeline
- CCS - Carbon capture and storage
- CH4 - Methane
- CO_2 - Carbon dioxide
- DKK - Danish Krone
- DPI - Development and Production International
- DPN - Development and Production Norway
- DPUSA - Development and Production USA
- DST - Drill Stem Test
- D&W - Drilling and Well
- EEA - European Economic Area
- EFTA - European Free Trade Association
- EMTN - Euro medium-term note
- EU - European Union
- EU ETS - EU Emissions Trading System
- EUR - Euro
- EXP - Exploration
- FPSO - Floating production, storage and offload vessel
- GAAP - Generally Accepted Accounting Principals
- GBP - British Pound
- GBS - Gravity-based structure
- GDP - Gross domestic product
- GHG - Greenhouse gas
- GSB - Global Strategy and Business Development
- HSE - Health, safety and environment
- HTHP - High-temperature/high pressure
- IASB - International Accounting Standards Board
- ICE - Intercontinental Exchange
- IEA - International Energy Agency
- IFRS - International Financial Reporting Standards
- IOR - Improved oil recovery
- LNG - Liquefied natural gas
- LPG - Liquefied petroleum gas
- MMP - Marketing, Midstream and Processing
- MPE - Norwegian Ministry of Petroleum and Energy
- MW - Mega watt
- NCS - Norwegian continental shelf
- NES - New Energy Solutions
- NIOC - National Iranian Oil Company
- NOK - Norwegian kroner
- NOx- Nitrogen oxide
- OECD - Organisation of Economic Co-Operation and Development
- OML - Oil mining lease
- OPEC - Organization of the Petroleum Exporting Countries
- OTC - Over-the-counter
- OTS - Oil trading and supply department
- P5+1 – UN Security Council's five permanent members
- PDO - Plan for development and operation
- PDQ – Production drilling quarters
- PIO - Plan for installation and operation
- PRD - Project Development organisation
- PSA - Production sharing agreement
- PSR - Procurement and Supplier Relations
- RDI - Research, Development and Innovation

- R&D - Research and development
- ROACE - Return on average capital employed
- RRR - Reserve replacement ratio
- SAGD - Steam-assisted gravity drainage
- SCP - South Caucasus Pipeline System
- SDFI - Norwegian State's Direct Financial Interest
- SEC - Securities and Exchange Commission
- SEK - Swedish Krona
- SFR - Statoil Fuel & Retail
- SIF - Serious Incident Frequency
- TAP - Trans Adriatic Pipeline AG
- TEX - Technology Excellence
- TLP - Tension leg platform
- TPD - Technology, projects and drilling
- TRIF - Total recordable injuries per million hours worked
- TSP - Technical service provider
- UKCS - UK continental shelf
- USD - United States dollar
- WTG - Wind Turbine Generators

Metric abbreviations etc.

- bbl - barrel
- mbbl - thousand barrels
- mmbbl - million barrels
- boe - barrels of oil equivalent
- mboe - thousand barrels of oil equivalent
- mmboe - million barrels of oil equivalent
- mmcf - million cubic feet
- MMBtu - million british thermal units
- bcf - billion cubic feet
- tcf - trillion cubic feet
- scm - standard cubic metre
- mcm - thousand cubic metres
- mmcm - million cubic metres
- bcm - billion cubic metres
- mmtpa - million tonnes per annum
- km - kilometre
- ppm - part per million
- one billion - one thousand million

Equivalent measurements are based upon

- 1 barrel equals 0.134 tonnes of oil (33 degrees API)
- 1 barrel equals 42 US gallons
- 1 barrel equals 0.159 standard cubic metres
- 1 barrel of oil equivalent equals 1 barrel of crude oil
- 1 barrel of oil equivalent equals 159 standard cubic metres of natural gas
- 1 barrel of oil equivalent equals 5,612 cubic feet of natural gas
- 1 barrel of oil equivalent equals 0.0837 tonnes of NGLs
- 1 billion standard cubic metres of natural gas equals 1 million standard cubic metres of oil equivalent
- 1 cubic metre equals 35.3 cubic feet
- 1 kilometre equals 0.62 miles
- 1 square kilometre equals 0.39 square miles
- 1 square kilometre equals 247.105 acres
- 1 cubic metre of natural gas equals 1 standard cubic metre of natural gas
- 1,000 standard cubic meter gas equals 1 standard cubic meter oil equivalent
- 1,000 standard cubic metres of natural gas equals 6.29 boe
- 1 standard cubic foot equals 0.0283 standard cubic metres
- 1 standard cubic foot equals 1000 British thermal units (btu)
- 1 tonne of NGLs equals 1.9 standard cubic metres of oil equivalent
- 1 degree Celsius equals minus 32 plus five-ninths of the number of degrees Fahrenheit

Miscellaneous terms

- Appraisal well: A well drilled to establish the extent and the size of a discovery
- Backwardation and contango are terms used in the crude oil market. Contango is a condition where forward prices exceed spot prices, so the forward curve is upward sloping. Backwardation is the opposite condition, where spot prices exceed forward prices, and the forward curve slopes downward
- Biofuel: A solid, liquid or gaseous fuel derived from relatively recently dead biological material and is distinguished from fossil fuels, which are derived from long dead biological material
- BOE (barrels of oil equivalent): A measure to quantify crude oil, natural gas liquids and natural gas amounts using the same basis. Natural gas volumes are converted to barrels on the basis of energy content
- Clastic reservoir systems: The integrated static and dynamic characteristics of a hydrocarbon reservoir formed by clastic rocks of a specific depositional sedimentary succession and its seal
- Condensates: The heavier natural gas components, such as pentane, hexane, iceptane and so forth, which are liquid under atmospheric pressure - also called natural gasoline or naphtha
- Crude oil, or oil: Includes condensate and natural gas liquids
- Development: The drilling, construction, and related activities following discovery that are necessary to begin production of crude oil and natural gas fields
- Downstream: The selling and distribution of products derived from upstream activities
- Equity and entitlement volumes of oil and gas: Equity volumes represent volumes produced under a production sharing agreement (PSA) that correspond to Statoil's percentage ownership in a particular field. Entitlement volumes, on the other hand, represent Statoil's share of the volumes distributed to the partners in the field, which are subject to deductions for, among other things, royalties and the host government's share of profit oil. Under the terms of a PSA, the amount of profit oil deducted from equity volumes will normally increase with the cumulative return on investment to the partners and/or production from the licence. The distinction between equity and entitlement is relevant to most PSA regimes, whereas it is not applicable in most concessionary regimes such as those in Norway, the UK, Canada and Brazil. The overview of equity production provides additional information for readers, as certain costs described in the profit and loss analysis were directly associated with equity volumes produced during the reported years
- Heavy oil: Crude oil with high viscosity (typically above 10 cp), and high specific gravity. The API classifies heavy oil as crudes with a gravity below 22.3° API. In addition to high viscosity and high specific gravity, heavy oils typically have low hydrogen-to-carbon ratios, high asphaltene, sulphur, nitrogen, and heavy-metal content, as well as higher acid numbers
- High grade: Relates to selectively harvesting goods, to cut the best and leave the rest. In reference to exploration and production this entails strict prioritisation and sequencing of drilling targets
- Hydro: A reference to the oil and energy activities of Norsk Hydro ASA, which merged with Statoil ASA
- IOR (improved oil recovery): Actual measures resulting in an increased oil recovery factor from a reservoir as compared with the expected value at a certain reference point in time. IOR comprises both of conventional and emerging technologies
- Liquids: Refers to oil, condensates and NGL
- LNG (liquefied natural gas): Lean gas - primarily methane - converted to liquid form through refrigeration to minus 163 degrees Celsius under atmospheric pressures
- LPG (liquefied petroleum gas): Consists primarily of propane and butane, which turn liquid under a pressure of six to seven atmospheres. LPG is shipped in special vessels
- Midstream: Processing, storage, and transport of crude oil, natural gas, natural gas liquids and sulphur
- Naphtha: inflammable oil obtained by the dry distillation of petroleum
- Natural gas: Petroleum that consists principally of light hydrocarbons. It can be divided into 1) lean gas, primarily methane but often containing some ethane and smaller quantities of heavier hydrocarbons (also called sales gas) and 2) wet gas, primarily ethane, propane and butane as well as smaller amounts of heavier hydrocarbons; partially liquid under atmospheric pressure
- NGL (natural gas liquids): Light hydrocarbons mainly consisting of ethane, propane and butane which are liquid under pressure at normal temperature
- Oil sands: A naturally occurring mixture of bitumen, water, sand, and clay. A heavy viscous form of crude oil
- Oil and gas value chains: Describes the value that is being added at each step from 1) exploring; 2) developing; 3) producing; 4) transportation and refining; and 5) marketing and distribution
- Organic capital expenditures: Capital expenditures excluding acquisitions, capital leases and other investments with significant different cash flow pattern
- Petroleum: A collective term for hydrocarbons, whether solid, liquid or gaseous. Hydrocarbons are compounds formed from the elements hydrogen (H) and carbon (C). The proportion of different compounds, from methane and ethane up to the heaviest components, in a petroleum find varies from discovery to discovery. If a reservoir primarily contains light hydrocarbons, it is described as a gas field. If heavier hydrocarbons predominate, it is described as an oil field. An oil field may feature free gas above the oil and contain a quantity of light hydrocarbons, also called associated gas
- Proved reserves: Reserves claimed to have a reasonable certainty (normally at least 90% confidence) of being recoverable under existing economic and political conditions, and using existing technology. They are the only type the US Securities and Exchange Commission allows oil companies to report
- Refining reference margin: Is a typical average gross margin of our two refineries, Mongstad and Kalundborg. The reference margin will differ from the actual margin, due to variations in type of crude and other feedstock, throughput, product yields, freight cost, inventory etc
- Rig year: A measure of the number of equivalent rigs operating during a given period. It is calculated as the number of days rigs are operating divided by the number of days in the period
- Upstream: Includes the searching for potential underground or underwater oil and gas fields, drilling of exploratory wells, subsequent operating wells which bring the liquids and or natural gas to the surface
- VOC (volatile organic compounds): Organic chemical compounds that have high enough vapour pressures under normal conditions to significantly vaporise and enter the earth's atmosphere (e.g. gasses formed under loading and offloading of crude oil)

10 Forward-looking statements

This Annual Report on Form 20-F contains certain forward-looking statements that involve risks and uncertainties, in particular in the sections "Business overview" and "Strategy and market overview". In some cases, we use words such as "aim", "ambition", "anticipate", "believe", "continue", "could", "estimate", "expect", "intend", "likely", "objective", "outlook", "may", "plan", "schedule", "seek", "should", "strategy", "target", "will", "goal" and similar expressions to identify forward-looking statements. All statements other than statements of historical fact, including, among others, statements regarding future financial position, results of operations and cash flows; future financial ratios and information; future financial or operational portfolio or performance; future market position and conditions; future credit rating; business strategy; growth strategy; sales, trading and market strategies; research and development initiatives and strategy; market outlook and future economic projections and assumptions; competitive position; projected regularity and performance levels; expectations related to our recent transactions and projects, such as the sale of interests in the Shah Deniz project and the South Caucasus Pipeline, interests in the Marcellus onshore play in the US, interests in Trans Adriatic Pipeline, interests in Gudrun and acquisition of interests in Eagle Ford in the US, the UK Mariner project, the Peregrino phase II project in Brazil, in addition to the Johan Sverdrup and Aasta Hansteen projects on the NCS, discoveries on the NCS and internationally; our ownership share in Gassled; completion and results of acquisitions, disposals and other contractual arrangements; reserve information; recovery factors and levels; future margins; projected returns; future levels or development of capacity, reserves or resources; future decline of mature fields; planned turnarounds and other maintenance; plans for cessation and decommissioning; oil and gas production forecasts and reporting; growth, expectations and development of production, projects, pipelines or resources; estimates related to production and development levels and dates; operational expectations, estimates, schedules and costs; exploration and development activities, plans and expectations; projections and expectations for upstream and downstream activities; expectations relating to licences; oil, gas, alternative fuel and energy prices and volatility; oil, gas, alternative fuel and energy supply and demand; renewable energy production, industry outlook and carbon capture and storage; organisational structure and policies; planned responses to climate change; technological innovation, implementation, position and expectations; future energy efficiency; projected operational costs or savings; our ability to create or improve value; future sources of financing; exploration and project development expenditure; our goal of safe and efficient operations; effectiveness of our internal policies and plans; our ability to manage our risk exposure; our liquidity levels and management; estimated or future liabilities, obligations or expenses; expected impact of currency and interest rate fluctuations; expectations related to contractual or financial counterparties; capital expenditure estimates and expectations; projected outcome, impact or timing of HSE regulations; HSE goals and objectives of management for future operations; expectations related to regulatory trends; impact of PSA effects; projected impact or timing of administrative or governmental rules, standards, decisions, standards or laws (including taxation laws); projected impact of legal claims against us; plans for capital distribution and amounts of dividends are forward-looking statements. You should not place undue reliance on these forward-looking statements. Our actual results could differ materially from those anticipated in the forward-looking statements for many reasons, including the risks described above in "Risk review", and in "Operational review", and elsewhere in this Annual Report on Form 20-F.

These forward-looking statements reflect current views about future events and are, by their nature, subject to significant risks and uncertainties because they relate to events and depend on circumstances that will occur in the future. There are a number of factors that could cause actual results and developments to differ materially from those expressed or implied by these forward-looking statements, including levels of industry product supply, demand and pricing; exchange rate and interest rate fluctuations; the political and economic policies of Norway and other oil-producing countries; EU directives; general economic conditions; political and social stability and economic growth in relevant areas of the world; Euro-zone uncertainty; global political events and actions, including war, terrorism and sanctions; security breaches, including breaches of our digital infrastructure (cybersecurity); changes or uncertainty in or non-compliance with laws and governmental regulations; the timing of bringing new fields on stream; an inability to exploit growth opportunities; material differences from reserves estimates; unsuccessful drilling; an inability to find and develop reserves; ineffectiveness of crisis management systems; adverse changes in tax regimes; the development and use of new technology, particularly in the renewable energy sector; geological or technical difficulties; operational problems; operator error; inadequate insurance coverage; the lack of necessary transportation infrastructure when a field is in a remote location and other transportation problems; the actions of competitors; the actions of field partners; the actions of the Norwegian state as majority shareholder; counterparty defaults; natural disasters, adverse weather conditions, climate change, and other changes to business conditions; failure to meet our ethical and social standards; an inability to attract and retain personnel and other factors discussed elsewhere in this report.

Although we believe that the expectations reflected in the forward-looking statements are reasonable, we cannot assure you that our future results, level of activity, performance or achievements will meet these expectations. Moreover, neither we nor any other person assumes responsibility for the accuracy and completeness of the forward-looking statements. Unless we are required by law to update these statements, we will not necessarily update any of these statements after the date of this Annual Report, either to make them conform to actual results or changes in our expectations.

11 Signature page

The registrant hereby certifies that it meets all of the requirements for filing on Form 20-F and that it has duly caused and authorised the undersigned to sign this Annual Report on its behalf.

STATOIL ASA
(Registrant)

By: /s/ Hans Jakob Hegge
Name: Hans Jakob Hegge
Title: Executive Vice President and Chief Financial Officer

Dated: 18 March 2016

12 Exhibits

The following exhibits are filed as part of this Annual Report:

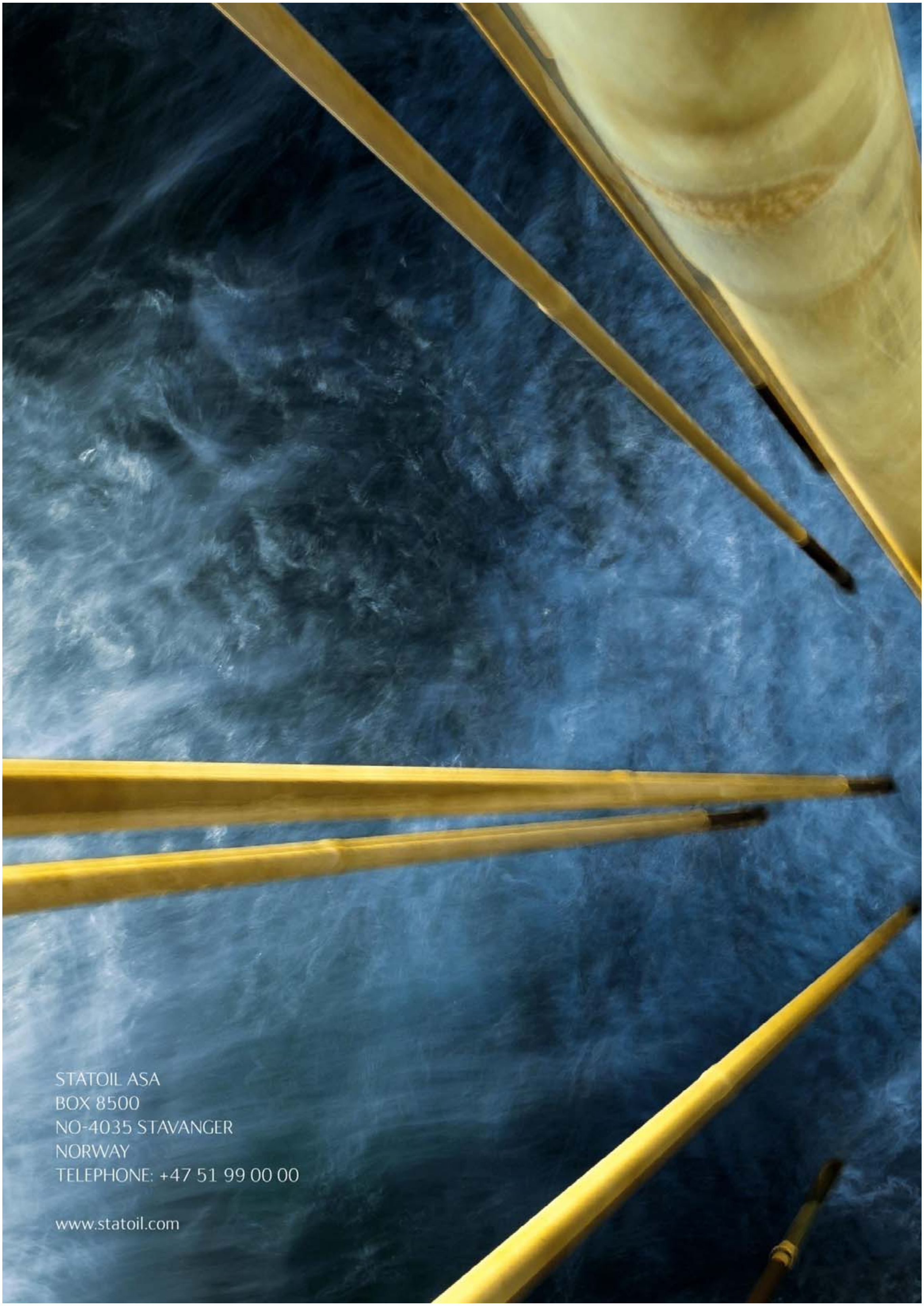
Exhibit no	Description
Exhibit 1	Articles of Association of Statoil ASA, as amended, effective from 14 May 2013 (English translation).
Exhibit 4(a)(i)	Technical Services Agreement between Gassco AS and Statoil Petroleum AS, dated November 24, 2010.
Exhibit 4(c)	Employment agreement with Eldar Sætre as of 4 February 2015.
Exhibit 7	Calculation of ratio of earnings to fixed charges.
Exhibit 8	Subsidiaries (see section 3.9 Significant subsidiaries included in this Annual Report).
Exhibit 12.1	Rule 13a-14(a) Certification of Chief Executive Officer.
Exhibit 12.2	Rule 13a-14(a) Certification of Chief Financial Officer.
Exhibit 13.1	Rule 13a-14(b) Certification of Chief Executive Officer.[1)]
Exhibit 13.2	Rule 13a-14(b) Certification of Chief Financial Officer.[1)]
Exhibit 15(a)(i)	Consent of KPMG AS.
Exhibit 15(a)(ii)	Consent of DeGolyer and MacNaughton.
Exhibit 15(a)(iii)	Report of DeGoyler and MacNaughton.

1) Furnished only.

The total amount of long-term debt securities of the Registrant and its subsidiaries authorised under any one instrument does not exceed 10% of the total assets of Statoil ASA and its subsidiaries on a consolidated basis. The company agrees to furnish copies of any or all such instruments to the Securities and Exchange Commission upon request.

13 Cross reference to Form 20-F

		Sections
Item 1.	Identity of Directors, Senior Management and Advisers	N/A
Item 2.	Offer Statistics and Expected Timetable	N/A
Item 3.	Key Information	
	A. Selected Financial Data	1.2; 4.1.2; 6; 6.1.1; 6.7
	B. Capitalisation and Indebtedness	N/A
	C. Reasons for the Offer and Use of Proceeds	N/A
	D. Risk Factors	5.1
Item 4.	Information on the Company	
	A. History and Development of the Company	3.1; 3.2; 4.1.4; 4.1.5; 4.2.3; 8.1.4
	B. Business Overview	2; 3; 4.1.1; 4.1.3
	C. Organisational Structure	3.1; 3.4; 3.9
	D. Property, Plants and Equipment	3.5 - 3.7; 3.13; 4.2.3; 8.1.11; 8.1.22
	Oil and Gas Disclosures	3.10.1; 3.10.2; 3.11; 3.11.1; 3.11.2; 3.11.3; 3.11.4; 8.1.27; Exhibit 15(a)(iv)
Item 4A.	Unresolved Staff Comments	None
Item 5.	Operating and Financial Review and Prospects	
	A. Operating Results	3.12; 4.1; 4.2.4; 5.2.1; 8.1.25
	B. Liquidity and Capital Resources	4.2; 4.2.1; 4.2.2; 4.2.5; 5.2.1; 5.2.2; 8.1.5; 8.1.16; 8.1.18; 8.1.25
	C. Research and development, Patents and Licenses, etc.	3.8.3; 8.1.7
	D. Trend Information	2; 3.3; 3.5.1; 3.5.3; 3.5.4; 3.6; 3.7.1; 3.11; 3.12.5; 4.2; 5; 8.1.23
	E. Off-Balance Sheet Arrangements	4.2.5; 4.2.6; 8.1.22; 8.1.23
	F. Tabular Disclosure of Contractual Obligations	4.2.5
	G. Safe Harbor	10
Item 6.	Directors, Senior Management and Employees	
	A. Directors and Senior Management	7.6; 7.8
	B. Compensation	7.9; 8.1.19
	C. Board Practices	7.5; 7.6; 7.8
	D. Employees	3.16.1; 3.16.3
	E. Share Ownership	6.2.1; 7.6; 7.8; 7.10
Item 7.	Major Shareholders and Related Party Transactions	
	A. Major Shareholders	6.8
	B. Related Party Transactions	3.14; 8.1.24
	C. Interests of Experts and Counsel	N/A
Item 8.	Financial Information	
	A. Consolidated Statements and Other Financial Information	4.1.3; 5.3; 6.1; 8
	B. Significant Changes	8.1.27
Item 9.	The Offer and Listing	
	A. Offer and Listing Details	6.4
	B. Plan of Distribution	N/A
	C. Markets	6; 6.4; 7.7
	D. Selling Shareholders	N/A
	E. Dilution	N/A
	F. Expenses of the Issue	N/A
Item 10.	Additional Information	
	A. Share Capital	N/A
	B. Memorandum and Articles of Association	6.1; 6.8; 7.1; 7.3; 7.10; 8.1.17
	C. Material Contracts	N/A
	D. Exchange Controls	6.6
	E. Taxation	6.5
	F. Dividends and Paying Agents	N/A
	G. Statements by Experts	N/A
	H. Documents On Display	1.1
	I. Subsidiary Information	N/A
Item 11.	Quantitative and Qualitative Disclosures About Market Risk	5; 8.1.5; 8.1.25
Item 12.	Description of Securities Other than Equity Securities	5; 8.1.5; 8.1.25
	A. Debt Securities	N/A
	B. Warrants and Rights	N/A
	C. Other Securities	N/A
	D. American Depositary Shares	6.4.2
Item 13.	Defaults, Dividend Arrearages and Delinquencies	None
Item 14.	Material Modifications to the Rights of Security Holders and Use of Proceeds	None
Item 15.	Controls and Procedures	7.12; 8.2.2
Item 16A.	Audit Committee Financial Expert	7.6.1
Item 16B.	Code of Ethics	7.2
Item 16C.	Principal Accountant Fees and Services	7.1
Item 16D.	Exemptions from the Listing Standards for Audit Committees	7.7
Item 16E.	Purchases of Equity Securities by the Issuer and Affiliated Purchases	6.2
Item 16F.	Changes in Registrant's Certifying Accountant	N/A
Item 16G.	Corporate Governance	7.7
Item 17.	Financial Statements	N/A
Item 18.	Financial Statements	8
Item 19.	Exhibits	12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PUBLIC COPY - CONFIDENTIAL INFORMATION REMOVED

Attachment 10

Equinor US Financial Statements

REDACTED

equinor

Attachment 11

Fisheries Survival Fund v. Sally Jewell Opinion

equinor

UNITED STATES DISTRICT COURT
FOR THE DISTRICT OF COLUMBIA

FISHERIES SURVIVAL FUND, *et al.*,	)	
Plaintiffs,	)	
v.	)	Case No. 16-cv-2409 (TSC)
SALLY JEWELL, *et al.*,	)	
Defendants.	)	

MEMORANDUM OPINION

This case concerns a Bureau of Ocean Energy Management ("BOEM") plan to lease a nautical area off the coast of New York to Defendant-Intervenor Statoil Wind US, LLC ("Statoil"), for development of a wind energy facility. Plaintiffs[1], including the Fisheries Survival Fund, claim that in issuing the lease, BOEM violated the National Environmental Policy Act ("NEPA"), the Outer Continental Shelf Lands Act ("OCSLA"), and the Administrative Procedure Act ("APA"). Plaintiffs filed a motion for preliminary injunction, which this court denied. Memorandum Opinion, ECF No. 26. Now before the court are Plaintiffs' Motion for Summary Judgment, ECF No. 39, Defendant-Intervenor's Cross-Motion for Summary Judgment, ECF No. 40, and Defendants' Motion for Summary Judgment, ECF No. 42. For the reasons stated herein, Plaintiffs' motion will be DENIED, Defendants' motion will be GRANTED, and Defendant-Intervenor's motion will be DENIED as moot.

[1] The other Plaintiffs are: Borough of Barnegat Light, NJ; the Town Dock; Seafreeze Shoreside; Sea Fresh USA; Rhode Island Fishermen's Alliance; Garden State Seafood Association; Long Island Commercial Fishing Association; the Town of Narragansett, RI; the Narragansett Chamber of Commerce; the City of New Bedford, MA; and the Fishermen's Dock Co-Operative of Point Pleasant.

I. BACKGROUND

A. Statutory & Regulatory Framework

1. OCSLA

As amended by the Energy Policy Act of 2005, Pub. L. 109-58, 119 Stat. 594 (2005), OCSLA authorizes BOEM to issue leases, easements, or rights-of-way for offshore renewable energy projects. 43 U.S.C. § 1337(p)(1)(C). In exercising this authority, BOEM is required to consult with the U.S. Coast Guard and other relevant federal agencies, and must consider several factors that include, *inter alia*, safety, protection of the environment, prevention of waste, conservation of natural resources, national security interests, and—critically—"the location of . . . a lease. . . for an area of the outer Continental Shelf" and "any other use of the sea or seabed, including use for a fishery, a sealane, a potential site of a deepwater port, or navigation." *Id.* § 1337(p)(4)(A)–(L) & (J)(i)–(ii).

2. NEPA

NEPA was enacted to establish "a national policy [to] encourage productive and enjoyable harmony between man and his environment," to "prevent or eliminate damage to the environment," and "to enrich the understanding of the ecological systems and natural resources important to the Nation." 42 U.S.C. § 4321; *see also Dep't of Transp. v. Pub. Citizen*, 541 U.S. 752, 756–57 (2004). NEPA serves these goals by imposing "procedural requirements on federal agencies with a particular focus on requiring agencies to undertake analyses of the environmental impact of their proposals and actions." *Pub. Citizen*, 541 U.S. at 756–57; *Theodore Roosevelt Conservation P'ship v. Salazar*, 616 F.3d 497, 503 (D.C. Cir. 2010) (noting that "[NEPA] is an 'essentially procedural' statute, meant to ensure 'a fully informed and well-considered decision, not necessarily' the best decision") (quoting *Vermont Yankee Nuclear Power Corp. v. Natural*

Res. Def. Council, Inc., 435 U.S. 519, 558 (1978)). The statute requires that the relevant agency (1) "consider every significant aspect of the environmental impact of a proposed action," *Baltimore Gas & Elec. Co. v. Nat. Res. Def. Council, Inc.*, 462 U.S. 87, 97 (1983) (quoting *Vermont Yankee*, 435 U.S. at 553), and (2) "inform the public that the agency has considered environmental concerns in its decisionmaking process." *Weinberger v. Catholic Action of Hawaii/Peace Educ. Project*, 454 U.S. 139, 143 (1981).

"NEPA requires that when an agency proposes a 'major Federal action[] significantly affecting the quality of the human environment,' the agency must prepare and circulate for public review and comment an environmental impact statement ("EIS") that examines the environmental impact of the proposed action and compares the action to other alternatives." *Theodore Roosevelt Conservation P'ship*, 616 F.3d at 503 (quoting 42 U.S.C. § 4332(2)(C)); *see also Sierra Club v. Van Antwerp*, 661 F.3d 1147, 1153 (D.C. Cir. 2011). Nevertheless, an EIS is not always necessary. *See Public Citizen v. NHTSA*, 848 F.2d 256, 265 (1988) ("NEPA requires the preparation of a complete EIS for 'major federal actions *significantly* affecting the quality of the human environment.'") (emphasis in original). Agencies may "prepare a more limited document"—known as an Environmental Assessment ("EA")—if a proposed action is neither categorically excluded from the EIS requirement nor of the kind that would normally require an EIS. *See* 40 C.F.R. §§ 1501.4(a)–(b); *Pub. Citizen*, 541 U.S. at 757 ("CEQ regulations allow an agency to prepare . . . an [EA] . . . if the agency's proposed action neither is categorically excluded from the requirement to produce an EIS nor would clearly require the production of an EIS."). An EA is a "concise public document" intended to "[b]riefly provide sufficient evidence and analysis for determining whether to prepare an environmental impact statement or a finding of no significant impact." 40 C.F.R. §§ 1508.9(a)(1); *Pub. Citizen*, 541 U.S. at 757–58. Where preparation of an EA leads an agency to decide that an EIS is unnecessary, the agency is required to issue a "finding of no significant impact"—"a document . . . briefly presenting the reasons why an action . . . will not have a significant effect on the human environment and for which an environmental impact statement will therefore not be prepared." 40 C.F. R. §§ 1501.4(e), 1508.13.

B. BOEM's Leasing Process

In accordance with OCSLA, BOEM promulgated a series of regulations governing the leasing and management of offshore renewable energy projects. *See* 30 C.F.R. § 585.200–234. Pursuant to these regulations, the commercial leasing process may be initiated by both solicited and unsolicited applications. A solicited application is one in which BOEM itself identifies the potential development site and initiates the leasing process by publishing a notice of Request for Interest ("RFI") or a Call for Information and Nominations in the Federal Register. *See* 30 C.F.R. §§ 585.210, 585.211(a). An unsolicited application is one in which a potential developer applies for a site not otherwise under consideration by BOEM. *See* 30 C.F.R. § 585.230.

Upon receiving an unsolicited request, BOEM publishes a RFI to seek public comment and determine whether there is competitive interest from other developers. *Id.* § 585.231(b). If there is competitive interest, BOEM proceeds with the competitive process. *Id.* § 585.231(c)(1). Otherwise, it publishes a notice of Determination of No Competitive Interest and follows a separate procedure. *Id.* § 585.231(d)–(i). Regardless of the procedure adopted in any case, BOEM must consult throughout the leasing process with state task forces, other state and local representatives, and with representatives of Indian Tribes whose interests may be affected. *Id.* §§ 585.102(e), 585.211(a)–(d), 585.231(e).

Before issuing a lease, BOEM follows a four-step procedure, issuing a Call for Information and Nominations, completing the Area Identification process, publishing a Proposed Sale Notice, and publishing a Final Sale Notice. *Id.* § 585.211(a)–(d). Once BOEM has issued a lease, the lessee must submit a Site Assessment Plan for review before any assessment activity takes place. *Id.* §§ 585.601, 585.605. Even after completing a site assessment, a lessee may not begin construction until it has submitted, and BOEM has approved, a Construction and Operations Plan. *Id.* § 585.620(c). BOEM can accept, reject, or accept with modifications a lessee's Site Assessment or Construction and Operations Plan, *id.* §§ 585.613, 585.628, and must analyze the potential environmental impacts of the plans. *See id.* §§ 585.613, 585.620(c).

C. Lease OCS–A 0512

In September 2011, a consortium of energy companies consisting of the New York Power Authority, Long Island Power Authority, and Consolidated Edison (collectively, "the Consortium"), proposed developing a wind energy facility covering approximately 81,500 acres of ocean off the coast of New York. NYAR-0074853, 0074854. Due to safety concerns about shipping lanes, the Consortium later amended the request to cover 81,130 acres, or about 127 square miles. NYAR-0074140. The Consortium claims the proposed project has "the potential to be the largest offshore wind energy facility in the United States." NYAR-0074853. Since the Consortium's request was unsolicited, BOEM initiated an RFI on January 4, 2013 to gauge other companies' interest in developing the area. 78 Fed. Reg. 760-02 (Jan. 4, 2013). The RFI also requested that "interested and affected parties comment and provide information about site conditions and multiple uses within the area identified in this notice that would be relevant to the proposed project or its impacts." *Id.* at 760 –61.

After reviewing nominations of interest and acknowledging competitive interest in the area, BOEM initiated the competitive leasing process. Compl. ¶ 54. On May 28, 2014, BOEM published (1) a Notice of Intent to prepare an EA and (2) a Call for Information and Nominations from companies interested in commercial wind energy leases in the proposed wind farm area. 79 Fed. Reg. 30,643–44 (May 28, 2014); 79 Fed. Reg. 30,645. BOEM also began the "Area Identification" process to "identify offshore locations that appear most suitable for wind energy development" and "designat[e] . . . an area with the greatest wind resource potential, minimal environmental and space use conflict, and possible alternatives for environmental analysis." NYAR-0044172; 30 C.F.R. § 585.211(b). BOEM completed this process on March 14, 2016, thereby marking the area as available for lease. *See* NYAR-0045776.

On June 6, 2016, BOEM published a "Proposed Sale Notice for Commercial Leasing for Wind Power on the Outer Continental Shelf Offshore New York" in the Federal Register. 81 Fed. Reg. 36,336 (June 6, 2016) (NYAR-0047230). The Proposed Sale Notice included a sixty-day comment period, which closed on August 6, 2016. *Id.* On June 6, BOEM also published an EA, along with a Notice of Availability for a thirty-day public comment period. 81 Fed. Reg. 36,344 (June 6, 2016) (NYAR-0047238). According to the Notice of Availability, the EA focused on assessing the potential impact of and reasonable alternatives to "commercial wind lease issuance, site characterization activities (geophysical, geotechnical, archaeological, and biological surveys) and site assessment activities (including the installation and operation of a meteorological tower and/or buoys)." *Id.* The Notice also stated that "[s]hould a lessee propose to construct a commercial wind facility through submission of a [Construction and Operations Plan], BOEM would conduct a separate site and project-specific [NEPA] analysis, likely an [EIS], and would provide additional opportunities for public involvement . . . ." *Id.* After requests from Plaintiff Fisheries Survival Fund and other groups, BOEM extended the public comment period to July 13, 2016. Compl. ¶ 62.

On October 31, 2016, BOEM published the Final Sale Notice for the lease sale of the area. 81 Fed. Reg. 75,429 (Oct. 31, 2016) (NYAR-0075588). BOEM determined that fourteen different bidders were "legally, technically, and financially qualified to hold a commercial wind lease" and to bid in the auction. *Id.* at 75,430 (NYAR-0075589). BOEM also published its revised EA, which found no significant impact for commercial wind lease issuance and related activities within the area. 81 Fed. Reg. 75,438 (Oct. 31, 2016). The finding of no significant impact concluded that "the reasonably foreseeable environmental impacts . . . would not significantly impact the quality of the human environment," and "therefore, the preparation of an environmental impact statement [was] not required." *Id.*; *see also* NYAR-0074241. The EA stated that "BOEM reduces its impacts early in the planning process by conducting site identification through public stakeholder meetings to avoid areas that may have significant impacts on the environment, including marine mammals." NYAR-0074521.

On December 15 and 16, BOEM held a lease auction, which Statoil won with a $42,469,725 bid. *See* Commercial Lease of Submerged Lands for Renewable Energy Development on Continental Shelf (NYAR-0046753). BOEM and Statoil executed the lease on March 15, 2017. NYAR-0046759. The lease grants Statoil the exclusive right to conduct site characterization activities and, within one year of lease issuance, to propose a Site Assessment Plan. NYAR-0046753; 30 C.F.R. §§ 585.601, 585.605. If BOEM approves the Plan, Statoil will have five years to engage in site assessment—including conducting surveys and using towers or buoys to evaluate wind resources—and propose a Construction and Operations Plan, 30 C.F.R. §§ 585.235(a)(2), 585.601(b), which must include detailed data and information to support the plan for the wind facility, and proposals for minimizing environmental impact. 30 C.F.R. § 585.626(b). BOEM would then conduct "an appropriate NEPA analysis" based on the information included in the Construction and Operations Plan, before deciding whether to approve the Plan. 30 C.F.R. § 585.628(b).

II. LEGAL STANDARD

The APA requires courts to "set aside any agency action that is 'arbitrary and capricious, an abuse of discretion, or otherwise not in accordance with law." 5 U.S.C. § 706(2)(A). In assessing a summary judgment motion brought under the APA, courts are "not empowered to substitute [their] judgment for that of the agency." *Beyond Nuclear v. U.S Dep't of Energy*, 233 F. Supp. 3d 40, 47 (D.D.C. 2017) (quoting *Citizens to Preserve Overton Park, Inc. v. Volpe*, 401 U.S. 402, 416 (1971)). Rather, the court's role is to "determine whether or not as a matter of law the evidence in the administrative record permitted the agency to make the decision it did." *Coe v. McHugh*, 968 F. Supp. 2d 237, 239–40 (D.D.C. 2013) (quoting *Occidental Eng'g Co. v. INS*, 753 F.2d 766, 769–70 (9th Cir. 1985)).

Generally, an agency action is arbitrary if:

> the agency has relied on factors which Congress has not intended it to consider, entirely failed to consider an important aspect of the problem, offered an explanation for its decision that runs counter to the evidence before the agency, or is so implausible that it could not be ascribed to a difference in view or the product of agency expertise.

Delaware Riverkeeper Network v. FERC, 753 F.3d 1304, 1313 (D.C. Cir. 2014) (quoting *Motor Vehicle Mfrs. Ass'n of the U.S., Inc. v. State Farm Mut. Auto. Ins.*, 463 U.S. 29, 43 (1983)). This standard also applies when assessing compliance with NEPA and the adequacy of an EIS. *City of Olmsted Falls, OH v. FAA*, 292 F.3d 261, 269 (D.C. Cir. 2002) (citing *Marsh v. Oregon Natural Resources Council*, 490 U.S. 360, 376 (1989)). "Courts may not use their review of an agency's environmental analysis to second-guess substantive decisions committed to the discretion of the agency," *Del. Riverkeeper Network*, 753 F.3d at 1313, and must instead "review the EIS to 'ensure that the agency took a "hard look" at the environmental consequences of its decision to go forward with the project.'" *Olmsted Falls*, 292 F.3d at 269 (quoting *City of Grapevine, Tex. v. DOT*, 17 F.3d 1502, 1503–04 (D.C. Cir. 1994)).

III. DISCUSSION

The parties' motions for summary judgment present two broad issues: (1) whether Defendants violated NEPA by improperly segmenting their NEPA analysis, failing to consider a reasonable range of alternatives, and failing to prepare an EIS in deciding the site of the proposed wind farm area; and (2) whether Defendants violated their obligations under OCSLA by failing to consider a number of relevant factors in the site selection process, failing to consider those factors in proceeding with the lease sale, and/or acting in accordance with a regulatory procedure that exceeds the authority granted under OCSLA. Pls. Mot. Summ. J. at 38–47, 47–54, ECF No. 39-1; Def. Intervenors Mot. Summ. J. at 17–24, 24–32, ECF No. 40; Defs. Mot. Summ. J. at 29–44, 45–54, ECF No. 42. The parties also raise issues of standing and constitutional ripeness. *See, e.g.*, ECF No. 42 at 22–28. As these latter issues present jurisdictional questions, this court will address them at the threshold.

A. Standing

Plaintiffs, who bear the burden of establishing standing, *see Kokkonen v. Guardian Life Ins. Co. of Am.*, 511 U.S. 375, 377 (1994), claim a procedural injury relating to BOEM's issuance of the lease. Plaintiffs contend that "the heart of [their] injury" results from BOEM's decision to issue the lease on key fishing grounds "prior to obtaining any public input or considering fishing, environmental, or safety interests with respect to the physical boundaries of that area," in violation of NEPA and OCSLA. ECF No. 39-1 at 37. Plaintiffs further allege that they will be injured by the "exploration and development of a wind farm" in the area that will likely follow from issuance of the lease and "directly damage the natural resources in that area, . . . physically preclude . . . fisheries from operating fishing vessels in that area, . . . [and] pose navigational safety issues." ECF No. 39-1 at 37.

Defendants respond that Plaintiffs' allegations of harm do not establish standing "because they all relate to the possible future approval of the construction of a wind energy facility," rather than "the site characterization and site assessment activities associated with issuance of the lease." Defs. Opp'n Mot. at 23, ECF No. 43. According to Defendants, Plaintiffs' alleged future injuries "fail to demonstrate that the construction of a wind energy facility is *substantially probable*," ECF No. 53 at 3 (emphasis in original), insofar as the construction depends on future events—including the preparation and approval of multiple reports and a development plan—that have not occurred and may not occur for six years, if at all. ECF No. 43 at 24.

Standing is a jurisdictional prerequisite—an "irreducible constitutional minimum" that requires a plaintiff to show: (1) an "injury in fact" that is "concrete and particularized" and "actual or imminent, not conjectural or hypothetical"; (2) that the injury is "fairly traceable to the challenged action of the defendant"; and (3) that it is "likely, as opposed to merely speculative, that the injury will be redressed by a favorable decision." *Chamber of Commerce of U.S. v. E.P.A.*, 642 F.3d 192, 200 (D.C. Cir. 2011) (quoting *Bennett v. Spear*, 520 U.S. 154, 167 (1997)); *Summers v. Earth Island Inst.*, 555 U.S. 488, 492 (2009) (noting that standing doctrine "requires federal courts to satisfy themselves that 'the plaintiff has alleged such a personal stake in the outcome of the controversy' as to warrant his invocation of federal-court jurisdiction.") (quoting *Warth v. Seldin*, 422 U.S. 490, 498 (1975)).

When a party alleges injury to its procedural rights, "courts relax the normal standards of redressability and imminence." *Sierra Club v. Fed. Energy Regulatory Comm'n*, 827 F.3d 59, 65 (D.C. Cir. 2016). In such cases, "the primary focus of the standing inquiry is not the imminence or redressability of the injury to the plaintiff, but whether a plaintiff who has suffered a personal and particularized injury has sued a defendant who has caused that injury." *City of Dania Beach v. FAA*, 485 F.3d 1181, 1185 (D.C. Cir. 2007) (quoting *Fla. Audubon Soc'y v. Bentsen*, 94 F.3d 68, 664 (D.C. Cir. 1996) (en banc)). "To establish injury-in-fact in a 'procedural injury' case, petitioners must show that 'the government act performed without the procedure in question will cause a distinct risk to a particularized interest of the plaintiff.'" *Id.* at 1185 (quoting *Fla. Audubon Soc'y*, 94 F.3d at 663). In other words, "[a] violation of the procedural requirements of a statute is sufficient to grant a plaintiff standing to sue, so long as the procedural requirement was designed to protect some threatened concrete interest of the plaintiff." *City of Dania Beach*, 485 F.3d at 1185 (quoting *City of Waukesha v. EPA*, 320 F.3d 228, 234 (D.C. Cir. 2003)); *see also Sierra Club*, 827 F.3d at 65 ("[A]n adequate causal chain must contain at least two links: one connecting the omitted [NEPA analysis] to some substantive government decision that may have been wrongly decided because of the lack of [proper NEPA analysis] and one connecting that substantive decision to the plaintiff's particularized injury."). A plaintiff alleging a violation of some procedural right "never has to prove that if he had received the procedure the substantive result would have been altered," and need only show "that the procedural step was connected to the substantive result." *Sugar Cane Growers Cooperative v. Veneman*, 289 F.3d 89, 95 (D.C. Cir. 2002).

Plaintiffs are entitled to bring their OCSLA and NEPA claims under a procedural standing theory because they have demonstrated a threat to a sufficiently concrete and particularized interest in the wind farm area, and the alleged procedural deficiencies are connected to a substantive governmental decision—issuing the lease—that is in turn connected to a risk of harm to Plaintiffs' identified interests. *See Dania Beach*, 485 F.3d at 1185 (describing need for distinct risk to particularized interest in procedural injury context); *Sierra Club*, 827 F.3d at 65 (discussing components of an adequate causal chain in procedural injury context). The Plaintiffs in this case include those who use or depend on the use of the wind farm area and the natural resources contained therein for fishing, navigation, and associated economic and recreational benefits. *See* ECF No. 39-1 at 15–17, 21–25. The use or enjoyment of wildlife is a cognizable interest for standing purposes, *see Ctr. for Biological Diversity v. U.S. Department of Interior*, 563 F.3d 466, 479 (D.C. Cir. 2009) ("*CBD*") (citing *Lujan v. Defenders of Wildlife*, 504 U.S. 555, 562–63 (1992)) (affirming the appropriateness of an interest in enjoyment of wildlife), and here, that interest is concrete and particularized insofar as it refers to specific marine species and activities within a distinct, identified area. *See Bentsen*, 94 F.3d at 667–68 (emphasizing need for particularization of alleged environmental interests in form of geographic nexus to claim of particularized injury). Furthermore, Plaintiffs claim—in multiple declarations—that their interest in the use or enjoyment of the area under the lease will be damaged or altogether precluded by development. *See, e.g.*, ECF No. 3-1 at 2–3, 5–9, 133–40, 115–16.

The court notes that the lease only authorizes site characterization and assessment, and that construction—the development phase involving the most transformative activity—has not yet received approval, and depends on multiple contingencies occurring over a six-year period. *See* ECF No. 43 at 24; ECF No. 53 at 11. Nevertheless, this fact does not render Plaintiffs' alleged injury too speculative or hypothetical for purposes of standing. The relevant injury here is the injury that Plaintiffs allege regarding the development process as a whole, including the lease sale phase. While the lease itself may not authorize construction of the wind farm, it is undeniably a milestone in the lessee's plan to transform an area currently used for industrial and recreational fishing into an area that Plaintiffs allege is likely to be rendered unsuitable for such purposes. Although the lease does not dispel all contingencies associated with the project, it does increase the probability that any planned development will occur in the designated area. In other words, Plaintiffs have alleged a particularized threat to their concrete interest in use of the leased area insofar as their stated concern is the progress of a development project affecting that interest.

It also appears that the challenged leasing decision is causally connected to an increased risk of harm to Plaintiffs' particularized interests, insofar as the decision increases the risk to their enjoyment of the marine life in the area likely to be affected by the development. *See CBD*, 563 F.3d at 479 (approving procedural theory of standing because "adoption of an irrationally based Leasing Program could cause a substantial increase in the risk to [Petitioners'] enjoyment of the animals affected by the offshore drilling"); *see also* 827 F.3d at 65 (noting need to connect substantive decision that may have been wrongly decided to a particularized injury). For these reasons, Plaintiffs have successfully articulated a procedural theory of Article III standing.[2]

[2] While the analysis of the standing issue applies directly to the municipal plaintiffs, the associational plaintiffs must satisfy additional requirements. Organizations have standing to sue on behalf of their members if: "(1) at least one of [the organization's] members would have standing to sue in his or her own right; (2) 'the interests it seeks to protect are germane to the organization's purpose'; and (3) 'neither the claim asserted nor the relief requested requires the participation of individual members in the lawsuit.'" *Sierra Club v. FERC*, 827 F.3d 59, 65 (D.C. Cir. 2016) (quoting *WildEarth Guardians v. Jewell*, 738 F.3d 298, 305 (D.C. Cir. 2013)). Here, the associational plaintiffs have standing to sue on behalf of their members, whose declarations demonstrate that they share the interest and injury identified above. *See, e.g.*, ECF No. 3-1 at 1–5, 133–40, 115–16. Moreover, the associational plaintiffs' organizational purposes—broadly, to promote the interests of Atlantic fishermen—plainly relate to the fishing industry and commercial

B. Ripeness of NEPA Claims

Plaintiffs contend that their NEPA[3] claims are ripe because "the Lease precludes any further action for the most critical stage of the leasing process—project siting—and constitutes an irretrievable commitment of resources," the key trigger for an agency's NEPA obligations. Pls. Opp. to Def. & Def. Intervenor Mot. at 23, ECF No. 48. Defendants argue that the NEPA claims are not ripe because they "allege that BOEM failed to properly analyze the environmental impacts of constructing and operating a wind energy facility," even though BOEM has yet to approve the construction or operation of such a facility. ECF No. 43 at 25.

The ripeness doctrine is related to standing, and requires that a litigant's claims be "constitutionally and prudentially ripe," so as to protect (1) "the agency's interest in crystallizing its policy before that policy is subjected to judicial review," (2) "the court's interests in avoiding unnecessary adjudication and in deciding issues in a concrete setting," and (3) "the petitioner's interest in prompt consideration of allegedly unlawful agency action." *Nevada v. Department of Energy*, 457 F.3d 78, 84 (D.C. Cir. 2006) (quoting *Eagle–Picher Indus., Inc. v. EPA*, 759 F.2d 905, 915 (D.C. Cir. 1985)). In "determining whether a dispute is ripe for review, courts consider 'both the fitness of the issues for judicial decision and the hardship to the parties of withholding court consideration.'" *Am. Tort Reform Ass'n v. Occupational Safety & Health Admin.*, 738 F.3d 387, 396 (D.C. Cir. 2013) (quoting *Abbott Laboratories v. Gardner*, 387 U.S. 136, 149 (1967)).

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or recreational fishing. *See* ECF No. 39 at 2, 34 (describing plaintiffs and organizational purpose); *Ctr. for Sustainable Economy v. Jewell*, 779 F.3d 588, 597 (D.C. Cir. 2015) ("*CSE*") ("The germaneness requirement [of associational standing] mandates 'pertinence between litigation subject and organizational purpose.'") (quoting *Humane Soc. of the United States v. Hodel*, 840 F.2d 45, 58 (D.C. Cir. 1988)).

[3] Plaintiffs' OCSLA claims "concern OCSLA requirements that are implicated at the initial stage of a leasing program," and are therefore ripe. *CBD*, 563 F.3d at 484.

Courts must also consider: "(1) whether delayed review would cause hardship to the plaintiffs; (2) whether judicial intervention would inappropriately interfere with further administrative action; and (3) whether the courts would benefit from further factual development of the issues presented." *Nevada*, 457 F.3d at 84 (quoting *Ohio Forestry Ass'n, Inc. v. Sierra Club*, 523 U.S. 726, 733 (1998)). Typically, "[a] claim is not ripe for adjudication if it rests upon contingent future events that may not occur as anticipated, or indeed may not occur at all." *Nevada*, 457 F.3d at 85 (quoting *Texas v. United States*, 523 U.S. 296, 300 (1998)).

An agency's NEPA obligations mature "only once it reaches a 'critical stage of a decision which will result in irreversible and irretrievable commitments of resources to an action that will affect the environment.'" *CBD*, 563 F.3d at 480 (quoting *Wyoming Outdoor Council v. United States Forest Service*, 165 F.3d 43, 49 (D.C. Cir. 1999) ("*Wyo. Outdoor Council II*")). Cases involving multiple-stage leasing programs—arising in the oil and gas context—indicate that an agency reaches this critical stage when it "no longer retain[s] the authority to preclude all surface disturbing activities subsequent to issuing an oil and gas lease," such that "an EIS assessing the full environmental consequences of leasing must be prepared before commitment to any actions that might affect the quality of the human environment." *Wyo. Outdoor Council II*, 165 F.3d at 49 (alteration in original) (quoting *Sierra Club v. Peterson*, 717 F.2d 1409, 1415 (D.C. Cir. 1983)); *see also Conner v. Burford*, 848 F.2d 1441, 1451 (9th Cir. 1988) ("[U]nless surface-disturbing activities may be absolutely precluded, the government must complete an EIS before it makes an irretrievable commitment of resources . . . ."). In other words, lease issuance triggers

NEPA obligations unless the issuing agency "retain[s] the authority to preclude all surface disturbing activities." *Wyo. Outdoor Council II*, 165 F.3d at 49.[4]

Though the parties agree that the above legal standard is appropriate, they disagree on how it should be applied. Plaintiffs contend that to avoid making an irreversible commitment of resources, the agency making a lease sale must unilaterally retain "the *absolute right* to prevent *all* surface-disturbing activity." ECF No. 48 at 22 (quoting *Conner*, 848 F.2d at 1449) (emphasis in original). They argue that BOEM does not retain the absolute right because its ability to cancel a lease is limited by lease criteria and Statoil's regulatory compliance. ECF No. 48 at 11–12. Defendants respond that the lease language establishes BOEM's absolute authority to preclude activity in the leased area, that Plaintiffs misunderstand the applicable legal standard in contending otherwise, and that "because BOEM retains the authority to deny a [Construction and Operations Plan], the issuance of the lease to Statoil was not an irreversible and irretrievable commitment of resources." ECF No. 53 at 14, 15. In the court's view, the applicable regulations and the terms of the lease preclude Statoil from engaging in any construction activities, and vest complete authority in BOEM to preclude such activity in the leased area before the Construction and Operations Plan is approved. Therefore, issuing the lease does not constitute an irreversible and irretrievable commitment of resources. *See Wyo. Outdoor Council II*, 165 F.3d at 49. Accordingly, Plaintiffs' NEPA claims must be dismissed as unripe at this stage.

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[4] Plaintiffs do not address ripeness in their memorandum in support of their motion for summary judgment. In their opposition to Defendants' motion, Plaintiffs appear to question in passing whether the standard in cases involving oil and gas leases should apply in the Outer Continental Shelf context or to renewable energy leases. ECF No. 48 at 19. Nevertheless, they do not offer any argument as to why the court should decline to apply that standard, and do not offer any alternative standard, instead opting to argue their position from within the oil and gas lease legal framework, which the court finds analogous and appropriate.

On its own, the lease at issue does no more than grant Statoil the exclusive right to submit a Site Assessment Plan and Construction and Operations Plan to BOEM for approval. NYAR-0046754. No activity is permitted absent the submission and approval of these plans, NYAR-0046754, and the lease provides that (1) "[the] lease does not, by itself, authorize any activity within the leased area," (2) "the Lessor will decide whether to approve a SAP or COP in accordance with the applicable regulations in 30 CFR Part 585," and (3) "the Lessor retains the right to disapprove a SAP or COP based on the Lessor's determination that the proposed activities would have unacceptable environmental consequences . . . ." NYAR-0046754. Moreover, BOEM regulations provide that a lease can be cancelled if, after "notice and opportunity for a hearing," BOEM determines that "continued activity under the lease or grant":

> (i) Would cause serious harm or damage to natural resources; life (including human and wildlife); property; the marine, coastal, or human environment; or sites, structures, or objects of historical or archaeological significance; and
> (ii) That the threat of harm or damage would not disappear or decrease to an acceptable extent within a reasonable period of time; and
> (iii) The advantages of cancellation outweigh the advantages of continuing the lease or grant in force.

30 C.F.R. § 585.437(b)(4)(i)–(iii).

The thrust of Plaintiffs' first argument is that BOEM's authority to preclude activity in the wind farm area cannot be absolute if it is subject to conditions, and that the criteria set forth above are conditions. Thus, Plaintiffs argue, the lease represents a commitment of resources, and therefore their NEPA claims are ripe. *See Conner*, 848 F.2d at 1449–50 (noting that leases permitting surface-disturbing activities subject to conditions do not retain authority to absolutely preclude activities and, therefore, constitute a commitment of resources); *Peterson*, 717 F.2d at 1412, 1414–15 (same).

Though it is true that the criteria may be "conditions" in the sense that BOEM must make certain findings—after notice and an opportunity for a hearing—before disapproving a Construction and Operations Plan and/or cancelling a lease, it does not necessarily follow that "BOEM's own regulations preclude BOEM from changing its mind unilaterally." ECF No. 48 at 20. That is because none of the "conditions" at issue involve or presuppose any transfer of authority to prevent lease activities out of BOEM's hands, which was not the case with the leases in *Peterson* and *Conner*.

Peterson involved an oil and gas leasing program for certain National Forests, administered by the United States Forest Service and Department of the Interior ("Department"). 717 F.2d at 1410. The leasing program divided lands into those designated as "highly environmentally sensitive" and "non-highly environmentally sensitive." *Id.* Leases contained either a "No Surface Occupancy Stipulation (NSO Stipulation)"—preventing any surface activities without departmental approval—or stipulations representing "reasonable," "mitigating" conditions on drilling and other activities, but with no ability to bar those activities entirely. *Id.* at 1412, 1414. The D.C. Circuit concluded that the Department had failed to comply with NEPA by neglecting to conduct a full EIS before issuing leases that relinquished the authority to prevent all development. 717 F.2d at 1414. Critical to the Circuit's reasoning was that under the terms of the leases without NSO Stipulations, "the government could not *deny* an application for a permit to drill, but could only enforce the lease stipulations to control and/or mitigate any environmental damage which result[s] from the drilling." *Id.* at 1414 & n.7 (emphasis in original).

Conner involved the same legal issue in virtually identical factual circumstances. 848 F.2d at 1444–46 (describing NEPA challenge to leasing program that issued NSO or non-NSO oil and gas leases in forest land). Citing *Peterson*, the Ninth Circuit concluded that issuing non-NSO oil and gas leases effectively traded the authority to *preclude* all activity for the authority to *regulate* that activity, and such a trade required an EIS. *See id.* at 1450 (emphasis added).[5]

In this case, the criteria at issue do not contemplate trading preclusion authority for regulatory authority. The criteria do not alter the fact that Statoil must submit Site Assessment and Construction and Operations Plans before starting development, or that BOEM retains the authority to prevent any activity in the wind farm area by rejecting any Site Assessment or Constructions and Operations Plan that Statoil submits. The criteria stem from BOEM's commitment to "NEPA's goal of insuring that federal agencies infuse in project planning a thorough consideration of environmental values," *id.* at 1451, and ensuring that NEPA-related preclusion authority is exercised according to due process and for NEPA-related reasons. Accordingly, the presence of these "conditions" does not transform the lease into an irretrievable commitment of resources.[6]

Plaintiffs also contend that their NEPA claims are ripe because the lease is the final word "for the most critical stage of the leasing process—the siting of development," ECF No. 48 at 14, and therefore constitutes an irretrievable commitment of resources. But this contention

[5] Although these cases do not address ripeness *per se*, their analysis applies here because an agency's irretrievable commitment of resources also triggers the obligation to conduct an EIS. *See* 848 F.2d at 1450; *CBD*, 563 F.3d at 480.

[6] Plaintiffs also contend that 30 C.F.R. § 585.628(f)(2) constitutes a "condition" on BOEM's right to absolutely preclude development activities, because it indicates that BOEM will give reasons for any disapproval of a Construction and Operations Plan and allow the lessee to resubmit without the identified defects. *Id.* However, as with the other criteria described above, Section 585.628(f)(2) does not appear to require BOEM to relinquish authority to preclude all activity within the leased area. Though the provision does grant the lessee an opportunity to cure any defects in the Plan, it does not confer any right to engage in the equivalent of surface disturbing activities, which still require approval from BOEM.

misrepresents the nature of the lease, which makes no promises other than giving the lessee the exclusive right to survey the area and submit a proposal. *See* NYAR-0046754, 0046760. Indeed, at least part of the purpose of conducting site characterization in the leased area is to determine whether the site is suitable for the proposed purpose. NYAR-0074262 ("After lease issuance, a lessee would conduct surveys and, if authorized to do so pursuant to an approved SAP, install meteorological measurement devices to characterize the site's environmental and socioeconomic resources and conditions and to assess the wind resources in the proposed lease area. A lessee would collect this information to determine whether the site is suitable for commercial development . . . ."). Against this background, the lease sale does not represent the final word on anything, nor does it commit any resources, even putting aside the question of whether it does so irretrievably.[7]

[7] Plaintiffs also note in passing that several of the cases addressing ripeness in the context of multi-stage leasing programs identified lease issuance as the point when NEPA claims ripen. ECF No. 48 at 10–11 & n.8; *see also, e.g.*, *CBD*, 563 F.3d at 480 (identifying specific lease sales as point of irreversible and irretrievable commitment). But this interpretation is misleading. *Wyoming Outdoor Council II*—the case upon which more recent cases such as *CBD* and *CSE* relied—described lease issuance as the critical stage for ripeness only as part of an explicit application of the *Peterson* rule. *See Wyoming Outdoor Council II*, 165 F.3d at 49. As this court has already discussed, the heart of the *Peterson* rule is the question of whether the agency retains the authority to preclude all surface disturbing activity. *Peterson*, 717 F.2d at 1414-15; *see also Wyoming Outdoor Council v. Bosworth*, 284 F. Supp. 2d 81, 92–93 (D.D.C. 2003) (noting that *Wyoming II* "based its irreversible commitment finding on the fact that the agency had chosen not to retain its authority to preclude all surface-disturbing activities after lease issuance," that the NEPA claim in the case before it was unripe where lease issuance did not involve relinquishment of preclusive authority or resolution of development contingency, and that ripeness is a "flexible" doctrine, not "a *per se* rule"). In *Wyoming II*, *CBD*, and *CSE*, the agency could not have relinquished its preclusive authority because it had yet to take any specific action under the leasing program. *See CBD*, 563 F.3d at 480 (noting that agency "had only approved the Leasing Program at issue," and that "[n]o lease-sales had yet occurred"); *CSE*, 779 F.3d at 599–600 (same); *Wyo. Outdoor Council II*, 165 F.3d at 49–50 (same). In *Peterson* and *Conner*, ripeness turned on lease issuance because the agency relinquished authority by the terms of the leases. *Peterson*, 717 F.2d at 1414 (noting that since the "decision to allow surface disturbing activities" was made "at the *leasing stage*," NEPA obligations attached at that point) (emphasis in original). But in this case—as in *Bosworth*—the lease does not relinquish preclusive authority. *See* 284 F. Supp. 2d at 93.

For these reasons, Plaintiffs' NEPA claims are not ripe.

C. OCSLA Violations

Plaintiffs allege that Defendants violated OCSLA by (1) failing to properly consider and provide for fishing, safety, conservation of natural resources, and navigation during both the site selection and the lease issuance process; and (2) adopting a set of regulations that on their face exceed the authority granted by OCSLA. ECF No. 39 at 47, 51–52. Statoil responds that (1) the regulations BOEM adopted were a reasonable interpretation of OCSLA's congressional mandate, ECF No. 40 at 17–19; (2) BOEM considered all relevant OCSLA factors at all relevant stages—through stakeholder meetings and public commentary—before reasonably deciding to adopt some changes and defer consideration of certain potential risks, ECF No. 40 at 19–22; and (3) BOEM's analysis of potential alternatives to development of the wind farm area was adequate. ECF No. 40 at 22–28. BOEM echoes these contentions and further argues that Plaintiffs' OCSLA claims are procedurally barred by their failure to observe the statutorily mandated sixty-day waiting period. ECF No. 42 at 28. The court agrees that Plaintiffs' OCSLA claims are barred for noncompliance with the statute.

OCSLA establishes a private right of action for persons "having a valid legal interest which is or may be adversely affected" by an agency's violation of OCSLA or its associated regulations. 43 U.S.C. § 1349(a)(1). OCSLA also provides that "[e]xcept as provided in paragraph (3) of this subsection, no action may be commenced . . . prior to sixty days after the plaintiff has given notice of the alleged violation, in writing, under oath, to the Secretary." 43 U.S.C. § 1349(a)(2)(A). Compliance with the sixty-day notice period is mandatory, although Section 1349(a)(3) provides an exception when "the alleged violation constitutes an imminent threat to the public health or safety or would immediately affect a legal interest of the plaintiff."

Id. § 1349(a)(3). *See Hallstrom v. Tillamook County*, 493 U.S. 20, 23 n.1, 26, 31 (1989) (holding that nearly identical sixty-day notice provision in Resource Conservation and Recovery Act represented a mandatory precondition to suit and expressly noting similarity to 43 U.S.C. § 1349(a)(2)); *Duke Energy Field Servs. Assets, LLC v. Fed. Energy Regulatory Comm'n*, 150 F. Supp. 2d 150, 156 (D.D.C. 2001) ("[T]he citizen suit provision in the instant [OCSLA] case plainly bars *all* cases which do not comply with the provision . . . .") (emphasis in original). Thus, unless they face an imminent threat to public health or safety or some immediate effect on a legal interest, plaintiffs must comply with the sixty-day notice provision. *Hornbeck Offshore Servs., LLC v. Salazar*, 696 F. Supp. 2d 627, 633 (E.D. La. 2010) (citing *Duke Energy*, 150 F. Supp. 2d at 156).

Plaintiffs advance two arguments in support of their compliance with OCSLA's pre-suit requirements: (1) since the lease auction occurred only forty-five days after the Final Sale Notice was published, they did not have sixty days to notify Defendants of their claims before the Final Sale and should therefore be excused from compliance with the sixty-day requirement, ECF No. 48 at 23–24; and (2) their claims fall within Section 1349(a)(3)'s exception because the lease "immediately affect[s] a legal interest of the plaintiff" insofar as it grants Statoil a property interest, along with "attendant rights to condition the access of others," and firmly determines the boundaries of the wind farm area. ECF No. 48 at 24.

Neither of these arguments is persuasive. The fact that there were fewer than sixty days between publication of the Final Sale Notice and the lease sale does not excuse Plaintiffs from compliance with the sixty-day notice period. They have identified no provision of the statute that requires BOEM to schedule its lease sales to accommodate potential claimants, and the plain language of Section 1349(a)(1) contains no ambiguity that is susceptible to such an interpretation. Rather, as in *Hallstrom*, Plaintiffs essentially argue that the statute "should be given a flexible or pragmatic construction" that would accommodate their view of the equities. 493 U.S. at 26. The court declines to engage in such an exercise. Congress has already addressed this situation in Section 1349(a)(1), which contains "explicit and unambiguous" language that "must be given palpable effect." *Duke Energy*, 150 F. Supp. 2d at 155; *see also Hallstrom*, 493 U.S. at 27 (noting in analogous context that "[g]iving full effect to the words of the statute preserves the compromise struck by Congress"). Against this background, the court sees no justification for adopting an interpretation of Section 1349(a)(1) that "flatly contradicts the language of the statute." *Hallstrom*, 493 U.S. at 27.

Moreover, Congress provided for situations in which the rigid sixty-day notice requirement of Section 1349(a)(1) would create unacceptable hardship by carving out an exception for exigent circumstances. *See* 43 U.S.C. § 1349(a)(3). To be eligible for that exception, a plaintiff must (1) provide notice of the alleged violation, and (2) demonstrate an imminent threat to public health or safety or that the alleged violation would immediately affect a plaintiff's legal interests. 43 U.S.C. § 1349(a)(3). While Plaintiffs in this case provided notice, and even signaled their intention to invoke the provision in their notice letter, ECF No. 3-1 at 148, they have failed to demonstrate any imminent threat to public health or safety, or any immediate effect on their legal interests that would authorize their claim under Section 1349(a)(3). As noted earlier, the lease has no immediate effect except to grant Statoil the right to submit an Site Assessment Plan and, potentially, a Construction and Operations Plan. Nothing in the lease authorizes Statoil to exclude others from the leased area or condition access to that area, and to the extent that the lease grants a type of property interest to Statoil, this grant fails to satisfy Section 1349(a)(3), which concerns the effect on a plaintiff's legal interest. *See* 43 U.S.C. § 1349(a)(3).

This case therefore differs from those in which the requirements of Section 1349(a)(3) were met. *See Chevron, U.S.A., Inc. v. FERC*, 193 F. Supp. 2d 54, 64–65 (D.D.C. 2002) (finding Section 1349(a)(3) satisfied where agency intended to "disclose the plaintiffs' commercially sensitive information within five days," which "would detrimentally affect the plaintiffs' legal interest in preserving the confidentiality of the information and in maintaining its suits [challenging disclosure orders]"); *Hornbeck*, 696 F. Supp. 2d at 636 n.8 (noting in alternative that immediate loss of business relationships satisfied requirements of Section 1349(a)(3)). Here, compliance with the sixty-day notice period would not have caused any immediate injury or loss of a legal right. Accordingly, Plaintiffs cannot invoke Section 1349(a)(3), and their OCSLA claims are barred for failure to comply with the terms of Section 1349(a)(1).

IV. CONCLUSION

For the foregoing reasons, the court hereby concludes that Defendants' Motion for Summary Judgment will be GRANTED, Plaintiffs' Motion for Summary Judgment will be DENIED, and Defendant-Intervenor's Motion will be DENIED AS MOOT. An appropriate order accompanies this memorandum opinion.

Date: September 30, 2018

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TANYA S. CHUTKAN
United States District Judge

UNITED STATES DISTRICT COURT
FOR THE DISTRICT OF COLUMBIA

FISHERIES SURVIVAL FUND, *et al.*, Plaintiffs,	
v.	Case No. 16-cv-2409 (TSC)
SALLY JEWELL, *et al.*, Defendants.	

ORDER

For the reasons set forth in the accompanying Memorandum Opinion, Defendants' Motion for Summary Judgment [42] is hereby GRANTED. Plaintiffs' Motion for Summary Judgment [39] is hereby DENIED. Defendant-Intervenor's Motion [40] is hereby DENIED AS MOOT.

This is a final appealable order.

Date: September 30, 2018

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TANYA S. CHUTKAN
United States District Judge

Attachment 12

Interconnection Evaluation Study

REDACTED

equinor

Attachment 13

Interconnection Information

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Attachment 14

Interconnection One-Line Diagram

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Attachment 15

System Reliability Impact Study

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Attachment 16

Permitting Matrix

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Attachment 17

Stakeholder Tracking Matrix

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Attachment 18

Site Assessment Plan

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Site Assessment Plan
Empire Wind Offshore Wind Farm Project

Prepared for:

equinor

Equinor Wind US, LLC
120 Long Ridge Road #3E01
Stamford, Connecticut 06902

Prepared by:

TETRA TECH

160 Federal Street, 3rd Floor
Boston, Massachusetts 02110

Submitted June 2018; Amended July 2018, August 2018, and October 2018

TABLE OF CONTENTS

TABLES

FIGURES

APPENDICES

Appendix A	Permits and Consultations
Appendix B	Equipment Specifications and Modelling Results (Contains Privileged or Confidential Information - Provided Under Separate Cover)
Appendix C	Site Characterization Report (Contains Privileged or Confidential Information - Provided Under Separate Cover)
Appendix D	Marine Archaeological Resource Assessment Report in Support of the Empire Wind Offshore Wind Farm (Contains Privileged or Confidential Information - Provided Under Separate Cover)
Appendix E	Benthic Assessment (Contains Privileged or Confidential Information - Provided Under Separate Cover)
Appendix F	Health and Safety Plan (Contains Privileged or Confidential Information - Provided Under Separate Cover)
Appendix G	Vessel Specifications
Appendix H	Air Quality Emissions Calculations

ACRONYMS AND ABBREVIATIONS

APE	Area of Potential Effect
BMPs	best management practices
BOEM	Bureau of Ocean Energy Management
CD	Coastal Zone Consistency Determination
CFR	Code of Federal Regulations
CMECS	Coastal and Marine Ecological Classification Standard
CM/CT Mooring	a subsurface current meter mooring equipped with three CM-04 Acoustic Current Meters and 3 Seabird SBE37 conductivity and temperature CT loggers
CO	carbon monoxide
COP	Construction and Operations Plan
CVA	Certified Verification Agent
DoD	Department of Defense
EA	See: New York Offshore EA
EPA	United States Environmental Protection Agency
ESA	Endangered Species Act of 1973
FCP	Fisheries Communication Plan
FLiDAR	Floating Light Detection and Ranging
ft	feet
GHG	greenhouse gas
ha	hectare
HAP	hazardous air pollutant
HRG	High Resolution Geophysical
HSE	health, safety, and environmental
Installation Areas	Official Protraction Diagram New York NK18-12, Blocks 6657 and 6760
kg	kilogram
km	kilometer
knot	nautical miles per hour
lb	pound
Lease	Commercial Lease of Submerged Lands for Renewable Energy Development on the Outer Continental Shelf (OCS-A 0512)
LiDAR	light detection and ranging
m	meter
mm	millimeter
Metocean Facilities	Two RPS FLiDAR Buoys, an RPS Wave and Met Buoy, and a CM/CT Mooring.
MLLW	mean lower low water
MMPA	Marine Mammal Protection Act of 1972
MPDC	Mandatory Project Design Criteria
NAAQS	National Ambient Air Quality Standard

NHPA	National Historic Preservation Act of 1966
NMFS	National Oceanic and Atmospheric Administration, National Marine Fisheries Service
NOAA	National Oceanic and Atmospheric Administration
NO_x	nitrogen oxides
NTL	Notice to Lessees
O_3	ozone
Offshore New York EA	BOEM's 2016 Commercial Wind Lease Issuance and Site Assessment Activities on the Atlantic Outer Continental Shelf Offshore New York
OCS	Outer Continental Shelf
PATON	Private Aids to Navigation
PM_{10}	particulate matter less than 10 microns in diameter
$PM_{2.5}$	particulate matter less than 2.5 microns in diameter
PSO	Protected Species Observer
RPS	RPS Group, Inc.
SAP	Site Assessment Plan
SO_2	sulfur dioxide
SOC	Standard Operating Conditions
U.S.C.	United States Code
USCG	United States Coast Guard
USFF	United States Fleet Forces
VOC	volatile organic compounds
WEA	Wind Energy Area

1. INTRODUCTION

Equinor Wind US LLC has prepared this Site Assessment Plan (SAP) in support of the installation and operation of two floating light detection and ranging buoys (FLiDARs), one metocean buoy, and one subsurface current meter mooring to be located within Official Protraction Diagram New York NK18-12, Blocks 6657 and 6760 (Installation Areas; see Figure 1-1). Equinor Wind US LLC has selected the RPS Group Inc. (RPS) to provide two FLiDAR Buoys, an RPS Wave and Met Buoy, and a subsurface current meter mooring equipped with three CM-04 Acoustic Current Meters and three Seabird SBE37 conductivity and temperature CT loggers (CM/CT Mooring [collectively referred to as the Metocean Facilities]) as the proposed meteorological and metocean data collection technologies, respectively. Although other suppliers and metocean systems are feasible and impacts can be mitigated to within acceptable limits, the selected Metocean Facilities and concept are deemed to have the following mitigating benefits over traditional concepts that include:

- Moored floating systems as opposed to traditional fixed Meteorological Masts, removing the need for percussion pile driving and jack up operations;
- Buoy power systems with 100% renewable charging sources, avoiding backup generators and subsequent emissions and potential for fuel spills;
- Power supply, data storage and mooring integrity that reduces service visit frequency and disturbance to marine life and other users of the marine environment;
- Mooring designs that are fully recoverable, using techniques that reduce the footprint of anchors and remove dynamic heavy chains in contact with the seabed; and
- Subsurface acoustic mooring recovery systems that reduce the risk of entanglement of marine life.

The Installation Areas are contained within the Lease Area[1] as defined under the Commercial Lease of Submerged Lands for Renewable Energy Development on the Outer Continental Shelf (OCS-A 0512) (Lease) taking into consideration the required buffer of 1NM from Traffic Separation Schemes (TSS). The Lease was issued to Statoil Wind US on March 10, 2017, with an effective date of April 1, 2017. On May 16, 2018, Statoil Wind US LLC changed its name to Equinor Wind US LLC, and is in the process of updating the name with BOEM in accordance with the agency's requirements. While this name change is still pending with BOEM, the SAP and associated attachments refer to Equinor Wind US LLC, based upon an expectation that the Lease and associated documentation will be updated.

On October 10, 2017, Statoil Wind US LLC requested a 12-month extension of the Preliminary Term of the Lease from the Bureau of Ocean Energy Management (BOEM), which was approved on November 13, 2017, extending the Preliminary Term from April 1, 2018 to April 1, 2019 (see Appendix A).

This SAP has been prepared in accordance with 30 Code of Federal Regulations (CFR) §§ 585.606, 610, and 611 (see Table 1-1), the Guidelines for Information Requirements for a Renewable Energy SAP issued by BOEM on February 24, 2016, and the stipulations of the Lease (see Table 2-2).

[1] The Lease Area is defined by *Addendum A of BOEM Lease No. OCS-A 0512, Section II. Description of the Lease Area*. The total acreage of the Lease Area is approximately 79,350 acres. The Lease Area is depicted in its entirety on Figure 1-1 of this SAP.

Prior to installation of the Metocean Facilities, Equinor Wind US LLC will obtain all required permits and approvals from various jurisdictional agencies as identified in Table 1-2. Equinor Wind US LLC will include copies of the final agency authorizations as part of the SAP (see Appendix A). Copies of agency authorizations will also be provided to BOEM prior to the initiation of SAP activities to begin no earlier than September 1, 2018. All installation, operation, and decommissioning activities will be conducted in compliance with any additional requirements stipulated in the final permits to be issued by other regulatory agencies.

The Metocean Facilities described in this SAP will collect wind resource and metocean data to support development of the Lease Area.

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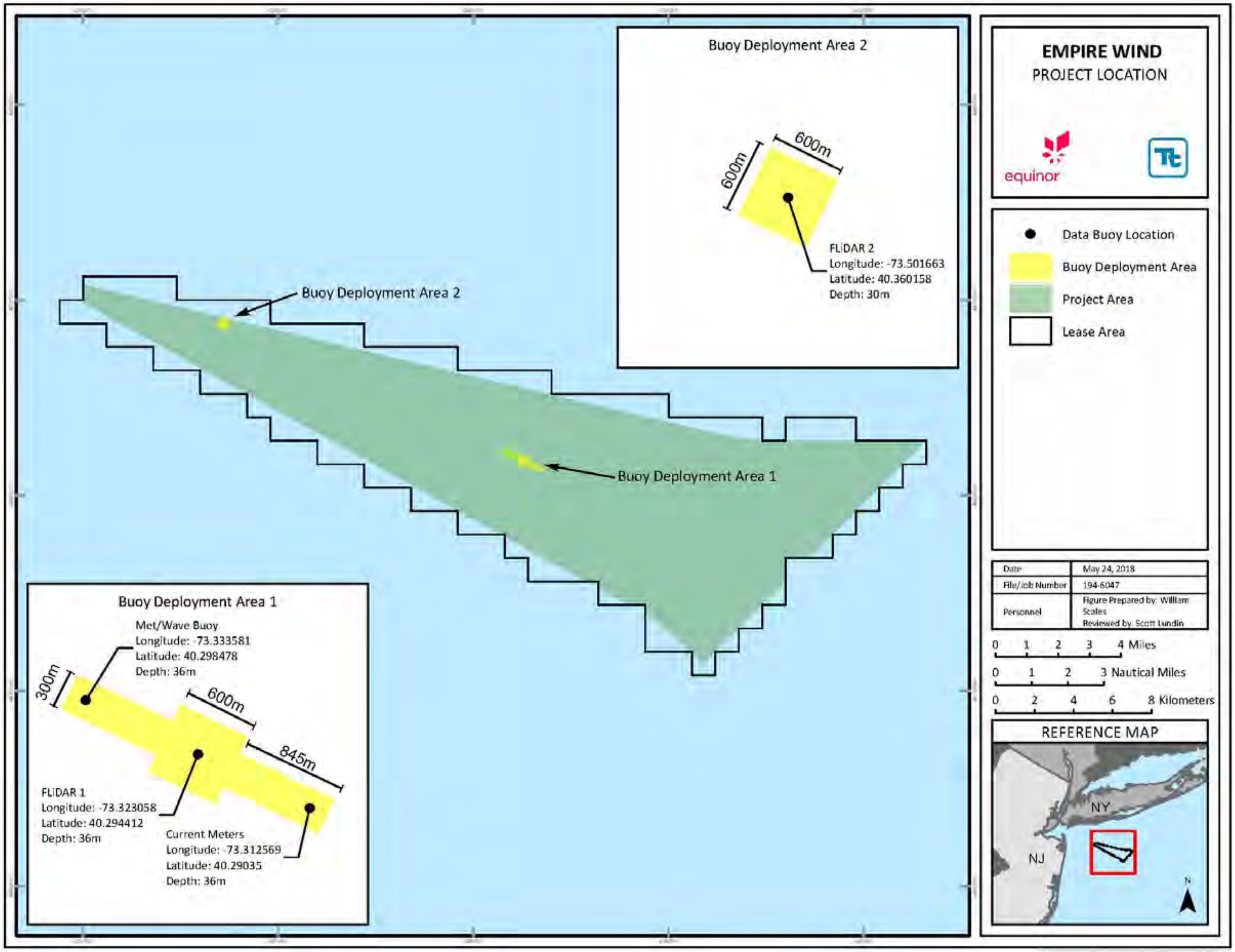

Figure 1-1 Site Assessment Plan Buoy Deployment Areas

1.1 Authorized Representative and Designated Operator

As the lease holder, Equinor Wind US LLC, by default, is also the lease operator. Equinor Wind US LLC proposes to have RPS serve as the contracted operator for the Metocean Facilities. The contact information for RPS's Authorized Representative is as follows:

Name of Authorized Representative	Kevin Redman
Title	Sr. Oceanographer / Regional Manager
Phone Number	+1 206 526 5622 office; +1 206 819 4966 cell
Email	Kevin.Redman@RPSGroup.com
Address	4608 Union Bay Pl. N.E. Seattle, WA 98372

1.2 Certified Verification Agent Waiver Request

Pursuant to 30 CFR § 585.610(a)(9), BOEM may require a Certified Verification Agent (CVA) to certify to BOEM that the Metocean Facilities are designed to withstand the environmental and functional load conditions for the intended life of the Metocean Facilities in the Installation Areas. Equinor Wind US LLC requests a waiver of the CVA requirement per 30 CFR § 585.705(c) because the selected Metocean Facilities are a commercially available technology that have been successfully deployed on many occasions in similar conditions by the selected supplier. Equinor Wind US LLC has had a Measurements Engineer from RPS perform the duties similar to those of a CVA. The Measurements Engineer will also inspect the equipment prior to installation, witness the installation, and prepare an installation report as described in Section 0.

Table 1-1 Site Assessment Plan Requirements for Commercial Leases Pursuant to §585.105(a), 606(a), 610(a) and (b), and 611(a) and (b)

Requirement	Compliance Statement
§ 585.105(a)	
1) The design of the environmental monitoring buoy and conduct of planned activities ensures safety and will not cause undue harm or damage to natural resources and will take measures to prevent unauthorized discharge of pollutants into the offshore environment.	Equinor Wind US LLC will comply with this requirement, as evidenced in this SAP.
§ 585.606(a)	
1) The Project will conform to all applicable laws, regulations, and lease provisions.	Equinor Wind US LLC will comply with this requirement. See Table 1-2, Table 1-3, Table 2-1, Table 2-2, and Appendix A.
2) The Project will be safe.	Equinor Wind US LLC will comply with this requirement. Specifically, see Section 4.8.
3) The Project will not unreasonably interfere with other uses of the Outer Continental Shelf (OCS), including national security or defense.	Equinor Wind US LLC will comply with this requirement. See Table 2-2 for specific activities to ensure compliance.
4) The Project will not cause undue harm or damage to natural resources; life; property; the marine, coastal, or human environment; or historical or archeological resources.	See Section 0 for an analysis of site characteristics and for avoidance and mitigation measures.
5) The Project will use best available and safest technology.	Equinor Wind US LLC will comply with this requirement. See Section 3.1 and Appendix B for a description and technical specifications on the selected Metocean Facilities.
6) The Project will use best management practices.	Equinor Wind US LLC will comply with this requirement. Best management practices are described in Table 1-3, Sections 0, 0, 0, and 0.
7) The Project will use properly trained personnel.	Equinor Wind US LLC will ensure that all personnel meet the company's standard technical as well as health, safety, and environmental (HSE) standards for the work being conducted.

Table 1-1 Site Assessment Plan Requirements for Commercial Leases Pursuant to §585.105(a), 606(a), 610(a) and (b), and 611(a) and (b)

Requirement	Compliance Statement
§ 585.610(a)	
1) Contact Information	Martin Goff Environmental & Permitting Manager +1 202 813 7444 MGOF@equinor.com 120 Long Ridge Road, Suite 3EO1, Stamford, CT 06902
2) Site assessment concept	Meteorological, metocean, and biological data collection using two RPS FLiDAR Buoys, one RPS Wave and Met Buoy, and one RPS Current Meter Mooring consisting of 3 CM-04 Acoustic Current Meters and 3 Seabird SBE37 conductivity and temperature CT loggers.
3) Designation of operator	Not applicable. See Section 1.1
4) Commercial lease stipulations and compliance	See Table 2-2.
5) A location plat	See Figure 1-1.
6) General structural and project design, fabrication and installation information	See Sections 0, 0, and 0.
7) Deployment activities	See Section 0.
8) Measures for avoiding, minimizing, reducing, eliminating, and monitoring environmental impacts	This SAP has been prepared in accordance with the Commercial Wind Lease Issuance and Revised Environmental Assessment for Commercial Wind Lease Issuance and Site Assessment Activities on the Atlantic Outer Continental Shelf Offshore New York, and Stipulations in the Commercial Lease. Specific efforts to avoid, minimize, reduce, eliminate, or monitor environmental impacts can be found in Sections 0 and 0. Conformance with the Offshore New York EA is detailed in Section 2.
9) Certified Verification Agent nomination	Not applicable. See Section 1.2.
10) Reference information	See Section 0.
11) Decommissioning and site clearance procedures	See Section 0.
12) Air quality information	See Section 7.8 and Appendix H.
13) A listing of all federal, state, and local authorizations or approvals required to conduct site assessment activities on your lease	See Table 1-2.
14) A list of agencies and persons with whom you have communicated, or with whom you will communicate, regarding potential impacts associated with your proposed activities	See Appendix A.
15) Financial assurance information	Activities and facilities proposed herein will be covered by an appropriate bond or other approved security.
§585.610(b)	
Geotechnical	
(i) A description of all relevant seabed and engineering data and information to allow for the design of the foundation for that facility	Section 7.1, Appendix C
Shallow Hazards	
(i) Shallow faults;	Section 7.1
(ii) Gas seeps or shallow gas;	Section 7.1
(iii) Slump blocks or slump sediments;	Section 7.1
(iv) Hydrates; or	Section 7.1
(v) Ice scour of seabed sediments.	Section 7.1
Archaeological Resources	
(i) A description of the results and data from the archaeological survey;	Section 7.1, Appendix D

Table 1-1 Site Assessment Plan Requirements for Commercial Leases Pursuant to §585.105(a), 606(a), 610(a) and (b), and 611(a) and (b)

Requirement	Compliance Statement
(ii) A description of the historic and prehistoric archaeological resources, as required by the National Historic Preservation Act of 1966 (NHPA), as amended.	Section 7.1, Appendix D
Geological Survey	
(i) Seismic activity at your proposed site;	Section 7.1
(ii) Fault zones;	Section 7.1
(iii) The possibility and effects of seabed subsidence; and	Section 7.1
(iv) The extent and geometry of faulting attenuation effects of geologic conditions near your site.	Section 7.1
Biological	
(i) Live bottoms	Sections 7.1 and 7.4
(ii) Hard bottoms	Sections 7.1 and 7.4
(iii) Topographic features; and	Sections 7.1 and 7.4
(iv) Surveys of other marine resources such as fish populations (including migratory populations), marine mammals, sea turtles, and sea birds.	Sections 7.1 and 7.4
§ 585.611(a) and (b) Requirements	
Hazard information	Section 7.1
Water quality	Section 7.7
Biological resources	
(i) Benthic communities	Section 7.3
(ii) Marine mammals	Section 7.5
(iii) Sea turtles	Section 7.5
(iv) Coastal and marine birds	Section 7.6
(v) Fish and shellfish	Sections 7.3 and 7.4
(vi) plankton and seagrasses, and	Sections 7.3
(vii) plant life	Sections 7.3
Threatened or endangered species	Sections 7.5 and 7.6
Sensitive biological resources or habitats	Sections 7.3
Archaeological resources	Section 7.1, Appendix D
Socioeconomic resources	Section 7.9
Coastal and marine uses	Section 7.10
Consistency Certification	Table 1-2
Other Resources, conditions, and activities	Not Applicable.

Table 1-2 Permit Matrix

Permitting Agency	Applicable Permit or Approval	Statutory Basis	Regulations	Applicant Requirements
National Oceanic and Atmospheric Administration (NOAA), National Marine Fisheries Service (NMFS)	Endangered Species Act (ESA) Section 7 Consultation	16 United States Code (U.S.C.) 1536	50 CFR 402	These consultations were completed prior to the issuance of the Lease. However, pursuant to its obligations under Section 7 of the ESA, BOEM is required to consult with NMFS prior to approval of any site assessment activities that may affect ESA-listed species that occur within the Lease Area.
	Magnuson-Stevens Fishery Conservation and Management Act Section 305(b) Consultation	16 U.S.C. 1801	50 CFR 600	No action required. BOEM will consult with NMFS to complete the essential fish habitat assessment and determination based on details provided herein.
	Incidental Take Authorization	Marine Mammal Protection Act of 1972 (MMPA)	16 U.S.C. §§ 1361 *et seq.*	No action required. As detailed in Sections 0, 0, and 0, installation, operation, and decommissioning of the Metocean Facilities will not result in the harassment of marine mammals protected under the MMPA. In addition, as demonstrated in Section 2.2, Equinor Wind US LLC will comply with Lease stipulations. The Lease stipulations are based on the Standard Operating Conditions (SOCs) included in Appendix B of the Offshore New York EA which are consistent with Incidental Take Statement of the NMFS Biological Opinion issued in March 10, 2013 (Revised April 10, 2013). Additionally, Equinor Wind US LLC received an Incidental Harassment Authorization to support its geophysical and preliminary geotechnical survey campaign on April 24, 2018.
U.S. Army Corps of Engineers, New York District	Nationwide Permit 5 – Scientific Measurement Devices	Clean Water Act 33 U.S.C. 134	33 CFR 320 *et seq.*	Equinor Wind US LLC confirmed with the United States Army Corps of Engineers on March 15, 2018 that the installation, operation, and decommissioning of the Metocean Facilities are authorized and in conformance with the terms of Nationwide Permit # 5.
United States Coast Guard (USCG)	Approval for Private Aids to Navigation	14 U.S.C. 81	33 CFR Part 66	Equinor Wind US LLC will submit an application to the USCG for a Private Aids to Navigation (PATON) prior to the installation of the Metocean Facilities. Equinor Wind US LLC will submit a copy of the approved PATON to BOEM prior to buoy deployment.
U.S. Department of Interior, BOEM	NHPA Section 106 Consultation	NHPA 16 U.S.C. 470	36 CFR Part 60, Part 800	No action required. BOEM has executed a Programmatic Agreement that establishes procedures for consultations for site assessment activities in the New York Wind Energy Area (WEA) and under NHPA Stipulations for the identification and protection of cultural resources are included in the Lease.
U.S. Fish and Wildlife Service	Endangered Species Act Section 7 Consultation	16 U.S.C. 1536	50 CFR 402	No action required. These consultations were completed prior to the issuance of the Lease.
New York Department of State, Division of Coastal Resources	Coastal Management Program Consistency Certification	Coastal Zone Management Act	15 CFR 930 Subpart C	No action required. A final Coastal Zone Consistency Determination (CD) was issued by BOEM for SAP activities in the New York WEA in June 2016. In August 2016, New Jersey provided conditional concurrence and New York provided concurrence with BOEM's CD. See Appendix A for a copy of the concurrence letters from the New York State Department of State and New Jersey Department of Environmental Protection.

1.3 Best Management Practices

Best management practices (BMPs) are described in Sections 1.3, 0, and 0. Equinor Wind US LLC will use its standard internal project execution structure to manage activities described in the SAP. As stated in Section 4.8, SAP activities will be supported by a detailed HSE Plan, which is included as Appendix F.

In addition, Equinor Wind US LLC will use many of the BMPs identified in the *Guidelines for Information Requirements for a Renewable Energy Site Assessment Plan* (BOEM 2016a) and *Establishment of an OCS Alternative Energy and Alternate Use Program*, Record of Decision, December 2007 (BOEM 2007). See Table 1-3 for a summary of these BMPs (numbering in Table 1-3 corresponds to the format of the noted SAP Guidelines).

Table 1-3 Best Management Practices

Best Management Practices	Location in SAP Document
1. Minimize the area disturbed by installation	Section 3.3
2. Contact and consult with the appropriate affected Federal, state, and local agencies early in the planning process	Table 2-2 and Section 4.1
5. Conduct seafloor surveys to ensure that the project is sighted to avoid or minimize impacts associated with seafloor instability and other hazards	Section 3.3
7. Avoid known sensitive seafloor habitats	Section 7.3
8. Avoid anchoring on sensitive seafloor habitats	Section 7.3
10. Routine inspection of the buoys to monitor scouring and ensure structural integrity	Section 5.2
11. Avoid the use of explosives that may impact fish or benthic organisms	No explosives will be used for activities proposed in the SAP.
14, 15, 16, 17, and 21 related to minimizing/avoiding vessel impacts to marine mammals and sea turtles.	Section 4.4
18. Use existing data to identify important, sensitive, and unique marine habitats in the vicinity of the project and design the deployment to avoid adverse impacts to these habitats	Section 0
19. Minimize construction activities in areas containing anadromous fish during migration periods	Section 7.4
20. Minimize seafloor disturbance during installation of the buoys	Section 4.1
25. Minimize perching opportunities	Section 7.6
27. Comply with USCG lighting and marking requirements while using lighting technology that minimizes impacts to avian species	Table 1-2 and Section 7.6
31 and 32. Minimize potential conflicts with commercial and recreational fishing interests by working with commercial/recreational fishing entities and reviewing planned activities with potentially affected parties	Section 7.4
33. Use practices and operating procedures that reduce the likelihood of vessel accidents and fuel spills	Section 0
34. Avoid impacts to the commercial fishing industry by marking the buoy(s) with USCG-approved marking and lighting to ensure safe vessel operation	Table 1-2 and Section 7.9
36. Avoid hard-bottom habitats, including seagrass communities and kelp beds	Section 7.3
50. Prepare an oil spill response plan	The Metocean Facilities will not require a backup generator or any other fuel dependent equipment. As such, no Oil Spill Response Plan or Oil Spill Response Measures will be required.

2. CONFORMITY WITH PRIOR BOEM ACTIONS REGARDING SAP ACTIVITIES

2.1 Offshore New York Environmental Assessment

On October 21, 2016, BOEM issued a Finding of No Significant Impact based on a comprehensive Environmental Assessment (referred to herein as the "Offshore New York EA") (BOEM 2016b). The Offshore New York EA analyzed the foreseeable consequences associated with issuing commercial leases within the New York WEA, which is inclusive of the Lease Area (Figure 1-1), as well as the site assessment activities including the installation of Metocean Facilities. The Metocean Facilities and proposed activities described herein are consistent with Section 3.2.2.2 of the Offshore New York EA, with the selected concept demonstrating lower impacts than some worst case, but acceptable concepts within the EA. Table 2-1 below provides a comparison of the information assessed in the Offshore New York EA and the relevant detail being proposed by Equinor Wind US LLC herein.

Table 2-1 Comparison of Offshore New York EA and SAP Elements

Project Component	Assessed in EA	Proposed in SAP	Summary
# of Buoys	Max 2 buoys per lease area and an additional small tethered buoy	2 RPS FLiDAR buoys, 1 RPS Wave and Met Buoy, 1 RPS Current Meter Mooring consisting of 3 CM-04 Acoustic Current Meters, and 3 Seabird SBE37 conductivity and temperature CT loggers.	The number of buoys proposed in this SAP are consistent with what was assessed in the EA.
Meteorological Buoy Specifications	Specific to hull type, discus-shaped (33 to 40 ft [10 to 12 m] in diameter), boat-shaped (20 ft (6 m), and spar buoys	RPS FLiDAR Buoy: 15.2 feet (ft, 4.6 meters [m]) diameter, weighing 9480 pounds (4.3 metric tons)	The Metocean Facilities proposed in this SAP are smaller and weigh less that what was assessed in the EA. The direct consequence is a reduction in the anchor requirement and subsequent footprint, and heavy mooring chain in dynamic contact with the seabed.
Meteorological Buoy Hull Type	NOMAD, COLOS	RPS FLiDAR: toroidal shape dodecagon steel hull with aluminum superstructure	Equinor Wind US LLC is proposing to use a hull type that is consistent with what was assessed in the EA.
Meteorological Buoy Height above ocean surface	30-40 ft (9-12 m)	RPS FLiDAR: 10.8 ft (3.3 m)	The Metocean Facilities proposed in this SAP are less than half the height that what was assessed in the EA
Meteorological Buoy Mooring Design	Specific to buoy type, all chain or a combination of chain, nylon, and buoyant polypropylene materials with 6,000- to 8,000-pound (2,721.5 to 3,628.7 kg) anchors, 6 ft^2 footprint, 370,260 ft^2 anchor sweep.	U-shaped mooring, with a combination of chain, polypropylene materials, wire rope, trawl floats, viny floats, amsteel rope dispensers and rubber cords with 2,645.5 lb and 661.4 lb (1,200 kg and 300 kg) steel chain clump weights or steel constructed wagon wheel weights no larger than 6 ft^2 resting on seafloor. Total area of mooring on seafloor, inclusive of both clump weights, chains, and wire ropes, is 67.8 ft^2 (6.3 m^2).	The weight and area of anchor resting on the sea floor is generally consistent with what was assessed in the EA. However, due to the mooring design, there is not expected to be an anchor sweep associated with the mooring proposed by Equinor Wind US LLC. Polypropylene rope will only be used where essential for mooring integrity and safe deployment/recovery operations and will be under tension, removing the risk of entanglement with marine life.
Small Tethered Buoy size	10 ft (3 m) in diameter or less	8.5 ft (2.6 m)	The proposed wave and met buoy is consistent with what was assessed in the EA.

Table 2-1 Comparison of Offshore New York EA and SAP Elements

Project Component	Assessed in EA	Proposed in SAP	Summary
Data Transmission	Transmit operational status and data to receiver on shore	Transmit operational status and data to shore via satellite or cellular telemetry	The data transmission protocols proposed by Equinor Wind US LLC are consistent with what was assessed in the EA.
Maintenance	Monthly or quarterly	Every 6 months	The maintenance schedule proposed in this SAP is less frequent than what was proposed in the EA, which is expected to result in lower impacts through reduced disturbance to marine life and other maritime users.
Installation and decommissioning process	Carried or towed by vessel, lower or place buoy over final location, drop mooring anchor, decommissioning is reverse of installation	Towed by vessel, deploy mooring system, lower anchor over final location, decommissioning is reverse of installation	The installation and decommissioning processes proposed by Equinor Wind US LLC are consistent with what was assessed in the EA.
Installation and decommissioning timeframe	Installation 1 day per buoy, Decommissioning 1 day per buoy	Installation up to seven days for all Metocean Facilities over three separate vessel trips including transit, decommissioning up to seven days for all Metocean Facilities, including transit. Subject to weather.	The installation and decommissioning timeframes proposed by Equinor Wind US LLC are consistent with what was assessed in the EA.
Power supply	Solar, Wind, Backup Diesel Generator	RPS FLiDAR: Solar and Wind RPS Wave and Met Buoy: Solar	The power supply proposed by Equinor Wind US LLC are consistent with what was assessed in the EA. However, unlike similar buoys that have been proposed and deployed on the Atlantic OCS, the RPS FLiDAR and Met/Wave Buoys do not have a backup diesel generator, and, as such, minimizes potential environmental impacts associated with fuel spills and emissions.

2.2 Lease OCS-A 0512

The Bureau of Ocean Energy Management (BOEM) identified mitigation measures or Standard Operating Conditions (SOC) in the Offshore New York EA for buoy installation, operation, and decommissioning. The SOCs were developed by BOEM in consultation with other federal and state agencies to reduce or eliminate the potential environmental risks to, or conflicts with, individual environmental and socioeconomic resources upon issuance of a commercial lease for site assessment and characterization activities. BOEM has issued the mitigation measures for Equinor Wind US LLC's lease-specific site characterization activities and site assessment activities in the Lease based upon these SOCs. Equinor Wind US LLC will implement these Lease specific measures as described in more detail in Table 2-2 and Section 0 of this SAP.

Table 2-2 Conformance with the Commercial Renewable Energy Lease Number OCS-A 0512 Stipulations

Addendum "C" Stipulation	Description	SAP Document
3 National Security and Military Operations		
3.2.4 Lessee Point-of-Contact for Evacuation/Suspension Notifications	The Lessee must inform the Lessor of the persons/offices to be notified to implement the terms of 3.2.2 and 3.2.3.	Martin Goff Environmental & Permitting Manager +1 (202) 813-7444 mgof@equinor.com 120 Long Ridge Road, Suite 3EO1 Stamford, CT 06902
3.2.5 Coordination with Command Headquarters	The Lessee must establish and maintain early contact and coordination with the appropriate command headquarters, in order to avoid or minimize the potential to conflict with and minimize the potential effects of conflicts with military operations.	Equinor Wind US LLC will establish contact with the United States Fleet Forces (USFF) N46 at 1562 Mitscher Avenue, Suite 250, in Norfolk, Virginia ([757]836-6206), as provided in the Commercial Lease.
3.3 Electromagnetic Emissions	Prior to entry into any designated defense operating area, warning area, or water test area for the purpose of commencing survey activities undertaken to support plan submittal, the Lessee must enter into an agreement with the commander of the appropriate command to coordinate the electromagnetic emissions associated with such survey activities. The Lessee must ensure that all electromagnetic emissions associated with such survey activities are controlled as directed by the commander of the appropriate command headquarters.	Equinor Wind US LLC will provide the frequencies the Metocean Facilities will use to transmit data to confirm electromagnetic emissions from the SAP activities will not conflict with military operations.
4 Standard Operating Conditions		
4.1.1 Briefing	Prior to the start of operations, the Lessee must hold a briefing to establish responsibilities of each involved party, define the chains of command, discuss communication procedures, provide an overview of monitoring procedures, and review operational procedures. This briefing must include all relevant personnel, crew members, and Protected Species Observers (PSOs). New personnel must be briefed as they join the work in progress.	See Section 4.3, Pre-Installation Briefing.
4.1.2	The Lessee must ensure that all vessel operators and crew members, including PSO's, are familiar with, and understand, the requirements specified in Addendum C.	See Section 4.3, Pre-Installation Briefing.
4.1.3	The Lessee must ensure that a copy of the standard operating conditions (Addendum C) is made available on every project-related vessel.	See Section 4.3, Pre-Installation Briefing.
4.1.4 Marine Trash and Debris Prevention	The Lessee must ensure that vessel operators, employees and contractors actively engaged in activities in support of plan (i.e., SAP and/or Construction and Operations Plan [COP]) submittal are briefed on marine trash and debris awareness and elimination, as described in the Bureau of Safety and Environmental Enforcement Notice to Lessees (NTL) No. 2015-G03 ("Marine Trash and Debris Awareness and Elimination") or any NTL that supersedes this NTL, except that the Lessor will not require the Lessee, vessel operators, employees and contractors to undergo formal training or post placards. The Lessee must ensure that vessel operator employees, and contractors are made aware of the environmental and socioeconomic impacts associated with marine trash and debris and their responsibilities for ensuring that trash and debris are not intentionally or accidentally discharged into the marine environment. The above-referenced NTL provides information the Lessee may use for this awareness briefing.	Equinor Wind US LLC will comply with this stipulation, except that formal training will not be conducted and placards will not be posted. Vessel Operators, employees, and contractors will be briefed prior to boarding the vessel.

Table 2-2 Conformance with the Commercial Renewable Energy Lease Number OCS-A 0512 Stipulations

Addendum "C" Stipulation	Description	SAP Document
4.1.5 Fisheries Communications Plan (FCP) and Fisheries Liaison	The Lessee must develop a publicly available FCP that describes the strategies that the Lessee intends to use for communicating with fisheries stakeholders prior to and during activities in support of the submission of a plan. The FCP must include the contact information for an individual retained by the Lessee as its primary point of contact with fisheries stakeholders (i.e. Fisheries Liaison). If the Lessee develops a project website, the FCP must be posted on the Lessee's project website. If the Lessee does not develop a project website, the FCP must be made available to the Lessor and the public upon request.	Equinor Wind US LLC will comply with this stipulation. A draft FCP has been posted to the project website, and a Fisheries Liaison has been selected.
4.2.1 Vessel Strike Avoidance Measures	The Lessee must ensure that all vessels conducting activities in support of the plan submittal, including those transiting to and from local ports and the lease area, comply with the vessel-strike avoidance measures specified in stipulations 4.2., except under extraordinary circumstances when complying with these requirements would put the safety of the vessel or crew at risk.	See Section 4.4, Protected Species Avoidance
4.3.6 No Impact without Approval	The Lessee must not knowingly impact a potential archaeological resource without the Lessor's prior approval.	See Section Archaeological Resources Archaeological Resources and Appendix D. Marine Archaeological Resource Assessment Report
4.3.7 Post-Review Discovery Clauses	If the Lessee, while conducting site characterization activities in support of a plan submittal, discovers a potential archaeological resource, such as the presence of a shipwreck (e.g., a sonar image or visual confirmation of an iron, steel, or wooden hull, wooden timbers, anchors, concentrations of historic objects, piles of ballast rock) or pre-contact archaeological site (e.g., stone tools, pottery) within the project area, the Lessee must:	Appendix D. Marine Archaeological Resource Assessment Report
4.3.7.1	Immediately halt seafloor/bottom-disturbing activities within the area of discovery;	Appendix D. Marine Archaeological Resource Assessment Report
4.3.7.2	Notify the Lessor within 24 hours of discovery;	Appendix D. Marine Archaeological Resource Assessment Report
4.3.7.3	Notify the Lessor in writing via report to the Lessor within 72 hours of its discovery;	Appendix D. Marine Archaeological Resource Assessment Report
4.3.7.4	Keep the location of the discovery confidential and take no action that may adversely affect the archaeological resource until the Lessor conducts an evaluation and instructs the applicant on how to proceed; and,	Appendix D. Marine Archaeological Resource Assessment Report
4.3.7.5	Conduct any additional investigations as directed by the Lessor to determine if the resource is eligible for listing in the National Register of Historic Places (30 CFR 585.802(b)). The Lessor will direct the Lessee to conduct such investigations if: (1) the site has been impacted by the Lessee's project activities; or (2) impacts to the site or to the area of potential effect cannot be avoided. If investigations indicate that the resource is potentially eligible for listing in the National Register of Historic Places, the Lessor will tell the Lessee how to protect the resource or how to mitigate adverse effects to the site. If the Lessor incurs costs in protecting the resource, under Section 110(g) of the National Historic Preservation Act, the Lessor may charge the Lessee reasonable costs for carrying out preservation responsibilities under the OCS Lands Act (30 CFR 585.802(c-d)).	Appendix D. Marine Archaeological Resource Assessment Report

Table 2-2 Conformance with the Commercial Renewable Energy Lease Number OCS-A 0512 Stipulations

Addendum "C" Stipulation	Description	SAP Document
4.5.2. Reporting Injured or Dead Protected Species	The Lessee must ensure that sightings of any injured or dead protected species (e.g., marine mammals, sea turtles, or sturgeon) are reported to the NMFS and the NMFS Greater Atlantic (Northeast) Region's Stranding Hotline (866-755-6622 or current) within 24 hours of sighting, regardless of whether the injury or death is caused by a vessel. In addition, if the injury or death was caused by a collision with a project-related vessel, the Lessee must notify the Lessor of the strike within 24 hours. The Lessee must use the form provided in Appendix A to Addendum C to report the sighting or incident. If the Lessee's activity is responsible for the injury or death, the Lessee must ensure that the vessel assist in any salvage effort as requested by NMFS.	See Section 4.4

3. PROJECT DESCRIPTION AND OBJECTIVES

3.1 Project Description and Objectives

Equinor Wind US LLC will collect and analyze meteorological data, inclusive of wind speed and direction at multiple heights, and information on other meteorological and metocean conditions as part of the site assessment activities of the Project within the Lease Area. As stated previously, Equinor Wind US LLC has proposed that the collection of this data will be performed using two RPS FLiDAR Buoys, one RPS Met and Wave Buoy, and one subsea Current Meter mooring. The proposed Metocean Facilities represent state-of-the-art equipment that incorporates the best available technologies, mooring components and mooring designs to ensure reliable, quality data collection, robust mooring integrity, safety and minimal environmental impacts. Design drawings of the technology proposed are provided in Appendix B.

The RPS FLiDAR Buoy will consist of instrumentation and supporting systems atop a floating moored buoy platform (Figure 3-1). Each floating platform consists of the toroidal shaped, dodecagon hull, mooring chain, clump weight anchors, floats and a pendant marker buoy. The hull consists of hot rolled HA1-grade steel with 10-millimeter (mm), 350-grade steel dividing plates. The hull is powder coated and has 12 zinc anodes installed to protect each hull segment from corrosion. The 5005-grade H34 aluminum superstructure is powder coated and measures 15.2 feet (ft) (4.63 meters [m]) in diameter. The vertical profile of RPS FLiDAR including instrumentation, will be approximately 15.8 ft (4.8 m) from the sea surface to the top of the D400 wind generators. The weight of the entire buoy including all electronics and keel is 9,480 pounds (lbs) (4,300kilograms [kg]) (4.3 metric tons).The submerged portion of the hull would measure approximately 13.8 ft (4.2 m) below the sea surface from the water line to the bottom of the buoy. The superstructure has also been designed with consideration for avian species. Landing areas have been minimized and anti-perching devices will be installed on the lights and mast. In addition, consideration has been given to potential icing issues and horizontal surfaces have been minimized to limit the potential ice/snow build up.

Figure 3-1 RPS FLiDAR Buoy

The RPS Wave and Met Buoy is a 8.5 ft (2.6 m) round buoy that measures directional waves, metoerological conditions at sensor height and sea water temperature (Figure 3-2). Similar to the RPS FLiDAR, the buoy hull and superstructure are constructed from hot rolled HA1-grade steel and 5005-grade H34 aluminum, respectively. The Wave and Met Buoy is attached to the seabed using a U-shape mooring design. The vertical profile of the Wave and Met Buoy will be approximately 7.9 ft (2.4 m) from the sea surface to the top of the buoy. The submerged portion of the buoy hull would measure approximately 7.9 ft (2.4 m) below the sea surface from the waterline to the bottom of the buoy. The Wave and Met Buoy weighs 4,409 lbs (2,000 kg).

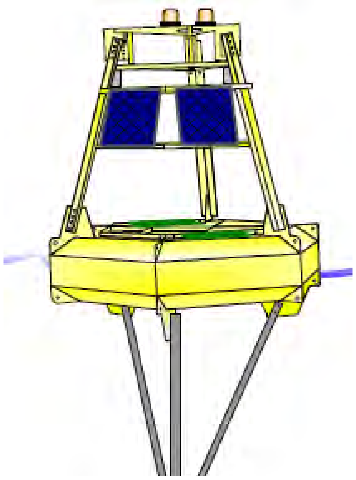

Figure 3-2 RPS Wave and Met Buoy

The CT/CM Mooring will be a subsurface inline mooring consisting of CM-04 Acoustic Current Meters and Seabird SBE37 CT loggers. The CM-04 Acoustic Current Meter, which measures approximately 45 inches (1155 millimeters [mm]) long by 8 inches (195 mm) wide, is a self-contained instrument that can be moored to record ocean currents and water temperature. CM-04 Acoustic Current Meter is constructed from Type 2 Titanium. The CM-04 Acoustic Current Meter will be incorporated into the subsea mooring at 9.8 ft (3 m), 55.8 ft (17 m), and 88.6 ft (27 m) above the seabed. The Seabird SBE37 CT logger, which measures 22.2 inches (563.9 mm) long by 4 in (102.9 mm) wide, is a high-accuracy conductivity and temperature recorder with internal battery and memory. The Seabird SBE37 CT logger is constructed from titanium and other non-corroding materials and has been designed for moorings and other long duration, fixed-site deployments.). The Seabird SBE37 CT loggers will be attached to the subsurface portion of the mooring line via plastic clamps and cables at 4.9 ft (1.5 m), 62.3 ft (19 m), and 95 ft (29 m) above the seafloor.

Figure 3-3 CM-04 Acoustic Current Meter (Left) and Seabird SBE37 CT Logger (Right)

Equinor Wind US LLC plans to deploy the Metocean Facilities no earlier than September 1, 2018, but as soon as all permits are in place thereafter. Equinor Wind US LLC requires a period of wind profile measurements data from the FLiDARs as early as possible to help inform development concepts for bids into upcoming competitive state power offtake solicitations. The two RPS FLiDAR Buoys are scheduled to be decommissioned at the end of their two-year operational life, and the Met and Wave Buoy and the CM/CT mooring will be decommissioned at the end of four years. The Metocean Facilities will be decommissioned at the end of the operational life as described in Section 0.

3.2 Site Location

The location of the proposed Metocean Facilities will fall within two sites that were surveyed and evaluated by Equinor Wind US LLC in spring 2018 (see Section 0 and Appendices C, D, and E). These sites are collectively referred to as the Installation Areas (Figure 1-1). For the purpose of the discussion in this SAP, the two Installation Areas where the Metocean Facilities are proposed to be located have been given unique identifiers. The RPS FLiDAR 1 Buoy, the RPS Wave and Met Buoy, and CM/CT Mooring to be located in the center of the Lease Area are referenced as FLiDAR 1, Wave and Met Buoy, and Current Meters, respectively, and will be deployed within Buoy Deployment Area 1. The RPS FLiDAR 2 Buoy to be installed in the western side of the Lease Area is referenced as FLiDAR 2 and will be deployed within Buoy Deployment Area 2. The coordinates for these locations are provided in Table 3-1 and depicted on Figure 1-1.

The Metocean Facilities will be deployed within the proposed Installation Areas at the coordinates listed in Table 3-1.

Table 3-1 Location of the Metocean Facilities

Platform	Northing (UTM 18N 2011 NAD83)	Easting (UTM 18N 2011 NAD83)	NAVD88 Water Depth	OCS Lease Block	Aliquot
FLiDAR 1	4461784	642530	36 Meters	6760	G
Wave and Met Buoy	4461350	643430	36 Meters	6760	F
Current Meters	4462217	641627	36 Meters	6760	L
FLiDAR 2	4468810	627225	30 Meters	6657	O

3.3 Mooring Designs, Power Supply, and Instrumentation

The location for the Installation Areas of the proposed Metocean Facilities as presented in Table 3-1 was based on a review of existing data, information collected during 2018 high resolution geophysical (HRG) surveys conducted within the Lease Area (See Appendix C), the most likely development scenarios for the lease area and the best available technologies. The following sections provide detailed descriptions of the proposed Metocean Facilities as well as their associated mooring designs, power supply, and instrumentation.

RPS carried out rigorous mooring design and modeling for the FLiDAR, Met and Wave Buoy and the Current Meter CM/CT using their decades of first-hand experience designing and deploying metocean moorings and utilizing the latest mooring technology and modelling software, ORCAFLEX. The FLiDAR, Met and Wave Buoy and the Current Meter CM/CT Mooring designs and testing processes were independent of each other due to differences in surface buoy characteristics and data measurement requirements. Mooring designs went through multiple design iterations and model runs until modelling results returned acceptable and safe values when run at extreme local metocean condition thresholds. Values used in models were 60 knots (30.1meters per second [m/s]) wind speed, 2 knots (1.0m/s) currents, and 27.9 ft (8.5 m) Hs at 13.1 seconds Tp. The

FLiDAR, Met and Wave Buoy, and Current Meter CM/CT moorings were designed with the following objectives:

- the surface FLiDAR buoy and Met and Wave Buoy remain secure on the sea surface without risk of detachment, submersions, significant overtopping from waves and within satisfactory limits of tilt for sensors;
- the mooring components are rated to a good level of safety factor when under tension to minimize risk of mooring failure during operational life and lifting operations;
- the mooring components can survive benign conditions without the risk of tangling or rubbing and causing self-wear;
- mooring components are of a material and length with 'stopping off points' that allow for safe deployment and recovery on a range of vessels; and
- where feasible, mooring designs use components and materials that minimize risk to marine life and other marine users.

The mooring designs have been selected to be consistent with other similar moorings deployed in the lease area including 25 BOEM funded Atlantic Sturgeon acoustic detection moorings made up of a combination of anchor weights, chain and rope with floats. The recovery section of the moorings are deemed to avoid the risk of entanglement for the following reasons:

- Unlike static fishing gear with rope recovery lines that extend to surface marker buoys that can go slack and have the ability to loop, the 32.8 ft (10m) of polypropylene rope on the FLiDAR and Met and Wave Buoy recovery section is under constant tension, provided by the 198 lbs (90kg) of positive buoyancy. This removes the risk of looping sections of rope and available slack.
- The upper 9.8 ft (3m) of polypropylene rope on the recovery sections are fed through the three viny floats, exposing approximately 5 ft (1.5m) of rope, which is not considered to be long enough to cause an entanglement risk. This section of rope is also under constant tension from the 198 lbs (90kg) of positive buoyancy produced by the viny floats.
- Unlike long, loose sections of rope on fishing gear, the combination of three subsurface viny floats, a rope dispenser and an acoustic release would provide an adequate target to produce a return signal from marine mammals using echo location, therefore it is expected that there is an ability to detect and avoid this section of mooring.

The final FLiDAR and Met and Wave Buoy mooring designs utilize a combination of rubber cords and chain from the buoy to the primary anchor weight to allow the buoy to ride the waves, with the rubber cords acting to absorb the tension and reduce a tugging/snatching action on the buoy and mooring. The lower section of rubber cord is held clear of the seabed by a float with 110 lb (50kg) buoyancy to remove the risk of the non-buoyant rubber cord wearing on the seabed or anchor. Modelling results demonstrated that the FLiDAR buoy and mooring system responds better to wave motion when the mooring line is secured to the side of the buoy hull as opposed to the underside of the buoy hull. The Met and Wave buoy mooring system is attached to the bottom of the buoy. The upper section of rubber cord is attached to the buoys via a section of heavy chain to ensure the upper section of rubber cord cannot rub and wear against the side of the FLiDAR or the underside of the Met and Wave Buoy hull. Extensive modelling demonstrated that the most effective means of ensuring mooring integrity through strength and an ability to respond to wave and current action was a section of mooring line between the upper and lower rubber cord sections, also acting as a means to separate the two sections of rubber cord and to give sufficient mooring line length. The use of chain or wire rope was not deemed to be feasible in this section as it introduces non-buoyant material that would act to pull the two rubber cord sections towards each other. These materials also introduce the risk of wear to and therefore failure of the rubber cords should they come into regular contact.

A section of wire rope ground line extends from the primary anchor weight with a length and material strength to allow for safe recovery of the primary anchor weight to the vessel during mooring recovery operations. The ground line is attached to a smaller secondary anchor weight, which serves both to secure the ground line to the seabed and to anchor the mooring recovery system.

For the mooring recovery system, a rope dispenser concept on an acoustic release positioned inline above the secondary anchor weight on a combination of polypropylene rope, chain and floatation has been selected. When the acoustic release is activated, the amsteel rope dispensers release high strength Spectra rope that floats to the surface on the three viny floats. The U-mooring design facilitates recovery of the Wave and Met Buoy in higher sea state conditions by allowing the mooring to be recovered and the Wave and Met Buoy to be towed without the need for lifting the buoy at sea.

The available rope dispensers house 131 ft (40m) of recovery line. To ensure there is adequate slack on the recovery line when activated during recovery operations, the rope dispenser needs to be raised off the seabed. This slack is required to ensure personnel on the recovery vessel have sufficient rope to secure on to with a recovery boat hook or grappling line and to have enough rope section to get onboard the vessel to secure it to a winch to then haul in the mooring. In addition to the slack required, the 32.8 ft (10m) section of mooring line from the secondary anchor weight to the acoustic release and rope dispenser is required to allow for safe deployment, as it allows the floats, acoustic release and rope dispenser to float clear of the vessel stern before the anchor weight is released to the seabed. Polypropylene rope has been used in this section of the mooring to allow for a semi-buoyant material during deployment, as alternative materials such as chain and wire rope introduce non-buoyant sections that would restrict the ability of the floats, acoustic release and rope dispenser to float clear of the vessel stern prior to releasing the anchor weight. In addition, this section of mooring is planned to be deployed by hand and therefore polypropylene rope is deemed the safest material to handle as opposed to chain or wire rope.

3.3.1 RPS FLiDAR Buoy

3.3.1.1 Mooring Design

The RPS FLiDAR Buoy will be attached to the seafloor by means of a U-shaped mooring design which is comprised of chain, polypropylene rope, wire rope, trawl floats, an amsteel rope dispenser with acoustic release and rubber cords that connect the RPS FLiDAR Buoy to both a primary and secondary clump anchor on the sea floor as well as three underwater viny floats that sit approximately 55.8 ft (17 m) above the seabed as part of the mooring recovery system. (Figure 3-4).

The primary and secondary clump weights would weigh approximately 4,409 lbs (2,000 kg) and 660 lbs (300 kg), respectively and sit on the seabed for a total area of up to 21.5 ft^2 (2 m^2) per clump weight. The chain would be attached to the side of the FLiDAR hull via the 12T bow shackle. Due to the use of rubber cords in the mooring design, there will be no anchor chain sweep associated with the long-term operation of the RPS FLiDAR Buoy. Total area of mooring resting on the seafloor, inclusive of both clump weights, chains and wire ropes, would be approximately 67.8 ft^2 (6.3 m^2). Vertical penetration of the primary and secondary clump weights into the seabed is anticipated to be approximately 1.6 ft and 0.7 ft (0.5 m to 0.2 m), respectively. All clump weights will be fully recovered.

3.3.1.2 Power Supply

The RPS FLiDAR Buoy instrumentation will be powered by 30 x 110 Amp-hour Victron Gel batteries, charged by 12 x 335-Watt solar panels and 4 x D200 wind generators. Five regulators protect the batteries from being damaged by possible overcharging. Equinor has selected a concept that has avoided the use of backup generators using traditional fuels in an attempt to mitigate the risk of oil spills and reduce emissions. The acoustic release is powered by an alkaline or lithium battery pack.

In the event of failure of the key power supply systems, the RPS FLiDAR Buoy instrumentation would be capable of operating at full capacity on battery power alone for up to ten days. The life of the acoustic release battery pack is over a year.

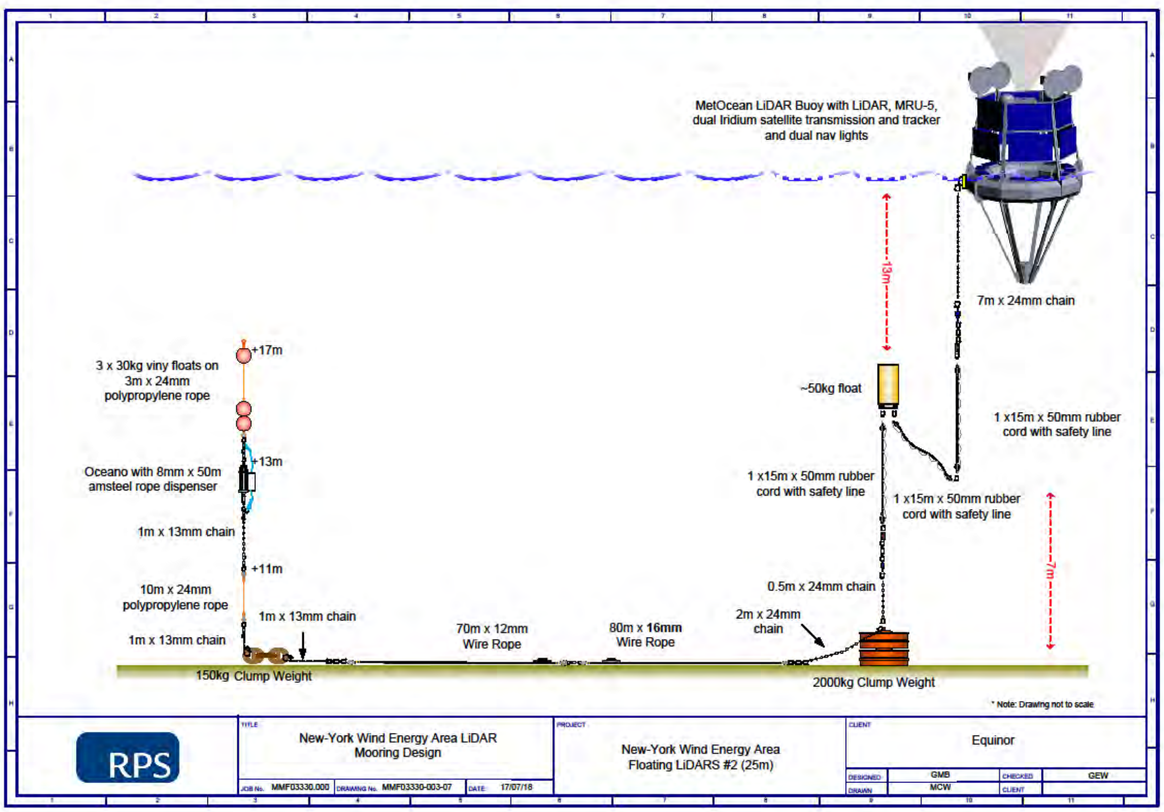

Figure 3-4 RPS FLiDAR Buoy U-Mooring Design

3.3.1.3 Instrumentation Equipment

A ZephIR300M light detection and ranging (LiDAR) and KONGSBERG MRU-5 motion reference unit, will be installed atop the RPS FLiDAR Buoy. The ZephIR300M unit is a wind profiling device capable of remotely measuring and collecting wind speeds and directions up 656 ft (200 m). The KONGSBERG MRU-5 motion reference unit collects high accuracy roll, pitch and heave measurements. The RPS FLiDAR Buoy would also contain the following equipment:

Table 3-2 provides a list of the parameters measured by the RPS FLiDAR Buoy, the associated instrumentation, as well as the range and accuracy of the measurements.

Table 3-2 Parameters Measured and Recorded by the RPS FLiDAR Buoys

Parameter	Instrumentation	Range	Accuracy
Wind Speed	ZephIR 300 LiDAR	<1 m/s to 70 m/s	0.1 m/s
Wind Direction		0 to 360°	<0.5°
Temperature		-40 + 50° C	
Orientation	KONGSBERG MRU-5	+180°	0.02° RMS
Gyro		+149°/s	0.08% RMS
Acceleration		+30 m/s^2	0.1 m/s^2 RMS
Heave		+50m	0.01 m/s RMS

The RPS FLiDAR Buoys will store data using a combination of the M200 data loggers and the Zephir LiDAR 300m instrument.

The M200 data logger is latest version of data loggers constructed by RPS. Custom firmware is written for the M200, thus allowing maximum control of communication options and data transmission protocols. The M200 logger has the ability to integrate various sensors via analogue, digital, serial and Ethernet inputs. Each RPS FLiDAR Buoy has two M200 data loggers installed to allow redundancy in data logging and transmission. The M200 Data Logger has a 64-gigabyte flashcard installed, which allows for years of data logging without the need for erasing.

Both M200s (System A and B) on the buoy will be connected to the LiDAR via Ethernet. The LiDAR 10 minute data will be retrieved via Modbus polling of the LiDAR, logged and transmitted by each M200 in an Iridium Short Burst Data message.

The M200 Data Logger will also receive 1 Hertz continuous data from the GPS compass, KVH compass and MRU. All of this data will be stored in daily files which will be retrieved once per day via 4G or Iridium Broadband (should 4G coverage not be available). The GPS compass is used to correct the M200 clock to GPS time once per day at midnight UTC.

The Zephir LiDAR 300M will log the 10 minute averaged LiDAR data as well as the raw data in daily files. The raw LiDAR data will be retrieved once per day via 4G or Iridium Broadband (should 4G coverage not be available).

The following supporting systems for navigational aids, position tracking, and remote monitoring will also be installed on the RPS FLiDAR Buoy:

- Buoy tracking system;
- V104S GNSS Compass;
- Two KVH Compass;
- Two M200 Logger units; and
- Two self-contained Global Star tracker units.

Using the maintenance plan described in Section 5.2, equipment on the RPS FLiDAR Buoy will have a minimum two-year operational lifespan.

3.3.2 Wave and Met Buoy

3.3.2.1 Mooring Design

The Wave and Met Buoy mooring design will also consist of the U-shaped mooring design. The Wave and Met Buoy will be attached to the seafloor by means of a U-mooring design which is comprised of a chain, polypropylene rope, wire rope trawl floats, and amsteel rope dispenser with acoustic release and rubber cord that connects the RPS Wave and Met Buoy to both a primary and secondary clump anchor on the sea floor as well as 3 underwater viny floats that sit approximately 55.8 ft (17 m) above the seabed (Figure 3-45).

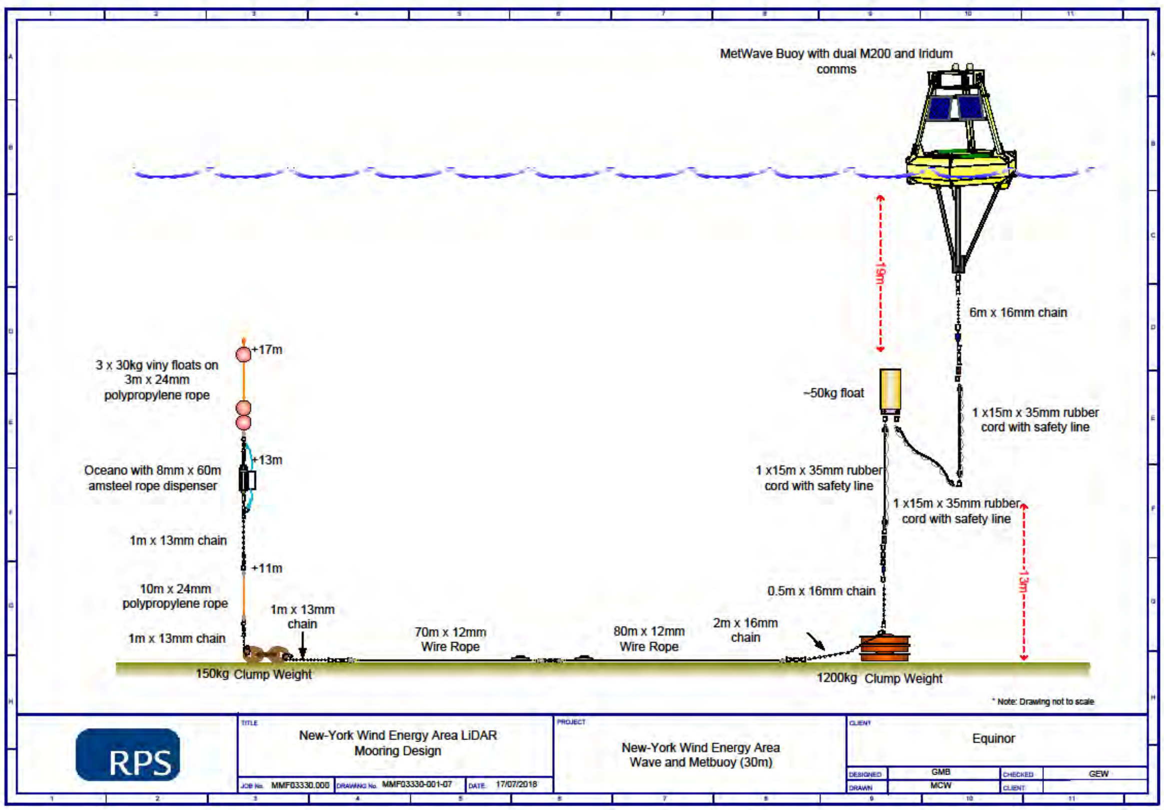

Figure 3-5 Wave and Met Buoy U-Mooring Design

The primary and secondary clump weights would weigh approximately 2646 lbs (1,200 kg) and 661 lbs (300 kg), respectively, and will rest on the seafloor for an area of approximately 21.5 ft² (2 m²) per clump weight. The chain would be attached to the underside of the hull. Due to the mooring design, which includes a rubber cord section, there will be no anchor chain sweep associated with the long-term operation of the Wave and Met Buoy. Total area of mooring resting on the seafloor, inclusive of both clump weights, chains and wire ropes, would be approximately 62.4 ft² (5.8 m²). Vertical penetration of the primary and secondary anchor chain for the Wave and Met Buoy into the seabed is anticipated to be approximately 1.5 ft and 0.5 ft (0.5 m to 0.2 m), respectively. The discrepancy between water depths reported in Table 3-1 and those presented on Figure 3-5 is negligible in light of the mooring design configuration. All clump weights will be fully recovered.

3.3.2.2 Power Supply

The Wave and Met Buoy instrumentation will be powered by 6 x 110 Amp-hour Victron Gel batteries, charged by 6 x 100 Watt solar panels. A regulator in the Power Management Unit protects the batteries from being damaged by overcharging. When fully charged the batteries have enough reserve capacity to power the buoy in a standard sampling routine for up to two months without being charged. The acoustic release is powered by an alkaline or lithium battery pack that has a life of at least a year.

3.3.2.3 Instrumentation Equipment

The Wave and Met Buoy is instrumented with the following sensors to provide in-situ monitoring and analysis of wave and meteorological activity:

- Datawell MOSE-G Waves Sensor;
- WindSonic Wind Sensor;
- A Gill WindObservor II Wind Sensor;
- Pyrosales RTD Air Temperature Sensor;
- A Vaisala HMP 155 Relative Humidity Sensor; and
- A Vaisala PTB110 Barometric Pressure Sensor.

Table 3-3 provides a list of the parameters measured by the Wave and Met Buoy, as well as the resolution and accuracy of the measurements.

Table 3-3 Parameters Measured and Recorded by the Wave and Met Buoy

Parameter	Instrumentation	Range	Resolution	Accuracy
Wind Speed	WindSonic	0 to 60 m s^{-1}	0.01 m s^{-1}	±4%
Wind Direction	WindSonic	0 to 360˚	1˚	±3˚
Wind Speed	WindObserver II	0 to 65 m s^{-1}	0.01 m s^{-1}	±2%
Wind Direction	WindObserver II	0 to 360˚	1˚	±2˚
Air Temperature	Pyrosales RTD	-200 to 600 ˚C	0.1 ˚C	±0.05 ˚C
Relative Humidity	Vaisala HMP-155	0 to 100%	0.025 % RH	±1.0% at 20 ˚C
Barometric Pressure	Vaisala PTB-110A	800 to 1060 hPa	0.1 hPa	±0.3 hPa at 20 ˚C
Waves	Datawell MOSE-G	1 – 100s period	1mm	2cm

The data acquisition system will acquire and store data using the dual M200 loggers with 64 Gigabyte flashcards. Wave and met parameters, including 30 minute wave spectrum and 3 x 10 minute met parameter data, will be transmitted from both M200 units via Iridium/Short Burst Data every 30 minutes.

The following supporting systems for navigational aids, position tracking, and remote monitoring will also be installed on the Wave and Met Buoy:

- Two Global Star Tracking Beacons;
- Iridium moderns; and
- MOSE-G sensor.

Using the maintenance plan described in Section 5.2, equipment on the Wave and Met Buoy will have a minimum four-year operational lifespan.

3.3.3 Current Meter CM/CT Mooring

3.3.3.1 Mooring Design

The CM/CT mooring design will consist of a subsurface mooring design. The CM-04 Acoustic Current Meters/Seabird SBE37 CT loggers will be deployed as part of the subsea mooring. The CM-04 Acoustic Current Meters will be incorporated into the subsurface portion of the mooring line at 9.8 ft (3 m), 55.8 ft (17 m), and 88.6 ft (27 m) above the seafloor via chain and 10 mm galv wire segments on the top and bottom of the meters that connect to the mooring line (Figure 3-6). The CT loggers will be attached to the subsurface portion of the mooring line via plastic clamps at 4.9 ft (1.5 m), 62.3 ft (19m), and 95.1 ft (29 m) above the seafloor. The remainder of the mooring is comprised of chain, wire rope, two amsteel rope dispensers with acoustic release and shackles and load rings that connects the subsurface portion of the mooring to a clump anchor on the sea floor as well as a pendant buoy that will sit approximately 16.4 ft (5 m) below the sea surface (Figure 3-6). When the acoustic release is activated, the amsteel rope dispensers release high strength Spectra rope that floats to the surface on the viny floats. The mooring has been designed to withstand the prevailing conditions and facilitates safe recovery of the CM/CT mooring.

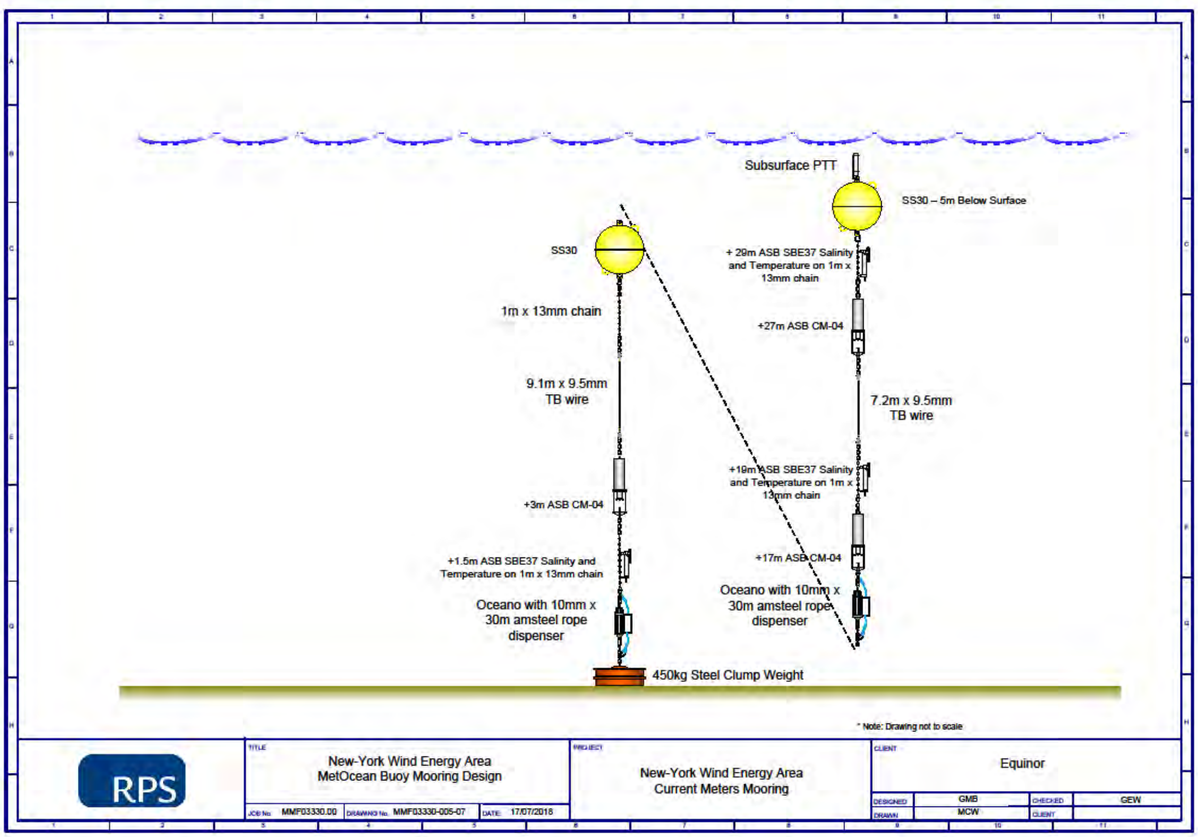

Figure 3-6 CM/CT Mooring Design

The clump weight would weigh approximately 992 lbs (450 kg), and will rest on the seafloor for an area of approximately 21.5 ft^2 (2 m^2). Vertical penetration of the anchor chain for the Current Meter mooring into the seabed is anticipated to be approximately 0.5 ft to 1.5 ft (0.2 m to 0.5 m). The discrepancy between water depths reported in Table 3-1 and those presented on Figure 3-6 is negligible in light of the mooring design configuration. All clump weights will be fully recovered.

3.3.3.2 Power Supply

Each CM-04 Acoustic Current Meter and Seabird SBE37 CT logger is powered by 28 Amp-hour alkaline battery packs and 12 AA lithium batteries, respectively. The current meter batteries can last over a year, but would be replaced during the 6-month maintenance trip (Section 5.2). The acoustic release is powered by an alkaline or lithium battery pack that has a life of at least a year.

3.3.3.3 Instrumentation Equipment

The CM-04 Acoustic Current Meter is a self-contained instrument that can be moored to record ocean currents and water temperature. The CM-04 Acoustic Current Meter consists of four piezoelectric transducers, an acoustic mirror positioned to measure velocities in two axes, a flux-gate compass unit, and a temperature sensor. Recording intervals range from 0.5 second to 10 minutes. On this project, the data will be measured in 1-minute averages of the continuous 30 Hertz current data. Data is stored on an internal flash card and will be downloaded during 6-month maintenance trips.

The Seabird SBE37 CT logger is a high-accuracy conductivity and temperature recorder with internal battery and memory. The Seabird SBE37 CT logger's internal field conductivity cell, which measures conductivity, is unaffected by external fouling which ensures stability. The aged and pressure protected thermistor, used to measure temperature, has a long history of accuracy and stability. There are several user selectable sampling rates that range from 5-second to 9.1-hour intervals, polled sampling, or serial line sync. On this project, the conductivity and temperature sampling data will be measured at 5-minute intervals. Data is stored on an internal non-volatile FLASH memory card and will be downloaded during 6-month maintenance trips.

Table 3-4 Parameters Measured and Recorded by the CM-04 Meter and CT Recorder

Parameter	Instrumentation	Range	Resolution	Accuracy
Current Speed	CM-04	0 to ±400 cms^{-1}	0.01 mms^{-1}	±1 cms^{-1} or ±1%
Current Direction	CM-04	0 to 360˚	1˚	±1˚
Water Temperature	CM-04	-3˚C to +37˚C	±0.01˚C	±0.2˚C
Water Conductivity	CT Logger	0 – 7 S/m	0.00001 S/m	0.0003 S/m
Water Temperature	CT Logger	-5˚C to +38˚C	0.0001 ˚C	0.002 ˚C

The CM-04 Acoustic Current Meter and Seabird SBE37 CT Logger will store data internally. Data will be downloaded every 6 months during maintenance of the equipment.

The CM/CT Mooring would also be equipped with a subsurface satellite transmitter PTT which would activate and send an alarm in the event that the subsea mooring has surfaced.

Using the maintenance plan described in Section 5.2, equipment on the CM/CT Mooring will have a minimum four-year operational lifespan.

4. DEPLOYMENT/INSTALLATION

Installation of the Metocean Facilities may take up to seven days over three separate vessel trips including transit, barring weather delays. It is anticipated that the deployment activities will be staged out of Millers Launch, Pier 7 ½, in Staten Island, New York.

4.1 Overview of Installation and Deployment Activities

Equinor Wind US LLC will notify BOEM, United States Fleet Forces (USFF) N46, the United States Army Corps of Engineers, and the United States Coast Guard (USCG) prior to mobilization to deploy the Metocean Facilities. Written notice via email will be provided to the appropriate contact at Fleet Forces Command prior to mobilization in order to avoid potential conflicts with military operations. Equinor Wind US LLC will update Fleet Forces Command on the installation schedule following approval of the SAP and detailed planning.

Equinor Wind US LLC will notify mariners, fisherman, and other users of the area by submitting a request to the USCG for publication of a Local Notice to Mariners at least two weeks prior to the start of the in-water work. This notice will include the contact names for the installation vessels, local fisheries liaison officer, channels of communication, and the duration of the work. Copies of all USCG communications will be provided to BOEM as required. Additionally, in accordance with standard maritime practices, the vessel captain(s) will broadcast via VHF radio on Marine Channel 16 notification to mariners of their position and limited mobility during installation activities and submit an application to the USCG for a Private Aids To Navigation (PATON) for the Metocean Facilities (see Table 1-2). Equinor Wind US LLC will submit a copy of the approved PATON to BOEM prior to buoy deployment.

Within 30 days of completing the installation of the Metocean Facilities, Equinor Wind US LLC will prepare an Installation Report and provide a copy to BOEM to fulfill the requirements of 30 CFR 585.615(a). This report will include a description of the equipment and the installation, including final coordinates of the installation site and photo documentation of the equipment deployed, the results of all commissioning tests, the plans and schedule for upcoming inspections and maintenance, and any noted problems or issues to be addressed.

Equinor Wind US LLC will provide written notification to BOEM and the DoD of any proposal to add new sensors to the data collection buoy(s). Equinor Wind US LLC will include the technical specifications (manufacturer, model, spectrum requirements, etc.) for any proposed new sensors, specifically seismometers and hydrophones, in the notification. The notification will be provided to the contacts listed in the Lease, or updated contact information as provided by BOEM.

4.1.1 RPS FLiDAR, Wave and Met Buoy, and CM/CT Mooring Deployment

One workboat, up to approximately 150 ft (46 m) in length, will be used for installation of the Metocean Facilities. The Installation of the Metocean Facilities will require three separate round trips over a 6-to 7-day period. FLiDAR 1 will be deployed following SAP approval. FLiDAR 2 will be deployed either concurrently with deployment of FLiDAR 1 or during the first 6-month service visit.

Installation of FLiDAR 1 will happen over a two-day period. The first day, the vessel will be loaded and prepared for deployment, and FLiDAR 1 will be secured for towing. The mooring system for FLiDAR 1 will also be loaded and stored on the deck of the vessel for transit. The vessel will transit out to the deployment location overnight. On arrival at the FLiDAR 1 deployment location the following day (day 2), the chain will be laid out on the deck of the vessel in a manner that will prevent tangling or twisting while it is let out into the water. The mooring system will then be prepared for connection on the deck of the vessel. The tow rope would then be pulled in so that the rubber cords on the mooring can be shackled to the mooring chain that is connected to FLiDAR 1. A quick release would be attached to the mooring chain, which would then be secured on deck, and the tow rope will be removed. The mooring chain for FLiDAR 1 will then be deployed. The mooring systems for the Metocean Facilities, inclusive of clump weights, chains, ropes, rope dispenser, acoustic release and lines, will be deployed from the work vessel by a crane.

Following deployment of FLiDAR 1, the vessel will return to shore, and the Wave and Met Buoy, the CM/CT Mooring, and the Wave and Met Buoy mooring system will be secured to the deck. The vessel will then transit to the Wave and Met Buoy deployment location, which will be located 3,279 ft (1,000 m) northwest from FLiDAR 1. The Wave and Met Buoy mooring chain will be laid out on the deck of the vessel in a manner that will prevent tangling or twisting while it is let out into the water. The Wave and Met Buoy will then be connected to the mooring system, the mooring will be streamed out, and the clump weight anchor will be released. Following deployment of the Wave and Met Buoy, the vessel will transit back to port.

Finally, the vessel will transit to the CM/CT Mooring deployment location, which will be located approximately 3,280 ft (1,000 m) southeast from FLiDAR 1. The CM/CT mooring chain will be laid out on the deck of the vessel in a manner that will prevent tangling or twisting while it is let out into the water. The CM/CT Mooring system, inclusive of clump weights, chains, ropes and lines, will be deployed from the work vessel by a crane. Following deployment of the CM/CT Mooring, the vessel will transit back to port. (NOTE: Final deployment procedures may be modified depending on the deployment vessel configuration). No vessel anchoring will take place during installation.

FLiDAR 2 will be deployed either concurrently with deployment of FLiDAR 1 or during the first 6-month service visit. Once secured for towing the FLiDAR 2 mooring will be secured to deck for transport to the deployment location overnight. On arrival at the FLiDAR 2 deployment location the following day (day 2) FLiDAR 2 will be deployed in the same manner as FLiDAR 1 described above. Following deployment of the FLiDAR 2, the vessel will transit to the CM/CT Mooring deployment location, and begin the scheduled service visit.

All personnel participating in the installation will attend a pre-installation briefing prior to mobilization (See Section 4.3).

4.2 Vessels

Equinor Wind US LLC will employ RPS to transport and deploy the Metocean Facilities.

It is anticipated that the deployment of the Metocean Facilities will require the support of a single work boat. Equinor Wind US LLC is currently proposing to use the Rana Miller or a similar vessel as the work boat. The Rana Miller is a multi-purpose offshore utility vessel with two Cummins KTA-38 main engines rated at 850 horsepower each. The Rana Miller measures 150 ft (46 m) in length with a 36 ft (11 m) beam and 11.5 ft (4 m) draft. See Appendix G for vessel specifications.

4.3 Pre-Installation Briefing

All personnel will attend a pre-installation briefing as required by Lease stipulation 4.1.1. The pre-installation briefing will be performed prior to departure from the RPS office in Perth Australia, and again, on the vessel prior to the installation of the Metocean Facilities. The pre-installation briefing will include a Tool-Box Talk (Appendix E) as well as HSE and hazard identification presentations. The briefing will occur prior to commissioning and again prior to boarding the vessel. The purpose of this briefing will be to review the HSE requirements and associated emergency response requirements for the proposed work, identify the responsibilities of each person, define the chains of command, discuss communication procedures, and provide an overview of planned installation activities. Additional topics for the briefing will include protected species avoidance, marine trash and debris awareness, and oil spill response procedures.

The Equinor Wind US LLC onsite representative will have the authority to stop or delay any of the installation activities, if deemed necessary. If change in personnel is required during installation activities, the new personnel will be briefed as they join the work in progress.

4.4 Protected Species Avoidance

All whales, dolphins, and porpoises in the northeast region are federally protected by the Marine Mammal Protection Act of 1972. In addition, many large whales in the area, as well as sea turtles, are further protected under the Endangered Species Act of 1973 (ESA).

The Lease contains specific stipulations to minimize risk to marine species that must be followed. Installation of the Metocean Facilities will not require pile-driving; accordingly, mitigations to reduce adverse impacts on protected species from pile driving do not apply to this installation. The Lease stipulations summarized in Table 4-1 apply to activities associated with installation, operation and decommissioning of the Metocean Facilities and must be adhered to.

Table 4-1 Standard Operating Conditions in the Lease Area

Addendum "C" Stipulation	Vessel Operations Conditions
4.2 Vessel Strike Avoidance Measures	
4.2.1	The Lessee must ensure that vessels conducting activity in support of a plan submittal, including those transiting to and from local ports and the lease area, comply with the vessel-strike avoidance measures specified in stipulations 4.2, except under extraordinary circumstances where complying with these requirements would put the safety of the vessel or crew at risk.
4.2.2	The Lessee must ensure that vessel operators and crews maintain a vigilant watch for cetaceans, pinnipeds, and sea turtles and slow down or stop their vessels to avoid striking these protected species.
4.2.3	The Lessee must ensure that all vessel operators comply with 10 nautical miles per hour (knot, <18. kilometers per hour [km/hr]) speed restrictions in any Dynamic Management Area[1].
4.2.4	The Lessee must ensure that vessels 65 ft (19.8 m) in length or greater, operating from November 1 through April 30, operate at speeds of 10 knots (<18.5 km/hr) or less.
4.2.5	The Lessee must ensure that all vessel operators reduce speed to 10 knots or less when mother/calf pairs, pods, or large assemblages of non-delphinoid cetaceans are observer near an underway vessel.
4.2.6 North Atlantic Right Whales	
4.2.6.1	The Lessee must ensure all survey vessels maintain a separation distance of 1,640 ft (500 m) or greater from any sighted North Atlantic right whale.
4.2.6.2	The Lessee must ensure that the following avoidance measures are taken if a vessel comes within 1,640 ft (500 m) of any North Atlantic right whale:
4.2.6.2.1	If underway, vessels must steer a course away from any sighted North Atlantic right whale at 10 knots (18.5 km/h) or less until the 1,640 ft (500 m) minimum separation distance has been established (except as provided in stipulation 4.2.6.2.2).
4.2.6.2.2	If a North Atlantic right whale is sighted within 328 ft (100 m) of an underway vessel, the vessel operator must immediately reduce speed and promptly shift the engine to neutral. The vessel operator must not engage engines until the North Atlantic right whale has moved outside of the vessel's path and beyond 328 ft (100 m), at which point the Lessee must comply with 4.2.6.2.1.
4.2.6.2.3	If a vessel is stationary, the vessel must not engage engines until the North Atlantic right whale has moved beyond 328 ft (100 m), at which point the Lessee must comply with stipulation 4.2.6.2.1.
4.2.7 Non-Delphinoid Cetaceans other than the North Atlantic Right Whale.	
4.2.7.1	The Lessee must ensure all vessels maintain a separation distance of 328 ft (100 m) or greater from any sighted non-delphinoid cetacean.

Table 4-1 Standard Operating Conditions in the Lease Area

Addendum "C" Stipulation	Vessel Operations Conditions
4.2.7.2	The Lessee must ensure that the following avoidance measures are taken if a vessel comes within 328 ft (100 m) of any non-delphinoid cetacean:
4.2.7.2.1	If any non-delphinoid cetacean is sighted, the vessel underway must reduce speed and shift the engine to neutral, and must not engage the engines until the non-delphinoid cetacean has moved beyond 328 ft (100 m).
4.2.7.2.2	If a vessel is stationary, the vessel will not engage engines until the sighted non-delphinoid cetacean has moved beyond 328 ft (100 m).
4.2.8 Delphinoid Cetaceans and Pinnipeds	
4.2.8.1	The Lessee must ensure that all vessels underway do not divert to approach any delphinoid cetacean and/or pinniped.
4.2.8.2	The Lessee must ensure that if a delphinoid cetacean and/or pinniped approaches any vessel underway, the vessel underway must avoid excessive speed or abrupt changes in direction to avoid injury to the delphinoid cetacean and/or pinniped.
4.2.9 Sea Turtles	
4.1.1.6.1	The Lessee must ensure all vessels maintain a separation distance of 164 ft (50 m) or greater from any sighted sea turtle.
Note: 1. A Dynamic Management Area is defined in Section 1.2 of the Lease. Vessel operators may send a blank email to ne.rw.sightings@noaa.gov for an automatic response listing all current Dynamic Management Areas.	

In addition to the Lease stipulations, between November 1 and July 1, vessel operators will monitor National Marine Fisheries Service (NMFS) North Atlantic Right Whale reporting systems (e.g., the Early Warning System, Sighting Advisory System, and Mandatory Ship Reporting System) for the presence of North Atlantic Right Whales.

4.4.1 Reporting of Injured or Dead Protected Species

During all phases of marine activities, sightings of any injured or dead protected species (sea turtles and marine mammals) will be reported within 24 hours, regardless of whether the injury or death was caused by a vessel as specified in Stipulation 4.5.2 of the Lease. All marine activities will be suspended immediately and the circumstances reported as specified below if a dead or injured right whale is found in any of the Installation Areas. The Lease stipulations summarized in Table 4-2 below apply and must also be adhered to.

Table 4-2 Protected Species Reporting Requirements in the Lease Area

Addendum "C" Stipulation	Lease Requirement
4.5.2 Reporting Injured or Dead Protected Species	The Lessee must ensure that sightings of any injured or dead protected species (e.g., marine mammals, sea turtles or sturgeon) are reported to the Lessor, NMFS and the NMFS Greater Atlantic (Northeast) Region's Stranding Hotline (866-755-6622 or current) within 24 hours of sighting, regardless of whether the injury or death is caused by a vessel. In addition, if the injury or death was caused by a collision with a project-related vessel, the Lessee must notify the Lessor of the strike within 24 hours. The Lessee must use the form provided in Appendix A to Addendum "C" to report the sighting or incident. If the Lessee's activity is responsible for the injury or death, the Lessee must ensure that the vessel assist in any salvage effort as requested by NMFS.
4.5.3 Reporting Observed Impacts to Protected Species	
4.5.3.1	The Lessee must report any observed takes (as defined in 1.13) of listed marine mammals, sea turtles or sturgeon resulting in injury or mortality within 24 hours to the Lessor and NMFS.
4.5.3.2	The Lessee must report any observations concerning any impacts to Endangered Species listed marine mammals, sea turtles, or sturgeon to the Lessor and NMFS Northeast Region's Stranding Hotline within 48 hours.
4.5.3.3	The Lessee must record injuries or mortalities using the form included as Appendix A to Addendum "C".

Table 4-2 Protected Species Reporting Requirements in the Lease Area

Addendum "C" Stipulation	Lease Requirement
4.5.4 Protected Species Observer Reports	The Lessee must ensure that the PSO record all observations of protected species using standard marine mammal PSO data collection protocols. The list of required data elements for these reports is provided in Appendix B to Addendum "C."

4.5 Avian and Bat Protection

Equinor Wind US LLC will provide an annual report to the to BOEM and U.S. Fish and Wildlife Service using the contact information listed in the Lease, or updated contact information as provided by BOEM, by January 31 of each year of the site assessment term. This report will document dead or injured birds or bats found on vessels and the meteorological buoy during construction, operations, and decommissioning of the meteorological buoy. Each report will contain the following information: the name of species, date found, location, a picture to confirm species identity (if possible) and any other relevant information. In addition to submitting the annual report, Equinor Wind US LLC will report carcasses with Federal or research bands to the United States Geological Survey Bird Band Laboratory within 30 calendar days of discovery using the following website: https://www.pwrc.usgs.gov/bbl/, or updated contact information as provided by BOEM.

4.6 Marine Trash and Debris Awareness and Elimination

Equinor Wind US LLC will comply with and ensure that all employees and contractors are briefed on marine trash and debris awareness elimination, as required in Addendum C, Section 4.1.4 of the Lease and as described in the Bureau of Safety and Environmental Enforcement NTL No. 2015-G03 or any NTL that supersedes NTL 2015-G03.

4.7 Oil Spill Response

The RPS FLiDAR Buoys, Wave and Met Buoy and CM/CT Mooring will not require a backup generator or any other fuel dependent equipment. As such, no Oil Spill Response Plan or Oil Spill Response Measures will be required.

4.8 Health and Safety

Equinor Wind US LLC will implement a project-specific HSE Plan to ensure the health and safety of all personnel involved in the installation, operation, and maintenance, and decommissioning of the Metocean Facilities. The project-specific plan will be prepared in accordance with Equinor's standard corporate HSE policies and procedures. The HSE Plan will also address emergency response and reporting requirements. The HSE plan is included as Appendix F to this SAP.

5. OPERATIONS AND MAINTENANCE

5.1 Data Collection and Operations for Wind and Metocean Data

As stated in Sections 0 and 0 the Metocean Facilities will remain moored in position and transmit wind data and metocean measurements autonomously via Iridium Broadband, or 4G, if available. The RPS FLiDAR Buoys will transmit motion reference data, heading data and charge/discharge once a day, and 10-minute average wind speed and direction profiles, as well as system voltage information and charge discharge rates will be transmitted every 10 minutes The Wave and Met Buoy will transmit wave and met parameters, including 30-minute wave spectrum and 3 x 10-minute met parameter data, every 30 minutes. Equipment on the CM/CT Mooring will store data internally to be downloaded every six months during maintenance trips.

5.2 Maintenance Activities

5.2.1 RPS FLiDAR Buoy

Planned on-site maintenance for the RPS FLiDAR Buoys is scheduled at 6-month intervals and will be completed by a vessel comparable to the work boat used for installation (see Section 4.2). Planned maintenance activities will include service of sensors, data retrieval, inspection of mooring components and replacement where appropriate, and cleaning of solar panels and wind turbines. A detailed service, which will include all 6-month activities, as well as replacement of the mooring system, will be performed at 12-month intervals.

5.2.2 Wave and Met Buoy

Planned on-site maintenance for the Wave and Met Buoy is scheduled every 6 months and will be completed by a vessel comparable to the work boat used for installation (see Section 4.2). Planned maintenance activities at the first 6-month interval would include cleaning of the buoy dome and hull if necessary, as well as visual inspection of the mooring system and replacement of parts where appropriate. At 12 months the mooring will be recovered to deck and replaced.

5.2.3 CM/CT Mooring

Planned on-site maintenance for the CM/CT Mooring is scheduled every 6 months and will be completed by a vessel comparable to the work boat used for installation (see Section 4.2). Planned maintenance activities include changing out batteries, downloading data, and visual inspection of the mooring system. At 12 months the mooring will be replaced. Equinor Wind US LLC will incorporate planned maintenance activities into a comprehensive annual Self-Inspection Plan pursuant to 30 CFR 585.824(a).

5.2.4 Unscheduled Visits

In addition to the planned 6-month maintenance activities, in exceptional circumstances an unscheduled visit to a deployment location may be required if there is evidence of damage (such as partial or total loss of data transmissions), or if transmitted GPS data indicated that a buoy had drifted significantly outside the “watch circle,” which allows for buoy movement inside a roughly 100-meter radius from the recorded deployment coordinates. Examples of events that could cause such damage or buoy displacement include, but are not limited to, hurricane-strength tropical or "nor'easter" storms, heavy snow accumulation, or heavy icing in the event of extremely low temperatures. It has been assumed that up to one unscheduled round trip per year may be needed to visit a buoy site, and potential emissions for unscheduled visits have been based on the round-trip distance to the farthest deployment location from Miller’s Launch, which is FLiDAR 1.

5.3 Reporting

Per Lease stipulation 2.2.1, Equinor Wind US LLC will submit a semi-annual progress report to BOEM every six months for the duration of the site assessment term. The semi-annual progress report will provide a brief narrative of overall progress since the previous semi-annual progress report (or since the effective date for the first semi-annual progress report). The progress report will include updated survey plans to account for modifications in schedule, as necessary. In addition to the semi-annual progress reports, Equinor Wind US LLC will prepare and submit a Self-Inspection Report, an Annual Report, and a Certification of Compliance to BOEM no later than November 1 of each year for the duration of the site assessment term. See Table 5-1 for a description of the content of each report and the associated regulatory citation.

Table 5-1 Reporting Requirements

Report Name	Content	Regulatory Citation
Self-Inspection Report	The Self-Inspection Report will be based on the comprehensive Self-Inspection Plan that Equinor Wind US LLC will develop pursuant to 30 CFR 585.824(a).	30 CFR 585.824(b)
Annual Report	The Annual Report will provide a summary of site assessment activities and the results of those activities.	30 CFR 585.615(b)
Certification of Compliance	Together with the certification, Equinor Wind US LLC will submit: • Summary reports that demonstrate compliance with the terms and conditions that require certification; and • A statement identifying and describing any mitigation measures and monitoring methods that have been taken, as well as their effectiveness. If Equinor Wind US LLC identifies measures that are not effective, we will make recommendations for substitute mitigations measures and monitoring methods, and explain why we believe they would be effective.	30 CFR 585.615(c)

5.4 Potential Faults or Failures

The Metocean Facilities will be remotely monitored for the duration of operations. This monitoring will include a range of key indicators such as power level, buoy location, and data quality to provide an insight to the 'health' of the buoy and payload. Unplanned maintenance activities may be required in the event of a power supply failure, buoy drift outside of designated area, mooring component failure, or other such event. If any of these problems are suspected, a technical service crew would be promptly dispatched to investigate and repair the issue. The RPS FLiDAR Buoys are capable of operating at full capacity without renewable power supply to the batteries for up to seven days. The RPS Wave and Met Buoy has enough reserve power to operate in a standard sampling routine for up to three months without being recharged.

6. DECOMMISSIONING

BOEM requires decommissioning of facilities described in the SAP in accordance with § 585.901. Equinor Wind US LLC will submit a decommissioning application to BOEM as required by § 585.902(b) prior to decommissioning of the Metocean Facilities. Following BOEM approval of the decommissioning application, Equinor Wind US LLC will submit a decommissioning notice to BOEM at least 60 days prior to vessel deployment as required by § 585.90(a).

6.1 Overview of Decommissioning Activities

Upon completion of SAP activities, the Metocean Facilities will be decommissioned. The decommissioning process will be similar to the installation process but in reverse. Similar types and numbers of vessels used for the installation of the Metocean Facilities would be used for decommissioning. The work vessel would position itself on-site to attach the chain to the crane or A-frame of the work vessel and the mooring would be recovered to deck. The Buoys would then be detached from the mooring and attached to the work vessel. The Metocean Facilities would then be towed off site.

6.2 Site Clearance

The operation of the Metocean Facilities is not expected to result in any trash or bottom debris. However, Equinor Wind US LLC will ensure that the seafloor has been cleared of all obstructions created by activities on the Lease as required in § 585.902(a)(2). This will be accomplished via photo documentation of all deployed and retrieved equipment. As stated in Section 4.1, Equinor Wind US LLC will provide an Installation Report that will contain the final coordinates and photo documentation of the equipment that was deployed. At the completion of decommissioning, similar documentation will be provided to BOEM to confirm that all equipment was retrieved from the site.

6.3 Reporting

As specified in the Lease, Addendum C, Section 2.2, Equinor Wind US LLC will submit semi-annual progress reports to BOEM throughout the duration of activities covered by the SAP. At the conclusion of the site assessment activities a Decommissioning Report will be prepared in accordance with §§ 585.900-913 and provided to BOEM with the semi-annual progress reports, or upon request. This report will include a description of the process and equipment used for decommissioning the Metocean Facilities and confirmation of site clearance.

7. AFFECTED ENVIRONMENT, POTENTIAL IMPACTS, AND MITIGATION MEASURES

The following sections describe the affected environment, impacts and proposed mitigation measures for benthic resources, archaeological resources, and geophysical conditions which have been developed through site surveys and analysis that were conducted in March and April 2018 in support of the SAP. Site surveys and analysis followed a detailed SAP Survey Plan which included protocols, methods, and/or used data that represented the state of industry techniques and knowledge at the time of the study. The SAP Survey Plan, detailing the SAP survey approach, timing, identified surveys, and reporting, was accepted by BOEM on February 27, 2018.

The analysis focuses on the maximum area of potential disturbance associated with the installation, operation, and decommissioning of the Metocean Facilities (site assessment activities): approximately 151.8 ft^2 (14.1 m^2) for Buoy Deployment Area 1 and 67.8 ft^2 (6.3 m^2) for Buoy Deployment Area 2.

As stated in Section 3.2, the two Buoy Deployment Areas where the Metocean Facilities are proposed to be located have been given unique identifiers. The Buoy Deployment Area 1 will have a RPS FLiDAR Buoy, a RPS Wave and Met Buoy, and a CM/CT Mooring, located at positions FLiDAR 1, Wave and Met Buoy, and Current Meters, as indicated in Table 3-1. The Buoy Deployment Area 2 will have a RPS FLiDAR Buoy at location FLiDAR 2, per Table 3-1. The coordinates for these locations are provided in Table 3-1 and depicted on Figure 1-1.

7.1 Geological Conditions

The following section summarizes results of the HRG survey that was conducted in March to April of 2018. The survey was conducted in accordance with the SAP Survey Plan, as approved by BOEM on February 27, 2018. The full site characterization report is provided in Appendix C.

The HRG survey and sampling program involved acquisition of the following data:

- **Multibeam echosounder bathymetry**– acoustic swath mapping to determine water depths and topographic features on the seabed and initial review of surficial sediment;
- **Side scan sonar imagery** – acoustic seabed imagery used to map surficial sediment distributions and bedforms, as well as detect possible natural and anthropogenic hazards on the seabed such as boulders, debris, and shipwrecks;
- **Sub-bottom profiler** – acoustic reflection profiling subsurface investigation using a shallow and a medium penetration sub-bottom profiler (high-frequency CHIRP and single channel sparker) to investigate shallow (up to 66 ft [20 m]) sediment stratigraphy;
- **Gradiometer** –magnetic field anomaly mapping to detect ferrous items on the seabed that could be potential hazards or cultural deposits, included debris and shipwrecks;
- **Sediment grab samples** – acquisition of physical samples of the surficial seabed to ground-truth interpretation of the geophysical data; and
- **Underwater video imagery** – visual imagery of the seabed collected using a remotely operated camera to identify natural and human-caused obstructions, as well as aid in benthic habitat assessment.

Data from the HRG and sampling program, along with information from publicly-available databases, were compiled and reviewed to describe the surface and subsurface geologic conditions in the Buoy Deployment Areas. Table 7-1 summarizes the water depth, surficial seafloor sediment, and side scan features or magnetometer contacts related to seafloor hazards identified within the Buoy Deployment Areas.

Table 7-1 Seafloor and Sub-Seafloor Hazards

Hazard	Definition	Identification and Description
Seafloor		
Scarp	An exposed face of soil above the head of a landslide.	None identified on bathymetry or side scan sonar data.
Channels	The deepest portion of a body of water through which the main volume or current of water flows.	None identified on bathymetry or side scan sonar data.
Ridges	A relatively narrow elevation which is prominent on account of steep angle at which it rises.	None identified on bathymetry or side scan sonar data.
Bedforms	Features that develop due to the movement of sediment by the interaction of flowing water; critical angle and forces required for movement are dependent upon many factors.	Low-relief bedforms are noted, which suggesting minor continuous or episodic seabed currents, but are not anticipated to present a hazard.
Exposed Rocky Area	Surface expression of bedrock outcropping on seafloor.	None identified on bathymetry, side scan sonar, or sub-bottom profiler datasets.
Boulders	Glacial erratics (boulders) greater than 12 inches in diameter; outcropping coarse till/drift or lag deposit.	Occasionally identified at seabed on bathymetry or side scan sonar data, often correlating to areas of coarser seabed sediments. Sizes and distances to installation locations indicate that the boulders will not be a hazard to mooring deployment, operation, or recovery.
Buried Boulders	Glacial erratics (boulders) greater than 12 inches in diameter; subsurface coarse till/drift or lag deposits.	None identified on the sub-bottom profiler datasets.
Pock Marks / Depressions	Craters in the seabed caused by fluids (gas and liquids) erupting /streaming through the seabed sediments.	None identified on bathymetry, side scan sonar, or sub-bottom profiler datasets.
Seabed Scars / Ice Scour / Drag Marks	Incisions or cuts into the seafloor may be associated with glacial advances/retreats or bottom fishing activity.	None identified on bathymetry or side scan sonar data.
Buried Channels	Former fluvial drainage pathways during sea level low stands, usually only deepest portion of the waterway in-filled and preserved. Mark ancestral patterns of glacier meltwater runoff.	Channeling events are interpreted within the Pleistocene sediments, but as these features occur deeper than 65.6 ft (20 m) below the seabed, there is no hazard posed to the mooring systems.
Submarine Canyons	Steep-sided valley cut into the seafloor of the continental slope, sometimes extending well onto the continental shelf.	None identified on bathymetry data.
River Channel	Outline of a path of relatively shallow and narrow body of fluid	None identified on bathymetry or side scan sonar data.
Exposed Hardbottom Surfaces	Any semi-lithified to solid rock strata exposed at the seafloor; in this area, may include bedrock or a nearly continuous pavement of fragmented rock or boulders.	None identified on bathymetry, side scan sonar, or sub-bottom profiler datasets.
Shallow Gas	Subsurface concentration of material in gaseous form that has accumulated by the process of decomposition of carbon-based materials (former living organisms).	None identified on the sub-bottom profiler datasets.
Gas Hydrates	Subsurface gas deposits that were formed at or near the seafloor in association with hydrocarbon seeps.	None identified on the sub-bottom profiler datasets.
Gas/Fluid Expulsion Features	Upward movement of gas/fluid via low resistance pathways through sediments onto the seafloor; may be related to other hazards diapirs, faults, shallow water flows).	None identified on bathymetry, side scan sonar, or sub-bottom profiler datasets.
Diapiric Structure Expressions	The extrusion of more mobile and ductile-deformable material forced onto the seafloor from pressure below.	None identified on the sub-bottom profiler datasets.
Karst Areas	Landscape formed from the dissolution of soluble rocks.	None identified on the sub-bottom profiler datasets.
Faults, Faulting Expression, Fault Activity	Physiographic feature (surface expression) related to a fracture, fault, or fracture zone along which there has been displacement of the sides relative to one another.	None identified on bathymetry, side scan sonar, or sub-bottom profiler datasets.
Slumping, Sliding Seafloor Features	Large scale structures that result from the downslope movement of sediments due to instability and gravity. In the	None identified on bathymetry, side scan sonar, or sub-bottom profiler datasets.

Table 7-1 Seafloor and Sub-Seafloor Hazards

Hazard	Definition	Identification and Description
	submarine environment these structures are often found in slope environments along coastal margins.	
Steep/Unstable Seafloor Slopes	Large scale feature/stretch of ground forming a natural or artificial incline, with a slope that approaches the angle of repose (maximum angle at which the material remains stable).	None identified on bathymetry, side scan sonar, or sub-bottom profiler datasets.
Scour/Erosion Features	Erosion of material due to water flow. Often associated with erosion adjacent to larger natural and man-made structures.	No significant scour-related features are identified on the seabed or near interpreted boulder features.
Sensitive Benthic Habitats (chemosynthetic communities, submerged aquatic vegetation)	Shallow water habitats of submerged aquatic vegetation including macroalgae and sea grasses	None identified on bathymetry, side scan sonar, or sub-bottom profiler datasets.

7.1.1 Buoy Deployment Area 1

Water depths across Buoy Deployment Area 1 range between 110 ft (33.6 m) and 124 ft (37.8 m) NAVD88. Water depth at the proposed FLiDAR 1, Wave and Met Buoy, and Current Meters Locations is 118 ft (36.0 m), 118 ft (35.9 m), and 119 ft (36.3 m) NAVD88 respectively. The seafloor is generally flat across the entire area, with slight shoaling in the west, displaying gradients of less than 1°. In Buoy Deployment Area 1 ripples are noted across much of the area, orientated from west-southwest to east-northeast with 0.3 ft (0.1 m) height and 20-33 ft (6-10 m) wavelength. Chart 11179.102 in Appendix C presents bathymetry contours for Buoy Deployment Area 1.

The seabed throughout Buoy Deployment Area 1 is characterized as predominantly sand with occasional shell fragments. Areas of higher reflectivity in the side scan sonar dataset map across the area and correlate to bathymetric lows. Environmental sampling and bottom photos show these areas to contain a higher proportion of coarser gravels. The seabed interpretation identifies three seabed types: sand with occasional shell fragments, slightly gravelly sand, and sandy gravel.

Seabed features and the side scan sonar mosaic for the Buoy Deployment Area 1 are presented as Chart 11179.103 and Chart 11179.104, respectively, in Appendix C. Two sonar contacts are present in the side scan sonar data within Buoy Deployment Area 1, with one target interpreted as a boulder with a height of 0.3 ft (0.1 m) and the other interpreted as linear debris with a length of 103 ft (31.5 m).

The residual (anomalous) magnetic field contours for Buoy Deployment Area 1 are presented as Chart 11179.107 in Appendix C. Thirteen (13) magnetic anomalies occur within Buoy Deployment Area 1 (see Appendix C). None of these anomalies are associated with either of the identified side scan sonar targets.

Shallow soils interpretation was based on both the shallow seismic chirp system as well as the medium penetration sparker seismic data. Horizons were predominantly digitized from the sparker data due to the limited penetration of the chirp system into the sandy sediments within the survey area. The elevation of the base of the Holocene Marine Deposits is mapped and presented on Chart 11179.106. The thickness of this unit is contoured as isopachs on Chart 11179.105. The base of these sediments below seabed at the FLiDAR 1, Wave and Met Buoy, and Current Meters Locations are 13.4 ft (4.1 m), 8.9 ft (2.7 m), and 13.1 ft (4.0 m), respectively. The Holocene deposits generally thicken slightly towards the East. Pleistocene sediments underlie the Holocene sediments, with unconformities present. The base of these deposits reaches a maximum depth below seabed of 128 ft (39 m) in a north-south trending channel feature in the east of the survey area.

7.1.2 Buoy Deployment Area 2

Water depths across Buoy Deployment Area 2 range between 92 ft (28.1 m) and 101 ft (30.8 m) NAVD88. Water depth at the proposed FLiDAR 2 location is 29.6 m NAVD88. The seafloor is characterized as generally flat lying, with low relief bedforms noted across much of the area. Seafloor gradients across the site are generally less than 1°. Bathymetry contours for the Buoy Deployment Area 2 are presented as Chart 11179.202 in Appendix C.

Environmental sampling show seabed sediments across the FLiDAR 2 survey area to predominantly comprise sand with occasional shell fragments. Areas of higher reflectivity side scan sonar data are noted across the site; which generally correlate with bathymetric lows. Environmental sampling and imagery show these areas to contain a higher proportion of gravels.

Seabed features and a side scan sonar mosaic for the Buoy Deployment Area 2 are presented as Chart 11179.203 and Chart 11179.204 in Appendix C respectively. Fifteen side scan sonar contacts are present within Buoy Deployment Area 2. Fourteen of these contacts are interpreted as boulders and occur within the locations of the gravelly sediments. One contact is interpreted as an item of debris. The boulders range in interpreted size from 0.3 ft (0.1 m) to 1.6 ft (0.5 m) in height.

Chart 11179.207 in Appendix C presents the residual (anomalous) magnetic field contours for Buoy Deployment Area 2. Twenty-one (21) magnetic anomalies occur within Buoy Deployment Area 2 (see Appendix C). None of these anomalies are associated with side scan sonar targets. Two larger magnetic anomalies of 23 nanotesla and 20 nanotesla were identified 1351.7 ft (412 m) and 662.7 ft (202 m) from the FLiDAR 2 location respectively. The other anomalies are not interpreted a hazard to mooring due to their distance from the location and small magnitude, as well as the absence of any features at or below seabed to confirm the presence of a hazard.

Shallow soils interpretation was based on both the shallow seismic chirp system as well as the medium penetration sparker seismic data. Horizons were predominantly digitized from the sparker data due to the limited penetration of the chirp system into the sandy sediments within Buoy Deployment Area 2. The base of the Holocene Marine Deposits is mapped and presented on Chart 11179.206. The base of these sediments below seabed at the FLiDAR 2 location is 6.2 ft (1.9 m). The thickness of this unit is contoured as isopachs on Chart 11179.205. The Holocene deposits generally thicken slightly towards the west. Pleistocene sediments underlie the Holocene sediments, with a number of unconformities present.

7.1.3 Natural Seafloor and Sub-Seafloor Hazards

The HRG datasets were analyzed for seafloor and sub-seafloor hazards, which could pose a potential risk to the installation, operation, and maintenance of the Metocean facilities.

The HRG datasets were used to determine the presence or absence of additional geological hazards (see Table 7-1). The side scan sonar, multibeam bathymetry, and sub-bottom profiler datasets were reviewed and do not provide any evidence of seismic activity, such as extensive or regional faulting or slump and mass wasting features. Additionally, no fault zones, nor any other faulting activity, are identified either from seabed data or from the sub-bottom profiler records, as would typically be indicated by offset sedimentary bedding planes in the sub-bottom profiles or linear fault-related features on the seabed. No faults or other sedimentary features indicative of differential compaction or localized seabed subsidence have been identified. As there has been no faulting identified, there has also been no evidence of faulting attenuation effects observed in the geophysical datasets. These results are consistent with the expected nature of the passive continental margin of the New York Bight.

No areas of acoustic whiteouts or other significant amplitude anomalies were observed in the sub-bottom profiler data, as would be anticipated for any significant accumulation of shallow gas. The sub-bottom profiler records do not contain any bottom simulating reflectors, which are a typical indication of the presence of hydrates. The interpretation of the side-scan sonar, multibeam bathymetry, and sub-bottom profile datasets provide no evidence of ice scour, such as seabed gouging by either icebergs or sea ice pressure ridges. Additionally, no craters or other seabed evidence of strudel scours were noted in any of the datasets.

Based on the Geophysical Site Investigation Site Characterization Reports for Site Acquisition Plan (Appendix C), the site conditions are suitable for the installation of the Metocean Facilities and associated mooring equipment in each of the two Buoy Deployment Areas. No notable hazards are identified which would preclude installation at these locations. The low-relief bedforms on areas of the seabed may indicate minor seabed currents, but no larger scour-related features, such as deep moats, nor evidence of large-scale migrating bedforms are present in the seabed and shallow subsurface datasets. Due to the absence of these more significant features, seabed currents are inferred to be modest and seabed scour due to bottom currents is not anticipated to be an issue for the mooring systems. The boulders identified within the Deployment Areas are generally small, with lower relief (1.6 ft [0.5 m] or less) and do not represent a significant hazard to the installation, operations, maintenance, or recovery of the mooring systems. While buried channels are identified within the Pleistocene sediments, these sub-seafloor features do not represent a hazard to the mooring systems.

7.2 Archaeological Resources

The following section summarizes the analysis and findings described in the Marine Archaeological Resource Assessment Report (Appendix D).

7.2.1 Affected Environment

Installation of the Metocean Facilities has the potential to affect submerged archaeological resources.

The New York Lease Area is located roughly 25 miles (40 km) from the mouth of New York Harbor at its closest point, which suggests a high potential for both historic and prehistoric archaeological sites. This high potential designation is based on the historic maritime activity of the area and prehistoric occupation on the once exposed continental shelf. The preservation potential for archaeological resources within the New York Lease Area, however is low. The low preservation potential results from two related factors: marine transgression and seafloor sedimentation. Sedimentation rates have been low along the continental margin within the last 10,000 years, and the seafloor has been exposed to erosional forces associated with both marine transgression and seabed currents. Consequently, relict channels of major rivers have the potential to be recognized in marine remote sensing datasets, but the identification of small-scale sites and landforms is limited.

SEARCH, Inc. conducted an archaeological assessment of the HRG survey data acquired in 2018 for the Project (described in Section 7.1). To support this effort, SEARCH maritime archaeologists, submerged paleoarchaeologists, and historians created a prehistoric and historic context for the region, assembled a geologic and environmental background, reviewed previous archaeological investigations conducted in the vicinity, and identified submerged cultural resources reported in the vicinity of the New York Lease Area to supplement and guide data analysis. This information, a discussion of survey and data processing technologies and methodologies, and the archaeological findings and recommendations are presented as the Marine Archaeological Resource Assessment Report for the Empire Wind SAP survey (Appendix D).

The HRG survey utilized numerous remote survey methods including: marine gradiometer, side scan sonar, subbottom profiler, and multibeam echosounder. Archaeological review of the survey data focused on the entire Buoy Deployment Areas, although bottom disturbing activity will be limited to the footprint of the clump weight anchors and mooring chain resting on the seafloor. The Area of Potential Effect (APE) is defined as the area of seabed disturbance associated with the metocean facilities.

The qualified marine archaeologist from SEARCH identified no magnetic anomalies and no side scan sonar contacts representing submerged cultural resources within the two Buoy Deployment Areas. Sub-bottom profiler data was collected and analyzed to identify paleolandscape features. This data indicated that no prominent seismic reflectors indicative of paleo-landforms are present that may preserve inundated archaeological sites.

7.2.1.1 Buoy Deployment Area 1

SEARCH identified twenty-two magnetic anomalies (meeting the 5-gamma threshold), five acoustic contacts, and forty unique acoustic reflectors (representing eleven total reflective features) in Buoy Deployment Area 1 (Appendix D, Appendix A-1 to A-4). These reflectors do not exhibit characteristics of a submerged paleolandscape potentially used for occupation but instead likely represent a geographically wide-spread, natural, geologic feature.

7.2.1.2 Buoy Deployment Area 2

SEARCH identified six magnetic anomalies, ten acoustic contacts, and six unique buried reflectors (representing six total reflective features) in the Buoy Deployment Area 2 APE (Appendix D, Appendix A-5 to A-8). These targets do not exhibit characteristics of verified shipwrecks.

The anomalies, contacts, and reflectors observed in the data records for the Buoy Deployment Area 1 and Buoy Deployment Area 2 likely relate to modern debris and non-cultural geological features. Given that no remote-sensing targets exhibit characteristics of verified shipwrecks or paleolandscapes, no features of cultural significance have been identified for both Buoy Deployment Area 1 and Buoy Deployment Area 2.

7.2.2 Potential Impacts and Proposed Mitigation Measures

Based upon the results of the 2018 marine archaeological assessment (Appendix D), no potential submerged cultural or archaeological resources were identified within Buoy Deployment Areas, and as such, the installation and operation of the proposed Metocean Facilities would result in no impacts to marine archaeological resources. Due to the height of the FLiDAR (13.5 ft [4.1 m]) from the sea surface to the top of the hull mast) and the distance from shore, the installation and operation of the Metocean Facilities will not result in any visual impacts.

7.3 Benthic Resources

The following section summarizes results of the benthic habitat assessment that was conducted in March to April 2018. The survey was conducted in accordance with the plan, approved by BOEM on February 27, 2018. The full benthic habitat assessment report is provided in Appendix E.

Benthic samples were collected at five locations using a stainless-steel 0.1-m^2 Day grab (Figure 7-1). The grab carried extra weights where appropriate to induce better penetration on impact and an extended bucket lip to reduce sediment washout. Storm feet and elastic straps were used to reduce the likelihood of the instrument pre-triggering in the water column during deployment. An attached, protective enclosure held a SubSea 1Cam HD digital camera with a dedicated video lamp. Pre-grab still photographs were taken at each station. Sediment grab samples were in general concordance with the remote imagery, confirming a predominance of sand occasionally mixed with gravel.

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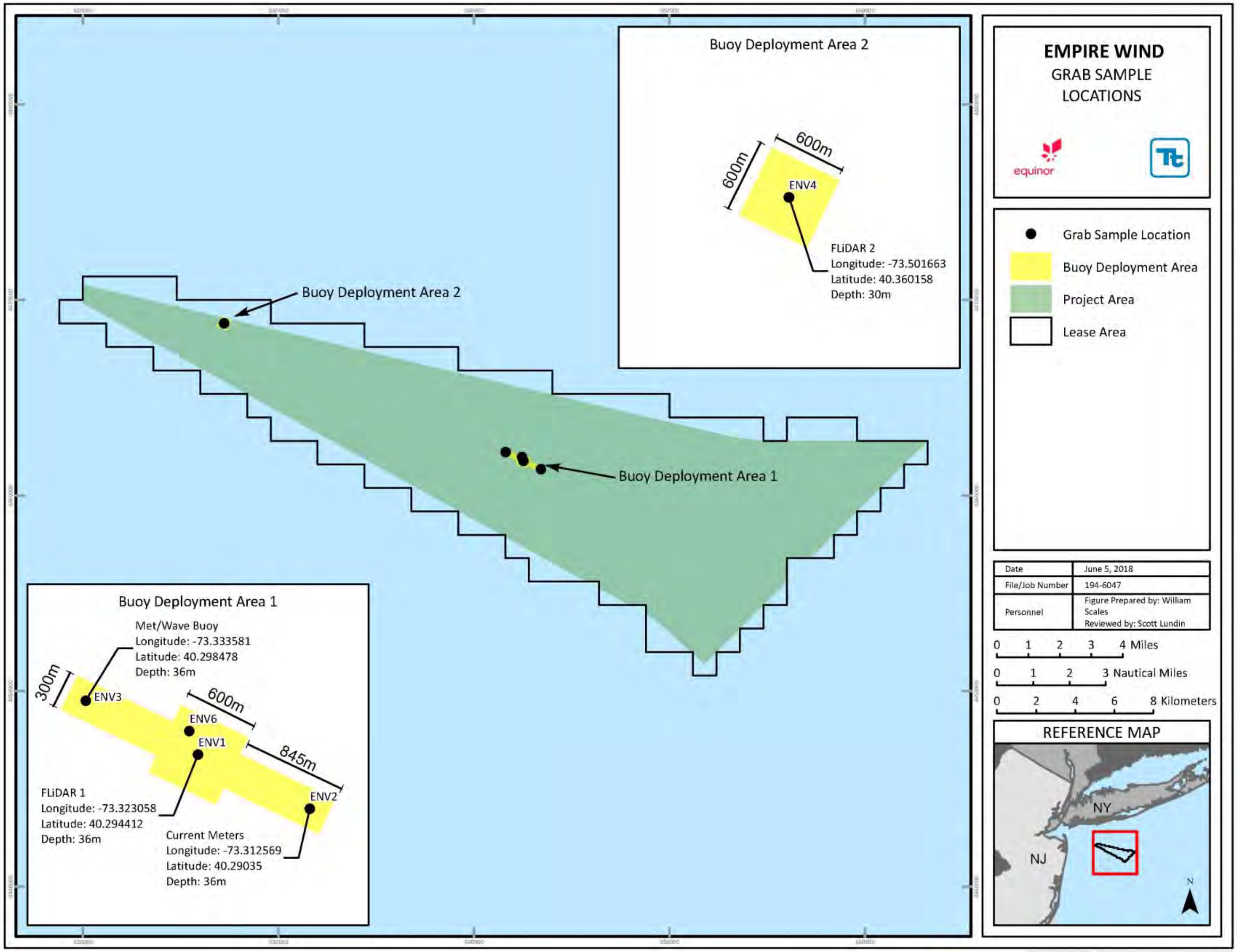

Figure 7-1 Grab Sample Locations

No evidence of protected or unique habitats was indicated by the seabed imagery or grab sampling in either Buoy Deployment Area. No benthic species listed under the ESA occur in the Lease Area. No protected fish species were observed during the survey.

7.3.1 Buoy Deployment Area 1

The side scan sonar imagery in the Buoy Deployment Area 1 indicated a generally flat bottom with a range of reflectivities. The substrate was dominated by slightly gravelly fine to medium sand with occasional shell fragments at Stations ENV1, ENV2, and ENV3. Station ENV6, which was added to represent an area of medium reflectivity near the FLiDAR 1 location, had larger grain sizes, identified as coarse sand. Total organic content was low at all stations, ranging from 0.2 to 0.4 percent. Water depths ranged between 108.3 ft (33.0 m) and 124.0 ft (37.8 m) NAVD88.

Infaunal organisms in grab samples from the four stations associated with Buoy Deployment Area 1 varied in taxonomic diversity and overall abundance of organisms. Station ENV2, which was farthest offshore and in the deepest water, had the fewest individuals (44 of 529) and the smallest number of distinct taxa (8 of 60). Species distribution was patchy among the four stations, as shown by the Coastal and Marine Ecological Classification Standard (CMECS). All four stations were classified as Benthic Biota: Faunal Bed: Soft Sediment Fauna, then diverged as shown in Table 7-2. Stations are presented in order of distance from shore.

Table 7-2 Buoy Deployment Area 1 Grab Samples

Station	Biotic Group	Biotic Community
ST18904-ENV3	Sand Dollar Bed	*Echinarachnius parma* Bed
ST18904-ENV6	Small Surface- Burrowing Fauna	Lumbrinerid Bed
ST18904-ENV1	Diverse Soft Sediment Epifauna	Sand Dollar/ Sea Pansy/ Mobile Mollusk Bed (Large Megafauna)
ST18904-ENV2	Sand Dollar Bed	*Echinarachnius parma* Bed

7.3.2 Buoy Deployment Area 2

The Buoy Deployment Area 2 was characterized as generally flat but traversed by a broad depression about 6.6 ft (2 m) deep running northwest to southeast. Thirteen boulders and one debris item were identified in the side scan sonar imagery. Only one station (ENV4) was sampled in this area.

Seabed imagery indicated that the low reflectivity seabed consisted of medium sand with occasional shell fragments. The grab was described as slightly gravelly silty sand with a very slight anoxic odor.

The single FLiDAR 2 location (ENV4) had notably higher species diversity and abundance than the four sampling locations associated with FLiDAR 1. Forty-five percent of the individuals and 42 percent of the taxa collected from grab samples were from this station. The Buoy Deployment Area 2 location also had relatively higher percent TOC (0.07) and finer grain size than the stations to the east. Water depths ranged between 92.2 ft (28.1 m) and 101.1 ft (30.8 m) NAVD88 in the Buoy Deployment Area 2.

The benthic community at ENV4 was characterized as Larger Tube-Building Fauna: Robust Ampelisca Bed; the infauna was dominated by polychaetes and amphipods. Epibenthic organisms observed in the imagery included cariid shrimp, bivalves, and gastropod snails. A solitary tube-dwelling anemone (Ceriantharia) was the only anthozoan observed in grab samples. Hydractinia symbiolongicarpu was observed in benthic imagery. Neither of these species form biogenic reefs. These species are not considered indicative of sensitive benthic habitat.

7.4 Fisheries

As demonstrated in Section 2, the equipment and methodologies proposed herein by Equinor Wind US LLC are consistent with the activity considered by BOEM in the Offshore New York EA (BOEM 2016b). Section 4.4.2.7 of the revised EA describes the affected environment and potential impacts to fisheries that may result from site assessment activity. The information in BOEM (2016) is incorporated by reference and not repeated.

Equinor Wind US LLC has reviewed currently available literature and data (see Section 8.2) regarding fisheries in and near the project area and has determined that no new substantive information has become available that warrants revision of the analysis in BOEM (2016). While stock assessments for the Mid-Atlantic fisheries resources are regularly updated, the description of species assemblages in the Revised Offshore New York EA are considered representative of current conditions.

Critical habitat for the Atlantic sturgeon was designated in August 2017, after the Revised Offshore New York EA was released. However, no critical habitat was designated within the Lease Area (NOAA 2017a), (82 FR 39160). BOEM's analysis is applicable and the determination that the proposed site assessment activity would not likely to adversely affect Atlantic sturgeon is appropriate. The oceanic whitetip shark (*Carcharhinus longimanus*) and the manta ray (*Manta birostris*) were proposed for listing as threatened under the ESA after the Revised Offshore New York EA was released (NMFS 2017 and 2018). These large mobile elasmobranchs will be assumed present in the Lease Area; they are expected to behave much like other more common sharks, skates, and rays by avoiding areas of human activity and noise. BMPs implemented for other fish, including Atlantic and shortnose sturgeon, would be protective of the whitetip shark and manta ray. The proposed site assessment activity would not adversely affect these proposed threatened species.

Equinor Wind US LLC has committed to implementing all applicable lease conditions, which include implementing BMPs during installation, operation, and decommissioning of the Metocean Facilities to minimize impacts on fisheries, including species protected under the ESA. Lease Stipulation 4.1.5 requires that Equinor Wind US LLC develop a publicly available Fisheries Communications Plan that describes the strategies that Equinor Wind US LLC intends to use for communicating with fisheries stakeholders prior to and during activities in support of the submission of a plan. The Fisheries Communications Plan presents Equinor Wind US LLC's proposed approach to outreach with the fishing industry in relation to the development of the Project. The draft Fisheries Liaison & Outline Coexistence Plan for survey activities is available online at https://www.equinor.com/en/what-we-do/empirewind.html. Additionally, Equinor Wind US LLC has contracted with Sea Risk Solutions LLC to provide Fisheries Liaison Officer(s) to the Project. Sea Risk Solutions leverages experience, technology, innovation, and people skills to mitigate risks and serve as a bridge among marine sectors. The lead Fisheries Liaison Officer for the Project will be:

Stephen Drew
Sea Risk Solutions LLC
sdrew@searisksolutions.com
Tel +1 908 339 7439

Equinor Wind US LLC will comply with any additional stipulations as set forth in permits or approvals in support of the proposed site assessment activity.

7.5 Marine Mammals and Sea Turtles

As demonstrated in Section 2, the equipment and methodologies proposed herein by Equinor Wind US LLC are consistent with the activity considered by BOEM in the Offshore New York EA (BOEM 2016b). Sections 4.4.2.5 and 4.4.2.6 of the EA provide details on the species and seasonal occurrence of marine mammals and sea turtles that may be present during the proposed site assessment activity and is incorporated by reference and not repeated.

Equinor Wind US LLC has reviewed publicly available literature and data published since the Offshore New York EA and Finding of No Significant Impact were issued (see Section 8.3). There is no substantive new information that would change BOEM's analysis and conclusion that the proposed activity is not anticipated to result in any significant or population-level effects to marine mammals or sea turtles.

BOEM's EA references NMFS biological opinion on assessment activities in the [Empire Wind Lease Area] (NMFS, 2013a), and states that, 'The potential for marine mammals to interact with the buoy and become entangled in the buoy or mooring system is extremely unlikely given the low probability of a marine mammal encountering one buoy or mooring system within the [Empire Wind Lease Area], and the high tension of the chain which further reduces risk of entanglement". Appreciating the biological opinion relates to an all chain mooring, the key points to note are the extremely unlikely possibility of that contact occurring, in addition to the reduced risk from a line under tension, which would be applicable to the polypropylene line under tension.

As stated above, the use of polypropylene rope in a taught and vertical section of the moorings is not deemed to be a significant entanglement risk, and alternative material such as chain or wire rope add risk to the safe and effective deployment and recovery procedures, while not necessarily adding any proportional value to mitigating extremely unlikely events. Other mitigation such as coating the rope section in plastic tubing have been explored, but have also been deemed to add risk through potential wear and failure of the rope section, again at little or no proportional mitigating value.

Equinor Wind US LLC has committed to implementing all applicable lease conditions, which include BMPs for the installation, operation, and decommissioning of the Metocean Facilities in order to further reduce the potential for interactions with or impacts on marine wildlife. Equinor Wind US LLC will comply with any additional stipulations as set forth in permits or approvals in support of the proposed site assessment activity.

Pile driving activity is not required for met buoy installation and therefore there will be no acoustic harassment associated with met buoy installation and mitigation measures are not applicable.

7.6 Avian and Bat Resources

As demonstrated in Section 2, the equipment and methodologies proposed herein by Equinor Wind US LLC are consistent with the activity considered by BOEM in the Offshore New York EA (BOEM 2016b). Sections 4.4.2.1 and 4.4.2.2 of the EA provide details on the species and seasonal occurrence of avian and bat resources that may be present during the proposed site assessment activity and is incorporated by reference and not repeated.

Equinor Wind US LLC has reviewed currently available literature and data (see Section 8.4) regarding avian and bat resources in the Mid-Atlantic off the coast of New York and has determined that there is no substantive new information that would change BOEM's analysis. The results of the EA and BOEM's analysis and conclusion that the proposed activity is not anticipated to result in any significant or population-level effects to avian and bat resources is applicable.

Equinor Wind US LLC has committed to implementing all applicable lease conditions, which include BMPs for the installation, operation, and decommissioning of the Metocean Facilities in order to further reduce the potential for interactions with or impacts on avian and bat resources. Equinor Wind US LLC will comply with any additional stipulations as set forth in permits or approvals in support of the proposed site assessment activity.

7.7 Water Quality

As demonstrated in Section 2, the equipment and methodologies proposed herein by Equinor Wind US LLC are consistent with the activity considered by BOEM in the Offshore New York EA (BOEM 2016b). Section 4.4.1.2 of the EA provide details on the potential impacts to water quality that result from the proposed site assessment activity and is incorporated by reference and not repeated.

Equinor Wind US LLC has reviewed currently available literature and data (see Section 8.5) regarding water quality in the Mid-Atlantic off the coast of New York and has determined that there is no substantive new information that would change BOEM's analysis. The results of the EA and BOEM's analysis and conclusion that the proposed activity is not anticipated to result in any significant impact to water quality is applicable.

Equinor Wind US LLC has committed to implementing all applicable lease conditions, which include BMPs for the installation, operation, and decommissioning of the Metocean Facilities in order to further reduce the potential for impacts on water quality. Equinor Wind US LLC will comply with any additional stipulations as set forth in permits or approvals in support of the proposed site assessment activity.

7.8 Air Quality

The closest points of land to the proposed site assessment activity are located in Nassau County, New York. In addition, vessels traveling from Miller's Launch to service the Project will transit through waters located in Richmond County, NY (Staten Island) and potentially also in Kings County, NY (Brooklyn). All three of these counties have been designated as moderate nonattainment for the 1997 8-hour ozone (O_3) standard in the revised National Ambient Air Quality Standards (NAAQS); as marginal nonattainment for the 2008 8-hour O_3 standard; as maintenance areas for the 1971 8-hour and 1-hour carbon monoxide [CO] standards; and as maintenance areas for the 1997 annual and 2006 24-hour $PM_{2.5}$ standards. In addition, the U.S. Environmental Protection Agency (EPA) has designated New York as an unclassifiable/attainment area for the new one-hour NO_2 NAAQS, which was promulgated in 2010, pending the collection of additional monitoring data. A similar designation is expected for the one-hour sulfur dioxide (SO_2) NAAQS. New York is designated as unclassifiable or attainment for all other NAAQS. Finally, all of New York is within the Northeast Ozone Transport Region as designated by the Clean Air Act.

7.8.1 Potential Impacts and Proposed Mitigation Measures

The proposed site assessment activity has the potential to impact local air quality. Potential emission sources would however be limited to a single work boat and a support vessel. The vessel associated with these activities would emit criteria air pollutants (NO_x, CO, SO_2, particulate matter less than 10 microns in diameter [PM_{10}], particulate matter less than 2.5 microns in diameter [$PM_{2.5}$]), and volatile organic compounds [VOCs]), hazardous air pollutants (HAPs) and greenhouse gasses [GHGs]). The vessel would emit pollutants both in state and federal waters while traveling to and from the Installation Areas throughout the operational lifecycle of the proposed buoys. Impacts from pollutant emissions associated with this vessel would likely be localized within the immediate vicinity of the site assessment activity.

It is anticipated that the installation and decommissioning of the buoys would each be completed over a period of up to seven over three separate vessel trips. During the operations phase, Equinor Wind US LLC has assumed one separate round trip every six months to each of the four deployment sites (FLiDAR 1, FLiDAR 2, wave and met buoy, and CM/CT mooring) for a single work boat during the operational period. After accounting for the 2-year operational life of the FLiDAR buoys and the 4-year operational life of the wave and met buoy and the CM/CT mooring, this results in a total of 20 round trips during the operations phase. A summary of the air emission estimates is presented in Table 7-3, and the detailed emission calculations and assumptions are presented in Appendix H.

Table 7-3 Equinor Metocean Facilities Air Emissions Summary

Metocean Facilities Activity	VOC tons	NO_X tons	CO tons	PM/PM_{10} tons	$PM_{2.5}$ tons	SO_2 tons	HAPs tons	GHG tons CO_2e
Deployment Activities (Yr. 1)	0.015	0.53	0.27	0.014	0.014	7.08E-05	0.003	38.0
Maintenance Activities (Yrs. 1-2)	0.034	1.25	0.64	0.033	0.032	1.66E-04	0.007	89.0
Maintenance Activities (Yrs. 3-4)	0.018	0.64	0.32	0.017	0.016	8.45E-05	0.004	45.4
Unscheduled Visits (up to 1 per yr.)	0.002	0.08	0.04	0.002	0.002	1.06E-05	0.000	5.7
Decommissioning Activities (end of Yr. 2)	0.010	0.35	0.18	0.009	0.009	4.92E-05	0.002	26.4
Decommissioning Activities (end of Yr. 4)	0.005	0.18	0.09	0.005	0.005	2.44E-05	0.001	13.0
Maximum Annual Emissions (tons) [1]	**0.051**	**1.86**	**0.95**	**0.049**	**0.048**	**2.47E-04**	**0.011**	**132.7**
Total Project Lifetime Emissions (tons)	**0.12**	**4.53**	**2.31**	**0.12**	**0.12**	**6.04E-04**	**0.026**	**324.3**

Note:
1. The maximum annual emissions occur for Year 1 of the project, and include the initial deployment activities, two rounds of 6-month inspections, and up to one unscheduled visit.

Emissions associated with the site assessment activity would be minor based on the estimate of less than 50 tons per year of NO_X and VOCs, 100 tons per year of the other criteria air pollutants, and 25 tons per year of HAPs or 10 tons per year of any individual HAP. The majority of these emissions would occur within Installation Areas and therefore would not affect local onshore air quality in New York. Additionally, since the buoys would not be considered an OCS source and the project emissions are associated with mobile sources, an OCS air permit for these activities will not be required.

7.9 Socioeconomic Resources

As demonstrated in Section 2, the equipment and methodologies proposed herein by Equinor Wind US LLC are consistent with the activity considered by BOEM in the Offshore New York EA (BOEM 2016b). Section 4.4.3 of the EA provide details on the affected environment and potential impacts to socioeconomic resources that may result from the proposed site assessment activity and is incorporated by reference and not repeated.

Equinor Wind US LLC has reviewed currently available literature and data (see Section 8.7) regarding socioeconomic resources in the Mid-Atlantic off the coast of New York and has determined that there is no substantive new information that would change BOEM's analysis. The results of the EA and BOEM's analysis and conclusion that the proposed activity is not anticipated to result in any significant impact to socioeconomic resources is applicable.

Equinor Wind US LLC has committed to implementing all applicable lease conditions, which include BMPs for the installation, operation, and decommissioning of the Metocean Facilities in order to further reduce the potential for impacts on social and economic resources. Equinor Wind US LLC will comply with any additional stipulations as set forth in permits or approvals in support of the proposed site assessment activity.

7.10 Coastal and Marine Uses

As demonstrated in Section 2, the equipment and methodologies proposed herein by Equinor Wind US LLC are consistent with the activity considered by BOEM in the Offshore New York EA (BOEM 2016b). Sections 4.3.3, 4.4.2., and 4.4.3 of the EA provide details on the affected environment and potential impacts to coastal and marine uses that may result from the proposed site assessment activity and is incorporated by reference and not repeated.

Equinor Wind US LLC has reviewed currently available literature and data (see Section 8.8) regarding coastal and marine uses off the coast of New York and determined that there is no substantive new information that would change BOEM's analysis. The results of the EA and BOEM's analysis and conclusion that the proposed activity is not anticipated to result in any significant impact to coastal and marine uses is applicable.

Equinor Wind US LLC has committed to implementing all applicable lease conditions, which include BMPs for the installation, operation, and decommissioning of the Metocean Facilities in order to further reduce the potential for impacts on coastal and marine uses. Equinor Wind US LLC will comply with any additional stipulations as set forth in permits or approvals in support of the proposed site assessment activity.

7.11 Meteorological and Oceanographic Hazards

As demonstrated in Section 2, the equipment and methodologies proposed herein by Equinor Wind US LLC are consistent with the activity considered by BOEM in the Offshore New York EA (BOEM 2016b). Sections 4.3.2 of the EA provide details on the affected environment and potential impacts to meteorological and oceanographic hazards that may result from the proposed site assessment activity and is incorporated by reference and not repeated.

Equinor Wind US LLC has reviewed currently available literature and data (see Section 8.9) regarding coastal and marine uses off the coast of New York and has determined that there is no substantive new information that would change BOEM's analysis. The results of the EA and BOEM's analysis and conclusion that the proposed activity is not anticipated to result in any significant impact to meteorological and oceanographic hazards is applicable.

Equinor Wind US LLC has committed to implementing all applicable lease conditions, which include BMPs for the installation, operation, and decommissioning of the Metocean Facilities in order to further reduce the potential for impacts on meteorological and oceanographic hazards. Equinor Wind US LLC will comply with any additional stipulations as set forth in permits or approvals in support of the proposed site assessment activity.

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Appendix A
Permits and Consultations

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Agency & Tribe Outreach Summary Table

Agency	Key Contacts	Meetings
Bureau of Ocean Energy Management (BOEM)	Luke Feinberg, Brian Hooker, Brian Krevor, Josh Gange, Michelle Morin, Kyle Baker, Dave O'Connell, Amy Stillings, David Bigger	May 2017, July 2017, August 2017, October 2017, November 2017, December 2017, January 2018, February 2018, April 2018, June 2017
Environmental Protection Agency	Suilin Chan, Viorica Petriman, Sarah Froiken (SF)	December 2017, March 2018
National Oceanographic and Atmospheric Administration National Marine Fisheries Service	Sue Tuxbury, Doug Christel	November 2017, December 2017, January 2018, February 2018, March 2018
U.S. Army Corps of Engineers, New York District	Naomi Handell, Peter Kuglstatter	September 2017, December 2017, March 2018
U.S. Coast Guard	Michelle DesAutels, Ed LeBlanc, Julia Lewis, Doug Simpson, Chris Scraba, Jeff Yunker, Shannon Andrew, George Detweiler	October 2017, December 2017
U.S. Department of the Interior	Josh Kaplowitz	May 2017, February 2018, December 2017
U.S. Fish and Wildlife Service	Steve Papa, Tim Sullivan	December 2017, February 2018
Massachusetts Department of Marine Fisheries	Cate O'Keefe, Kathryn Ford	August 2017
Rhode Island Department of Environmental Management	Julia Livermore, Nicole Lengyel, Jay MacNamee	August 2017
New York Department of Environmental Conservation	Karen Chytalo, Karen Gaidasz, Sherryl Jones, Kim McKown, Morgan Brunbauer, Emily Runnells	August 2017, February 2018, March 2018
New Jersey Department of Environmental Protection		*Meeting scheduled for July 3, 2018*
New England Habitat Management Council	Michelle Bachmann	March 2018
Shinnecock Tribe	Don Collins, Randy King, Chivon Smith, Kelsey Leonard, Terrell Terry, Reverend Mike Smith	January 2018

Environmental NGOs – Roundtable in June 2017 and February 2018:

- ACENY
- All Our Energy
- Citizens Campaign for the Environment
- National Wildlife Federation
- Natural Resources Defense Council
- NY Audubon
- Operation Splash
- Renewable Long Island
- Sane Energy
- Seatuck Environmental
- Sierra Club
- Surfriders
- Sustainability Institute at Molloy College
- The Nature Conservancy
- Wildlife Conservation Society

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United States Department of the Interior

BUREAU OF OCEAN ENERGY MANAGEMENT
WASHINGTON, DC 20240-0001

JUN 1 5 2016

Mr. Matthew P. Maraglio
New York Department of State
Consistency Review Unit
Office of Planning & Development
One Commerce Plaza
99 Washington Avenue, Suite 1010
Albany, New York 12231

Dear Mr. Maraglio:

This document provides the State of New York with the Bureau of Ocean Energy Management's (BOEM) Consistency Determination (CD) for the Wind Energy Area offshore of New York under the Coastal Zone Management Act Section 307(c)(1) and 15 CFR Part 930 Subpart C. The information in this CD is provided pursuant to 15 CFR 930.36(a) and 930.39. The CD takes into consideration the reasonably foreseeable coastal effects of the proposed action and its consistency with the enforceable policies identified by New York's Coastal Zone Management Program. The proposed action includes:

- Lease issuance (including reasonably foreseeable consequences associated with shallow hazards, geological, geotechnical, archaeological resources, and biological surveys); and

- Site assessment activities (including reasonably foreseeable consequences associated with the installation and operation of a meteorological tower and/or meteorological buoys) as indicated in the *Commercial Wind Lease Issuance and Site Assessment Activities on the Atlantic Outer Continental Shelf Offshore New York Environmental Assessment* (EA).

BOEM's analysis of the effects of the proposed action on land and water uses and/or natural resources can be found in the enclosed EA. The New York Coastal Zone Management Program's applicable enforceable policies and reasonably foreseeable coastal effects are included in Table 6 (enclosed) for your review.

Based upon the above referenced information, data and analysis, BOEM finds the proposed action consistent to the maximum extent practicable with the enforceable policies of the New York Coastal Zone Management Program.

Pursuant to 15 CFR 930.41, the New York Coastal Zone Management Program has sixty (60) days from the receipt of this letter in which to concur with or object to this CD, or request an extension under 15 CFR 930.41(b). New York's concurrence will be presumed if its response is not received by BOEM within sixty (60) days of receipt of this determination.

The state's response should be sent to:

Bureau of Ocean Energy Management
Office of Renewable Energy Programs
45600 Woodland Road, VAM-OREP
Sterling, Virginia 20166

We appreciate having a cooperative working relationship with the State of New York as we move forward with our review of potential offshore renewable energy activities.

Sincerely,

James F. Bennett
Program Manager
Office of Renewable Energy Programs

Enclosures

U.S. Department of the Interior
Bureau of Ocean Energy Management

Coastal Zone Management Act, Consistency Determination
(15 CFR 930.36(a))

Wind Energy Area Offshore the States of New York and New Jersey

The purpose of this Consistency Determination (CD) is to determine whether issuing a commercial wind energy lease and approving site assessment activities (including the installation, operation, and decommissioning of a meteorological tower and/or buoys) within the Wind Energy Area (WEA) offshore New York and New Jersey (*see* Figure 1) is consistent to the maximum extent practicable with the enforceable policies of the New York and New Jersey Coastal Management Programs (CMPs). This document is provided pursuant to the requirements of 15 CFR 930.39(a) of the Coastal Zone Management Act (CZMA) federal consistency regulations.

Section 307(c)(1) of the CZMA, as amended, requires that Federal agency activities affecting any land or water use or natural resource of the coastal zone shall be carried out in a manner which is consistent to the maximum extent practicable with the enforceable policies of federally-approved state management programs.

The States of New York and New Jersey share common coastal management issues and have similar enforceable policies as identified by their respective CMPs. Due to the proximity of the WEA to both states (*see* Figure 1), and their shared impacts on environmental and socioeconomic resources and uses, the Bureau of Ocean Energy Management (BOEM) has prepared a single CD for the WEA.

BOEM is proposing to issue a commercial wind energy lease within the WEA (as illustrated in Figure 1 and described below) and approve site assessment activities that would determine whether the lease is suitable for, and would support, commercial-scale wind energy production. The lease, by itself, would not authorize the lessee to construct or operate any wind energy project on the Outer Continental Shelf (OCS).

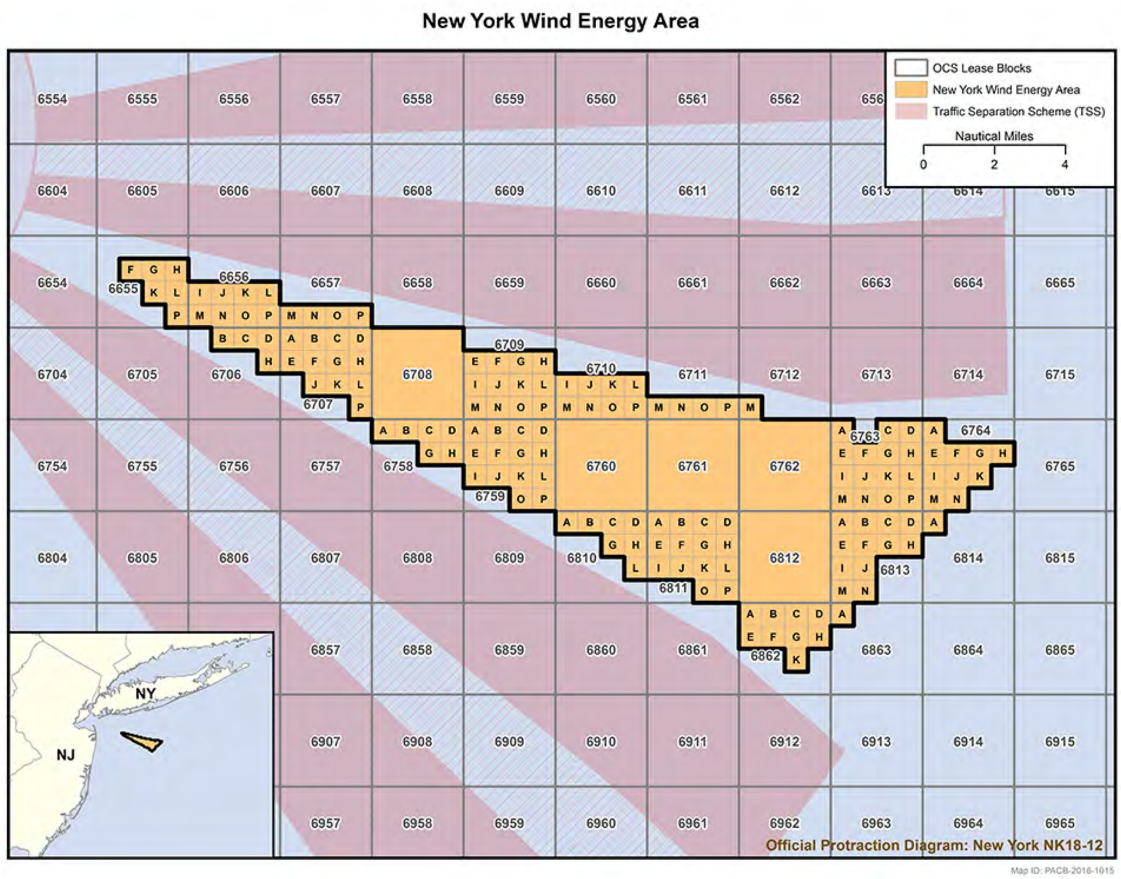

Figure 1: Wind Energy Area

In September 2011, BOEM received an unsolicited request for a commercial lease offshore New York from the New York Power Authority (NYPA). NYPA worked together with the Long Island Power Authority and Consolidated Edison to propose a 350-700 megawatts offshore wind power project south of Long Island, New York, approximately 13 miles (mi) (21 kilometers [km]) off Rockaway Peninsula.

On January 4, 2013, BOEM published a Request for Interest (RFI) in the *Federal Register* (Docket ID: BOEM-2012-0083; 78 FR 760-764) to assess whether there were other parties interested in developing commercial wind facilities in the same area proposed by NYPA. In addition to inquiring about competitive interest, BOEM also sought public comment on the NYPA proposal, its potential environmental consequences, and the use of the area in which the proposed project would be located. BOEM received indications of interest from Fishermen's Energy, LLC, and Energy Management, Inc. BOEM reviewed the nominations received in response to the RFI and determined that competitive interest in the area proposed by NYPA exists. Therefore, BOEM stopped processing NYPA's unsolicited lease application and initiated the competitive leasing process pursuant to 30 CFR 585.211.

On May 28, 2014, BOEM published in the *Federal Register* (Docket ID: BOEM-2013-0087; 79 FR 30645-30651) a Call for Information and Nominations offshore New York to seek additional nominations from companies interested in obtaining commercial wind energy leases within the Call Area.

On March 16, 2016, BOEM released the Announcement of Area Identification (*see* http://www.boem.gov/NY-Area-ID-Announcement/). The WEA begins about 11 nautical miles (nm) (20 km) south of Long Beach, New York and extends approximately 26 nm (48 km) southeast along its longest portion. The WEA contains five whole OCS blocks and 148 sub-blocks (127 square miles [mi^2] [329 square kilometers (km^2)] or 81,130 acres (ac) [32,830 hectares (ha)]). The WEA is shown in Figure 1 and described in Table 1 below.

Table 1
Wind Energy Area

Wind Energy Area (WEA)	Official Protraction Diagram	Size (sq nautical miles (nm^2))	Distance to Shore (nm)	Minimum Water Depth (feet [ft])	Maximum Water Depth (ft)
New York	New York NK18-12	96	11	61	137

Activities that may occur over the site assessment period of the lease (i.e., up to five years) include site characterization survey activities and site assessment activities involving the construction, operation, maintenance, and decommissioning of a meteorological tower and/or buoys. Site characterization surveys would inform a lessee about the site specifics of the lease area in order to prepare for submission of a site assessment plan (SAP) and, potentially, a construction and operations plan (COP). The projected site characterization and site assessment activities within the WEA are discussed in detail in Section 2 and summarized in Table 2 (below).

Table 2
Projected Site Characterization & Assessment Activities in the WEA

Potential Leaseholds	Site Characterization Activities			Site Assessment Activities	
	High Resolution Geophysical (HRG) Surveys (Total Trips)	Sub-bottom Sampling (Total Trips)	Avian and Fish Surveys	Installation of Met Towers (max)	Installation of Met Buoys (max)
1	167	247	116-128	1	2

1. BACKGROUND

BOEM is authorized to issue leases on the OCS for the purposes of wind energy development pursuant to Section 388 of the Energy Policy Act of 2005 (EPAct). On April 22, 2009, BOEM promulgated regulations implementing this authority at 30 CFR Part 585. The regulations establish a program to grant leases, easements, and rights-of-way for orderly, safe, and environmentally responsible renewable energy development activities, such as the siting and construction of offshore wind facilities on the OCS, as well as other forms of renewable energy such as marine hydrokinetic (i.e., wave and current). The Minerals Management Service (MMS) prepared a programmatic Environmental Impact Statement (EIS) to evaluate the impact of establishing of a comprehensive, nationwide MMS Alternative Energy Program on the OCS (*Programmatic Environmental Impact Statement for Alternative Energy Development and Production and Alternate Use of Facilities on the Outer Continental Shelf, Final Programmatic Environmental Impact Statement*, October, 2007) (Programmatic EIS.) The final rule and the Programmatic EIS can be reviewed for reference on the BOEM website at: http://www.boem.gov/Renewable-Energy-Program/Regulatory-Information/Index.aspx and http://www.boem.gov/Renewable-Energy-Program/Regulatory-Information/Guide-To-EIS.aspx. In addition, BOEM published the *Atlantic Geological and Geophysical Activities Programmatic Final Environmental Impact Statement* (G&G Final PEIS). The G&G PEIS can be viewed at: http://www.boem.gov/Atlantic-G-G-PEIS/.

On June 2, 2016, BOEM released the *Commercial Wind Lease Issuance and Site Assessment Activities on the Atlantic Outer Continental Shelf Offshore New York Environmental Assessment* (EA), which is available online at: http://www.boem.gov/New-York/. The EA analyzes the reasonably foreseeable consequences associated with two distinct BOEM actions in the WEA:

(1) Lease issuance (including reasonably foreseeable consequences associated with shallow hazards, geological, geotechnical, archaeological resources, and biological surveys); and

(2) SAP approval (including reasonably foreseeable consequences associated with the installation and operation of a meteorological tower and/or meteorological buoys).

BOEM does not issue permits for shallow hazards, geological, geotechnical, archaeological resource, or biological surveys. However, since BOEM regulations require that a lessee include the results of these surveys in its application for SAP and COP approval, the EA treats the environmental consequences of these surveys as reasonably foreseeable consequences of issuing a lease.

2. PROPOSED ACTION DESCRIPTION

Offshore Site Characterization Surveys

BOEM regulations require that a lessee provide the results of a number of surveys with both a SAP and a COP, including: a shallow hazards survey, a geological survey, biological surveys, a geotechnical survey, and an archaeological resource survey (30 CFR 585.626(a)(1) to (a)(5), respectively). BOEM refers to these surveys as “site characterization” activities. Site characterization activities (e.g., locating shallow hazards, cultural resources, and hard-bottom areas; evaluating installation feasibility; assisting in the selection of appropriate foundation system designs; and determining the variability of subsurface sediments) would necessitate using high-resolution geophysical (HRG) surveys and geotechnical exploration. The purpose of the HRG survey would be to acquire geophysical shallow hazards data and information pertaining to the presence or absence of archaeological resources and to conduct bathymetric charting. The purpose of geotechnical exploration would be to assess the suitability of shallow foundation soils for supporting a structure or transmission cable under any operational and environmental conditions that might be encountered (including extreme events), and to document soil characteristics necessary for the design and installation of all structures and cables. The results of geotechnical exploration allow for a thorough investigation of the stratigraphic and geo-engineering properties of the sediment that may affect the foundations or anchoring systems of a meteorological tower or buoy, which would be necessary for BOEM to consider in a SAP, or later a COP, for a given lease.

Site characterization activities would also necessitate vessel and/or aerial surveys to characterize three primary biological resource categories: (1) benthic habitats; (2) avian resources; and (3) marine fauna. BOEM does not anticipate the lessee needing to conduct separate surveys to characterize the benthic habitats which could be affected by their potential future leasehold activities because the geological and geotechnical surveys would provide enough detailed information for BOEM to adequately assess potential impacts on benthic habitats in the area. For the lessee to describe the state of the avian and marine fauna resources, resource surveys would generally involve simple visual observation, either from a vessel or aircraft. For avian and marine fauna surveys, multi-year assessment periods may be necessary to capture natural seasonal and inter-annual variability of marine fauna within the WEA and immediate surroundings if current data available is not sufficient to determine spatial and temporal distribution of species. It is generally envisioned that the fish, marine mammal, sea turtle, and bird aerial and shipboard surveys could be conducted simultaneously.

It is assumed that the site of a meteorological tower and/or buoys would be surveyed first, to meet the similar data requirements for a lessee's SAP (30 CFR 585.610 and 585.611), and the site of a meteorological tower or buoy would not be resurveyed when the remainder of the leasehold is surveyed to meet the data requirements for a lessee's COP (30 CFR 585.626(a)). However, a lessee could conduct all of their surveys at the same time (to support both a SAP and a COP).

Meteorological Tower and Buoys

A typical meteorological tower consists of a mast mounted on a foundation, anchored to the seafloor. The mast may be either a monopole or a lattice (similar to a radio tower). The mast and data collection devices would likely be mounted on a fixed or pile-supported platform (monopile, jackets, or gravity bases) or floating platform (spar, semi-submersible, or tension-leg). Total installation time for one meteorological tower would be eight days to ten weeks, depending on the type of structure installed and the weather and ocean conditions.

Different types of foundations include tripod, monopile, or steel jacket. Characteristics of these foundation types are summarized in Table 3 below. The final foundation selection would be included in a detailed SAP submitted to BOEM for its review and approval, along with the results of SAP-related site characterization surveys.

Table 3
Meteorological Tower Foundations

	Number of Foundation Piles	Diameter of Foundation Piles (ft)	Area of Bottom Covered[1] (square feet [ft^2])	Depth Driven below Seafloor (ft)	Height above Mean Sea Level (ft)
Tripod	3	10	1,500	25 to 100	295 to 393
Monopile	1	10	200	25 to 100	295 to 393
Steel Jacket	3 to 4	3	2,000	25 to 100	295 to 393

[1]Foundations may be surrounded by a scour system placed at the base of the structure that would cover up to 2 acres (0.81 hectares) of ocean bottom

While a meteorological tower has been the traditional device for characterizing wind conditions, several companies have expressed their interest in installing one or two meteorological buoys instead. Meteorological buoys can be used as an alternative to or in combination with a meteorological tower for collecting wind, wave, and current data in the offshore environment. The EA assumes that, should a lessee choose to employ buoys instead of meteorological towers, it would install a maximum of two buoys. These meteorological buoys would be anchored at fixed locations and would regularly collect observations from many different atmospheric and oceanographic sensors. There are three primary types of buoys BOEM anticipates could be used for meteorological resource data collection on the lease: discus-shaped hull buoys; boat-shaped hull buoys; and spar-type buoys. Discus-shaped and boat-shaped buoys are typically towed or carried aboard a vessel to the installation location. A discus-type buoy would use a combination of chain, nylon, and buoyant polypropylene materials, while a boat-shaped buoy would be moored using an all-chain mooring. Once at the installation site, the buoy would be either lowered to the surface from the deck of the transport vessel and the mooring anchor dropped. Transport and installation vessel anchoring would typically require one day for these types of buoys. The total area of bottom disturbance for boat-shaped and discus shaped buoys would be approximately 6 ft^2 (.55 square meters [m^2]) for the actual footprint and 370,260 ft^2 (34,398 m^2) for the anchor sweep. A spar-type buoy would require two distinct phases for installation, with typically a total of 2 to 3 days for installation. The total area of bottom disturbance associated with a spar-type buoy and installation vessel anchors would be roughly 784 ft^2 (73 m^2). See Section 3.2.2.2 of the EA for more information on meteorological buoys and their anchor systems.

To obtain meteorological data, scientific measurement devices consisting of anemometers, vanes, barometers, and temperature transmitters would be mounted either directly on a tower, buoy, or on instrument support arms. A meteorological tower or buoy also could accommodate environmental monitoring equipment, such as avian monitoring equipment (e.g., radar units or thermal imaging cameras), acoustic monitoring for marine mammals, data-logging computers, power supplies, visibility sensors, water measurements (e.g., temperature or salinity), communications equipment, material hoist, and storage containers.

To measure the speed and direction of ocean currents, Acoustic Doppler Current Profilers (ADCPs) would likely be installed on or near a meteorological tower or buoy. An ADCP is a remote-sensing technology which transmits sound waves at a constant frequency and measures the ricochet of the sound wave off fine particles or zooplanktons suspended in the water column. The ADCPs may be mounted independently on the seafloor, to the legs of the platform, or attached to a buoy. A typical ADCP is about 1 to 2 ft tall (approximately 0.3 to 0.6 meters) and 1 to 2 ft wide (approximately 0.3 to 0.6 meters).

A SAP describes the activities (e.g., installation of meteorological towers and/or buoys) a lessee plans to perform for the assessment of the wind resources and ocean conditions at its commercial lease (30 CFR 585.605). No site assessment activities may take place on a lease until BOEM has approved a lessee's SAP (30 CFR 585.600(a)). Once approved, the site assessment term for a commercial lease is five years from the date of SAP approval (30 CFR 585.235(a)(2)). It is assumed that the lessee would install a data-collection device (e.g., meteorological tower, buoy, or both) on its lease area to assess the wind resources and ocean conditions of the leasehold. This information would allow the lessee to determine whether the lease is suitable for wind energy development, where on the lease it would propose development, and what form of development to propose in a COP.

A lessee must submit a COP at least six months before the end of the site assessment term if the lessee intends to continue to the lease's operations term (30 CFR 585.601(c)). If the COP describes continued use of existing facilities, such as a meteorological tower or buoy approved in the SAP, a lessee may keep such facilities in place on their lease during BOEM's review of the COP (30 CFR 585.618(a)), which may take up to two years. If, after the technical and environmental review of a submitted COP, BOEM determines that such facilities may not remain in place throughout the operations term, a lessee must initiate the decommissioning process (30 CFR 585.618(c)). BOEM anticipates that a meteorological tower could be present for up to five years before the agency decides whether to allow the tower to remain in place for the lease's operations term, or whether the tower must be decommissioned immediately.

Coastal Activity

A lessee will likely determine specific ports used for site assessment and survey activities based primarily on proximity to the lease blocks, capacity to handle the proposed activities, and/or established business relationships between port facilities and the lessee. Existing ports or industrial areas in New York and New Jersey are adequate to support proposed action activities. BOEM therefore does not anticipate expansion of port facilities to meet lessee needs, and considers only existing facilities which can currently accommodate proposed site characterization and site assessment activities.

Installation of a meteorological tower and/or two buoys would require port facilities with the following requirements:

- Deep-water vessel access (greater than 15 ft [4.6 m]) to accommodate large vessels;
- Landing and unloading facilities in close proximity to fabrication yards for staging, assembly, and temporary materials storage; and
- Located within a reasonable travel distance to the WEA, which BOEM assumes to be 40

miles from the WEA boundary to the port.

BOEM has identified the following ports as potential staging ports for the WEA:

- Staten Island, NY
- Erie Basin, NY
- Brooklyn, NY
- Bayonne, NJ
- Newark, NJ
- Elizabeth, NJ
- Perth Amboy, NJ

Surveying and operations and maintenance activities could be supported by smaller ports because these types of activities can use smaller vessels and don't need access to fabrication and storage yards for large infrastructure that would be required for installation of a meteorological tower and/or buoys. Vessels used for these activities are anticipated to be approximately 65 to 100 ft (20 to 30 meters) in length. These smaller ports would serve as staging areas and crew/cargo launch sites for the survey, and operations and maintenance vessels. While a variety of ports could be used for the survey, operations and maintenance activities, including some of the staging ports listed above, BOEM has identified the following ports as likely to support these activities associated with the WEA:

- Staten Island, NY;
- Kismet Harbor, NY;
- Ocean Beach Harbor, NY;
- Perth Amboy, NJ;
- Shark River, NJ; and
- Manasquan, NJ.

Vessel Traffic

Approximately 574 to 1010 total vessel round trips are anticipated to occur as a result of the proposed action over a five-year period (*see* Table 4). Approximately 530 to 542 of these vessel trips (round trips) would be associated with all site characterization surveys as a result of the proposed action over five years, from 2017 to 2022. The total vessel traffic estimated as a result of the installation, decommissioning, and routine maintenance of the meteorological towers and/or meteorological buoys that could be reasonably anticipated in connection with the proposed action would range from 44 to 468 round trips over a five-year period.

Table 4
Total Vessel Round Trips

HRG Surveys	Cable surveys	Geotechnical Sampling Surveys	Avian Surveys	Fish Surveys	Met Buoys	Met Tower	Total
157	10	247	24-36	92	44-128	100-340	574-1010

The total vessel traffic estimated as a result of the HRG surveys and geotechnical exploration work that could be reasonably anticipated in connection with the proposed action would be approximately 167 round trips over five years, and spread over existing and available port facilities in New York and New Jersey. In addition, BOEM presumes 116 to 128 extra independent surveys conducted to characterize avian and fish resources under the proposed action.

Should the lessee decide to install a meteorological tower on its leasehold, a total of 40 round trips are estimated for construction (*see* Table 5). These vessel trips may be spread over multiple construction seasons as a result of weather and sea state conditions, the time to assess suitable site(s), the time to acquire the necessary permits, and the availability of vessels, workers, and tower components. Because the decommissioning process would basically be the reverse of construction, vessel usage during decommissioning would be similar to vessel usage during construction, so another 40 round trips are estimated for decommissioning of the tower. Meteorological buoys would typically take 1 to 2 days to install by one vessel, and 1 to 2 days to decommission by one vessel. Maintenance trips to each meteorological tower may occur weekly to quarterly, and monthly to quarterly for each buoy. However, to provide for a conservative scenario, total maintenance vessel trip calculations are based on weekly trips for towers and monthly trips for buoys over the entire 5-year period (*see* Table 5).

Table 5
Vessel Traffic for Meteorological Buoys and Tower Construction, Maintenance, and Decommissioning

Site Assessment Activity	Round Trips	Formula
Meteorological Buoys		
Meteorological Buoy Installation	2-4	1-2 round trips x 2 buoys
Meteorological Buoy Maintenance – Quarterly/Monthly	40-120	4 quarters x 2 buoys x 5 years 12 months x 2 buoys x 5 years
Meteorological Buoy Decommissioning	2-4	1-2 round trips x 2 buoys
Total Buoy Trips Over 5-year period	**44-128**	
Meteorological Tower		
Meteorological Tower Construction	40	40 round trips x 1 tower
Meteorological Tower Maintenance – Quarterly/Weekly	20-260	4 quarters x 1 tower x 5 years 52 weeks x 1 towers x 5 years
Meteorological Tower Decommissioning	40	40 round trips x 1 tower
Total Tower Trips Over 5-year Period	**100-340**	
Total Trips for a Tower and Two Buoys	**144-468**	

3. STATE ENFORCEABLE POLICIES

As part of this CD, BOEM has evaluated and documented in the enclosed table (*see* Table 6), policies identified by New York and New Jersey as enforceable, applicable offshore and coastal resources or uses, and CZMA "reasonably foreseeable coastal effects" that might be expected for activities conducted under the proposed action. While reviewing and making these determinations on the policies the states have identified as enforceable in this CD, BOEM has considered the common enforceable policies identified by each of the two states as enforceable in their CMP, as listed in Table 6.

4. CONSISTENCY DETERMINATION

BOEM has evaluated all applicable enforceable policies of New York and New Jersey, and the potential activities resulting from the proposed action. This CD has examined whether the proposed action described in Section 1 is consistent to the maximum extent practicable with the policies and provisions identified as enforceable by the CMPs of New York and New Jersey (*see* Table 6). Based on the preceding information and analyses, and the incorporated-by-reference Programmatic EIS, G&G Final PEIS, and EA, BOEM has determined the proposed action will be consistent to the maximum extent practicable with the policies that New York and New Jersey have identified as enforceable.

Table 6: Applicable Enforceable Policies for the Coastal Management Programs of New York and New Jersey

CATEGORY	ENFORCEABLE POLICIES: APPLICABLE COASTAL ZONE MANAGEMENT RULES	REASONABLY FORESEEABLE COASTAL EFFECTS (CZMA COASTAL EFFECTS)
Coastal Habitats and Wetlands	Policy 44 (NY) 7:7E-3.6 Submerged vegetation habitat (NJ) 7:7E-3.16 Dunes (NJ) 7:7E-3.18 Coastal high hazard areas (NJ) 7:7E-3.22 Beaches (NJ) 7:7E-3.27 Wetlands (NJ)	No dunes, beaches, submerged vegetation habitat, or wetlands will be altered as a result of the proposed action. No direct impacts on wetlands or other coastal habitats would occur from routine activities in the Wind Energy Area (WEA) due to the distance of the WEA from shore. No cables would be installed to shore to support the meteorological tower or buoys. Additionally, existing ports or industrial areas in New York and New Jersey are expected to be used in support of the proposed activities. No expansion of existing facilities is expected to occur as a result of the proposed action. Indirect impacts from routine activities may occur from wake erosion and associated added sediment caused by increased traffic in support of the proposed action. Given the volume and nature of existing vessel traffic in the area, a negligible increase of wake-induced erosion may occur. Existing channels could accommodate the vessels anticipated to be used, and no additional dredging would be required to accommodate different vessel size(s). For more information on ports and navigation, see the Ports, Navigation, and Waterfront section below. Should an incidental diesel fuel spill occur as a result of the proposed action, the impacts on coastal habitats, including dunes, beaches, and wetlands, are expected to be negligible. See Section 4.4.2.4 of the *Environmental Assessment for Commercial Wind Lease Issuance and Site Assessment Activities on the Atlantic Outer Continental Shelf Offshore New York* (EA) for additional information on potential impacts to coastal habitats.
Ports, Navigation, and Waterfront	Policy 2 (NY) Policy 3 (NY)	Ports that could serve as potential staging areas include: Staten Island, NY; Erie Basin, NY; Brooklyn, NY; Bayonne, NJ; Newark, NJ; Elizabeth, NJ; and Perth Amboy, NJ. While a variety of ports could be used for the survey, operations, and maintenance activities, including some of the staging ports listed above, the Bureau of Ocean Energy Management (BOEM) has identified the following ports as likely to support these

	Policy 4 (NY) Policy 5 (NY) Policy 24 (NY) Policy 25 (NY) Policy 35 (NY) 7:7E-3.7 Navigation channels (NJ) 7:7E-3.11 Ports (NJ) 7:7E-3.41 Special hazard areas (NJ) 7:7E-7.5 Transportation use rule (NJ) 7:7E-7.7 Industry use rule (NJ) 7:7E-7.9 Port use rule (NJ) 7:7E-7.10 Commercial facility use rule (NJ) 7:7E-8.14 Traffic (NJ)	activities associated with the WEA: Staten Island, NY; Kismet Harbor, NY; Ocean Beach Harbor, NY; Perth Amboy, NJ; Shark River, NJ; and Manasquan, NJ. Wake erosion and sedimentation effects would be limited to approach channels and the coastal areas near ports and bays used to conduct activities. Given the existing amount and nature of vessel traffic, there would be a negligible, if any, increase to wake-induced erosion of associated channels based on the relatively small size and number of vessels associated with the proposed action. Moreover, all approach channels to these ports are armored, and speed limits would be enforced, which also helps to prevent most erosion. Several existing fabrication sites, staging areas, and ports in New York and New Jersey could support site characterization surveys and the construction, operation, and decommissioning of the meteorological tower and buoys. No expansion of these existing onshore areas is anticipated. Existing channels could accommodate the vessels anticipated to be used, and no additional dredging would be required to accommodate different vessel size(s). In addition, no cables would be installed to shore to support the meteorological tower or buoys. The meteorological tower platform would likely be constructed onshore at an existing fabrication yard near one of the ports. The meteorological tower could also be fabricated at various facilities, or at inland facilities in sections, and then shipped by truck or rail to the port staging area. Project related vessels traveling to or from the ports for survey activities, installation, maintenance, and decommissioning of the meteorological tower and buoys could experience spills within a channel or bay that could potentially reach shoreline areas. The impacts on coastal habitats would depend on the type of material spilled, the size and location of the spill, the meteorological conditions at the time, and the speed with which cleanup plans and equipment could be employed. These impacts are expected to be minimal because vessels are expected to comply with the United States Coast Guard regulations at 33 CFR Part 151, relating to the prevention and control of oil spills. Based on the distance from shore where proposed action activities would occur, and the rapid evaporation and dissipation of diesel fuel, a spill occurring in the WEA would likely not contact shore. Collisions between vessels and allisions between vessels and the meteorological tower and buoys are unlikely. However, if a vessel collision or allision was to occur, and in the unlikely event that a spill would result, the most likely pollutant to be discharged into the environment would be diesel fuel. Diesel dissipates very rapidly in the

		water column, then evaporates and biodegrades within a few days, resulting in negligible, if detectable, impacts on the area of the spill. For the proposed action, approximately 574-1,010 vessel trips from site characterization and assessment activities are projected to occur over a 5-year period if the entire WEA was leased and the maximum number of site characterization surveys were conducted in the lease area (*see* Table 4 for vessel traffic calculations). For more information on ports, see Section 3.2.3 of the EA. For more information on vessel traffic and navigation see Sections 3.2.4 and 4.4.2.10 of the EA.
Energy Facilities	Policy 12 (NY) Policy 14 (NY) Policy 17 (NY) Policy 27 (NY) Policy 29 (NY) 7:7E-7.4 Energy facility use rule (NJ)	This analysis is limited to the effects of lease issuance, conducting site characterization activities (i.e., surveys of the lease area), and approval of site assessment activities (i.e., construction and operation of a meteorological tower and/or two buoys) within the WEA. This analysis does not consider construction and operation of any commercial wind power facilities, which would be evaluated later in the process during the review of a construction and operations plan (COP). BOEM takes this approach based on several factors. First, BOEM does not consider the issuance of a lease to constitute an irreversible and irretrievable commitment of agency resources toward the authorization of a commercial wind power facility. Section 1.1.1 of the EA describes BOEM's phased planning and authorization process for offshore wind development. Under this process, the issuance of a lease only grants the lessee the exclusive right to use the leasehold to (1) gather resource and site characterization information, (2) develop its plans, and (3) subsequently seek BOEM approval of its plans for the development of the leasehold. The purpose of conducting the surveys and installing meteorological measurement devices is to assess the wind resources in the lease area and to characterize the environmental and socioeconomic resources and conditions. A lessee must collect this information to determine whether the site is suitable for commercial development and, if so, submit a COP with its project-specific design parameters, for BOEM's review. Should a lessee submit a COP, BOEM would consider its merits; perform the necessary consultations with the appropriate state, federal, local, and tribal entities; solicit input from the public and the Task Force; and perform an independent, comprehensive, site- and project specific National Environmental Protection Act (NEPA) analysis. This separate

		site- and project-specific NEPA analysis may take the form of an environmental impact statement (EIS) and would provide additional opportunities for public involvement pursuant to NEPA and the CEQ regulations at 40 CFR Parts 1500–1508. BOEM would use this information to evaluate the potential environmental and socioeconomic consequences associated with the lessee-proposed project, when considering whether to approve, approve with modification, or disapprove a lessee's COP pursuant to 30 CFR 585.628. After lease issuance, but prior to COP approval, BOEM retains the authority to prevent the environmental impacts of a commercial wind power facility from occurring. Secondly, BOEM does not consider development of a commercial wind power facility within the WEA, and its attendant environmental impacts, to be reasonably foreseeable at this time. Based on the experiences of the offshore wind industry in northern Europe, the project design and the resulting environmental impacts are often geographically and design specific, and it would, therefore, be premature to analyze environmental impacts related to the potential approval of any future COP at this time. There are a number of design parameters that would be identified in a project proposal, including foundation type, project layout, installation methods, and associated onshore facilities. However, the development of these parameters would be determined by information collected during site characterization and assessment activities conducted by the lessee after lease issuance. Each design parameter, or combination of parameters, would have varying environmental effects. Therefore, additional analyses under NEPA would be required before any future decision is made regarding construction of wind energy facilities on the OCS. Additionally, while BOEM has issued 11 commercial wind energy leases offshore, only one lessee has submitted a COP to date. Construction of a commercial wind power facility on the Outer Continental Shelf (OCS) has yet to commence. Given the nascent nature of the offshore wind industry and market uncertainties, it is speculative at this time whether projects will actually be proposed within these areas.
Protected Species	Policy 7 (NY) Policy 8 (NY) 7:7E-3.38 Endangered or	<u>Marine Mammals</u> More information on potential impacts to marine mammals can be found in Section 4.4.2.5 of the EA. There are 31 species of marine mammals that occur in the New York Bight. These 31 species include the following:

	threatened wildlife or plant species habitats (NJ) 7:7E-3.39 Critical wildlife habitats (NJ)	• six mysticetes (baleen whales; five federally endangered); • 21 odontocetes (toothed whales, including: dolphins, a porpoise, beaked whales, dwarf and pygmy sperm whales, and federally endangered sperm whales); and • four pinnipeds (seals). The Endangered Species Act (ESA)-listed marine mammal species that occur in the New York Bight include six large whale species (fin, sei, humpback, North Atlantic right, blue, and sperm whales) (*see* Table 4-6 of the EA). Sperm, blue, and sei whales that are sighted in the New York Bight are generally found farther offshore and/or near the shelf edge. Thus, these species are not expected to occur in the action area. Three listed species, all endangered, are likely to occur in the action area: fin, humpback, and North Atlantic right whales. However, National Marine Fisheries Service (NMFS) is currently proposing to establish 14 distinct population segments (DPS) for humpback whales, two of which will be listed as endangered and two will be listed and threatened. The West Indies DPS covers all humpbacks along the Atlantic, and this DPS will be de-listed (80 FR 22303). Sightings per unit effort (SPUE) results for the three species combined indicate that while these species are not particularly common (*see* Figure 4-11 of the EA), they could occur in the action area at any time during the year (*see* Table 4-6 of the EA). Marine mammals listed as federally endangered or threatened under the ESA (i.e., listed) and marine mammals protected under the Marine Mammal Protection Act (i.e., non-listed) are discussed together because the potential impact mechanisms are the same for all marine mammals. **Site Characterization** Impacts on marine mammals from site characterization were analyzed in the *Atlantic Geological and Geophysical Activities Final Programmatic Environmental Impact Statement* (G&G Final PEIS) and are incorporated herein by reference and summarized below. Although the geographic boundary in the G&G Final PEIS was outside of the WEA (it included BOEM's Mid-Atlantic and South Atlantic planning areas: Delaware to Florida), many of the same species occur in the New York Bight area, and the conclusions

		on impact levels are applicable. The following conclusions for site characterization that were made in the G&G Final PEIS for BOEM's Mid-Atlantic and South Atlantic planning areas are expected to be the same in the WEA: • Impacts from High Resolution Geophysical (HRG) survey sound sources are expected to be minor because acoustic signals from electromechanical survey equipment are within the hearing range for marine mammals, and may cause Level B harassment. However, standard operating conditions (SOCs) implemented to minimize acoustic impacts would include monitoring by a protected species observer (PSO) of a 1,640 ft (500 m) exclusion zone for North Atlantic right whales and a 656 ft (200 m) exclusion zone for all other marine mammals, clearance of the exclusion zone 60 minutes prior to equipment start-up, "ramp up" of equipment, and immediate shut down if a non-delphinoid cetacean (large whale) is sighted at or within the exclusion zone (*see* Appendix B of the EA). If a delphinoid cetacean (dolphin or porpoise) or pinniped (seal) is sighted at or within the exclusion zone, the survey equipment must be powered down to the lowest power output feasible until the exclusion zone is clear; • Impacts from vessel and equipment noise, including geotechnical sampling (e.g., coring) are expected to be negligible to minor. BOEM based this finding on our conclusion that vessel and equipment source levels can be high enough to exceed threshold criteria for behavioral disturbance and undetected marine mammals may occur in the ensonified area during sampling activities. The following SOCs would minimize acoustic impacts: monitoring of the 656 ft (200 m) exclusion zone by a PSO, clearance of the 656 ft (200 m) exclusion zone 60 minutes prior to activity, and immediate shut down if a non-delphinoid cetacean is sighted at or within the exclusion zone. Subsequent restart of geotechnical survey equipment may only follow clearance of exclusion zone for at least 60 minutes for all marine mammals (*see* Appendix B of the EA); and • Impacts from project-related vessel traffic are expected to be negligible because SOCs require that all vessel operators and crew maintain a vigilant watch for marine mammals, separation of 1,640 ft (500 m) from a sighted North Atlantic right whale, and 328 ft (100 m) from all other non-delphinoid cetaceans (*see* Appendix B of the EA). Additional vessel strike avoidance measures for North

		Atlantic right whales apply from November 1 to July 31. SOCs also require that all vessels underway do not divert to approach a delphinoid cetacean or pinniped. **Site Assessment** Impacts on marine mammals from site assessment activities are divided into two categories: underwater noise impacts and non-acoustic impacts. Impacts are assessed by relative potential of overlap, both spatially and temporally, between marine mammal species and impact-producing factor. **Underwater Noise Impacts** Marine mammals use sound for vital biological functions, including socialization, foraging, responding to predators, and orientation. It has been documented that some anthropogenic noise can negatively impact the biological activities of marine mammals in some instances. The response of marine mammals to sound depends on a range of factors, including (1) the sound presser level; frequency, duration, and novelty of the sound; (2) the physical and behavioral state of the animal at the time of perception; and (3) the ambient acoustic features of the environment. Noise can cause behavioral disturbance, including changes in feeding, vocalization, and dive patterns, or avoidance of the ensonified area (i.e., the area filled with sound). Auditory masking, defined as the obscuring of sounds of interest by interfering sounds, generally at the same or similar frequency, may also cause important behavioral changes to marine mammals exposed to sound. In addition to behavioral disturbance, underwater noise can result in two levels of potential injury to marine mammal hearing: (1) Temporary Threshold Shift (TTS), a non-permanent decrease in hearing sensitivity, and (2) Permanent Threshold Shift (PTS), a physical injury that results in a permanent decrease in hearing sensitivity. Detailed discussions on underwater sound and its importance to marine mammals and their hearing capabilities can be found in the G&G Final PEIS and the *Commercial Wind Lease Issuance and Site Assessment Activities on the Atlantic Outer Continental Shelf Offshore Massachusetts Revised Environmental Assessment*. NMFS interim threshold criteria, based on received levels of sound for marine mammals during acoustic activities, are defined as follows:

		• 120 decibels (dB) re 1 µPa root mean square (RMS) for the potential onset of behavioral disturbance or harassment (Level B) from a *continuous* source of sound (e.g., vessel noise, geotechnical drilling, or vibratory pile driving); • 160 dB re 1 µPa RMS for the potential onset of behavioral disturbance (Level B) from a *non-continuous* source (e.g., impact pile driving, HRG surveys); and • Potential injury (Level A) from received levels of 180 dB re 1 µPa RMS for cetaceans, and 190 dB re 1 µPa RMS for pinnipeds. Although distinct exposure thresholds can be determined for injury, behavioral reactions follow a wider spectrum of variable responses, some which may be negligible, while others can have more severe consequences. The traditional threshold level to predict behavioral reactions are 160 dB RMS for impulsive noise and 120 dB (RMS) for continuous noise where only animals exposed to levels above the threshold have the potential to be disturbed. An increasing number of studies indicate that the effect of underwater sound on marine mammal behavior is quite variable between species, individuals, life history stage, and behavioral state. Additionally, some species (e.g., beaked whales and porpoises, or migrating baleen whales) or animals in certain behavioral states may be more sensitive to disturbance, while other species may be more tolerant to environmental noise. **Pile Driving** Among all acoustic activities during site assessment, pile driving has the potential to produce the highest noise levels. Sound levels from pile driving are highly variable depending on site location, type of pile, type and size of hammer, water depth, and bottom type. There are two methods of pile driving that may be used in the WEA, vibratory pile driving and impact pile driving, and each has different potential impacts. BOEM anticipates that pile driving would occur for 3 to 8 hours per day for up to 3 consecutive days, and that pile diameters would be approximately 3 ft (1 m) to 10 ft (3 m) depending on the structural design of the meteorological tower. Under BOEM's SOCs (*see* Appendix B, Section B.4 of the EA), which require that pile driving be conducted from May 1 to October 31, a monitoring zone of 3,280 feet (ft) (1,000 meters [m]), and implementation of "soft start", no marine mammals are expected to experience Level A noise (>180 dB re 1 µPa). However, measurements from

		Illingworth and Rodkin, Inc. (2013) indicate that source levels above Level B harassment (120 dB RMS) could occur from 6,824 to 31,053 ft (2,080 to 9,465 m) from the source at a 33 ft (10 m) water depth, and from 10,745 to 37,730 ft (3,275 to 11,500 m) at a 66 to 98 ft (20 to 30 m) water depth. Therefore, because marine mammals may occur in or near the WEA during times of the year when pile driving may take place, behavioral impacts may occur. The requirements under BOEM's SOCs are expected to reduce the potential impacts to marine mammals from vibratory pile driving activities. Nonetheless, the potential for behavioral impacts remains. Overall, impacts from vibratory pile driving activities are expected to be minor to moderate for both non-ESA-listed marine mammals and for ESA-listed fin, humpback, and North Atlantic right whales that could occur in the WEA. The three ESA-listed threatened and endangered mysticete species that are most likely to occur in the WEA are fin, humpback, and North Atlantic right whales. The only other non-listed mysticete that may occur in the New York Bight area, and thus the action area, is the minke whale. Pile-driving activities are expected to be minor for minke whales because SPUE data suggest that these whales do not typically occur within 25 nautical miles (nm) (40 kilometers [km]) of the WEA. BOEM's SOCs (*see* Appendix B, Section B.4 of the EA), which require a lessee to limit pile driving between May 1 and October 31, a monitoring zone of 3,281 ft (1,000 m), and the implementation of "soft start", are expected to minimize Level A noise (>180 dB re 1 μPa) exposures to ESA-listed marine mammals. However, it is possible that some endangered whales may experience Level A or Level B harassment. For example, recent acoustic data indicate the possible presence of North Atlantic right whales in the New York Bight at any time during the year (Whitt et al., 2013). Large whales engaged in migration are known to be more sensitive to relatively low levels of noise (lower than Level B harassment threshold levels), and this sensitivity may cause them to avoid the area. Considering the short duration of impact pile driving activities (anticipated to be approximately 3 to 8 hours per day for up to 3 consecutive days), impacts from impact pile driving on fin, humpback, and North Atlantic right whales are expected to be minor to moderate.

		Considering the short duration of impact pile driving activities (anticipated to be approximately 3 to 8 hours per day for up to 3 consecutive days), impacts from impact pile-driving activities are expected to be minor for harbor, harp, hooded, and gray seals, and negligible for ringed seals. **Vessel Strike** Potential impacts to marine mammals include strikes from vessels used during the construction, operation, and decommissioning phases of the tower and/or buoy installation. BOEM anticipates that between approximately 44 to 468 round trips of various vessel types may occur during site assessment activities (*see* Table 5). While the number of vessel trips anticipated is relatively low compared to the existing level of vessel traffic in the area, it is possible that underwater noise (e.g., pile driving) may cause behavioral changes for some whale species that could increase the chances for a collision between a marine mammal and a vessel. This is especially important for endangered whales (North Atlantic right, fin, and humpback whales) due to vessel strikes being a major cause of mortality, which indicate that the behavioral response of some whale species to noise may secondarily increase the risk of vessel strike to large whales (e.g., changes in ascent behavior and rapid acceleration away from the source). Recent studies have also indicated that some whale species are more sensitive to sound during migration than during feeding and may show avoidance responses at greater distances if the noise can be heard by the animal. These studies suggest that North Atlantic right whales, known to migrate through the New York Bight could be susceptible to such behavioral reactions from project-related noise. However, considering the existing levels of vessel traffic noise generated in the general area of the WEA (between the two traffic separation schemes surrounding the WEA), it is unlikely that noise related to the construction, operation, or decommissioning phases of a meteorological tower or buoy would be detected at levels or durations that might result in an increase in risk of vessel strike to North Atlantic right whales. BOEM's SOCs were designed to minimize potential vessel strikes to marine mammals (*see* Appendix B, Section B.1.1 of the EA). NMFS concluded that during site assessment activities, the potential for construction- and maintenance-related vessel strike to marine mammals is extremely low. Potential impacts to marine mammals from vessel strikes

		during site assessment activities are, therefore, expected to be negligible because of the low probability of such an event. Nonetheless, if vessel strikes did occur they could result in minor to moderate impacts to ESA-listed marine mammal species. Impacts from trash and debris are expected to be negligible. Potential impacts on marine mammals from fuel spills are expected to range from negligible (if the fuel does not contact individual marine mammals) to minor (if individual marine mammals encounter the slick). Overall, impacts to marine mammals are expected to be moderate due to potential acoustic impacts during site assessment activities that involve pile driving; however, potential impacts covering site characterization and other site assessment activities would range from negligible to minor**,** depending on the activity being conducted. Vessel strike and noise are two of the most important factors that may affect marine mammals. Implementing the vessel strike avoidance measures in the SOCs (*see* Appendix B, Section B.1.1 of the EA) would minimize the potential for vessel strikes. BOEM's SOCs related to site characterization surveys (*see* Appendix B, Section B.3 of the EA) and site assessment (*see* Appendix B, Section B.4 of the EA) would minimize the potential for noise impacts to marine mammals. <u>Sea Turtles</u> More information on potential impacts to sea turtles can be found in Section 4.4.2.6 of the EA. Four species of sea turtles occur in the New York Bight: loggerhead, green, Kemp's ridley, and leatherback. All four species are listed as threatened or endangered under the ESA. Of the four species, loggerhead turtles are sighted more frequently than any other sea turtle species in the vicinity of the WEA (*see* Appendix E of the EA). Impact-producing factors associated with the proposed action that could have potential impacts on Kemp's ridley, loggerhead, leatherback, and green sea turtles include vessel traffic, vessel noise, HRG active acoustic sources, equipment noise, seafloor disturbance, pile driving noise, dynamic positioning thruster use during vessel positioning, release of

		trash and debris, and accidental fuel spill. BOEM has developed SOCs for sea turtles that are designed to prevent or reduce any possible impacts during both site characterization and site assessment activities. These SOCs are described in detail in Appendix B of the EA. Potential impacts to sea turtles would range from negligible to moderate depending on the activity being conducted during site characterization and site assessment. Vessel strike and noise are two of the most important factors that may affect sea turtles. However, implementing the vessel strike avoidance measures in the SOCs (*see* Appendix B, Section B.1.1 of the EA) would minimize the potential for vessel strikes and adverse impacts on sea turtles. There are large data gaps regarding behavioral and physiological responses of sea turtles to sound, and recommendations for future studies include the potential physiological (critical ratios, TTS, and PTS) and behavioral effects of exposure to sound sources. Although implementation of the SOCs is expected to minimize the potential of hearing injury impacts and disruption the behavior of sea turtles, pile driving from May 1 to October 31 (*see* Appendix B, Section B.4 of the EA) coincides with the time of year that sea turtles are known to occur in the WEA. However, pile driving of one meteorological tower would take a relatively short time (approximately 3 to 8 hours per day for up to 3 days), which would limit the turtles' exposure to the sound to periodic disruptions over a 1-day to 3-day period. Sea turtles that avoid the area are expected to successfully forage in nearby habitats with similar prey availability. There are no critical or otherwise important foraging habitats known to occur in the area of the WEA. <u>Protected Fish Species</u> For information on protected fish species, see the Fisheries Management section below.

Fisheries Management	Policy 9 (NY) Policy 10 (NY) 7:7E-3.2 Shellfish habitat (NJ) 7:7E-3.3 Surf clam areas (NJ) 7:7E-3.4 Prime fishing areas (NJ) 7:7E-3.5 Finfish migratory pathways (NJ) 7:7E-8.2 Marine fish and fisheries (NJ)	<u>Commercial and Recreational Fisheries</u> In 2012, BOEM contracted with NMFS to characterize the commercial fishing industry in the New York Call Area (the WEA is identical to the New York Call Area). NMFS developed a statistical model to predict the spatial footprint of a fishing trip by merging vessel trip reports with data collected by at-sea fisheries observers. NMFS then linked these locations to seafood dealer reports to create revenue-intensity maps as a visual representation of the fishing harvest. According to the NMFS fishing revenue study *Socio-Economic Impact on Outer Continental Shelf Wind Energy Development on Fishing in the U.S. Atlantic. Draft* (Kirkpatrick et al. 2015*)*, commercial fishermen sourced an average of $3.59 million annually from the New York Call Area from 2007 to 2012. Based on analysis of NMFS data, input derived from outreach efforts with the fishing industry, and public comments, BOEM determined that the fisheries that use the area the most, based on a percentage of total revenue, are the Atlantic sea scallop, and the squid, mackerel, and butterfish (SMB) fisheries. Other species of commercial importance with distributions that overlap the WEA include monkfish, Atlantic herring, black sea bass, summer flounder, and scup. The average annual scallop revenue represents more than 90 percent of the total fishing revenue sourced from the New York Call Area (*see* Figure 4-1 in the EA). During the six-year study period, the scallop revenue from the New York Call Area ranged from $494,326 to $6 million. The average annual scallop revenue from the New York Call Area was $3.26 million, which represents 0.8 percent of the total Atlantic sea scallop revenue from the Atlantic seaboard. Much of the total scallop revenue is from regulated access areas farther offshore, such as on Georges Bank, Hudson Canyon, and the Delmarva access areas. The New York Call Area's annual SMB fishery revenue ranged from $71,673 to $319,686. These values equate to 0.2 and 0.7 percent of the total squid value landed from the Atlantic in those low and high years, respectively (Kirkpatrick et al., 2015). The squid fishery operates in and around the New York Call Area primarily between June and September. The fishery is highly variable regarding where the squid will occur and where they will be caught. Although the entire New York Call Area is used as a squid fishery, the primary

		area fished by the squid fleet is in waters less than 16 fathoms (30 m) closer to Cholera Banks Waters off New York and New Jersey are home to substantial recreational fishing activities. The WEA is adjacent to, and overlaps with, some reported recreational fishing ground. The major recreational fishing areas along the south coast of Long Island are roughly 10 to 25 nm (19 to 46 km) from the WEA. NMFS described the recreational fishery as lightly overlapping the New York Call Area (Kirkpatrick et al., 2015). Site characterization and site assessment activities would result in underwater noise from survey activity and the installation of piles to support the meteorological tower. The direct impact of these noise sources on fish is analyzed in Section 4.4.2.7 of the EA. The analysis in that section concludes that impacts of low frequency sound on fish and fish populations, including SOCs such as the "soft-start" provision for pile driving, is anticipated to be negligible. BOEM does not anticipate adverse impacts from noise associated with installation of piles on fish populations that are targeted by commercial and recreational fishing groups. However, noise generated from low frequency sound, like pile driving and some survey equipment, may result in decreased catch rates of fish while the noise producing activity is occurring. Decreased catch rates may be most acute in hook and line fisheries, since behavioral changes may reduce the availability of the fish to be captured in the fishery. The increase in vessel traffic associated with installation, maintenance, and decommissioning of a meteorological tower and/or buoys could potentially deter commercial and recreational fishermen from using the area around the tower or buoys while work-related vessels are in the area. To avoid collisions and gear entanglement with vessels, commercial and recreational fishermen may temporarily move to other locations. The tower and buoys could provide previously unavailable habitat for species that prefer structured and hardbottom habitats, creating a temporary increase in these types of fish in the area of the tower or buoy while the structure is in place. This could have a temporary beneficial effect to commercial and recreational fisheries, depending on the species of interest and the fishing gear used. Commercial fisheries in areas adjacent to the WEA are more productive than the commercial fisheries in the WEA (Kirkpatrick et al., 2015), so the temporary increased vessel traffic associated with site assessment is expected to be minor. Similarly, most coastal recreational fishing for New York and New Jersey takes

		place away from the WEA, and impacts of increased vessel traffic are anticipated to be negligible. Mollusks, such as scallops, would likely be adversely affected in the immediate area of the tower foundations and/or buoy moorings, and suffer from suspended sediment during the construction process. Exclusion zones are typically established around large and/or slow work-related vessels (referred to as "source vessels"; e.g., barges and tow vessels) to maintain safe passage of the source vessel, and by keeping it clear of other vessel traffic. Temporary adverse impacts expected to result from vessel traffic and/or vessel exclusion zones could be avoided by recreational anglers because these user groups tend to use smaller boats that are more maneuverable; therefore, avoidance of survey vessels could be achieved as needed. Impacts would be limited geographically to the vessel exclusion zone and would be temporary at any given location since the exclusion area would move along with the movement of the vessel. Temporary exclusion zones would also be established around the meteorological tower during construction and decommissioning. During construction/ decommissioning, BOEM anticipates that the typical temporary vessel exclusion zone around a 377 ft- (115 m-) meteorological tower would be approximately 162 acres (ac) (66 hectares [ha]). Impacts on recreational fishing could be greater if the exclusion zone is established over a popular and/or critical sport fishing location, such as one that may coincide with the migration route of a target fishing species. Impacts on recreational boating and fishing from temporary vessel exclusion zones are expected to be negligible, and impacts on recreational boating and fishing from temporary exclusion zones are expected to be minor. Accidental oil spills from damaged gear or machinery (e.g., vessels, generators, or pile-driving hammers) associated with site assessment could directly affect commercial and recreational fisheries by contaminating fish and gear, and interfering during cleanup and recovery operations, or indirectly affect fisheries by temporarily degrading fishing habitat. Spills could result from severe weather damage to vessels or the tower/buoys, from vessel collisions/allisions, or during generator refueling. However, the impact of a spill on commercial and recreational fishing activity would largely depend on the size of the spill. The effects would be detrimental to commercial and recreational fisheries if they led to

		declines in target species. While such spills are hard to predict, based on the structures and vessels associated with the activities, the potential for oil spills, the size of these spills, and the impact to commercial recreational fisheries from non-routine events is expected to be negligible. Overall, impacts to commercial and recreational fisheries under the proposed action would be minor. Impacts would range from negligible to minor depending on the fishery and proposed action activity. Minor impacts are expected based on the low level of vessel traffic activity associated with site characterization and site assessment activities, the fact that one meteorological tower and/or two buoys would be installed over a relatively large geographic area, the level and duration of sound produced from routine activities and events, and the low likelihood of potential impacts from disturbances and pollution. See Section 4.4.4.5 of the EA for more information on potential impacts to commercial and recreational fisheries. <u>Finfish, Shellfish, and Essential Fish Habitat</u> Essential Fish Habitat (EFH) has been designated for 37 species in the WEA. No Habitat Areas of Potential Concern (HAPCs) have been designated in the WEA. EFH descriptions for several of the designated species in the WEA are provided in the G&G Final PEIS. EFH descriptions for species and lifestages that were not discussed in the G&G Final PEIS are summarized in Table 4-14 of the EA. Surf clam concentrations in the WEA appear to be moderate or secondary (<1 bushel) concentrations. The NEFSC 2011 clam dredge survey data showed low catch rates (0 and 1 to 50 clams per tow) of total surf clams and prerecruits in the WEA. The *PEIS for Alternative Energy Development and Production and Alternate Use of Facilities on the Outer Continental Shelf, Final Environmental Impact Statement* identified potential impacts to fish resources and EFH that could occur in OCS WEAs in the Atlantic region during site characterization, including: G&G surveys; vessel and equipment noise; and meteorological tower/buoy installation, operation, and decommissioning.

		The potential impacts of renewable energy site characterization on finfish resources and EFH have been analyzed in the G&G Final PEIS and were incorporated into the EA by reference. Although the geographic boundary in the G&G Final PEIS is outside of this WEA (it included BOEM's Mid-Atlantic and South Atlantic planning areas: Delaware to Florida), many species occur in both areas, and the conclusions on impact levels are applicable. The following conclusions for site characterization that were made in the G&G Final PEIS are expected to be the same in the WEA: • Impacts from acoustic sound sources from HRG surveys and geotechnical exploration are expected to be negligible. A boomer sub-bottom profiler is the only sound source expected to produce sounds within finfish and invertebrate hearing ranges; • Impacts from vessel and equipment noise are expected to be negligible**;** and • Impacts from seafloor disturbances are expected to be negligible**.** The G&G Final PEIS assessment of impacts on fish and EFH from acoustic sound sources, vessel and equipment noise, seafloor disturbance, and discharge of waste materials and accidental fuel releases was for G&G-related site characterization activities only. While the number of vessel trips and area of seafloor disturbance for activities covered in the EA differ from those in the G&G Final PEIS, the overall types of impacts to finfish, shellfish, and EFH —and the impact levels and conclusions—are anticipated to be the same. The SOCs required by BOEM (*see* Appendix B, Section B.4 of the EA) to reduce the potential for adverse impacts to marine mammals and sea turtles are expected to also benefit fish. With the "soft start" procedure for pile driving, it is anticipated that the majority of fish would flee the area during the tower installation period and return to the area and resume normal activity after construction. Fish that do not flee the area during pile driving could be exposed to noise levels that result in temporary hearing threshold shifts, injuries, or mortality. Thus, the noise associated with pile driving would cause avoidance or other adverse effects resulting in minor impacts to adult finfish. Demersal eggs and larvae may also be vulnerable to pile driving-generated vibrations, and could experience some adverse effects near pile installation resulting in minor impacts on finfish

		populations. Underwater noise impacts (from all sources) to finfish and shellfish populations, and EFH, are expected to be negligible to minor. Installation of piles or anchor systems associated with a tower and/or buoys may cause an increase in local suspended sediments. These impacts would be limited to the immediate area surrounding the piles or anchors, and of short duration. Depending on the currents, the suspended sediment is expected to disperse and settle on the surrounding seafloor, potentially coating or burying some benthic organisms. Effects on finfish and shellfish populations, and EFH, from suspended sediments would be negligible because these activities would be localized and of short duration. The installation of a meteorological tower foundation and/or buoy anchor systems and associated scour control systems may result in the direct mortality of benthic invertebrates, the loss of benthic habitat, and the displacement of water column (pelagic) habitat. Sessile marine invertebrates, including molluscan shellfish (including surf clams), would be lost (buried or crushed) in the footprint (200 square ft to two ac [19 square m to 0.8 ha]) of the tower foundations/moorings and scour control systems. Although sea scallops are mobile molluscan shellfish, it is a conservative assumption that they would not be able to avoid sudden deployment of an anchor or foundation/mooring system, and for these analyses are considered to be sessile. The amount of habitat temporarily displaced or lost in the area is small compared to the amount of habitat available in the surrounding area. Overall, impacts from site characterization and site assessment activities to finfish and shellfish populations, and EFH, in the WEA would be minor. However, impacts would range from negligible to minor depending on the activity. A meteorological tower foundation and/or buoy anchor systems installation and decommissioning would produce noise that could disturb normal fish behaviors. Fish are expected to avoid or flee from the noise source. Fish that do not flee the immediate action area during pile driving could be exposed to injurious or lethal noise levels that may result in adverse effects. The short duration (3 to 8 hours per day over 3 days) and the use of mitigation measures required by the SOCs (Appendix B of the EA) would minimize the possible exposure to injurious and lethal noise levels, resulting in minor effects to finfish and shellfish populations, and EFH. The increases in suspended sediments, loss of benthic

		habitat, and displacement or alteration of water column habitat due to meteorological tower installation, operation, and decommissioning, and/or installation and operation of buoy anchor systems are expected to be small compared to the available habitat in the surrounding areas, and would, therefore, result in negligible effects to finfish and shellfish populations, and EFH. The potential increase in vessel collisions and allisions that could result in accidental fuel spills due to a meteorological tower and/or buoys is expected to be minimal. The overall impact on finfish and shellfish populations and EFH from a fuel spill that could result from such an occurrence is expected to be minimal and temporary, and would; therefore, be considered minor. See Section 4.4.2.7 of the EA for more information on potential impacts to finfish, shellfish, and essential fish habitat.
Public Access	Policy 19 (NY) 7:7E-8.11 Public Access (NJ)	Short-term limitations on public access within the WEA may occur during certain activities under the proposed action. Exclusion zones are typically established around large and/or slow work-related vessels (referred to as “source vessels”; e.g., barges and tow vessels) to maintain safe passage of the source vessel and keep it clear of other vessel traffic. Recreational anglers can avoid temporary adverse impacts expected to result from vessel traffic and/or vessel exclusion zones because they tend to use smaller boats that are more maneuverable; therefore, avoidance of survey vessels could be achieved as needed. Impacts would be limited geographically to the vessel exclusion zone, and would be temporary at any given location since the exclusion area would move along with the movement of the vessel. Temporary exclusion zones would also be established around the meteorological tower during construction and decommissioning. During construction/ decommissioning, BOEM anticipates that the typical temporary vessel exclusion zone around a 377 ft- (115 m-) meteorological tower would be approximately 162 ac (66 ha). Impacts on recreational fishing could be greater if the exclusion zone is established over a popular and/or critical sport fishing location, such as one that may coincide with the migration route of a target fishing species. Although recreational fishing and boating access may be limited by temporary exclusion zones, impacts on recreational boating and fishing from temporary vessel exclusion zones are expected to be negligible. In addition, impacts on recreational boating and fishing from temporary construction or decommissioning exclusion zones are expected to be minor.

		See Section 4.4.3.4 of the EA for more information on potential impacts to recreational fishing. Impacts to recreation and tourism resulting from routine and non-routine activities would be minor. Impacts would result primarily from vessel traffic restrictions in exclusion zones, potential for small scale spills, and from vessel traffic associated with installation of a meteorological tower and/or buoys. For more information on recreation and tourism, see the Recreation and Tourism section below.
Water Quality	Policy 30 (NY) Policy 33 (NY) Policy 34 (NY) Policy 36 (NY) Policy 37 (NY) 7:7E-8.4 Water Quality (NJ)	The routine activities associated with the proposed action, which would impact coastal and marine water quality, include mechanical disturbance of the seafloor and discharge of bilge water, ballast water, or sanitary/domestic wastewater, as well as non-routine events such as accidental spills of fuel and maintenance materials, such as lubricants and solid debris. Additional information on water quality and impacts to coastal and marine water quality can be found in Section 4.4.1.2 of the EA. Routine activities that have the potential to adversely affect water quality include discharges from survey vessels and vessels servicing the tower and/or buoys (i.e., bilge water, ballast water, sanitary waste, and debris). Bilge and ballast water discharges may contain small amounts of petroleum-based products and metals, and as such, are prohibited within 13 nm (24 km) of the shore. Any vessels conducting surveys or servicing a tower and/or buoys are likely to be equipped with holding tanks for sanitary waste and would not discharge untreated sanitary waste within state or federal waters. The regulations governing the relevant discharges are discussed in the EA, Section 3.2.1.5, *Operational Waste Associated with Site Characterization*. The instrumentation used for site characterization is self-contained, so there should be no discharges from instruments aboard the survey vessels that would impact water quality. Impacts to water quality would occur during construction and decommissioning, with water quality returning to its original state both during operation of the tower and/or buoys and after decommissioning. The seabed would be disturbed locally during construction of a meteorological tower and/or buoys as a byproduct of anchoring, pile driving, and placement of scour protection devices. The resulting mobilization of sediments would

		produce minor, transient impacts to water quality in the immediate vicinity of the disturbance in the form of increased turbidity. Releases/spills (oils, lubricants, trash, debris, fuel) due to non-routine events are likely to be small and result in minor, transient impacts on water quality over a localized area in the immediate vicinity of the release/spill. Overall, activities associated with proposed action would have a minor impact on water quality, with any changes being small in magnitude, highly localized, and transient. Any operational discharges from vessels during surveying or servicing of buoys and a tower would be small and have a minor adverse effect. Seabed disturbances during construction, deployment, and decommissioning of buoys or a tower would result in minor, localized impacts on water quality in the area immediately adjacent to the structure or disturbance.
Air Quality	Policy 41 (NY) Policy 42 (NY) Policy 43 (NY) 7:7E-8.10 Air Quality (NJ)	Air quality impacts that could result from site characterization activities under the proposed action were evaluated in the G&G Final PEIS and found to be negligible. Section 4.4.1.1 of the EA includes an area-specific evaluation of air quality impacts associated with G&G activities, along with an evaluation of air quality impacts associated with site assessment activities. Increased vessel traffic associated with site characterization surveys would add to current vessel traffic levels associated with the ports used by the vessel operators. The additional vessel activity associated with the proposed action is anticipated to be relatively small when compared with existing and future vessel traffic levels in the area. Impacts from pollutant emissions associated with these vessels would likely be localized within the WEA and in the vicinity of vessel activity. Appendix C of the EA provides further information on the anticipated numbers of project-related vessel trips and associated emission calculations. The onshore areas that are closest to the WEA are classified as nonattainment areas for O_3. Hudson, Queens, Kings, Nassau, and Richmond Counties are classified as maintenance areas for CO (*see* Table 4-1 of the EA). Nonattainment and maintenance areas are subject to the EPA General Conformity Rule (40 CFR 93, Subpart B). The rule establishes emissions thresholds, or *de minimis* levels, for use in evaluating a project's conformity with the applicable State Implementation Plan. If the net air pollutant emissions exceed

		these thresholds, a formal conformity determination may be required. If a submitted site assessment plan (SAP) indicates that project-related activities in the non-attainment and maintenance areas would emit more than the thresholds, then a General Conformity analysis would be performed. The *de minimis* levels for consideration in the project's conformity analysis are: • 100 tons/year (90.7 metric tons/year) of NO_x (O_3 precursor); • 50 tons/year (45.5 metric tons/year) VOCs (O_3 precursor); and • 100 tons/year (90.7 metric tons/year) CO. If the net increases in emissions due to a project are lower than the *de minimis* levels, the project is presumed to conform, and no further conformity evaluation is necessary. Based on the emissions sources and assumptions listed above, estimated annual emissions associated with the proposed action for NO_x, VOCs, and CO were below *de minimis* levels; therefore, no further conformity evaluation is needed. Emissions associated with buoy deployment would be less than those associated with tower installation because buoys would be towed or carried aboard a vessel and then anchored to the seafloor. No drilling equipment would be required to install meteorological buoys. Although unlikely, a spill could occur in the event of vessel collision while in route to and from the WEA, or during surveys. Spills occurring in these areas, including harbor and coastal areas, are not anticipated to have significant impacts on onshore air quality due to the small estimated size and short duration of the spill. A diesel spill in the WEA would not be expected to have impacts on onshore air quality because of the estimated size of the spill, prevailing atmospheric conditions over the WEA, and distance from shore. Although the emissions estimates from site characterization and site assessment activities are measurable, they would not be distinguishable from other air emissions onshore or offshore; therefore, emissions associated with the proposed action would be negligible. As shown in Table 4-1 of the EA, air pollutant concentrations due to emissions from the

		proposed action are not expected to lead to any violation of the National Ambient Air Quality Standards.
Recreation and Tourism	Policy 21 (NY) Policy 22 (NY) 7:7E-7.3 Resort/Recreational Use (NJ)	More information on recreation and tourism can be found in Section 4.4.3.4 of the EA. The coastal areas of New York and New Jersey are characterized by an abundance of coastal recreation and tourism opportunities. Coastal counties that may depend on their coastal setting for tourism and recreation include Monmouth and Kings Counties in New Jersey, and Nassau, Suffolk, and Queens Counties in New York. The following impact-producing factors from both site characterization and assessment have the potential to impact recreation and tourism opportunities: • Vessel traffic during site characterization and site assessment; • Vessel exclusion zones surrounding the meteorological tower and/or buoys during deployment (no exclusion zones once a tower and/or buoys are operational); • Trash and debris from vessels; • Viewshed-related impacts associated with site characterization and site assessment from additional vessels, and nighttime lighting on the vessels that could be seen both from shore and from recreational boaters; • Viewshed-related impacts from the meteorological tower, including nighttime lighting; and • Fuel spills. Information on potential exclusion zones can be found in the Public Access section above. The primary impact-producing factor for recreation and tourism associated with vessels used in support of the proposed action would be the potential for generation of trash and debris. Trash and debris, if accidentally released, could wash up on beaches and into harbors, bays, and coastal marshes, and other recreation and tourism destinations. Presence of trash/debris could adversely affect the aesthetic quality of the setting and alter the perception of affected areas, particularly for those areas valued for beach and near

		shore recreation (e.g., Gateway National Recreation Area, and Jones Beach State Park), or those considered pristine wilderness. However, because of restrictions that prohibit the release of trash and debris provided by existing regulations (MARPOL 73/78 Annex V) impacts to recreation and tourism resulting from trash and debris are expected to be negligible. Potential impacts to recreation and tourism settings resulting from the visual contrast of the meteorological tower and/or buoys and associated nighttime lighting would be minor, as described in Section 4.4.4.6 of the EA. As noted in the G&G Final PEIS, potential impacts to recreation and tourism from a fuel spill would depend on the location of a spill, meteorological conditions at the time of the spill, and the speed with which cleanup occurred. Should a spill occur, access to recreation and tourism destinations could be temporarily limited by cleanup and response vessel activity. However, a spill would likely be relatively small in size (88 gallons [333 liters]) so a large-scale spill response involving multiple cleanup vessels is not expected. Therefore, impacts on recreational resources from a small diesel fuel spill are expected to be minor. Impacts to recreation and tourism resulting from routine and non-routine activities would be minor**.** Impacts would result primarily from vessel traffic restrictions in exclusion zones, potential for small scale spills, and from vessel traffic associated with installation of a meteorological tower and/or buoys.
Historic, Cultural, and Subaqueous Areas Management	Policy 23 (NY) Policy 26 (NY) 7:7E-3.36 Historic and archaeological resources (NJ) 7:7E-3.6 Submerged vegetation habitat (NJ)	Historic properties are defined as any pre-contact or historic period districts, sites, buildings, structures, or objects included in, or eligible for inclusion in, the National Register of Historic Places (NRHP). Historic properties that could experience impacts from site characterization (i.e., HRG surveys and geotechnical sampling) and/or site assessment activities (i.e., installation of a meteorological tower and/or buoys) include: • Offshore historic properties on or below the seafloor within portions of the WEA or cable routes to shore that could be affected by seafloor disturbing activities; and • Onshore historic properties within the viewshed of survey activities, construction activities, or a meteorological tower and/or buoys.

	7:7E-3.12 Submerged infrastructure (NJ) 7:7E-4.14 Submerged pipelines (NJ) 7:7E-4.20 Submerged cables (NJ) 7:7E-4.21 Artificial reefs (NJ) 7:7E-4.22 Miscellaneous Water Area uses (NJ) 7:7E-8.12 Scenic Resources and Design (NJ)	For more information on cultural, historical, and archaeological resources in the effected environment, see Section 4.4.3.1 of the EA. <u>Offshore Historic Properties</u> Due to historic sea level rise, the WEA has a high potential for the presence of submerged archaeological sites dating from the Paleoindian through Early Archaic periods, but very low to no potential for the presence of submerged archaeological sites more recent than the end of the Early Archaic (*see* Table 4-18 of the EA). There are nine shipwrecks reported for the WEA, two of which have dates for sinking; the remaining seven do not have dates associated with them (*see* Table 4-21 of the EA). One of the nine is simply identified as an unknown vessel and has no further data to suggest construction, rig, or purpose. Additionally, the precision of the hull locations of the nine vessels is medium to low, and the hulls may be up to 3 mi (4.8 km) from the plotted positions. These vessels potentially meet several of the criteria for eligibility on the NRHP. The types of historic properties expected within the onshore affected environment include districts, sites, buildings, structures, or objects within the viewshed of site characterization and site assessment activities. There are 40 known NRHP-listed and potentially eligible properties within the analysis area that are considered in the EA (*see* Figure 4-19 of the EA). Site characterization activities include both HRG survey (e.g., shallow hazard, geological, and archaeological surveys) and geotechnical sampling techniques. Geophysical surveys do not come in contact with the seafloor and, therefore, have no ability to impact offshore historic properties, submerged infrastructure, pipelines, or cables. Geotechnical sampling activities, when conducted to inform the design and installation of renewable energy structures or cables, disturb the seafloor and, therefore, have the potential to impact historic properties located on or below the seafloor. Coring, sediment grab sampling, and other direct sampling techniques (e.g., cone penetrometer tests and deep borings), in addition to anchoring, anchor chain sweep from moored or anchored support vessels, use of jack-up barges, or other equipment used in conducting geotechnical sampling, all have the

		potential for damaging or destroying historic properties, submerged infrastructure, pipelines, or cables located on or under the seafloor. These potential impacts can be reduced to negligible through the completion of geophysical surveys in the WEA consistent with BOEM's *Guidelines for Providing Archaeological and Historic Property Information Pursuant to 30 CFR Part 585*. Geophysical surveys, in part, serve to identify offshore historic properties. If geophysical surveys are completed by a lessee prior to conducting geotechnical/sediment sampling, historic properties (and other obstructions) can be identified and bottom disturbing activities can be located in areas where historic properties are not present. Therefore, BOEM would require a lessee to conduct geophysical surveys consistent with the *Guidelines for Providing Archaeological and Historic Property Information Pursuant to 30 CFR Part 585* prior to conducting geotechnical sampling, and if a potential offshore historic property is identified, the lessee would be required to avoid it. The following elements, designed to avoid impacts to offshore historic properties from site characterization activities, would be included in a commercial lease issued for the WEA: • The lessee may only conduct geotechnical exploration activities, including geotechnical sampling or other direct sampling or investigation techniques, which are performed in support of plan (i.e., SAP and/or COP) submittal, in areas in which an archaeological analysis of the results of geophysical surveys has been completed for that area; • The analysis must be completed by a qualified marine archaeologist who both meets the Secretary of the Interior's Professional Qualifications Standards (48 FR 44738–44739) and has experience analyzing marine geophysical data; • The qualified marine archaeologist's analysis of the geophysical data must include a determination of whether any potential archaeological resources are present in the area of geotechnical sampling, including consideration of both pre-contact and historic period archaeological resources; • If present in the area, the lessee's geotechnical sampling activities must avoid any potential archaeological resources by a minimum of 164 ft (50 m). The avoidance

		distance must be calculated by the qualified marine archaeologist from the maximum discernible extent of the archaeological resource; • The qualified marine archaeologist must certify in the lessee's archaeological reports, included with a SAP or COP, that geotechnical exploration activities did not affect potential historic properties identified as a result of the HRG surveys; and • In no case may the lessee's actions affect a potential archaeological resource without BOEM's prior approval. In addition, BOEM would require that the lessee observe the unanticipated finds requirements at 30 CFR 585.802. The following requirements would also be included in a commercial lease issued within the WEA: • If the lessee, while conducting site characterization activities in support of plan (i.e., SAP and/or COP) submittal, discovers a potential archaeological resource such as the presence of a shipwreck or pre-contact archaeological site within the project area, the lessee must: o Immediate halt of seafloor-disturbing activities in the area of discovery; o Notify the lessor within 24 hours of discovery; o Notify the lessor in writing by report within 72 hours of its discovery; o Keep the location of the discovery confidential and take no action that may adversely affect the archaeological resource until the lessor has made an evaluation and instructs the applicant on how to proceed; and o Conduct any additional investigations as directed by the lessor to determine if the resource is eligible for listing in the NRHP (30 CFR 585.802(b)). The lessor will direct the lessee to conduct such investigations if: (1) the site has been affected by the lessee's project activities; or (2) impacts on the site or on the area of potential effect cannot be avoided. If investigations indicate that the resource is potentially eligible for listing in the NRHP, the lessor will tell the lessee how to protect the resource or how to mitigate adverse effects on the site. If the lessor incurs costs in protecting the resource, under Section 110(g) of the National Historic Preservation Act (NHPA), the lessor may charge the lessee

		reasonable costs for carrying out preservation responsibilities under the OCS Lands Act (30 CFR 585.802(c-d)). Because a lessee would be required to conduct geophysical surveys prior to conducting geotechnical sampling, and would be required to follow the lease stipulations regarding avoidance and unanticipated discovery protocols for submerged historic properties, impacts from site characterization on offshore historic properties, submerged infrastructure, pipelines, and cables are expected to be negligible. In some cases, geotechnical testing methods may also provide a useful strategy of confirming the presence or absence of features of archaeological interest and for gathering information that informs the archaeological interpretation of HRG data. If a lessee intends to impact a potential offshore historic property for the purpose of historic property identification or National Register testing and evaluation, the lessee would be required to provide written notification describing these activities to BOEM for approval under the elements of lease issuance outlined above. BOEM would review this information under Section 106 of the NHPA and the stipulations of the Programmatic Agreement, discussed below. Impacts to submerged historic properties from vibracores or other direct samples collected, by or under the supervision of a Qualified Marine Archaeologist, for the purposes—at least in part—of historic property identification or National Register eligibility testing and evaluation, are expected to be negligible. Although installation of a meteorological tower and/or buoys would affect the seafloor, the lessee's SAP must be approved by BOEM prior to installation. To assist BOEM in complying with the NHPA and other relevant laws (30 CFR 585.611(a) and 30 CFR 585.611(b)(6)), the SAP must contain a description of the historic properties that could be affected by the activities proposed in the plan. Under its Programmatic Agreement, BOEM will consult with the New York and New Jersey State Historic Preservation Officers and other appropriate parties prior to approval of a SAP to ensure potential effects on historic properties are avoided, minimized, or mitigated under Section 106 of the NHPA. The seafloor impacts associated with installation of a meteorological tower and/or buoys include: disturbance resulting from foundation installation; dropping and dragging anchors from construction vessels; and mooring chain sweeping.

		Impacts on archaeological resources in these activity areas could result in destruction of all or part of the historic properties, or loss of their archaeological context. Should the archaeological surveys reveal the possible presence of an archaeological site in an area that may be affected by activities proposed in a SAP, BOEM would likely require the lessee to avoid the potential site or to demonstrate through additional investigations that an archaeological resource either does not exist, or would not be adversely affected by the seafloor/bottom-disturbing activities. If avoidance of the historic property is not possible, BOEM would continue Section 106 consultation under the Programmatic Agreement to resolve adverse effects. Although site assessment activities have the potential to affect historic properties either on or below the seabed, existing regulatory measures, coupled with the information generated for a lessee's initial site characterization activities and presented in the lessee's SAP, make the potential for bottom-disturbing activities to damage historic properties low. Therefore, impacts on offshore historic properties from site assessment activities are expected to be negligible. In addition, installation of a meteorological tower and/or buoys would affect the seafloor and could impact submerged infrastructure, pipelines, cables, and artificial reefs. Should survey results reveal the presence of submerged infrastructure, pipelines, cables, or artificial reefs, BOEM would likely require the lessee to avoid impacting the existing submerged infrastructure. Therefore, impacts on submerged infrastructure, pipelines, cables, and artificial reefs from site assessment activities are expected to be negligible. <u>Onshore Historic Properties</u> Vessel traffic from site characterization activities could be visible from onshore historic properties and scenic resources. As noted in Section 4.4.3.2 of the EA, BOEM anticipates that there would be one to three vessels at any given time in the WEA and between the shore and the WEA associated with the proposed action. Survey vessels in the WEA would appear small in scale or would fall below the horizon, thereby reducing the likelihood that vessels are seen from onshore locations. Similarly, lighting associated with survey vessels operating under night conditions would appear small in scale and isolated, consistent with existing nautical lighting visible on the horizon. However, the increased ocean vessel traffic from these survey activities would be indistinguishable from existing ocean vessel traffic, and these impacts would be temporary and minimal. Based on the distance of survey activities from any onshore historic properties, the impacts to the

		characteristics of these properties that contributed to their eligibility for listing in the NRHP are expected to be negligible. Additionally the distance of survey activities from scenic resources would make any impacts to these resources negligible. Because of the distance of the WEA from shore, it is anticipated that meteorological buoys would not be visible from onshore areas and would have no impact on onshore historic properties or scenic resources. Under daytime conditions, if a lessee installed a meteorological tower at the closest point of the WEA that is available for structure placement to the shoreline (at the western tip of the 1 nm [1.9 km] buffer), approximately 13.5 nm (25 km) from the shoreline, the tower may be visible, although it would be difficult to detect by the casual observer when viewed from onshore historic properties or scenic resources. Assuming no daytime avoidance lighting on the meteorological tower (*see* discussion of avoidance lighting per FAA [2015] in Section 4.4.4.6 of the EA), if the tower was detected by an observer on the shore, it would appear small in scale relative to the broad horizon of the seascape, and visual contrast would be weak. During nighttime conditions, avoidance lighting on the tower could be visible from onshore historic properties and scenic resources; however, lighting would be discrete and isolated and appear consistent with existing nautical lighting on the horizon. Lighting would appear similar to lights visible from existing vessel traffic. Visibility of the meteorological tower, and related viewshed impacts, would attenuate with distance due to the influence of atmospheric haze and the reduction in scale of the tower relative to the surrounding seascape. No portion of the structure or lighting would be visible if the tower was placed beyond 23.5 nm (44 km), because the entire tower would fall below the horizon when viewed from the shore. Consequently, visual impacts to onshore historic properties and scenic resources resulting from the proposed action would be minor. <u>Conclusion</u> Overall, impacts to cultural, historical, archaeological, and scenic resources would be minor.

		Impacts to submerged historic properties, infrastructure, pipelines, cables, and artificial reefs from site characterization activities are expected to be negligible given the geophysical surveying requirements and lease conditions discussed above. Impacts to submerged historic properties, infrastructure, pipelines, cables, and artificial reefs, from installation of a meteorological tower and/or buoys are expected to be negligible as avoidance would likely be required by BOEM. If avoidance of potential historic properties is not feasible, BOEM will continue its Section 106 consultation to resolve adverse effects. Vessel traffic associated with survey activities would be indistinguishable from existing vessel traffic and short-term. Therefore, impacts to onshore historic properties and scenic resources from site characterization activities are expected to be negligible. A meteorological tower is not expected to be detected by the casual observer when viewed from onshore historic properties under daytime conditions. Nighttime lighting would be discrete and isolated and appear consistent with existing nautical lighting on the horizon and is not expected to adversely impact the character of onshore historic properties or scenic resources. Therefore, overall impacts on onshore historic properties and scenic resources from installation of a meteorological tower are expected to be minor. For more information on visual resources, see Section 4.4.3.6 of the EA. For more information on BOEM's compliance with the NHPA, see Section 5.3.4 of the EA.

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CERTIFIED MAIL

Mr. James F. Bennett
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Department of the Interior
Bureau of Ocean Energy Management
Office of Renewable Energy Programs
45600 Woodland Road VAM-OREP
Sterling, VA 20166

RE: Federal Consistency Determination
DLUR File No. 0000-13-0021.1CDT160001
Bureau of Ocean Energy Management (BOEM)
Proposed Lease Issuance and Site Assessment Activities
New York Wind Energy Area (WEA)
Atlantic Continental Shelf Offshore New York

Dear Mr. Bennett:

The New Jersey Department of Environmental Protection, Division of Land Use Regulation, acting under Section 307 of the Federal Coastal Zone Management Act (P.L. 92-583) as amended, agrees with the certification that the above referenced project is consistent with the approved New Jersey Coastal Management Program. The Division has determined that the project is conditionally consistent with New Jersey's Rules on Coastal Zone Management N.J.A.C. 7:7-1.1 et seq., as amended on July 6, 2015, with the implementation of the below.

The proposed activities include:

- Lease issuance for the New York Wind Energy Area (including reasonably foreseeable consequences associated with shallow hazards, geological, geotechnical, archaeological resources, and biological surveys). The Wind Energy Area is approximately 11 nautical miles south of Long Beach, NY and extends 26 nautical miles southeast. The lease issuance grants the lessee the right to use the leasehold to 1) gather resource and site characterization information, 2) develop its plan, 3) subsequently seek BOEM approval of its plans for the development of the leasehold. This analysis does not consider construction and operation of any commercial wind power facilities, which would be evaluated later in the process during the review of a construction and operations plan.

- Site Assessment Plan approval (including reasonably foreseeable consequences associated with the installation of a meteorological tower and meteorological buoys).

The purpose of conducting the surveys and installing meteorological measurement devices is to assess the wind resources in the lease area and to characterize the environmental and socioeconomic resources and conditions. A lessee must collect this information to determine whether the site is suitable for a commercial wind development. In the event that it is determined that the lease area is suitable for development, the lessee will submit for BOEM's review, a construction and operations plan with its project-specific design parameters.

The Division has determined that the project is consistent with New Jersey's Rules on Coastal Zone Management N.J.A.C. 7:7-1.1 et seq., as amended on July 6, 2015.

Conditional Compliance:

To ensure consistency with the New Jersey Coastal Management Program, the following conditions must be met:

1. The Bureau of Ocean Energy Management (BOEM) and the New Jersey Department of Environmental Protection's Historic Preservation Office have executed a Programmatic Agreement to cover all cultural resource issues as they are related to Outer Continental Shelf Renewable Energy Activities Offshore New Jersey and New York. The BOEM and any lessee to the WEA, shall adhere to said Programmatic Agreement.

2. This Federal Consistency Determination shall not affect any future review by the NJ Department of Environmental Protection of any commercial wind power facility nor should this Federal Consistency Determination be construed as an endorsement of any future facility.

This Federal Consistency is authorized pursuant to all parties following the guidelines set forth, and agreed upon, for the construction of the proposed structures.

Pursuant to 15 CFR 930.44, the Division reserves the right to object and request remedial action if the proposal is conducted in a manner, or is having an effect on, the coastal zone that is substantially different than originally proposed.

Thank you for your attention to and cooperation with New Jersey's Coastal Zone Management Program. If you have any questions regarding this determination, please do not hesitate to call Cathryn Schaffer of our staff at (609) 633-2289.

Sincerely,

Christopher Jones

Christopher Jones, Manager
Bureau of Urban Growth & Redevelopment
Division of Land Use Regulation

7/29/16
Date

C: Elizabeth Semple, Division of Coastal and Land Use Planning

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August 15, 2016

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Bureau of Ocean Energy Management
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45600 Woodland Rd. VAM-OREP
Sterling, VA 20166

RE: F-2016-0510 (DA)
Lease Issuance and Site Assessment Activities for the Wind Energy Area offshore of NY.
New York Bight
Concurrence with Consistency Determination

Dear Mr. Bennett:

The Department of State (DOS) received the Bureau of Ocean Energy Management's (BOEM) consistency determination (CD) on June 17, 2016 prepared in accordance with the Coastal Zone Management Act (16 U.S.C. § 1451 et seq.) and pursuant to 15 CFR part 930 subpart C, for the above referenced project.

BOEM's proposed actions include a lease issuance for a delineated wind lease area (WEA), and subsequent site assessment activities to be conducted by the lessee post lease issuance, as indicated in the *Draft Commercial Wind Lease Issuance and Site Assessment Activities on the Atlantic Outer Continental Shelf Offshore New York Environmental Assessment (EA)*, which was appended to the CD. The site assessment activities would determine whether the lease is suitable for, and would support, commercial-scale wind energy production. BOEM's identification and evaluation of the impacts of site assessment activities on New York's coastal resources and uses are included in the EA. DOS concurs with BOEM's CD for lease issuance and site assessment activities as they are evaluated and assessed in the EA. We note that the lease, by itself, does not authorize a lessee to construct or operate any wind energy project on the Outer Continental Shelf.

As described in BOEM's CZMA consistency determination analysis accompanying its June 17, 2016 letter to DOS, following the award of a lease issuance for the WEA, the lessee will be required to prepare a Site Assessment Plan (SAP) enumerating the site assessment activities that it will be conducting within the WEA. Prior to BOEM approval of the lessee's SAP, DOS will make a determination as to whether the SAP contains site activities which will cause an effect on any New York State coastal use or resource substantially different that those addressed within the CD. If effects on the state's coastal uses and resources are found to be substantially different, then the lessee will be required to submit a consistency certification in accordance with 15 CFR part 930 subpart D. To facilitate this review, DOS will make itself available to consult with the lessee while the SAP is developed.

E

Please feel free to discuss any additional comments or concerns with Jeffrey Zappieri (Jeffrey.Zappieri@dos.ny.gov) or Matthew Maraglio (Matthew.Maraglio@dos.ny.gov) of my staff.

Sincerely,

Gregory Capobianco
Office of Planning and Development

Cc: NOAA- David Kaiser
USCG – Captain Michael Day
– Jeff Yunker
– Michele E. DesAutels
NYSDEC – William Little
NYSDPS – Andrew Davis

Our reference
OCS-A- 512 SAP

Statoil

October 10, 2017

Attn.: Lucas Feinberg, Program Manager
Office of Renewable Energy Programs
Bureau of Ocean Energy Management
45600 Woodland Road (VAM-OREP)
Sterling, Virginia 20166

[Submitted via email to lucas.feinberg@boem.gov and by mail to the above address]

RE: Commercial Lease of Submerged Lands for Renewable Energy Development on the Outer Continental Shelf, OCS-A 512 – Request for Extension of Preliminary Term

Dear Mr. Bennett,

In accordance with 30 CFR Part 585.235(a), Statoil Wind US LLC (Statoil) is required to submit a Site Assessment Plan (SAP) within 12 months of executing the Commercial Lease of Submerged Lands for Renewable Energy Development on the Outer Continental Shelf: Lease No. OCS-A 0512 (the Lease). This preliminary term is currently scheduled to expire on April 1, 2018. Pursuant to 30 CFR 585.235(b), Statoil is requesting a 12-month extension of the preliminary term to April 1, 2019.

In preparation for site investigations (SAP pre-surveys) of the Lease area, and the subsequent submittal of a SAP, Statoil has engaged with the Bureau of Ocean Energy Management (BOEM) regarding the SAP, survey plans, requirements and expectations, in a workshop on May 30, 2017. Statoil has also begun discussions with relevant organizations and stakeholders, which will be an ongoing process.

Statoil has been actively maturing the project survey plans and technical scope towards SAP submission. A geological desktop study was commissioned and completed, providing the information necessary to effectively plan SAP survey activities. Work has been carried out in consultation with the supply chain, regarding the appropriate concept to use for site characterization (wind resource and metocean), which in turn informs the SAP survey requirements and plan. As a result, Statoil has decided on a buoy based 'Floating Light Detection and Ranging' (FLiDAR) approach for wind resource measurements, and metocean buoys for oceanographic and meteorological measurements. The procurement process for selecting a supplier and final concept is underway, with the intention to award a contract by the end of calendar year (CY) 2017. There are currently no plans for traditional fixed bottom meteorological masts.

SAP survey plans are currently being drafted, with the intended submission in Q4 2017. Consultation on the survey plans with BOEM and Tribes and other relevant stakeholders will take place in Q1 2018.

A draft Fisheries Liaison Plan and Coexistence Plan have been developed, which will feed into the Fisheries Communications Plan. This will be published on the Statoil project webpage in Q1 2018.

During the requested preliminary term extension, and subject to BOEM's approval of the survey plan(s), Statoil intends to undertake site investigations, including geophysical and geotechnical surveys. The relevant data collected from these surveys will be included in the SAP and the COP as appropriate. Once the SAP is approved and other necessary permits are issued, Statoil intends to deploy FLiDAR buoy(s) / meteorological buoy(s) in the Lease area. A preliminary calendar year schedule for SAP activities is:

- Submission of survey plans Q4 2017;
- Procurement of survey contractors Q4 2017;
- Survey plan consultation meetings with BOEM, Tribes and relevant stakeholders Q1 2018;
- Initiate surveys Q2 2018;
- SAP submission Q3 2018; and
- FLiDAR and metocean buoy deployment Q4 2018.

An extension to the preliminary term will increase the time available to allow for full and effective stakeholder engagement, survey planning and project related technical decisions. It is also important for the project to aim for a survey window in spring 2018 that provides an opportunity for maximizing synergies with the wider COP survey and consultation activities.

We appreciate your review of our request for a 12-month extension of the preliminary term. If you have any questions or comments, please contact the Permitting Manager, Martin Goff, at mgof@statoil.com or +1 (202) 813-7444.

Sincerely,

Meagan Keiser

Secretary, Statoil Wind US LLC

United States Department of the Interior

BUREAU OF OCEAN ENERGY MANAGEMENT
WASHINGTON, DC 20240-0001

NOV 13 2017

Ms. Meagan Keiser
Statoil Wind US LLC
120 Long Ridge Road, Suite 3E01
Stamford, Connecticut 06902

Dear Ms. Keiser:

The Bureau of Ocean Energy Management (BOEM) has received Statoil Wind US LLC's (Statoil) October 10, 2017, letter requesting a 12-month extension of the preliminary term for commercial lease OCS-A 0512, from April 1, 2018, to April 1, 2019, pursuant to 30 C.F.R. § 585.235(b). BOEM is approving your request for the reasons described below.

Your letter indicates that Statoil has been actively maturing the project survey plans and technical scope towards submission of a Site Assessment Plan (SAP) as required by lease OCS-A 0512, by conducting the following activities:

1. Hosting a workshop with BOEM on May 30, 2017.
2. Completion of a geological desktop study.
3. Consultation with wind resource and metocean supply chain representatives resulting in a decision to pursue deployment of a buoy based Floating Light Detection and Ranging (FLiDAR) as a wind resource solution.
4. Drafting of SAP survey plans and consultation with BOEM, Tribes, and other relevant stakeholders.

Your letter also states that while Statoil has made significant progress to date, more time is necessary to complete several activities to collect information required to submit a SAP. These include:

1. Advancing full and effective stakeholder engagement;
2. Survey planning and project related technical decisions, and;
3. Seasonal considerations in relation to undertaking offshore site characterization work as well as planning to maximize synergies with wider construction and operations plan survey and consultation efforts.

Your letter provides a plan for conducting geophysical and geotechnical surveys during the requested preliminary extension term. The results from these surveys will be included in the SAP planned for filing in Q3 (calendar year) 2018. Assuming the SAP is approved by BOEM; Statoil would deploy the FLiDAR(s) and wave buoy(s) in the lease area in Q4 2018.

BOEM has reviewed your request and has determined an extension of the preliminary term is justified. We base our decision on the fact that Statoil has identified their previous and planned activities over the next year to support SAP submission and development of commercial lease OCS-A 0512.

Therefore, pursuant to 30 C.F.R. § 585.235(b) and in consideration of the information provided in your October 10, 2017 letter, your request to extend the preliminary term of commercial lease OCS-A 0512 to April 1, 2019, is approved.

If you have any questions please contact Mr. Luke Feinberg at 703-787-1705 or luke.feinberg@boem.gov.

Sincerely,

James F. Bennett
Program Manager
Office of Renewable Energy Programs

Appendix B
Equipment Specifications and Modelling Results

(Contains Privileged or Confidential Information - Provided Under Separate Cover)

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Appendix C
Site Characterization Report

(Contains Privileged or Confidential Information - Provided Under Separate Cover)

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Appendix D
Marine Archaeological Resource Assessment Report in Support of the Empire Wind Offshore Wind Farm

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Appendix E

Benthic Assessment

(Contains Privileged or Confidential Information - Provided Under Separate Cover)

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Appendix F
Health and Safety Plan

(Contains Privileged or Confidential Information - Provided Under Separate Cover)

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Appendix G
Vessel Specifications

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PUBLIC COPY - CONFIDENTIAL INFORMATION REMOVED

RANA MILLER

MILLER'S LAUNCH
PIER 7 1/2, STATEN ISLAND, NY

Main Particulars

Length Overall	150 ft.	46 m
Length BP	130.9 ft.	40 m
Beam	36 ft.	11 m
Depth	11.5 ft	4 m
Light Draft	5 ft.	2 m
Loaded Draft	10 ft.	3 m
Summer Freeboard	2 ft.	1 mm
Lightship	387.73 LT.	395 MT

Capacities

Potable Water (Deliverable)	62,878 USG	264 Tons
Fuel	31,478 USG	119 m³
Liquid Mud	1,200 BBLS	191 m³
Methanol	515 BBLS	82 m³
Potable Water (Domestic)	15,288 USG	58 m³
Deadweight	530 LT.	540 MT.

Cargo Deck

Tonnage	390 LT.	397 MT.
Strength	0.36 lbs./ft.²	4 MT./m²
Length	92 ft	28 m
Width	30 ft.	9 m
Clear Area	2,670 ft.2	248 m²

Tonnage

GRT	90 US tons	443 tons
NRT	50 US tons	132 tons

Machinery

Main Engines	Cummins KTA-38
Brake Horsepower	1700
Reduction Gears	Rentjies561
Gear Ratio	5:01
Propellers	74x59
Rudders	Spade
Auxiliary Generators	2 100kw
Bow Thrusters	Schottel
Liquid Mud Circulation	5X4X14 Mission Magnum

Performance

Maximum Speed	12 knots	
Cruising Speed	10 knots	
Maximum Fuel Consumption	85 USG/Hr	
Cruising Fuel Consumption	50 USG/Hr	5 m³/24 Hrs

Discharge Rates

Potable Water	400 USG/min @ 80 ft.	91 m³/Hr @ 24 m
Fuel Oil	400 USG/min @ 80 ft.	91 m³/Hr @ 24 m
Liquid Mud	700 USG/min @ 150 ft.	159 m³/Hr @ 46 m
Methanol	400 USG/min @ 80 ft.	91 m³/Hr @ 24 m

AccomModations

Cabins*Berths	5*18
Officers	2
Crew	3
VIP	0
Lounge	6
Mess	10

Electronics & Controls

Depth Recorder	1
DP	N/A
GPS	Furuno / Northstar GPS Plotter
Radar(s)	2-Furuno
HF Radio	1
SSB	1
Internet E-mail	Satellite (Boat Tracs)
VHF	2-ICOM
XM Satallite	Real Time 3D Weather
Autopilot	Comnav Marine

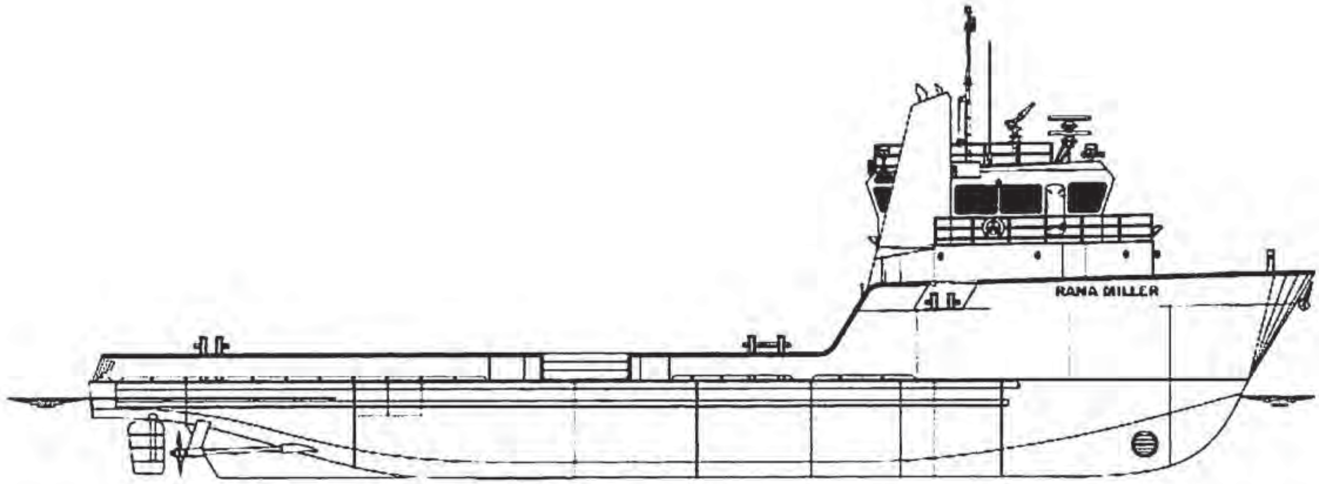
Special Equipment

Windlass	Bolinger 2 Inches 600 ft.	750LB Anchor
External FIFI	1900 GPM	
Stern Deck Winch	Skagit Model JUW-075	Single Drum
Stern Tugger Winch	2-Gear Matic	Tugger
Number of Monitors	1	
E-Pirb	Equipped	
Satellite TV	Direct TV	

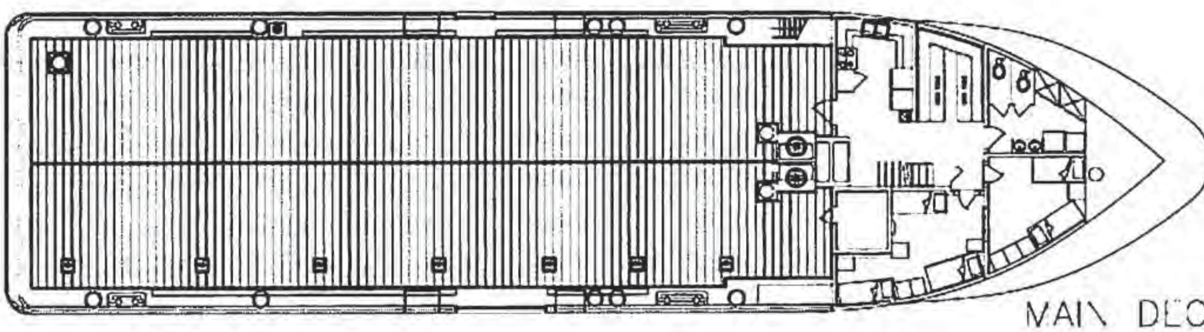
Documentation

Class	150 FT. MS
Flag	United States
USCG	USCG Sub L, OSV
Year Built	1997
Official Number	1052663
BUILDER	Bollinger Shipyard

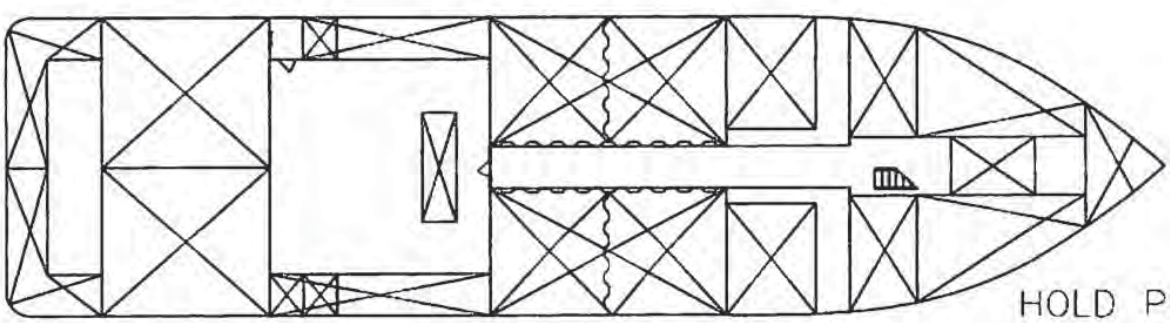
This specification is preliminary and subject to change without notice. Exact tank capacities, deadweight, deck cargo capacity and other figures that have been calculated and may change when the actual vessel is delivered.



OUTBOARD PROFILE



MAIN DECK



HOLD PLAN

Appendix H
Air Quality Emissions Calculations

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EMPIRE WIND OFFSHORE WIND FARM
Air Emission Calculations
Emission Summary - FLiDAR Buoy Deployment

Met Facilities Activity	VOC tpy	NO_X tpy	CO tpy	PM/PM_{10} tpy	$PM_{2.5}$ tpy	SO_2 tpy	HAPs tpy	GHG tpy CO_2e
Deployment Activities (yr. 1)	0.015	0.53	0.27	0.014	0.014	7.08E-05	0.003	38.0
Maintenance Activities (yrs. 1-2)	0.034	1.25	0.64	0.033	0.032	1.66E-04	0.007	89.0
Maintenance Activities (yrs. 3-4)	0.018	0.64	0.32	0.017	0.016	8.45E-05	0.004	45.4
Unscheduled Visits (up to 1 per yr.)	0.002	0.08	0.04	0.002	0.002	1.06E-05	0.000	5.7
Decommissioning Activities (End of Yr. 2)	0.010	0.35	0.18	0.009	0.009	4.92E-05	0.002	26.4
Decommissioning Activities (End of Yr. 4)	0.005	0.18	0.09	0.005	0.005	2.44E-05	0.001	13.0
Maximum Annual Emissions (tons)[1]	**0.051**	**1.86**	**0.95**	**0.049**	**0.048**	**2.47E-04**	**0.011**	**132.7**
Total Project Lifetime Emissions (tons)	**0.12**	**4.53**	**2.31**	**0.12**	**0.12**	**6.04E-04**	**0.026**	**324.3**

Note:
1. The maximum annual emissions occur for Year 1 of the project, and include the initial deployment activities, two rounds of 6-month inspections, and up to one unscheduled visit.

EMPIRE WIND OFFSHORE WIND FARM
Air Emission Calculations
Marine Vessel Emissions - FLiDAR Buoy Deployment (Rana Miller)

														Total Emissions										
Vessels/Equipment	**No. of Engines per vessel**	**Dimensions (ft) length x breadth x draft**	**Emission Factor Used (see EFs worksheet)**	**Activity**	**Engine Rating (hp)**	**Fuel Type**	**Trips**	**Hrs/trip**	**Operating Days**	**Operating Hours (hrs/day)**	**Total Vessel Operating Hours (hrs)**	**Average load (%)**	**Fuel Usage Gallons**	**VOC tons**	**NO_X tons**	**CO tons**	**PM_{10} tons**	**$PM_{2.5}$ tons**	**SO_2 tons**	**HAPs tons**	**CO_2 tons**	**CH_4 tons**	**N_2O tons**	**CO_2e tons**
Work boat (Rana Miller or similar)		150' x 36' x 10'		Deploying FLIDAR 1																				
- main engines	2		2		850	Diesel	1	14	1	12	26	43%	958.2	4.22E-03	0.15	0.08	4.03E-03	3.91E-03	2.03E-05	8.68E-04	10.78	1.41E-03	3.13E-04	10.91
- aux. generator	1		2		99	Diesel	1	14	1	12	26	43%	55.8	2.46E-04	8.92E-03	4.55E-03	2.35E-04	2.28E-04	1.18E-06	5.05E-05	0.63	8.19E-05	1.82E-05	0.64
bow thruster	1		2		300	Diesel	0	0	1	12	12	43%	78.0	3.44E-04	1.25E-02	6.36E-03	3.28E-04	3.19E-04	1.65E-06	7.07E-05	0.88	1.15E-04	2.55E-05	0.89
- aux. engine	1		2		99	Diesel	0	0	1	12	12	100%	59.9	2.64E-04	9.57E-03	4.88E-03	2.52E-04	2.44E-04	1.27E-06	5.43E-05	0.67	8.79E-05	1.95E-05	0.68
Work boat (Rana Miller or similar)		150' x 36' x 10'		Deploying FLIDAR 2																				
- main engines	2		2		850	Diesel	1	11	1	12	23	43%	847.6	3.73E-03	0.14	0.07	3.57E-03	3.46E-03	1.80E-05	7.68E-04	9.54	1.24E-03	2.77E-04	9.65
- aux. generator	1		2		99	Diesel	1	11	1	12	23	43%	49.4	2.17E-04	7.89E-03	4.03E-03	2.08E-04	2.01E-04	1.05E-06	4.47E-05	0.56	7.25E-05	1.61E-05	0.56
bow thruster	1		2		300	Diesel	0	0	1	12	12	43%	78.0	3.44E-04	1.25E-02	6.36E-03	3.28E-04	3.19E-04	1.65E-06	7.07E-05	0.88	1.15E-04	2.55E-05	0.89
- aux. engine	1		2		99	Diesel	0	0	1	12	12	100%	59.9	2.64E-04	9.57E-03	4.88E-03	2.52E-04	2.44E-04	1.27E-06	5.43E-05	0.67	8.79E-05	1.95E-05	0.68
Work boat (Rana Miller or similar)		150' x 36' x 10'		Deploy met buoy + subsea mooring																				
- main engines	2		2		850	Diesel	1	14	1	12	26	43%	958.2	4.22E-03	0.15	0.08	4.03E-03	3.91E-03	2.03E-05	8.68E-04	10.78	1.41E-03	3.13E-04	10.91
- aux. generator	1		2		99	Diesel	1	14	1	12	26	43%	55.8	2.46E-04	8.92E-03	4.55E-03	2.35E-04	2.28E-04	1.18E-06	5.05E-05	0.63	8.19E-05	1.82E-05	0.64
bow thruster	1		2		300	Diesel	0	0	1	12	12	43%	78.0	3.44E-04	1.25E-02	6.36E-03	3.28E-04	3.19E-04	1.65E-06	7.07E-05	0.88	1.15E-04	2.55E-05	0.89
- aux. engine	1		2		99	Diesel	0	0	1	12	12	100%	59.9	2.64E-04	9.57E-03	4.88E-03	2.52E-04	2.44E-04	1.27E-06	5.43E-05	0.67	8.79E-05	1.95E-05	0.68
Work boat (Rana Miller or similar)		150' x 36' x 10'		6-month maintenance (x3)																				
- main engines	2		2	FLIDAR 1 (Yrs. 1-2)	850	Diesel	9	10	9	12	198	43%	7,297.0	3.21E-02	1.17	0.60	3.07E-02	2.98E-02	1.55E-04	6.61E-03	82.12	1.07E-02	2.38E-03	83.10
- aux. generator	1		2	met buoy (Yrs. 1-2)	99	Diesel	9	10	9	12	198	43%	424.9	1.87E-03	6.79E-02	3.47E-02	1.79E-03	1.73E-03	9.01E-06	3.85E-04	4.78	6.24E-04	1.39E-04	4.84
bow thruster	1		2	subsea mooring (Yrs. 1-2)	300	Diesel	0	0	9	12	108	43%	702.4	3.09E-03	1.12E-01	5.73E-02	2.96E-03	2.87E-03	1.49E-05	6.36E-04	7.90	1.03E-03	2.29E-04	8.00
- aux. engine	1		2		99	Diesel	0	0	9	12	108	100%	539.0	2.37E-03	8.62E-02	4.40E-02	2.27E-03	2.20E-03	1.14E-05	4.88E-04	6.07	7.91E-04	1.76E-04	6.14
Work boat (Rana Miller or similar)		150' x 36' x 10'		6-month maintenance (x3)																				
- main engines	2		2	FLIDAR 2 (Yrs. 1-2)	850	Diesel	3	8	3	12	60	43%	2,211.2	9.74E-03	0.35	0.18	9.31E-03	9.03E-03	4.69E-05	2.00E-03	24.89	3.25E-03	7.21E-04	25.18
- aux. generator	1		2		99	Diesel	3	8	3	12	60	43%	128.8	5.67E-04	2.06E-02	1.05E-02	5.42E-04	5.26E-04	2.73E-06	1.17E-04	1.45	1.89E-04	4.20E-05	1.47
bow thruster	1		2		300	Diesel	0	0	3	12	36	43%	234.1	1.03E-03	3.74E-02	1.91E-02	9.85E-04	9.56E-04	4.96E-06	2.12E-04	2.63	3.44E-04	7.64E-05	2.67
- aux. engine	1		2		99	Diesel	0	0	3	12	36	100%	179.7	7.91E-04	2.87E-02	1.47E-02	7.56E-04	7.33E-04	3.81E-06	1.63E-04	2.02	2.64E-04	5.86E-05	2.05
Work boat (Rana Miller or similar)		150' x 36' x 10'		6-month maintenance (x4)																				
- main engines	2		2	met buoy (Yrs. 3-4)	850	Diesel	8	10	8	12	176	43%	6,486.2	2.86E-02	1.04	0.53	2.73E-02	2.65E-02	1.38E-04	5.88E-03	73.00	9.52E-03	2.12E-03	73.87
- aux. generator	1		2	subsea mooring (Yrs. 3-4)	99	Diesel	8	10	8	12	176	43%	377.7	1.66E-03	6.04E-02	3.08E-02	1.59E-03	1.54E-03	8.01E-06	3.42E-04	4.25	5.54E-04	1.23E-04	4.30
bow thruster	1		2		300	Diesel	0	0	8	12	96	43%	624.3	2.75E-03	9.98E-02	5.09E-02	2.63E-03	2.55E-03	1.32E-05	5.66E-04	7.03	9.17E-04	2.04E-04	7.11
- aux. engine	1		2		99	Diesel	0	0	8	12	96	100%	479.1	2.11E-03	7.66E-02	3.91E-02	2.02E-03	1.96E-03	1.02E-05	4.34E-04	5.39	7.03E-04	1.56E-04	5.46
Work boat (Rana Miller or similar)		150' x 36' x 10'		Unscheduled buoy check																				
- main engines	2		2	(assume up to 1 trip/yr in event	850	Diesel	1	10	1	12	22	43%	810.8	3.57E-03	0.13	0.07	3.41E-03	3.31E-03	1.72E-05	7.34E-04	9.12	1.19E-03	2.64E-04	9.23
- aux. generator	1		2	of damage or malfunction)	99	Diesel	1	10	1	12	22	43%	47.2	2.08E-04	7.55E-03	3.85E-03	1.99E-04	1.93E-04	1.00E-06	4.28E-05	0.53	6.93E-05	1.54E-05	0.54
bow thruster	1		2		300	Diesel	0	0	1	12	12	43%	78.0	3.44E-04	1.25E-02	6.36E-03	3.28E-04	3.19E-04	1.65E-06	7.07E-05	0.88	1.15E-04	2.55E-05	0.89
- aux. engine	1		2		99	Diesel	0	0	1	12	12	100%	59.9	2.64E-04	9.57E-03	4.88E-03	2.52E-04	2.44E-04	1.27E-06	5.43E-05	0.67	8.79E-05	1.95E-05	0.68
Work boat (Rana Miller or similar)		150' x 36' x 10'		Decommissioning FLIDAR 1																				
- main engines	2		2	(end of Yr. 2)	850	Diesel	1	14	1	12	26	43%	958.2	4.22E-03	0.15	0.08	4.03E-03	3.91E-03	2.03E-05	8.68E-04	10.78	1.41E-03	3.13E-04	10.91
- aux. generator	1		2		99	Diesel	1	14	1	12	26	43%	55.8	2.46E-04	8.92E-03	4.55E-03	2.35E-04	2.28E-04	1.18E-06	5.05E-05	0.63	8.19E-05	1.82E-05	0.64
bow thruster	1		2		300	Diesel	0	0	1	12	12	43%	78.0	3.44E-04	1.25E-02	6.36E-03	3.28E-04	3.19E-04	1.65E-06	7.07E-05	0.88	1.15E-04	2.55E-05	0.89
- aux. engine	1		2		99	Diesel	0	0	1	12	12	100%	59.9	1.97E-04	7.14E-03	3.64E-03	1.88E-04	1.82E-04	4.07E-06	1.63E-05	2.16	2.81E-04	6.26E-05	2.18
Work boat (Rana Miller or similar)		150' x 36' x 10'		Decommissioning FLIDAR 2																				
- main engines	2		2	(end of Yr. 2)	850	Diesel	1	11	1	12	23	43%	847.6	3.73E-03	0.14	0.07	3.57E-03	3.46E-03	1.80E-05	7.68E-04	9.54	1.24E-03	2.77E-04	9.65
- aux. generator	1		2		99	Diesel	1	11	1	12	23	43%	49.4	2.17E-04	7.89E-03	4.03E-03	2.08E-04	2.01E-04	1.05E-06	4.47E-05	0.56	7.25E-05	1.61E-05	0.56
bow thruster	1		2		300	Diesel	0	0	1	12	12	43%	78.0	3.44E-04	1.25E-02	6.36E-03	3.28E-04	3.19E-04	1.65E-06	7.07E-05	0.88	1.15E-04	2.55E-05	0.89
- aux. engine	1		2		99	Diesel	0	0	1	12	12	100%	59.9	2.64E-04	9.57E-03	4.88E-03	2.52E-04	2.44E-04	1.27E-06	5.43E-05	0.67	8.79E-05	1.95E-05	0.68
Work boat (Rana Miller or similar)		150' x 36' x 10'		Decomm. met buoy + subsea mooring																				
- main engines	2		2	(end of Yr. 4)	850	Diesel	1	14	1	12	26	43%	958.2	4.22E-03	0.15	0.08	4.03E-03	3.91E-03	2.03E-05	8.68E-04	10.78	1.41E-03	3.13E-04	10.91
- aux. generator	1		2		99	Diesel	1	14	1	12	26	43%	55.8	2.46E-04	8.92E-03	4.55E-03	2.35E-04	2.28E-04	1.18E-06	5.05E-05	0.63	8.19E-05	1.82E-05	0.64
bow thruster	1		2		300	Diesel	0	0	1	12	12	43%	78.0	3.44E-04	1.25E-02	6.36E-03	3.28E-04	3.19E-04	1.65E-06	7.07E-05	0.88	1.15E-04	2.55E-05	0.89
- aux. engine	1		2		99	Diesel	0	0	1	12	12	100%	59.9	2.64E-04	9.57E-03	4.88E-03	2.52E-04	2.44E-04	1.27E-06	5.43E-05	0.67	8.79E-05	1.95E-05	0.68
													27,358.1	**0.12**	**4.37**	**2.23**	**0.12**	**0.11**	**5.83E-04**	**2.47E-02**	**309.4**	**4.04E-02**	**8.97E-03**	**313.1**

Notes:
1. Three separate round trips will be required for equipment deployment: one for FLIDAR 1; one for FLIDAR 2; and one for both the met buoy and subsea mooring.
2. Three separate round trips will be required for equipment decommissioning: one for FLIDAR 1; one for FLIDAR 2; and one for both the met buoy and subsea mooring.
3. Four separate round trips will be required for each 6-month maintenance period: one for FLIDAR 1; one for FLIDAR 2; one for the met buoy; and one for the subsea mooring.
4. 6-month maintenance activities will be performed at 6 months, 12 months, and 18 months after the initial deployment of equipment.
5. It is also assumed that up to one unscheduled round trip per year may be needed to visit a buoy site if there is evidence of damage (such as partial or total loss of data transmissions), or if transmitted GPS data indicated that a buoy had drifted significantly outside the "watch circle," which allows for buoy movement inside a roughly 100-meter radius from the recorded deployment coordinates.
Examples of events that could cause such damage or buoy displacement include, but are not limited to, hurricane-strength tropical or "nor'easter" storms, heavy snow accumulation, or heavy icing in the event of extremely low temperatures. Trip time is based on travel to the farthest away buoy location (FLIDAR 1).
6. Trip time constitutes the round trip transit time to and from the project site. The number of hours per trip were estimated based on an assumed transit speed of 4 knots when towing a buoy, and 8 knots when not towing a buoy. Round trip distances are estimated to be: 82 nm to the deployment location for FLIDAR 1, the met buoy, and the subsea mooring; and 66 nm to the deployment location for FLIDAR 2.
7. Operating hours/day is the estimated time each vessel is at the deployment site performing its associated activities.
8. The auxiliary engine on the work boat powers the winch, crane, and A-frame, and will only operate in the immediate vicinity of each deployment site.
9. Emission calculations based on vessels traveling from Miller's Launch in Staten Island.
10. The engines utilized on each of the vessels are assumed to be Category 1 engines based on engine horsepower rating (<1,000 kW) and cylinder displacement (1-5 liters per cylinder).
11. Emission factors for marine vessel engines are from Table 3-8 in the ICF International report to the US EPA "Current Methodologies in Preparing Mobile Source Port-Related Emissions Inventories", April 2009. (See emission factors summary page) Assumed all engines to be used are certified to meet EPA Tier 1 engine standards; therefore, the Tier 1 emission factors in Table 3-8 from the ICF International report was used to provide conservative estimate.
12. HAP emission factors for commercial marine vessels were determined using the methodology identified by US EPA for the 2011 National Emissions Inventory (NEI); i.e., they are calculated as percentages of the PM_{10}, $PM_{2.5}$, or VOC emissions from the CMVs. The HAP emisson for nonroad engines were based on EPA's AP-42 Volume 1, Chapters 3.3 and 3.4 for small and large diesel engines. (see HAP emission factor summary pages)
13. Average load factors were estimated based on load factors presented in Table 3-4 of the ICF International report.

EMPIRE WIND OFFSHORE WIND FARM
Emission Factor Summary

Commercial Marine Vessels (CMVs)

		Commercial Marine Vessel Emission Factors (g/hp-hr) /a									Fuel Cons.
	Engine Type	VOC	NO_x	CO	PM/ PM_{10} /b, /c	$PM_{2.5}$ /b	SO_2 /c	CO_2	CH_4	N_2O	(gal/hp-hr) /d
1	Category 2 engines	0.37	7.3	3.73	0.46	0.45	0.0010	515	0.067	0.015	0.050
2	Category 1 engines ≤ 1000 kW	0.20	7.3	3.73	0.19	0.19	0.0010	515	0.067	0.015	0.050
3	Category 3 engines (MSD using MDO) (>30L/cyl.)	0.37	9.8	0.82	0.14	0.13	0.296	482	0.003	0.023	0.046
4	All Categories aux. engines (MSD using MDO)	0.30	10.4	0.82	0.14	0.13	0.316	515	0.003	0.023	0.049

/a Emission factors for Category 1 and 2 engines are from Table 3-8 from ICF International report to the US EPA "Current Methodologies in Preparing Mobile Source Port-Related Emissions Inventories", April 2009 (converted from g/kW-hr to g/hp-hr by multiplying by 0.746 kW/hp). Assumed all Category 1 and 2 engines to be used are certified to meet EPA Tier 1 and 2 marine engine standards respectively (providing conservative estimate for Category 1 engines); therefore the Tier 1 and 2 emission factors in Table 3-8 from the ICF International report was used. Note, the CO emission factor for Category 1 Tier 2 engines is higher than what is provided for Tier 1 engines, thus the Tier 2 emission factor for CO was used to provide a conservative estimate.

/b All PM is assumed to less than 10 µm in diameter; therefore, PM emission factor is equivalent to PM_{10} emission factor. $PM_{2.5}$ is estimated to be 97 % of PM_{10} per EPA guidance in "Exhaust and Crankcase Emission Factors for Nonroad Engine Modeling - Compression-Ignition," EPA420-R-10-018/NR-009d, July 2010.

/c Emission factors for Category 1 and 2 engines for SO_2 and PM_{10} presented in Table 3-8 of the ICF report (ICF International 2009) are based on a fuel sulfur content of 1.5 percent. These factors were adjusted for the 15 ppmw sulfur content in ultra-low sulfur diesel fuel, by multiplying the emission factors by 0.001 and 0.86 for SO_2 and PM_{10}, respectively, following the approach used in Section 3.4.2 of the ICF Report.

/d Fuel consuption rate for Category 1 and 2 marine engines was estimated based on CO_2 emission factor (g/hp-hr) and the emission factor for the mass of CO_2 generated per gallon of fuel (10.21 kg CO_2/gal fuel) as presented in the Table 13.1 of the “2014 Climate Registry Default Emission Factors.” Fuel consumption for Category 3 marine engines was based on the BSFC (g/kW-hr) in the ICF International report.

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EMPIRE WIND OFFSHORE WIND FARM
EPA NEI HAP emission factors for Commercial Marine Vessels

HAP emission factors for commercial marine vessels were determined using the methodology identified by US EPA for the 2011 National Emissions Inventory (NEI); i.e., they are calculated as percentages of the PM10, PM2.5, or VOC emissions from the CMVs.

CMV fuel type			Diesel (distillate)		Residual			
Operating description			In Port	Underway	In Port		Underway	
SCC code			2280002100	2280002200	2280003100		2280003200	
Type			Maneuvering	Cruising	Manuevering	Hotelling	Cruising	Reduced Speed Zone
Type Code			M	C	M	H	C	Z
Pollutant	HAP?*	Fraction of						
Ammonia	No	PM10	0.01	0.02	0.00238	0.0108	0.00477	0.00477
Arsenic	Yes	PM10	0.0000175	0.00003	8.74126E-05	0.0004	0.000174825	0.000174825
Benzo[a]Pyrene	Yes	PM10	0.0000025	0.000005	4.37063E-07	0.000002	8.74126E-07	8.74126E-07
Benzo[b]Fluoranthene	Yes	PM10	0.000005	0.00001	8.74126E-07	0.000004	1.74825E-06	1.74825E-06
Benzo[k]Fluoranthene	Yes	PM10	0.0000025	0.000005	4.37063E-07	0.000002	8.74126E-07	8.74126E-07
Beryllium	Yes	PM10			0.000000546	0.000000546	0.000000546	0.000000546
Cadmium	Yes	PM10	0.00000283	0.00000515	0.0000226	0.0000059	0.0000226	0.0000226
Chromium (VI)	Yes	PM10	0.0000085	0.000017	0.00006528	0.000204	0.00006528	0.00006528
Chromium III	Yes	PM10	0.0000165	0.000033	0.00012672	0.000396	0.00012672	0.00012672
Cobalt	Yes	PM10			5.94406E-05	0.000292	0.000153846	0.000153846
Hexachlorobenzene	Yes	PM10	0.00000002	0.00000004	3.4965E-09	0.000000016	6.99301E-09	6.99301E-09
Indeno[1,2,3-c,d]Pyrene	Yes	PM10	0.000005	0.00001	8.74126E-07	0.000004	1.74825E-06	1.74825E-06
Lead	Yes	PM10	0.000075	0.00015	1.39642E-05	0.00006	0.0000262	0.0000262
Manganese	Yes	PM10	0.00000153	0.000001275	0.0000573	0.0000573	0.0000573	0.0000573
Mercury	Yes	PM10	0.000000025	0.00000005	2.7076E-07	0.0000014	5.24476E-07	5.24476E-07
Nickel	Yes	PM10	0.0005	0.001	0.003250219	0.0154	0.00589	0.00589
Phosphorus	Yes**	PM10			0.001787587	0.00438	0.005734266	0.005734266
Polychlorinated Biphenyls	Yes	PM10	0.00000025	0.0000005	4.37063E-08	0.0000002	8.74126E-08	8.74126E-08
Selenium	Yes	PM10	2.83E-08	5.15E-08	1.9125E-06	0.00000908	0.00000348	0.00000348
Total HAP (ratioed to PM10)			**0.0006**	**0.0013**	**0.0055**	**0.0212**	**0.0123**	**0.0123**
Acenaphthene	Yes	PM2.5	0.000018	0.000015	0.00000034	0.00000034	0.00000034	0.00000034
Acenaphthylene	Yes	PM2.5	0.00002775	0.000023125	0.000000525	0.000000525	0.000000525	0.000000525
Anthracene	Yes	PM2.5	0.00002775	0.000023125	0.000000525	0.000000525	0.000000525	0.000000525
Benz[a]Anthracene	Yes	PM2.5	0.00003	0.000025	0.000000567	0.000000567	0.000000567	0.000000567
Benzo[g,h,i,]Perylene	Yes	PM2.5	0.00000675	0.000005625	0.000000128	0.000000128	0.000000128	0.000000128
Chrysene	Yes	PM2.5	0.00000525	0.000004375	9.93E-08	9.93E-08	9.93E-08	9.93E-08
Fluoranthene	Yes	PM2.5	0.0000165	0.00001375	0.000000312	0.000000312	0.000000312	0.000000312
Fluorene	Yes	PM2.5	0.00003675	0.000030625	0.000000695	0.000000695	0.000000695	0.000000695
Naphthalene	Yes	PM2.5	0.00105075	0.000875625	0.0000199	0.0000199	0.0000199	0.0000199
Phenanthrene	Yes	PM2.5	0.000042	0.000035	0.000000794	0.000000794	0.000000794	0.000000794
Pyrene	Yes	PM2.5	0.00002925	0.000024375	0.000000553	0.000000553	0.000000553	0.000000553
Total HAP (ratioed to PM2.5)			**0.0013**	**0.0011**	**0.000024**	**0.000024**	**0.000024**	**0.000024**
2,2,4-Trimethylpentane	Yes	VOC	0.0003	0.00025	NA	NA	NA	NA
Acetaldehyde	Yes	VOC	0.0557235	0.04643625	0.000229	0.000229	0.000229	0.000229
Acrolein	Yes	VOC	0.002625	0.0021875	NA	NA	NA	NA
Benzene	Yes	VOC	0.015258	0.012715	0.0000098	0.0000098	0.0000098	0.0000098
Ethyl Benzene	Yes	VOC	0.0015	0.00125	NA	NA	NA	NA
Formaldehyde	Yes	VOC	0.1122	0.0935	0.00157	0.00157	0.00157	0.00157
Hexane	Yes	VOC	0.004125	0.0034375	NA	NA	NA	NA
Propionaldehyde	Yes	VOC	0.004575	0.0038125	NA	NA	NA	NA
Styrene	Yes	VOC	0.001575	0.0013125	NA	NA	NA	NA
Toluene	Yes	VOC	0.0024	0.002	NA	NA	NA	NA
Xylenes (Mixed Isomers)	Yes	VOC	0.0036	0.003	NA	NA	NA	NA
Total HAP (ratioed to VOC)			**0.2039**	**0.1699**	**0.0018**	**0.0018**	**0.0018**	**0.0018**

*For completeness, all of the pollutants in EPA's database are shown, but not all are HAP as defined in Section 112 of the Clean Air Act and as updated in 40 CFR 63 Subpart C.

**Only elemental phosphorus (CAS #7723140) is a HAP; phosphorus-containing compounds in general are not.

Reference: US EPA, "2011 National Emissions Inventory, version 1, Technical Support Document", draft, November 2013, available from http://www.epa.gov/ttn/chief/net/2011nei/2011_neiv1_tsd_draft.pdf; Table 104 on pp. 178-179 refers to the dataset "2011EPA_HAP-Augmentation" for HAP emissions, which is available from ftp://ftp.epa.gov/EmisInventory/2011/doc; the factors above are from that

Attachment 19

Site Assessment Plan Approval

United States Department of the Interior
BUREAU OF OCEAN ENERGY MANAGEMENT
WASHINGTON, DC 20240-0001

NOV 21 2018

Mr. Martin Goff
Leader - Permitting
Equinor Wind US LLC
120 Long Ridge Road, Suite 3E01
Stamford, Connecticut 06902

Dear Mr. Goff:

This letter serves to inform you that the Bureau of Ocean Energy Management (BOEM) has approved the Site Assessment Plan (SAP) submitted on June 18, 2018, by Equinor Wind US LLC, subject to the enclosed conditions of approval pursuant to 30 CFR 585.613(e)(1). Your five-year site assessment term commences on the date of this letter, pursuant to 30 CFR 585.235(a)(2).

To help maintain compliance with the approved SAP, please take note of the following requirements, among others, that must be implemented:

1. Adhere to the enclosed Conditions of SAP Approval.
2. Notify BOEM in writing within 30 days of completing installation activities approved in your SAP, pursuant to 30 CFR 585.615(a).
3. Prepare and submit to BOEM a report annually each November 1 of your site assessment term that summarizes your site assessment activities and the results of those activities, pursuant to 30 CFR 585.615(b).
4. Submit a certification of compliance annually, pursuant to 30 CFR 585.615(c), with certain terms and conditions of your SAP that BOEM identifies under 30 CFR 585.613(e)(1). Together with your certification, you must submit:
    a. Summary reports that demonstrate compliance with the terms and conditions that require certification; and
    b. A statement identifying and describing any mitigation measures and monitoring methods that you have taken, as well as their effectiveness. If you identify measures that are not effective, you must make recommendations for substitute mitigation measures or monitoring methods and explain why you believe they would be effective.

    These reports are due annually starting on November 1, 2019.
5. Develop a comprehensive annual Self-Inspection Plan, pursuant to 30 CFR 585.824(a), and submit an annual Self-Inspection Report no later than November 1 of each year that your site assessment facility is in operation, pursuant to 30 CFR 585.824(b).

This letter constitutes a final BOEM decision that may be appealed pursuant to 30 CFR 585.118, 30 CFR Part 590, and 43 CFR Part 4, Subpart E.

Please do not hesitate to contact Mr. Luke Feinberg at (703) 787-1705 if you have any questions.

Sincerely,

James F. Bennett
Program Manager
Office of Renewable Energy Programs

Enclosure

U.S. DEPARTMENT OF THE INTERIOR
BUREAU OF OCEAN ENERGY MANAGEMENT

Conditions of Site Assessment Plan Approval

Lease Number OCS-A 0512

The Lessee's rights to conduct activities under the approved Site Assessment Plan (SAP) are subject to the following conditions. The Lessor reserves the right to impose additional conditions incident to any future approval of any modifications to the SAP.

Table of Contents

Section:

Attachments:

1. Conditions for Cultural Resource Protection

1.1. No Impact without Approval. The Lessee must not knowingly impact a potential archaeological resource without the Lessor's prior approval.

1.2. Post-Review Discovery Clauses. If, while conducting SAP activities, the Lessee discovers a potential archaeological resource, such as the presence of a shipwreck (e.g., a sonar image or visual confirmation of an iron, steel, or wooden hull; wooden timbers; anchors; concentrations of historic objects; or piles of ballast rock), or pre-contact archaeological site (e.g., stone tools; pottery) within the project area, the Lessee must:

1.2.1. Immediately halt seafloor/bottom-disturbing activities within the area of discovery;

1.2.2. Notify the Lessor within 24 hours of discovery;

1.2.3. Notify the Lessor in writing via report to the Lessor within 72 hours of discovery;

1.2.4. Keep the location of the discovery confidential and take no action that may adversely affect the archaeological resource until the Lessor has made an evaluation and instructs the applicant on how to proceed; and

1.2.5. Conduct any additional investigations as directed by the Lessor to determine if the resource is eligible for listing in the National Register of Historic Places (NRHP) (30 CFR §585.802(b)). The Lessor will direct the Lessee to conduct such investigations if: (1) the site has been impacted by the Lessee's project activities; or (2) impacts to the site or to the area of potential effect cannot be avoided. If investigations indicate that the resource is potentially eligible for listing in the NRHP, the Lessor will instruct the Lessee as to how to protect the resource, or how to mitigate adverse effects to the site. If the Lessor incurs costs in protecting the resource, under Section 110(g) of the National Historic Preservation Act, the Lessor may charge the Lessee reasonable costs for carrying out preservation responsibilities under the Outer Continental Shelf Lands Act (30 CFR 585.802(c & d)).

2. Conditions Relating to Protected Marine Mammals, Sea Turtles, and Fish

2.1. Project Meetings and Protected Species Briefings. Prior to conducting at-sea activities pursuant to the SAP, the Lessee must hold a briefing on protected species (all marine mammals, sea turtles, and fish listed under the Endangered Species Act and Marine Mammal Protected Act) that occur in the project area, the conditions and reporting requirements specified herein, and establish the responsibilities of each party involved in at-sea operations. During this briefing, the parties involved must define the chains of command, discuss communication procedures, provide an overview of mitigation and monitoring requirements, and review operational procedures. This briefing must include all relevant personnel, crew members, and any Protected Species Observers (PSOs). New personnel must be briefed as they join the work in progress.

2.1.1. The Lessee must ensure that all vessel operators and crew members, including any PSOs, are familiar with, and understand, the requirements specified in Sections 2 and 4 of these conditions.

2.1.2. The Lessee must ensure that a copy of Section 2 and Section 4 of these conditions are made available on every project-related vessel.

2.2. Minimum Separation Distance for Protected Species. The Lessee must ensure all vessel operators and crews maintain a vigilant watch for protected species. All vessels must maintain the following minimum separation distances from any sighted protected species to avoid potential harm or harassment, except when the safety of the vessel or crew is at risk:

2.2.1. 500 meters (m) (547 yards [yds]) or greater from any sighted North Atlantic right whale or any other unidentified large marine mammal;

2.2.2. 100 m (109 yd) or greater from any sighted Endangered Species Act (ESA)-listed whales other than a North Atlantic right whale; and

2.2.3. 50 m (55 yd) or greater from any sighted small cetaceans (dolphins and porpoises), seals, sea turtles, and giant manta rays.

2.3. Requirements for Vessel Strike Avoidance. The Lessee must ensure that all vessels conducting activities pursuant to the SAP, including those transiting to and from local ports and the lease area, comply with the vessel-strike avoidance measures specified below, except when the safety of the vessel or crew is at risk.

2.3.1. The Lessee must ensure that vessel operators and crews maintain a vigilant watch for marine mammals, sea turtles, and giant manta rays, and take appropriate measures to avoid striking sighted protected species. Vessels must route around the animals and maintain minimum separation distances (per Section 2.2 above) from protected species whenever possible.

2.3.2. The Lessee must ensure that vessel operators reduce vessel speed to 10 knots (18.5 kilometer [km]/hour [hr]) or less in the following circumstances:

2.3.2.1. When operating a vessel in any Dynamic Management Area (DMA) established for North Atlantic right whales including those established in transit routes to and from local ports, and within the lease area.

2.3.2.2. When mother/calf pairs, pods, or large assemblages of marine mammals are observed near an underway vessel.

2.3.3. The Lessee must ensure that underway vessels do not divert their course to approach protected species.

2.3.4. When marine mammals approach an underway vessel (e.g., bow-riding by small cetaceans), the Lessee must ensure that vessel operators make best efforts to remain parallel to the animal's course and avoid excessive speed or abrupt changes in direction until the animal has left the area.

2.3.5. When an animal is sighted in the vessel's path or in close proximity to a moving vessel, the Lessee must ensure that vessel operators reduce speed and shift the engine to neutral. Vessel operators must not engage the engines until the animals are clear of the area.

2.3.6. The Lessee must ensure all vessel operators check communication media for general information regarding avoiding ship strikes and daily information regarding North Atlantic right whale sighting locations. These media may include, but are not limited to, National Oceanic and Atmospheric Administration (NOAA weather radio, U.S. Coast Guard NAVTEX broadcasts, Notices to Mariners, and the Whale Alert app.

2.4. North Atlantic Right Whales

2.4.1. The Lessee must ensure that all vessels greater than or equal to 19.8 m (65 feet [ft]) in length must operate at 10 knots (11.5 miles per hour [mph]) or less when operating within any current Seasonal Management Area (SMA) designated for the North Atlantic right whale, including those established in transit routes to and from local ports and within the lease area (see the current SMA maps and coordinates at https://www.fisheries.noaa.gov/national/endangered-species-conservation/reducing-ship-strikes-north-atlantic-right-whales).

Seasonal Management Area	**Effective Dates**
Northeast Feeding Areas	
Cape Cod Bay SMA	Jan 1 – May 15
Off Race Point SMA	Mar 1 – Apr 30
Great South Channel SMA	Apr 1 – Jul 31
Mid-Atlantic Migratory Route	
Port and vessel route areas from Block Island, RI to Savannah, GA	Nov 1 – Apr 30

2.4.2. The Lessee must ensure that the following avoidance measures are taken if a vessel comes within 500 m (547 yd) of any North Atlantic right whale:

2.4.2.1. If underway, any vessel must steer a course away from any North Atlantic right whale at 10 knots (18.5 km/h) or less until the 500 m (547 yd) minimum separation distance has been established.

2.4.2.2. If a North Atlantic right whale is sighted within 100 m (109 yd) of an underway vessel, the vessel operator must immediately reduce speed and promptly shift the engine to neutral. The vessel operator must not engage the engines until the North Atlantic right whale has moved beyond 100 m (109 yd) and steer a course away from the whale.

2.4.3. <u>If a vessel is stationary, the vessel must not engage engines until the North Atlantic right whale has moved beyond 100 m (109 yd) and steer a course away from the whale.</u> The Lessee must ensure that any sighted injured, dead or entangled North Atlantic right whale is immediately reported to the U.S. Coast Guard via VHF Channel 16, in addition to the reporting requirements set forth in Section 2.6 below.

2.5. Entanglement Avoidance.

2.5.1. The Lessee must ensure that any structures or devices attached to the seafloor for continuous periods greater than 24-hours use the best available mooring systems. Buoy lines (chains, cables, or coated rope systems), swivels, shackles, and anchor designs must prevent any potential entanglement or entrainment of marine mammals, sea turtles, and giant manta rays while ensuring the safety and integrity of the structure or device.

2.5.2. All mooring lines and ancillary attachment lines must use one or more of the following measures to reduce entanglement risk: shortest practicable line length, rubber sleeves, weak-links, chains, cables or similar equipment types that prevent lines from looping, wrapping, or entrapping protected species.

2.5.3. Any equipment utilized for activities conducted pursuant to the SAP must be attached by a line within a rubber sleeve for rigidity. The length of the line must be as short as necessary to meet its intended purpose.

2.5.4. If a live or dead marine protected species becomes entangled, the Lessee must immediately contact the marine mammal or sea turtle stranding network coordinator per Section 2.6 below, and provide any on-water assistance requested by the coordinator.

2.6. <u>Reporting</u>. The Lessee must ensure compliance with the following reporting requirements for activities conducted pursuant the SAP, and must use the contact information provided in Attachment 1, or updated contact information as provided by the Lessor, to fulfill these requirements.

2.6.1. The Lessee must ensure that sightings of any injured or dead protected species (e.g., listed marine mammals, sea turtles, giant manta rays, or sturgeon) are immediately reported within 24 hours to the Lessor, NMFS, and the appropriate stranding network.

2.6.2. The Lessee must record all sighting data reported per Section 2.6.1, including observed injuries or mortalities, using the form provided in Attachment 2 below.

2.6.3. The Lessee must additionally ensure that any sighted injured, dead, or entangled North Atlantic right whale is immediately reported to the U.S. Coast Guard via VHF Channel 16,

2.6.4. If the Lessee's activity is responsible for the injury or death, the Lessee must ensure that the vessel assist in any salvage effort as requested by NMFS.

3. Conditions for Avian and Bat Protection

3.1. <u>Anti-perching Devices</u>. The Lessee must install anti-perching devices on the meteorological buoy to the extent practicable.

3.2. <u>Lighting</u>. Any lights used by the lessee to aid marine navigation during SAP activities must meet U.S. Coast Guard requirements for private aids to navigation, available at: https://www.navcen.uscg.gov/pdf/AIS/CG_2554_Paton.pdf. The Lessee must use any additional lighting only when necessary, and such lighting must be hooded downward and directed when possible, to reduce upward illumination and illumination of adjacent waters.

3.3. <u>Reporting Requirement for Avian and Bat Species</u>. The Lessee must provide BOEM and the United States Fish and Wildlife Service (USFWS) an annual report documenting any dead or injured birds or bats found on structures, as well as during installation, operation, and decommissioning of the meteorological buoy. The reports are due each November 1 after the date of the SAP approval and required for every year that the buoy is deployed. Each report must be sent to the USFWS contact provided in Attachment 1 below, and must contain the following information: the name of species; date found; location; a picture to confirm species identity (if possible); and any other relevant information. The Lessee must report carcasses with Federal or research bands to the United States Geological Survey Bird Band Laboratory (https://www.pwrc.usgs.gov/bbL/bblretrv).

4. **Marine Trash and Debris Prevention**

The Lessee must ensure that vessel operators, employees, and contractors engaged in activities pursuant to the SAP are briefed on marine trash, debris awareness and elimination, as described in the Bureau of Safety and Environmental Enforcement (BSEE) Notice to Lessees (NTL) No. 2015-G03 ("Marine Trash and Debris Awareness and Elimination") or any NTL that supersedes this NTL. The Lessee must ensure that its vessel operators, employees and contractors participating in activities pursuant to the SAP, receive training on the environmental and socioeconomic impacts associated with marine trash and debris, as well as their responsibilities for ensuring that trash and debris are not intentionally or accidentally discharged into coastal and marine environment. Briefing materials on marine debris awareness, elimination, and protected species are available at http://oocmain.theooc.us/page41.html.

5. **Conditions Related to Private Aids to Maritime Navigation**

5.1. The Lessee must file an application (form CG-2554), either in paper form or electronically, with the Commander of the United States Coast Guard (USCG) First District to establish a private aid to maritime navigation (PATON) for all facilities deployed pursuant to the SAP, per 33 CFR part 66.

5.2. The Lessee must submit a copy of the USCG-approved PATON to BOEM prior to deployment of any facilities covered by 5.1.

6. **Conditions Related to the Avoidance of Magnetic Anomalies**

The Lessee must ensure that all anchor points for vessels and SAP facilities are placed at least 30 m from any identified magnetic anomalies on the sea floor.

7. **Modifications**

The Lessee, by itself or through its designated operator, may request a modification of a term in the SAP or these conditions of approval. The Lessor will review this request and determine whether the modification requires a revision to the SAP under 30 CFR 585.617. If the Lessor determines that the requested modification does not require a revision to the SAP, the Lessor will provide a written response to the Lessee and its designated operator approving, approving with conditions, or disapproving the modification. This written response will become a part of the approved SAP.

Attachment 1

Contact Information for Reporting Requirements

The following contact information must be used for the reporting requirements in Section 2.6 of the Conditions for Site Assessment Plan approval (Attachment 2):

Dead and/or Injured Protected Species
National Marine Fisheries Service
Northeast Region's Stranding Hotline
866-755-6622

All other reporting requirements in Section 2.6
Bureau of Ocean Energy Management
Environment Branch for Renewable Energy
Phone: 703-787-1340
Email: renewable_reporting@boem.gov

National Marine Fisheries Service
Northeast Regional Office, Protected Resources Division
Section 7 Coordinator
Phone: 978-281-9328
Email: incidental.take@noaa.gov

Vessel operators may send a blank email to ne.rw.sightings@noaa.gov for an automatic response listing all current Dynamic Management Areas.

The following contact information must be used for the reporting and coordination requirements specified in Section 3.3 of the Conditions for Site Assessment Plan approval:

Field Supervisor
U.S. Fish and Wildlife Service
New York Field Office
3817 Luker Road
Cortland, New York 13045

Attachment 2

Incident Report: Protected Species Injury or Mortality

Photographs/Video should be taken of all injured or dead animals.

Observer's full name: ____

Reporter's full name: ____

Species Identification: ____

Name and type of platform: ____

Date animal observed: ____________________ Time animal observed: ______________

Date animal collected: ____________________ Time animal collected: ______________

Environmental conditions at time of observation (i.e. tidal stage, Beaufort Sea State, weather):

____

____

Water temperature (°C) and depth (m/ft) at site: ______________________________

Describe location of animal and events 24 hours leading up to, including and after, the incident (incl. vessel speeds, vessel activity and status of all sound source use):

____

____

____

____

____

Photograph/Video taken: YES / NO If Yes, was the data provided to NMFS? YES / NO
(Please label *species, date, geographic site* and *vessel name* when transmitting photo and/or video)

Date and Time reported to NMFS Stranding

Hotline: ________________________________

Sturgeon Information: *(please designate cm/m or inches and kg or lbs)*

Species: ____

Fork length (or total length): ________________ Weight: ______________________

Condition of specimen/description of animal: ______________________________

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Fish Decomposed: NO SLIGHTLY MODERATELY SEVERELY

Fish tagged: YES / NO If Yes, *please record all tag numbers.*

Tag #(s):____

Genetic samples collected: YES / NO

Genetics samples transmitted to:_______________________________on____/_____/20___

Sea Turtle Species Information: *(please designate cm/m or inches)*

Species:__________________________________Weight (kg or lbs):________________

Sex: Male Female Unknown

How was sex determined?:____

Straight carapace length:____________________Straight carapace width:______________

Curved carapace length:_____________________Curved carapace width:_______________

Plastron length:___________________________Plastron width:______________________

Tail length:_______________________________Head width:________________________

Condition of specimen/description of animal:_____________________________________

____

____

Existing Flipper Tag Information

Left:____________________________________Right:____________________________

PIT Tag#:____

Miscellaneous:

Genetic biopsy collected: YES NO Photographs taken: YES NO

Turtle Release Information:

Date:____________________________________Time:_____________________________

Latitude:_________________________________Longitude:_________________________

State:____________________________________County:___________________________

Remarks: (note if turtle was involved with tar or oil, gear or debris entanglement, wounds, or mutilations, propeller damage, papillomas, old tag locations, etc.)_____________________

____

____

____

Marine Mammal information: *(please designate cm/m or ft/inches)*

Length of marine mammal (note direct or estimated): ________________________________

Weight (*if possible, kg or lbs*):____

Sex of marine mammal (if possible):____

How was sex determined?:____

Confidence of Species Identification: SURE UNSURE BEST GUESS

Description of Identification characteristics of marine mammal:_____________________

____

____

____

____

Genetic samples collected: YES / NO

Genetic samples transmitted to:_________________________________on____/______/20___

Fate of marine mammal:____

____

____

____

Description of Injuries Observed:____

____

____

____

Other Remarks/Drawings:____

____

____

Attachment 20

Turbine Certification Plan

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Attachment 21

Confirmation of Certification Plan Feasibility

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Attachment 22

Sample Supplier Declaration

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Supplier Declaration

Compliance with Laws
As a supplier to Equinor we will comply with all applicable laws and regulations.

Improper Payments
As a supplier to Equinor we will not, in order to obtain or retain business or any advantage in the conduct of business, offer, promise or give any improper advantage to a public official (or a third party) to make the official act or refrain from acting in relation to the performance of her/his official duties. This applies regardless whether the advantage is offered directly or through an intermediary.

Gifts, Hospitality and Expenses
As a supplier to Equinor we will not offer, directly or indirectly, to Equinor employees or representatives or anyone closely related to them gifts except for promotional items of minimal value normally bearing a company logo.

Hospitality such as social events, meals or entertainment may be offered if there is a clear business reason, but the cost must be kept within reasonable limits. Travel, accommodation and other expenses for the individual representing Equinor will always be paid by Equinor.

Hospitality, expenses, gifts or other favours shall not be offered or received in situations of contract bidding, evaluation or award.

Conflict of Interest
As a supplier to Equinor we, and our employees, will not take part in or seek to influence any decision under circumstances that can give rise to an actual or perceived conflict of interest. Such circumstances may be a business interest or a personal interest in the subject matter – economically or otherwise – directly or through someone closely related. If we become aware of a potential conflict of interest we will, without delay, notify Equinor.

Minimum Age of Labour
As a supplier to Equinor we shall not employ children below the age of 15. If the child is secured the right for education, play, rest and family life, limited exceptions may be made if this is clearly in the best interests of the child.

Forced Labour
As a supplier to Equinor we will not engage or employ people against their own free will, nor will personnel be required to lodge ‘deposits’ or identity papers upon commencing employment.

Freedom of Association & Right to collective Bargaining
As a supplier to Equinor we recognise that our employees are entitled to be – or refrain from being – union members and to be represented in collective bargaining agreements. In countries where these rights are restricted our employees will anyway have the right to influence their work situation.

Working Hours
As a supplier to Equinor we will comply with local law or agreements regarding working hours.

Wages
As a supplier to Equinor we will ensure that wages paid to employees and hired labour are considered fair.

Employment Practices
As a supplier to Equinor we will treat our employees equally and fairly. We will not accept any form of harassment or discrimination.

Minority Rights

As a supplier to Equinor, we recognize and shall respect the special importance of the social, cultural, religious and spiritual values and practises of the indigenous and tribal peoples and their relationship with the land or territories. To the extent our work may affect indigenous peoples, a process to minimize and manage such impacts will be undertaken.

Security Resources

As a supplier to Equinor, we will observe strict requirements for the selection of security contractors to avoid human rights risks in countries where security firms are not properly regulated.

Environment

As a supplier to Equinor we will work according to internationally recognized environmental management principles and aim for continuous improvement. We will comply with national environmental legislation and discharge permits. We will work to achieve energy efficiency and minimize harmful discharge, emissions, and waste production in a lifecycle perspective.

Health and Safety

As a supplier to Equinor we will work ambitiously, through continuous improvement, for a healthy work environment and safe and secure conduct according to internationally recognized health and safety management principles and practices and applicable law.

Selection of Business Partners, Agents and other Intermediaries

As a supplier to Equinor we will promote that potential business partners, agents and intermediaries adopt the principles set forth in this Supplier Declaration.

Standards towards own Suppliers

As a supplier to Equinor we will promote the implementation of the principles set forth in this Supplier Declaration towards own suppliers.

Declaration signed by supplier

Supplier Name ______________________________

Address ______________________________

Date ______________________________

Name ______________________________

Title ______________________________

Signature ______________________________

By signing this document, you confirm that you fulfill the requirements in the Supplier Declaration. To the extent you are not able, upon our request, to provide supporting documentation with respect to fulfillment of the requirements; you confirm your willingness to start a process of documenting your promotion and performance.

Attachment 23

Project Master Schedule

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Attachment 24

Main Activity Logic Chart

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Attachment 25

Permitting Schedule

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Attachment 26

Construction Schedule

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Attachment 27

WTG Schedule

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Attachment 29

Foundations Schedule

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Attachment 29

Cables Schedule

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Attachment 30

Electrical System Schedule

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Attachment 31

Marine Operations Schedule

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Attachment 32

Supplier Letters of Support

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Attachment 33

Ports Letters of Support

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Attachment 34

Fisheries Liaison & Outline Coexistence Plan

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Empire Wind Offshore Wind Farm
OCS-A 0512

Fisheries Liaison & Outline Coexistence Plan

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Table of contents

1 Introduction

1.1 About this document

This document is the first draft Fisheries Liaison Plan (FLP) (Document ref. RE-PM710-00001, Version 01) developed to present Statoil's proposed approach to liaison and consultation with the fishing industry in relation to the development of offshore wind farm projects, cable corridors and landfall sites in the New York Lease OCS-A 0512 Wind Energy Area (WEA). This document will continue to be updated and evolve in consultation with the fishing industry as the project(s) moves through the various stages of development, and will conclude with a 'Final' Fisheries Liaison and Communications Plan and Fisheries Coexistence Plan for implementation.

The FLP has been produced for stakeholders from the fishing industry and is intended to provide clarity on Statoil's delivery objectives, as well as the approach to liaison and co-existence.

1.2 Background

In 2014, Governor Andrew M. Cuomo launched New York's energy policy, 'Reforming the Energy Vision'. The associated State Energy Plan (SEP) set a goal for 50% of electricity consumed in the state of New York to come from renewable sources by 2030. Offshore wind has the potential to be the most significant renewable energy resource available in the southeast portion of the state where currently only a small proportion of renewable energy is being generated and consumed. In January of 2017, Governor Andrew M. Cuomo committed to develop up to 2.4 gigawatts of offshore wind by 2030. The development of the New York Lease OCS-A 0512 WEA is expected to make a significant contribution towards achieving this objective.

The New York OCS-A 0512 WEA was originally proposed September 2011, as the result of an unsolicited request to the Bureau of Ocean Energy Management (BOEM) from the New York Power Authority (NYPA), Long Island Power Authority (LIPA) and ConEd, for a commercial lease. In June 2012 the WEA was modified to expand the buffer between shipping lanes and proposed wind turbines from one-quarter nautical mile to one nautical mile. In January 2013, BOEM issued a 'Request for Interest' seeking public comments on the proposal, followed by a 'Call for Information and Nominations' in May 2014 seeking public comments on the development authorization process.

In December 15 – 16, 2016, BOEM conducted an auction for the New York WEA, which concluded with Statoil as the successful bidder. Statoil signed the commercial wind energy lease OCS-A 0512 on March 15, 2017.

Statoil has the objective of developing the New York OCS-A 0512 WEA, with the first stage of development involving site characterization surveys, stakeholder engagement and securing the necessary permits and licenses required to construct and operate a utility scale offshore wind farm.

The first step in Statoil's permitting process is to develop and submit to BOEM a Site Assessment Plan (SAP). BOEM requires the SAP to describe the initial activities necessary to characterize a lease site. This includes for example, wind resource measurements using meteorological masts or buoys, and/or meteorological and oceanographic (metocean) data collection, as well as any requirements for testing new technology that comes into contact with the seabed.

The next phase is the development of the Construction and Operations Plan (COP). The COP describes all the activities necessary for the construction, operation, and decommissioning of proposed offshore wind farm(s) on the lease. It also outlines the environmental, social and technical information needed for BOEM to undertake Environmental and Social Impact Assessments (ESIA) as part of its review under the National Environmental Policy Act (NEPA).

As part of the ESIA, a wide range of potentially affected receptors, identified through stakeholder engagement and scoping, will form part of the detailed process of information gathering, site investigations, site specific environmental surveys, stakeholder engagement and impact assessments that will inform the federal and state environmental review processes.

In addition to the BOEM SAP and COP submittals, Statoil will seek and obtain authorizations from Federal and State regulatory agencies for the deployment of a metocean data measuring system and construction of the wind energy facility. The SAP and COP phases of the Project are anticipated to occur over the coming years.

1.3 Empire Wind OCS-A 0512 Lease

The New York OCS-A 0512 WEA site extends 14-30 miles southeast of Long Island, spanning 79,350 acres, in water depths between 65 and 131 feet (see map). Subject to environmental and technical constraints, which will be explored as part of the development phase, it is believed that the site has a potential generating capacity of over 1 GW.

The WEA has water depths suitable for conventional, bottom-fixed foundations, such as monopiles or jackets. The exact details of the wind farm design and installation techniques will be determined during the survey and design phase, and will be influenced by consultation with affected parties, for example the fishing community.

The exact location of the electricity grid connection points and associated landfall and electrical export cable routes have yet to be determined, but will be identified during the development phase in consultation with the relevant affected parties.

The offshore wind farm(s) may be developed and constructed in phases, subject to technical, grid and commercial constraints that are yet to be determined.

TABLE 1.1 NEW YORK EMPIRE WIND OCS-A 0512 WEA KEY PROJECT CHARACTERISTICS

Project Information	Detail
Project size	79,350 acres
Project capacity	1-2 GW
Distance from shore	14-30 miles
Water depth range	65 and 131 feet

TABLE 1.2 NEW YORK EMPIRE WIND OCS-A 0512 WEA COORDINATES

NAD83 z18N East / NAD83				
Point	**Easting (m)**	**Northing (m)**	**Latitude**	**Longitude**
EW1	664,168	4,462,588	40° 17' 51.65"	-073° 04' 06.24"
EW2	652,400	4,450,800	40° 11' 37.54"	-073° 12' 34.52"
EW3	618,319	4,469,085	40° 21' 50.22"	-073° 36' 23.29"
EW4	619,519	4,471,485	40° 23' 07.4"	-073° 35' 30.8"
EW5	664,168	4,462,588	40° 17' 51.65"	-073° 04' 06.24"

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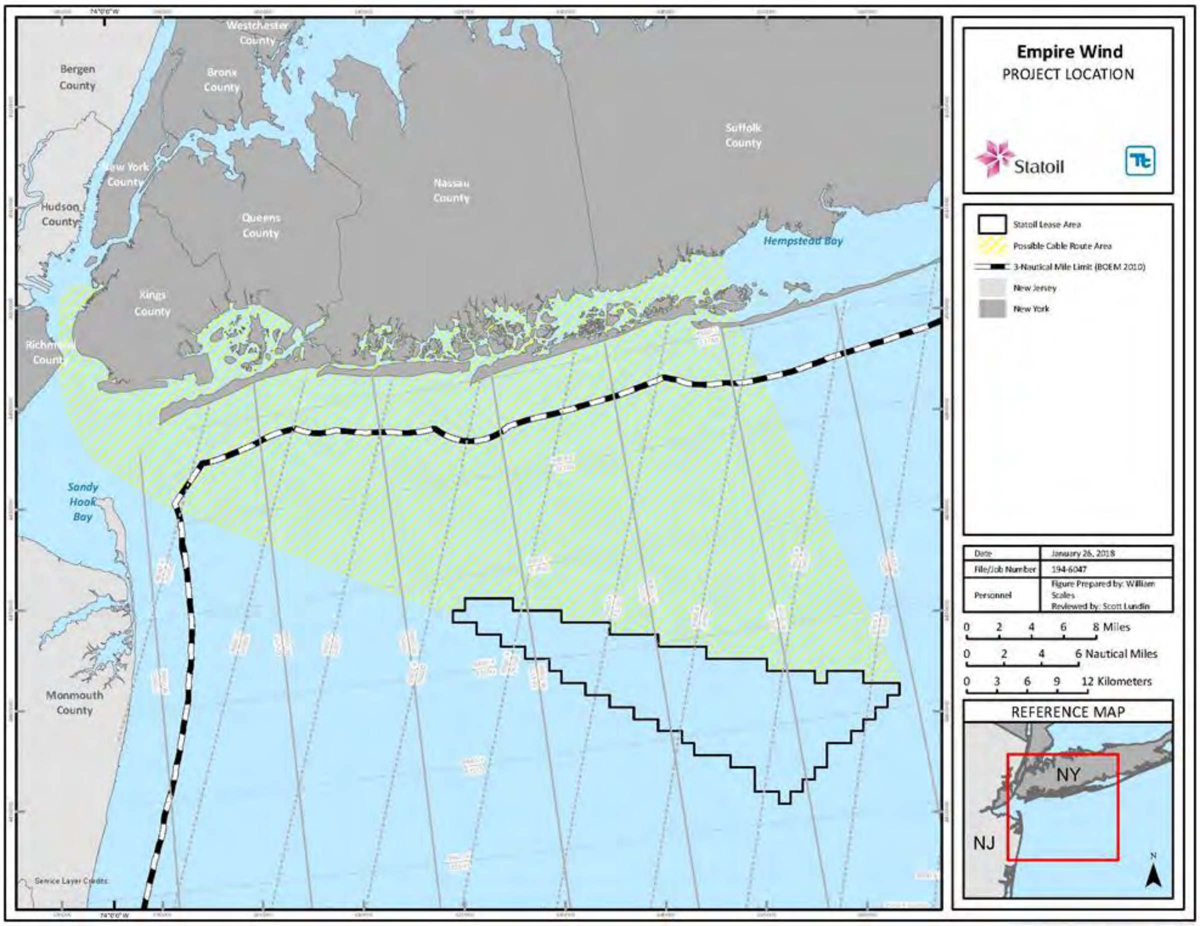

FIGURE 1 NEW YORK EMPIRE WIND OFFSHORE WIND FARM OCS-A 0512 LEASE AREA

2 Outline Co-existence Strategy

2.1 Co-existence

Statoil believes that the fishing industry and offshore wind farm developments can co-exist and, as such, sets out with the objective to co-exist with the fishing industry in and around the New York OCS-A 0512 WEA. Statoil has no intentions to restrict or apply for restrictions on fishing activities of any sort within the wind farm area(s), or electrical export cable area(s) post construction. Restrictions, if applicable, will likely be limited to the application for standard safety zones during the construction phase, and operational safety zones around manned or sensitive offshore platforms or in some cases access points to turbines. Co-existence can be achieved through the objective to avoid impacts where feasible and, where this is not feasible, to reduce impacts through mitigation. A successful co-existence strategy will require open and regular communication between Statoil and the fishing industry starting with the development phase leading up to permitting and construction, through construction, operation, and decommissioning of the wind farm.

A Co-existence Plan will be finalized in consultation with the fishing industry at the time of COP submission. This will be at a time when detailed wind farm designs and construction and operation practices will be better understood, as well as a better understanding of the interaction between the fishing industry and the proposed offshore wind farms.

The co-existence plan will present:

- A commitment to continuing consultation and liaison with the aim of assisting fishermen to safely resume their fishing activities within the operational site and along the export cable corridor;
- The sharing of wind turbine and cable locations in a format appropriate to the fishing industry to use in chart plotters and/or the provision of charts with key facility locations appropriately called out;
- A distribution system for ongoing liaison plans and dissemination of information, including construction schedules, survey schedules and planned operations and maintenance activities using a variety of media;
- Mitigation measures (where feasible) to minimize potential impacts on the fishing industry and an execution plan for each measure;
- Details of the main project contacts, including the Fisheries Liaison Officer as the primary point of contact;
- Codes of conduct for vessels undertaking project related activities within the wind farm area and ports;
- Safe operations procedures;
- Emergency response procedures;
- Fishing gear snagging and loss procedures and any required claim procedures thereafter;

3 Fisheries Liaison

3.1 Fisheries Liaison Strategy

Openness is one of Statoil’s core values and will form the basis of the fisheries liaison philosophy. Regular, open consultation will be key to ensuring all parties are well informed, are able to contribute to the discussions and can work towards the joint objective of co-existence.

The FLP will be an evolving plan throughout the project development process. The identification of potential impacts on the fishing industry may change as the wind farm design and installation methodology change or become more detailed during the various phases of development. The FLP will be designed to describe the liaison and coordination of activities appropriate to the life cycle of the wind farm, through the permitting phase, construction, operation and decommissioning phases, where there the requirements and potential impacts may vary in each of these phases.

Liaison activities will be primarily based on best practice guidance and feedback from the fishing industry through consultation. It will also draw on consultation from fisheries bodies, regulators, ports and harbors and legislation, as well as previous experiences of the Statoil team with fisheries liaison work in the offshore wind industry. The best practice guidance will include, but not be limited to:

- Development of Mitigation Measures to Address Potential Use Conflicts between Commercial Wind Energy Lessees/Grantees and Commercial Fishermen on the Atlantic Outer Continental Shelf, BOEM 2014-654;
- Best Practice Guidance for Offshore Renewables Developments: Recommendations for Fisheries Liaison - Fishing Liaison with Offshore Wind and Wet Renewables Group (FLOWW), UK;
- Fishing and Submarine Cables Working Together – published by the International Cable Protection Committee

3.2 Fishing Industry Contacts & Affected Parties

Effective dialogue and consultation will be facilitated with the establishment of a comprehensive contact database for local and regional fisheries associations, societies, groups, individual fishermen and the different industry organizations. This database will be maintained and regularly updated by the FLO in conjunction with Statoil’s key project team members. It should be noted that the fishing industry ‘database’ will be used solely for the purposes of Statoil’s fisheries liaison activities and will not be made available to any individual or group, outside of Statoil’s specific requirements. It is acknowledged and appreciated that some fisheries information, such as fishing sites, can be commercially sensitive. In these circumstances Statoil will work with the individual fishing organization / fisherman to establish confidentiality agreements for the purpose of sharing information with the objective of using it to work towards the objective of coexistence.

3.3 Fisheries Liaison Officers

Statoil will contract a Fisheries Liaison Officer(s) (FLO) with the appropriate level of knowledge of or first-hand experience in the fishing industry of the region to aid in communication with, and the dissemination and gathering of information between, Statoil and the fishing industry. The FLO will also support Statoil in the identification of potential impacts, potential mitigation measures, and support with data gathering to inform the environmental and social impact assessments related to commercial and recreational fishing. A FLO will be acting on Statoil's behalf throughout all development stages, including during the operation and decommissioning phases. The primary roles and responsibilities of the FLO are:

- To serve as the primary point of contact between the project and the fleets

- To log all interactions between the project team and fisheries representatives accurately and in a way that can be shared by the project team

- To maintain a fisheries stakeholder database and contacts list for all identified fisheries operating within the vicinity of the offshore wind lease area and export cable throughout all stages the project, covering the following details:
  - Vessel names, owners, registrations and base ports
  - Vessel radio call sign
  - Dominant method(s) of fishing and any new technology developing within the fisheries
  - Static gear surface marker details where applicable
  - Target species as well as key by-catch species
  - Fishing grounds relevant to the project
  - Fishing periods and operating practices of each key fishery
  - Feedback, comments and concerns voiced within consultations

- To arrange meetings with the fishing industry throughout all stages of project development, with frequency, timings and method of communication appropriate to the level of activity at the time.

- To consult the relevant Fishing Industry Representatives (see section 3.4 below).

- To maintain regular liaison with relevant fishermen's associations, individual skippers and vessel owners, the Mid-Atlantic Fishery Management Council, and any relevant fisheries regulatory bodies as appropriate.

- To disseminate project related activities which could potentially interact with fisheries stakeholders. This will include:
  - A description of the survey activity or other works to be undertaken;
  - The location and timing of survey activities;
  - The coordinates of partially and/or fully installed infrastructure;
  - A look ahead of the schedule of works where available;
  - Details of the vessels involved in the works including the vessels contact details;
  - Survey and installation vessels transit routes to and from site;
  - The locations and timings of safety exclusion zones that may be required during installation or maintenance activities;

- Health & Safety standards and COLREGS obligations;
- Contractor obligations towards fisheries stakeholders;
- Conflict avoidance response procedures and reporting procedures.

- Be available to receive and relay back to Statoil all relevant concerns from the fisheries stakeholders in respect of the various activities associated with the project;
- To keep fisheries stakeholders updated of any changes in project design, or scheduling;
- To assess and advise Statoil on the need for, and subsequently support Statoil in organizing, guard vessels and offshore Fisheries Liaison Representatives (see section 3.4 below);
- Monitor fishing activity within the wind farm site and export cable route during all phases of the project;
- Support Statoil in making wind farm survey, installation and operations and maintenance contractors aware of relevant fishing activities, including any relevant fishermen's sensitivities, and procedures for communicating with fishing vessels at sea;
- Advising and supporting Statoil on the procurement of offshore Fishing Liaison Representatives (OFLRs);

3.4 Fishing Industry Representatives (FIRs)

Fishing Industry Representatives (FIRs) will be established as the main point of contact within a fishing industry organization. These representatives should represent the views of the fishermen within his or her remit. The FIRs should have the backing and support of the fisheries stakeholders they represent. The FIRs should be able and willing to disseminate information from the FLO or Statoil to the fishing community and vice versa on a timely and all-inclusive basis. The FIR is normally an individual who has worked extensively within the industry. The primary responsibilities of the FIR are:

To be the main focal point for liaison with fisheries stakeholders;

- To liaise and cooperate with the FLO to ensure the objectives of the FLP and co-existence strategy are achievable;
- To feed back to the FLO any fishermen's concerns, data, or requests for meetings; and
- To assist in the distribution of notices and relevant project information to fisheries stakeholders and to follow up that all relevant parties received such notices.

3.5 Offshore Fisheries Liaison Representatives (OFLRs)

Where required and appropriate, Fisheries Liaison Representatives (FLRs) will be present on vessels that are working on behalf of Statoil in the wind farm related activities, for example survey vessels and installation vessels. The main purpose is to ensure good communications with fishing vessels encountered on site. This may be for the purpose of disseminating information, responding to queries from fishing vessels and acting as a conduit for information offshore between the FLO, FIR and fisheries stakeholders within or near the site. The primary responsibilities of the OFLR are:

- To maintain daily contact with, and keep records of, fishing vessels observed to be within the vicinity of the work areas of wind farm related vessels;
- To keep the masters and watch officers of wind farm related vessels informed of fishing vessels in the vicinity of their working area and the gears and modes of operation of such fishing vessels;
- To keep fishing vessels advised of the wind farm vessels locations, operations, schedules, safety zones and Health & Safety restrictions; and
- To provide on-site adhoc assistance and advice to wind farm related vessel officers with the objective of minimizing hindrance to fishing activities, avoid conflicts and ensuring the commitments in the co-existence plan are adhered to.

3.6 Communication Channels

Notices and Information for fishermen will be distributed via the following options:

- Via the FIRs where relevant;
- Fishermen's associations;
- Directly from the FLO to individual fishermen not represented by an FIR, but identified on the FLO's database;
- USCG Notice to Mariners;
- Electronic email distribution to commercial fishing permit holders (NOAA or state agencies)
- Statoil's relevant website page;
- Local harbor masters;
- Newsletters;
- Fishing news publications.

3.7 Communications Plan & Scheduling

Prior to the onset of site surveys and installation activities, a survey specific fisheries communications and emergency response plan will be drafted specifically for the identified fisheries stakeholders. This will include:

- Primary points of contact;
- Points of contact in an emergency situation offshore;
- Follow up / incident reporting procedures.

A scheduling plan will be drafted in consultation with fisheries stakeholders on the appropriate amount of notice required prior to the onset of surveys, installation or operations and maintenance activities. The plan will also detail the agreed effective frequency of general project and project development updates, and how these updates are conducted (e.g. meetings, email, via FIRs etc).

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Attachment 35

Fisheries Outreach Matrix

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Attachment 36

Example Survey Flyer

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Offshore Survey Activities 2018 Update

Attention Fishermen and Other Mariners: Survey Activities for the Empire Wind Offshore Lease, New York Bight - Ongoing 2018

Equinor Wind US, formerly known as Statoil Wind US, is the lease holder of the New York offshore wind energy area OCS-A 0512 known as the 'Empire Wind' project. As part of the site development process, Equinor has been conducting geophysical & geotechnical surveys over the project area since spring 2018.

Details of the survey activities were covered in the Survey Newsletter issued in February 2018. The purpose of this newsletter is to provide an update on active survey activities, planned surveys and metocean mooring deployments.

Survey vessel RV Ocean Researcher has been engaged in surveys in the wind lease area since April 2018 and is finishing surveys as of December 2, 2018.

Following the approval of Equinor's Site Assessment Plan (SAP) by BOEM on November 21, 2018, contractor RPS will deploy two meteorological & oceanographic (metocean) buoys and one subsurface metocean mooring in the lease area as of December 2018 for a period of up to 2-years.

Details of the metocean buoy positions and relevant contact details are covered on the next page.

NEWSLETTER

Notice of Surveys

28 November 2018


Indicative Offshore Wind Farm: Dudgeon, UK

Empire Wind OCS-A 0512

The Empire Wind site extends 14-30 miles south of Long Island, spanning 79,350 acres, in water depths between 65 and 131 feet (see map). Subject to environmental and technical constraints, which will be explored as part of the development phase, it is believed that the site has a potential generating capacity of over 1 GW. The exact details of the wind farm design and installation techniques will be influenced by consultation with the maritime and fishing community. Equinor intends to consult on draft layouts this winter 2018/2019.

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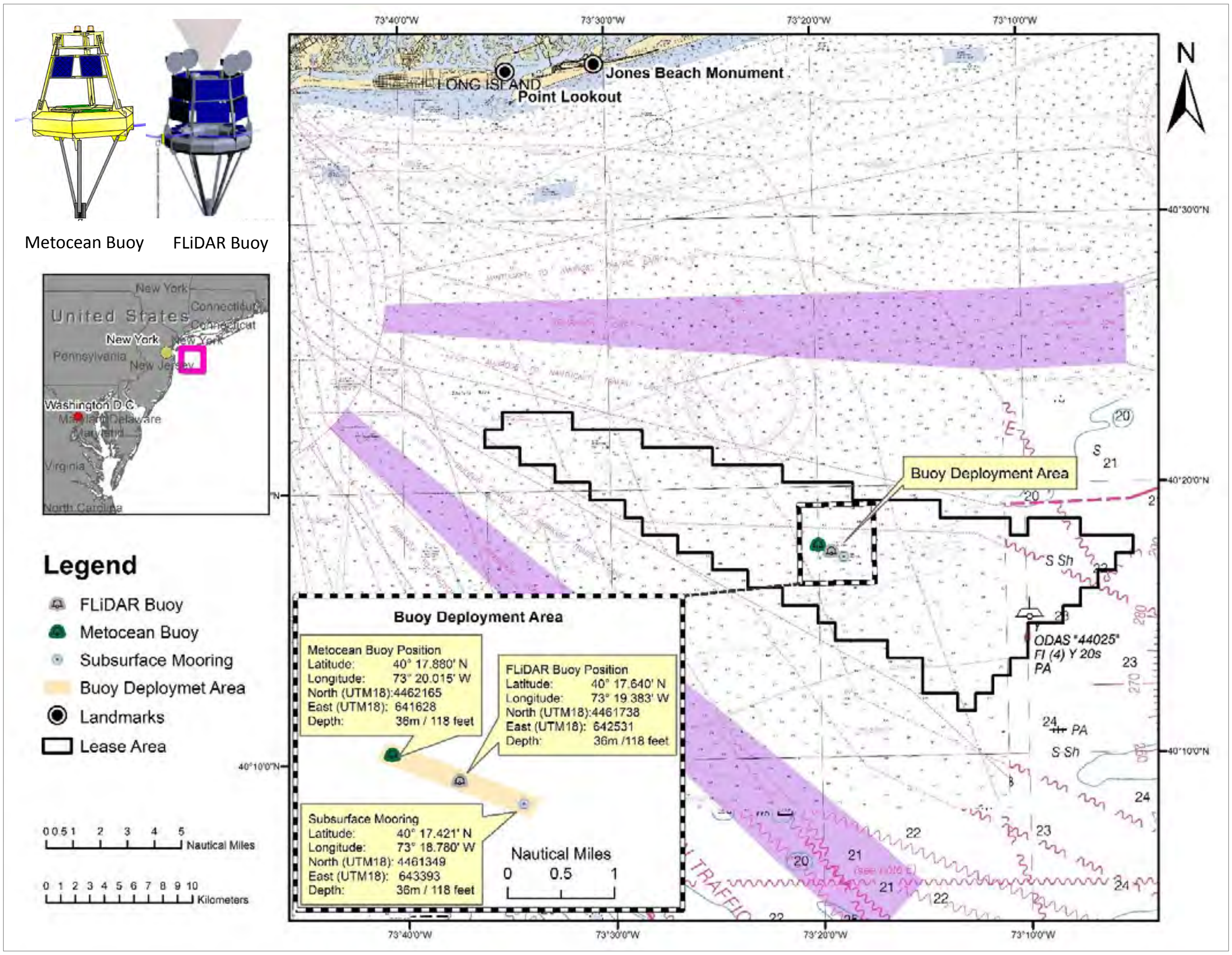

Equinor Wind Lease and Metocean Mooring Deployment Positions

Helpful Data?

Equinor intends to make non-commercially sensitive data collected by the moorings publicly available to help support research and other offshore operations. Data may become available both as reports or in near real-time via a web page.

Anyone interested can contact Equinor to gain access.

Contact: Steve Drew, Fisheries Liaison Officer

Steve Drew of Sea Risk Solutions is representing Equinor Wind as Fisheries Liaison Officer.

Steve Drew
sdrew@seariksolutions.com
+1-908-339-7439 / +1-206-427-6553

RPS Metocean Moorings

RPS has been contracted to supply and deploy surface and subsurface metocean moorings on Equinor's offshore wind lease in order to measure wind, meteorological and oceanographic conditions to help inform the design and development of the proposed wind farm. This consists of 1 x Floating LiDAR (FLiDAR) buoy, 1 x surface Metocean buoy and 1 x subsurface current meter mooring.

FLiDAR Buoy - the FliDAR buoy is made up of a surface buoy of approx. 15 ft diameter and 16 ft overall height, moored to the seabed via a combination of mooring chains, rubber cords and anchor weights. The FLiDAR measures wind speed and direction.

Metocean Buoy – the Metocean buoy, measuring waves and meteorological conditions, is made up of a surface buoy of approx. 9 ft diameter and 8 ft in height, moored to the seabed via a combination of mooring chains, rubber cords and anchor weights.

Current Meter Mooring – The current meter mooring is an inline subsurface mooring made up of subsurface floats, chain, wire rope and oceanographic sensors measuring current speed and direction and seawater properties. The upper most float is approx. 15 ft below sea surface.

Attachment 37

Example Fisheries Newsletter

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Issue Five

Spring 2015

Fisheries Update 5

Dogger Bank Creyke Beck consented

The first consent order for offshore wind energy at Dogger Bank was granted in February making it the largest renewable energy development ever to receive planning consent in the UK.

The consent approval is the result of more than four years of comprehensive assessments, stakeholder consultation and planning by Forewind, which included the most extensive study of an offshore area by a wind energy developer ever undertaken with more than £60 million spent on surveys, the vast majority going to UK-based contractors.

The fish ecology surveys were undertaken by Suffolk-based Brown & May Marine and Hull-based Precision Marine Services Limited. Local UK fishing vessels including the *Jubilee Spirit* were used to carry out a number of surveys employing scientific and traditional fishing sampling methods.

Energy and Climate Change Secretary Ed Davey approved the application for the Dogger Bank Creyke Beck development, which was submitted to the Planning Inspectorate by the Forewind consortium in August last year. He said:

"This is another great boost for Yorkshire and Humberside. This development has the potential to create hundreds of green jobs and power up to two million homes.

"Making the most of Britain's home grown energy is supporting jobs and businesses in the UK, getting the best deal for consumers and reducing our reliance on foreign imports. Wind power is vital to this plan, with £14.5 billion invested since 2010 into an industry which supports 35,400 jobs."

Fishing survey vessel, *Jubilee Spirit* used during the environmental impact assessment

Dogger Bank Creyke Beck, which has a total generating capacity of 2.4GW, comprises two separate 1.2GW offshore wind farms, each with up to 200 turbines installed across an area of around 500km^2.

The wind farms will be located 131 kilometres from the UK coast and will connect into the existing Creyke Beck substation near Cottingham, in the East Riding of Yorkshire.

When constructed, Dogger Bank Creyke Beck will be one of UK's largest power generators, second only to the 3.9GW Drax coal-fired station in North Yorkshire.

In total it will be capable of generating 8 terrawatt hours (TWh) of green energy per annum, equal to the amount used annually by approximately two million British homes.*

* Homes powered equivalent: This is calculated using the most recent statistics from the Department of Energy and Climate Change showing that annual UK average domestic household consumption is 4,192kWh.

Dogger Bank Teesside A&B decision due August

The Planning Inspectorate's six-month examination of the Dogger Bank Teesside A&B development consent order application concluded in February, with a recommendation due to be submitted to the Secretary of State for Energy and Climate Change in May and a decision anticipated in August.

As per Dogger Bank Creyke Beck, Dogger Bank Teesside A&B also comprises two 1.2 gigawatt wind farms, however they are located further from the UK coast at their closest point (165 kilometres) and are planned to connect to the national grid at the existing Lackenby substation near Eston, in Redcar & Cleveland.

If consent is granted, fisheries stakeholders, and particularly those directly impacted, will continue to be engaged and involved by operators in planning for the construction and operation and maintenance phases of the wind farms.

Issue highlights

This is the fifth edition of Fisheries Update – Forewind's newsletter for the commercial fishing industry. It gives the latest news on the Dogger Bank development and consenting progress.

If you would like to receive copies electronically please email your request and contact details to info@forewind.co.uk.

forewind.co.uk

DOGGER BANK
CREYKE BECK

Dogger Bank Creyke Beck comprises two up to 1.2GW wind farms subject to a single development consent order application. Consent was granted for the 2.4GW development in February 2015.

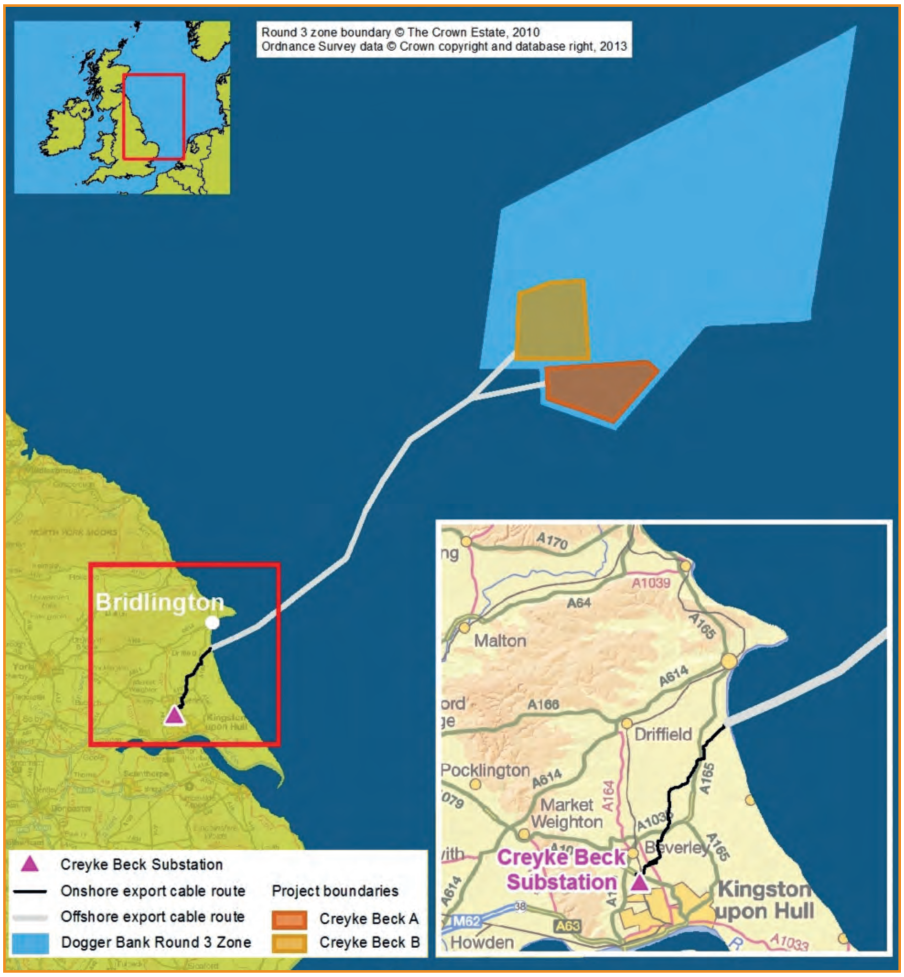
Next steps post-consent

The Forewind consortium is a joint venture formed specifically with the remit to gain the consents for the Dogger Bank projects, and now that the consent for Dogger Bank Creyke Beck has been granted, the work to further the development will be transferred to operators for the next phase.

General Manager, Tarald Gjerde said the organisation and its four owners were thrilled when the first consent for the Dogger Bank Zone was granted, taking the flagship development a step closer to supplying the UK with a significant amount of renewable energy, and to realising the many potential economic opportunities, particularly on the east coast.

Dogger Bank Creyke Beck could create up to 4,750 new direct and indirect full time equivalent jobs** and generate more than £1.5 billion for the UK economy, with the majority of opportunities in the North East and Yorkshire and the Humber regions.

This is particularly due to the regions proximity to the development as well as their historic strengths, existing skills in large-scale production activities and a marine support legacy.



Operators will take over the further development of the two Dogger Bank Creyke Beck projects.

Operators to take over

The operators of the two Dogger Bank Creyke Beck projects should be in place this year. The operators look set to come from within the four Forewind owner companies, and they are now carrying out the complex work to finalise the administrative and governance arrangements for the handover.

Once in place, the operators will begin the postconsent work which will include the technical and commercial design of the wind farms, developing links with supply chain and stakeholders and carrying out all the pre-construction activity needed to reach the stage of financial investment decision.

Fisheries stakeholders will be informed about the operators and provided with relevant contact details as soon as practicable after they are appointed.

Maintaining good working relationships with the fisheries industry will be one of their priorities and Forewind will be closely involved to facilitate a smooth handover.

Offshore Environmental Impact Assessment Manager Martin Goff will be responsible for the process to personally introduce the fisheries contacts from the Dogger Bank Creyke Beck operators to the fishing industry. A key task will be to coordinate workshops that will be forums to ensure there is mutual understanding of the fishing related requirements in the development consent order as well as the commitments within the Statements of Common Ground.

While the responsibility for fisheries liaison for the Dogger Bank Creyke Beck projects will transfer to the operators once they are in place, Forewind will continue to manage fisheries liaison for the Dogger Bank Zone and, for a period, for Dogger Bank Teesside A&B.

The responsibility for fisheries liaison for the Dogger Bank Teesside projects is expected to transfer to operators following the consent award, however there will be emphasis amongst all the operators on maintaining a coordinated approach for the Dogger Bank Zone.

Until the operators take responsibility, the fisheries liaison contacts named on the back page will remain in place for any relevant enquiries or concerns.

** Full time equivalent (FTE) employment is equivalent to 10 annual job years (filled by either one employee or multiple employees).

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DOGGER BANK
TEESSIDE A&B

Dogger Bank Teesside A&B comprises two up to 1.2GW wind farms subject to a single development consent order application. A decision on the development consent application is expected in August 2015.

Examination brings revisions

Input from fisheries industry representatives during the Dogger Bank Teesside A&B examination process resulted in an updated Fisheries Liaison Plan (FLP) and other relevant commitments.

The examination started in Redcar in August last year and included both open floor and issue-specific hearings plus five site visits to the proposed landfall, along the onshore cable route, and to the sites for the two proposed converter stations and connection works into the national grid.

The examination involved approximately 40 stakeholder organisations and individuals with an interest in the project proposals. Around 55 statements of common ground were agreed with key groups as part of the process, including with 11 with fisheries groups and four with shipping and navigation organisations. More than 550 documents were submitted over the period.

The FLP was discussed specifically during the examination and updated following feedback from examiners, Hartlepool Fishermen's Society, National Federation of Fishermen's Organisations and Anglo-Dutch fisheries body, VisNed.

The plan covers Forewind's approach to coexistence and includes a consultation strategy with objectives to ensure early, effective, meaningful and transparent engagement with stakeholders. The necessary future roles are defined and it also includes an overall strategy covering mitigation or compensation for those within the commercial fisheries industry likely to be subject to residual significant impacts.

Specifically, the main updates to the draft FLP included:

- A commitment to early engagement from the start of the design phase to enable operators to benefit from previous lessons learned by the fishing industry and existing knowledge of ground conditions, as well as to give a platform for concerns

- A commitment to sharing post-installation survey results with fishermen

Teesside fishing boats – local fisheries organisations helped shape the new Fisheries Liaison Plan.

- Consideration of the use of guard vessels outside of safety zones

- Collaborative use of the Dogger Bank 3D computer generated simulation.

The updated plan is now available for download on the Forewind website (www.forewind.co.uk).

Fisheries related commitments

The revisions to the FLP were not the only change resulting from fisheries involvement during the examination process.

Its iterative approach enabled fisheries groups to attend and highlight their main issues, resulting in a number of conditions to be committed to within Deemed Marine Licenses as part of the Dogger Bank Teesside A&B draft Development Consent Order.

These commitments relate to: securing the Fisheries Liaison Plan, the appointment of Fisheries Liaison Officers; the cable specification and installation plan, post-installation cable surveys, and the search and rescue emergency response plan (ERCOP).

A position to alleviate key concerns was agreed with the Hartlepool Fishermen's Society during the examination. The concerns related to a potential loss of habitat and safety issues over cable protection and it was agreed these would be best dealt with post consent through early engagement in the early design phase and the sharing of information.

Forewind's Offshore Environmental Impact Assessment Manager, Martin Goff said that the cornerstone for Forewind has always been the belief that the fishing industry and the Dogger Bank offshore wind farm development will be able to co-exist peacefully.

"The operators will be keen to also ensure good cooperation and a close working relationship once they take over the projects," he said. "Key to this will be adhering to the commitments made by Forewind and secured within the Development Consent Order and Fisheries Liaison Plan."

What's in a name?

The Dogger Bank projects were early on given names that linked the offshore wind farm location with the onshore substation site.

The names were intentionally functional for the development consent process and it was understood they would most likely be later changed in line with the longer-term needs of the operators and to meet the practical needs of key offshore stakeholders.

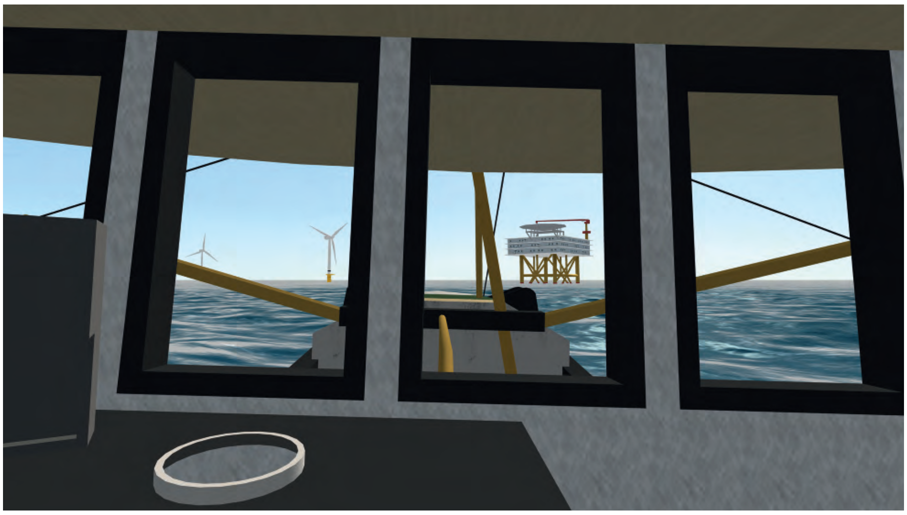
The re-naming will be the responsibility of the operators and will be changed and publicised when the timing is appropriate.

Trawler view added to 3D programme

Forewind's 3D computer generated simulation of the proposed Dogger Bank offshore development has been updated to include the view from the bridge of a trawler which is of particular relevance to fisheries.

The model was developed to enable fishermen and offshore authorities to better understand and visualise how the development will look once constructed and can now downloaded from the organisation's website.

Anyone wanting to download a copy of the model should email info@forewind.co.uk to request a username and password. They can then visit the Downloads section of www.forewind.co.uk to install the 2GB .exe file and find instructions and a user guide.



The view from a trawler has now been incorporated into the Dogger Bank 3D computer simulation, which has proved popular with offshore and other stakeholders.

Dealing with subsea cable risks

The potential risk to fishing trawlers from subsea cables will be the focus of a new subgroup of the Fisheries Liaison with Offshore Wind and Wet Renewables (FLOWW) group, which Forewind supports and will actively participate in.

The risk to trawlers from subsea cables from the Dogger Bank offshore wind farms was a topic which emerged during the examination of Dogger Bank Teesside A&B, however it is recognised as a wider issue extending to the whole offshore wind industry as well as oil and gas, telecommunications and other sectors.

The newly formed FLOWW subsea cables subgroup has the remit to develop best practice guidance on this important issue as well as guiding principles for the fisheries liaison related to offshore renewables cables, from planning through to operation, and dealing with emerging concerns.

Forewind will be represented on the subgroup to contribute to the discussions and assist with the development of guidance on this issue.

Danish fishermen assist in porpoise research

Danish fishermen have been assisting a group of offshore wind developers, which have joined forces to better assess the impact of offshore wind farm construction on the harbour porpoise population of the North Sea.

Harbour porpoise in the North Sea.
Photo courtesy of Malcolm Barradell.

The fishermen have contacted the researchers at Aarhus University, who are carrying out the research known as Disturbance Effects on the Harbour Porpoise Population in the North Sea (DEPONS), when harbour porpoise have been found in their pound nets. The researchers have then been able to tag the harbour porpoise for monitoring.

The research will continue this year with the final results published in peer-reviewed scientific publications in 2016.

Fisheries contacts

Any queries about Forewind's activity can be directed to:

Nigel Proctor
Fisheries Liaison Coordinator, Cable corridor
+44 7702 730 891
n.proctor@precisionmarine.co.uk

Stephen Appleby
Fisheries Liaison Coordinator, Wind farm zone
+44 7887 777 001
sja@brownmay.com

Martin Goff
Offshore Environmental Impact Assessment Manager
+44 7867 355 935
martin.goff@forewind.co.uk

Forewind
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Davidson House
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forewind.co.uk

To receive copies of this newsletter electronically, please register at **www.forewind.co.uk**

Attachment 38

Example Statement of Common Ground

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Attachment 39

Community Letters of Support

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TEL: (518) 455-3401
FAX: (518) 426-6914

DISTRICT OFFICE
55 FRONT STREET, ROOM 1
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TEL: (516) 766-8383
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WEBSITE
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E-MAIL
KAMINSKY@NYSENATE.GOV

THE SENATE
STATE OF NEW YORK
ALBANY

SENATOR TODD KAMINSKY
9TH SENATE DISTRICT

CHAIRMAN MAJORITY MEMBER
ENVIRONMENTAL CONSERVATION

COMMITTEES:
CODES
CIVIL SERVICE AND PENSIONS
HEALTH
INVESTIGATIONS AND GOVERNMENT OPERATIONS
TRANSPORTATION

February 12, 2019

NYS Energy Research and Development Authority
17 Columbia Circle
Albany, NY 12203-6399

To Whom It May Concern,

I am writing to express my strong support of the proposed Empire Wind Project by Equinor Wind US. This offshore wind project proposal is currently under consideration by the New York State Energy Research and Development Authority ("NYSERDA") and is the only proposal that would be located off the coast of Long Island.

With the effects of climate change becoming ever-more apparent, and the impacts from superstorm Sandy still reverberating throughout communities on Long Island, the need for strong investments in renewable resources should be readily apparent. With this project, New York has the opportunity to become an economic hub for the emerging offshore wind industry. Additionally, situating an offshore wind project off the New York coast, rather than selecting a project from Massachusetts, Rhode Island or New Jersey, will create thousands of good green jobs for New Yorkers.

Choosing the Empire Wind Project will greatly assist in enabling New York to accomplish its goal of 100% renewable energy by 2040, while creating quality jobs for the local community. I am pleased to be able to offer a recommendation on the behalf of this project. Thank you for your consideration and please do not hesitate to contact me if you have any questions.

Sincerely,

Todd Kaminsky
Senator, 9th District

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Michael J. Cusick
Assemblymember
63rd District
Richmond County

The New York State Assembly

Chairman
Committee on Energy

Committee Member
Governmental Employees
Higher Education
Transportation
Veterans' Affairs
Ways and Means

February 12, 2019

President and CEO Alicia Barton
New York State Energy Research and Development Authority
17 Columbia Circle - Albany NY 12203

Dear Alicia Barton,

I write in support of Equinor Wind US and their offshore wind project proposal under consideration by NYSERDA. As a champion for the transition to a clean and renewable energy economy, I was especially excited with Governor Cuomo's recent proposal to increase the state's offshore wind target from 2,400 MWs by 2030 to 9,000 MWs by 2035.

With the effects of climate change becoming ever-more apparent, and the impacts from Hurricane Sandy still reverberating throughout communities in New York City and on Long Island years later, I am encouraged by the opportunity for New Yorkers to seize this moment and lead the nation as an economic hub for the emerging offshore wind industry. I believe siting an offshore wind project off the New York coast, rather than selecting a project from Massachusetts, Rhode Island, or New Jersey, will further the intent of the state to create thousands of good paying jobs for New Yorkers for decades to come.

As New York procures Offshore Wind Renewable Energy Certificates (ORECs) to achieve the Clean Energy Standard, I urge you to give strong consideration to the economic benefits for New Yorkers and the application by Equinor Wind.

Thank you for your consideration. Please contact my office with any questions.

Sincerely,

Michael J. Cusick
Member of Assembly

Albany Office: Legislative Office Building, Room 724, Albany NY, 12248 - (518) 455-5526
District Office: 1911 Richmond Avenue, Staten Island NY, 10314 - (718) 370-1384
cusickm@nyassembly.gov

February 8, 2019

Re: Empire Wind Project

To Whom it May Concern:

I write to express my support of the Empire Wind Project proposed by Equinor Wind LLC ("Equinor") in response to NYSERDA's request for proposals.

Renewable energy, particularly offshore wind, is critically important to Nassau County and the State of New York as a whole. My Administration has been following the developments of the State's Offshore Wind Program with great interest, given the exciting potential it offers for meeting the State's ambitious clean energy goals, as well as the tremendous economic development opportunities for our region.

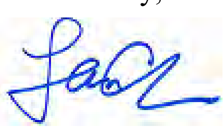
Throughout this process we have made the case that the local communities expected to "host" wind generation activities, like Nassau County, should be able to participate in the economic opportunities created by these projects.

We are pleased that Equinor has engaged in an on-going dialogue with Nassau County to ensure that jobs and facilities created as a result of this new industry be located here. We appreciate the company's commitment to Nassau regarding such investments, particularly in the area of potential land-based operations and maintenance activities.

We believe the Equinor Wind project holds great promise for a partnership with Nassau County and look forward to the associated economic benefits for our residents.

Thank you for the opportunity to offer our views on this matter.

Sincerely,



Laura Curran

COUNTY OF SUFFOLK

OFFICE OF THE COUNTY EXECUTIVE

Steven Bellone
SUFFOLK COUNTY EXECUTIVE

February 5, 2019

Re: Empire Wind Project

To whom it may concern,

I am pleased to have an opportunity to express our support for Equinor Wind US LLC ("Equinor Wind"), as it works towards development of the Empire Wind Project. I particularly appreciate Equinor Wind's willingness to engage in an open dialogue with my office and keep Suffolk County updated about the progress of the project. It is especially important to Suffolk County that Equinor continue to engage stakeholders from throughout the region, including our heritage commercial fisheries, in order to balance the needs of all constituencies as the offshore industry develops in the region.

I am optimistic about the potential impact that the Empire Wind Project will have on establishing New York as a hub for offshore wind development. We look forward to collaborating with Equinor on potential synergies with Suffolk County companies that can play a role in the project.

We wish continued success as it pursues development of the Empire Wind Project and look forward to the project's completion.

Sincerely,

STEVEN BELLONE
County Executive

SCVOA Suffolk County Village Officials Association
FIGHTING FOR VILLAGE RESIDENTS SINCE 1934

February 7, 2019

RE: Empire Wind Project

To Whom It May Concern,

We would like to express our support of Equinor Wind US LLC ("Equinor Wind") and the Empire Wind Project. Renewable energy, particularly offshore wind, is critically important to Suffolk County and New York State as a whole. We appreciate Equinor Wind's continued dialogue with local municipalities as it works to develop this project.

The villages of Suffolk County are excited about the Empire Wind Project and the benefits it could bring to the area, if selected. We particularly appreciate the significant effort Equinor Wind has made in reaching out to interested stakeholder groups and communities. If selected, development of the Empire Wind Project has the potential to establish New York as a national leader in the offshore wind industry and result in a range of environmental and economic benefits for local municipalities.

Sincerely,

Richard B. Smith

Hon. Richard B. Smith
President, SCVOA
Mayor, Village of Nissequogue

69 Chichester Road Huntington, NY 11743 631.327.7342
www.scvoa.com

ROYAL NORWEGIAN
CONSULATE GENERAL

Consul General

New York, 31.01.2019

To Whom It May Concern

Equinor is a reputable, prosperous company, known for its high ambitions for sustainable solutions and shaping the future of energy – ambitions which it is already following through on, among other things by entering the market for offshore wind.

Equinor is the largest company noted on the Norwegian stock exchange, and has been instrumental to the economic development of the country since its inception in 1972. It is a highly profitable company, with a total revenue of $61 billion in 2017. It is present in over 30 markets, including several of the world's most important oil and gas markets. Its products include crude oil and natural gas, as well as processed products such as petrochemicals – and now it aims to seize the new business opportunities that are opening up in clean energy. It already powers 650 000 British homes through its offshore wind projects, and has several new projects in Germany, Norway and the US on the horizon.

In the past year, The Royal Consulate General has had the pleasure of hosting two events relating to clean energy policy in New York with Equinor as a valued partner on both, showing their dedication to collaborate with stakeholders to work together toward a clean energy future. We follow the developments of Equinor with great interest, and appreciate our close dialogue with the company on offshore wind developments.

Yours sincerely

Harriet E. Berg

Postal address: 825 Third Avenue, 38th floor, New York 10022, USA
Office address: 825 Third Avenue 38th floor Telephone: 646 430 7500 Fax: 646 430 7599
Org. no.:972417920

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WCS

February 12, 2019

To whom it may concern,

The Wildlife Conservation Society (WCS) saves wildlife and wild places worldwide through science, conservation action, education, and inspiring people to value nature. To achieve our mission, WCS, based at the Bronx Zoo, harnesses the power of its Global Conservation Program in nearly 60 nations and in all the world's oceans and its five wildlife parks in New York City, visited by 4 million people annually. WCS combines its expertise in the field, zoos, and aquarium to achieve its conservation mission.

The New York Aquarium is located along Brooklyn's famed Coney Island Boardwalk. The aquarium connects visitors to marine life in New York waters and around the world through innovative exhibits and world-class animal care, educates more than 60,000 youth and adults in our formal education programs and conducts field research and conservation policy action in the waters of New York. The aquarium is accredited by the Association of Zoos and Aquariums (AZA).

Over the last two years, and as part of our work to protect and conserve the rich marine life in the New York Seascape, we have engaged with Equinor's Empire Wind team. Beginning in 2017, our discussions have ranged from the availability of baseline information about marine wildlife that exists in the NY Bight to best conservation practices that might be followed by the Empire Wind project.

Equinor and WCS recently have agreed to undertake a multi-year collaboration involving the collection of near real-time acoustic monitoring for several baleen whales species in the Empire Wind lease area. This effort will yield information critical to the conservation of whales in the New York Bight, and might help Equinor reduce potential impacts to whales in the NY Bight. The collaboration also includes a public outreach and education component through our New York Aquarium.

We have appreciated the constructive engagement with Equinor, and their willingness to consider approaches to conserve marine species and important habitats. Equinor has expressed their desire to undertake responsible development of offshore wind resources consistent with New York's environmental goals.

Thank you for your time and consideration.

Jon Forrest Dohlin
Vice President and Director
WCS's New York Aquarium
602 Surf Avenue
Brooklyn, NY 11224
718-265-3474

ATLANTIC MARINE CONSERVATION SOCIETY
Promoting Conservation Through Action

February 4, 2019

Equinor Wind US LLC
120 Long Ridge Road Ste 3E01
Stamford, CT 06902

RE: Empire Wind Project

To Whom It May Concern:

On behalf of the Board of Directors, staff, and volunteers, I am pleased to hear of Equinor Wind US LLC's commitment to the development of renewable energy in an environmentally conscious manner. I look forward to building a relationship promoting marine conservation and, in particular, investigating marine mammal and sea turtle strandings in the region.

The Atlantic Marine Conservation Society (AMCS) is a multi-faceted organization promoting marine conservation through action. In addition to our grassroots efforts involving community outreach and educational programs, we are authorized by NOAA Fisheries and the New York State Department of Environmental Conservation to respond to stranded marine mammals and sea turtles throughout New York. The primary functions of AMCS are to coordinate and manage stranding response for all deceased marine mammals and sea turtles in New York waters and to develop and implement response plans for live large whale strandings and fishery interaction cases. AMCS conducts investigations on the causes of strandings, whether human induced or natural. As part of our stranding response program, we compile and analyze data to assess trends.

AMCS's team is comprised of individuals that have investigated marine mammal and sea turtle strandings for more than two decades. These team members have responded to over 5,400 strandings in New York waters alone. Since its inception, AMCS has responded to over 350 whales, dolphins, seals and sea turtles. In the last two years, AMCS has reported an unprecedented 28 large whale strandings. AMCS's team is currently working closely with NOAA Fisheries concerning four ongoing Unusual Mortality Events (UMEs) in the Northwest Atlantic involving humpback, minke, and North Atlantic right whales and harbor and gray seals.

Our twenty-five years of experience is not just related to responding to stranded marine mammals and sea turtles. AMCS's team also conducts land, boat and aerial surveys of marine mammals and sea turtles throughout the Northwest Atlantic to collect and disseminate data to

ATLANTIC MARINE CONSERVATION SOCIETY
Promoting Conservation Through Action

environmental managers, ensuring the long-term survival of critical members of our ocean ecosystems. We have also conducted health assessments on seals and sea turtles and satellite tagged over 200 marine mammals and sea turtles throughout North America to gain insight into the effects of climate change, marine traffic, and other man-made changes to the environment. Our team also works closely with NOAA Fisheries' large whale and sea turtle disentanglement teams to provide support for operations in the New York region.

AMCS's relationship with Equinor Wind will help us continue our efforts to better identify and understand changes in the marine environment and, specifically, with stranding occurrences. Without this continued effort, many animals will go undocumented and causes of mortality will remain speculation. Through this relationship, AMCS hopes to enhance its response capabilities and to build our health assessment and monitoring programs in the New York region. We also hope that through this relationship we can expand our outreach efforts, so we can better inform the public of the threats facing the marine environment and identify ways in which concerned citizens can minimize their negative impact.

Please do not hesitate to contact me should you require any additional information.

Very truly yours,

Robert A. DiGiovanni, Jr.
Executive Director and Chief Scientist

Re: Empire Wind Project

To whom it may concern,

As northern New Jersey, and New York City and Long Island fishing guides, we are writing to express the growing support among recreational anglers for offshore wind power development in our region. We are seeing the impacts of fossil fuel pollution, including climate change, first hand, and see offshore wind power as an important clean energy solution.

Evidence from European developments and America's first offshore wind farm off of Block Island, Rhode Island, demonstrate that the turbine bases act as artificial reefs, attracting numerous sought-after game species as well as the anglers and charter boats that pursue them.

We both support the goals of Anglers for Offshore Wind Power, an organization that advocates for responsibly developed offshore wind power that can benefit recreational fishing if done correctly. We call for guaranteed fishing access within wind farms, commitments to monitoring fisheries impacts before, during and after construction, and opportunities to connect with developers and agencies to ensure our voices are heard in all stages of project development.

As licensed captains, we know development of offshore wind turbines within the Equinor lease area would attract the attention of private and for-hire captains from both New York and New Jersey. Assuming this project follows the pattern of the Block Island Wind Farm, on any given day we could see dozens of fishing vessels in the Empire Wind project area within a few years. At 20 miles offshore, the turbine bases could also attract highly sought after pelagic species like tuna and mahi-mahi.

In New York alone, recreational fishing supports 10,000 jobs and generates more than $1.1 billion in sales. Responsibly developing the Equinor lease area will benefit local saltwater anglers as well as the businesses they support. We hope that the state of New York will consider the support of recreational anglers for responsibly developed offshore wind power, as well as our economic impact, when evaluating the costs and benefits of all offshore wind projects competing to sell power to New York.

Signed,

Captain Paul Eidman
Tinton Falls, New Jersey

Captain John McMurray
Oceanside, New York

LONNIE R. STEPHENSON
International President

KENNETH W. COOPER
International
Secretary-Treasurer

INTERNATIONAL BROTHERHOOD OF ELECTRICAL WORKERS®

Ellen A. Redmond
International Representative, Third District
111 Brook Lane
Smithtown, NY 11787

February 13, 2019

Ms. Alicia Barton
President & CEO
NYS Energy Research & Development Agency
17 Columbia Circle
Albany, NY 12203

RE: Empire Wind Project

Dear Ms. Barton:

The International Brotherhood of Electrical Workers (IBEW), Third District is pleased to be working with Equinor Wind US, LLC ("Equinor Wind") and the Empire Wind Project. The IBEW has been in active dialogue with Equinor Wind regarding potential employment opportunities associated with the Empire Wind Project.

Since 1891, the IBEW has steadfastly represented the interests of workers in the electrical industry, throughout the United States and Canada, with our current membership at approximately 775,000 members. Our members work in a wide variety of fields, including construction, utilities, manufacturing, telecommunications, broadcasting, railroads and government. In New York State alone, the IBEW represents approximately 50,000 members in various trades ranging from construction to utility jurisdictions. It is because of our diverse membership that we are confident we would be well positioned to adequately meet the needs of the Empire Wind project.

Furthermore, the IBEW has been engaged for a number of years in helping the State of New York achieve its offshore wind and clean energy goals while also establishing the state as a hub of offshore wind development with the most skilled and experienced workforce in the industry.

In conclusion, the IBEW once again confirms its support of the offshore wind industry, and the potential to grow the industry in New York State. We believe that should Equinor win the solicitation they would be a be a good partner in providing good union jobs. We look forward to drawing upon our many years of experience to deliver high-quality jobs to New York and further contribute to the local economy.

Sincerely,

Ellen A. Redmond

Ellen A. Redmond
International Representative

C: M. Welsh, IVP, Third District

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WRISE
Women of Renewable Industries and Sustainable Energy

2/10/2019

E’Lon Hall
Operations Manager
WRISE
155 Water Street
Brooklyn, NY 11201

Re: Empire Wind Project

To whom it may concern,

On behalf of Women in Renewable Industries and Sustainable Energy (WRISE), I am pleased to have an opportunity to express our gratitude to Equinor Wind US for supporting WRISE as a corporate sponsor. As New York prepares to lead the new US offshore wind industry, it is crucial that companies competing to power New York understand the importance of creating an industry that is open to all workers, and does not perpetuate the exclusion of women in the way the fossil fuel industry historically has.

WRISE promotes the education, professional development, and advancement of women to achieve a strong diversified workforce and support a robust renewable energy economy. We appreciate Equinor Wind’s sensitivity to the importance of both workforce training that includes women, as well as hiring practices that promote diversity.

WRISE strongly supports Equinor’s commitment to implement these values in developing and building the Empire Wind Project in New York.

Sincerely,

E'Lon Hall

E’Lon Hall
Operations Manager

Building and Construction Trades Council of Nassau and Suffolk Counties

February 8, 2019

Equinor Wind US, LLC

RE: Empire Wind Project

Dear Sir/Madam,

The Nassau and Suffolk Building and Construction Trades Council ("NSBCTC") is looking forward to partnering with Equinor Wind US, LLC ("Equinor Wind") under the terms of a Project Labor Agreement as required by the bid specification for the Empire Wind Project.

The NSBCTC represents sixty thousand (60,000) men and women in the construction trades on Long Island and due to the size and strength of our affiliate unions and related apprentice training programs, are uniquely positioned to support the Project. We look forward to helping New York State achieve its offshore wind and clean energy goals by utilizing the safest, best trained and most skilled workforce in the industry.

In conclusion, NSBCTC once again confirms its support of Equinor Wind and the offshore wind industry and looks forward to our workforce delivering high quality jobs to the local and New York economy.

Yours truly,

Nassau and Suffolk Building and Construction Trades Council

By: ______________________________
Matthew Aracich, President

Affiliated with Building and Construction Trades Department AFL-CIO
300 Motor Parkway. Suite 200. Hauppauge, New York 11788 . (631) 951-3315/16 . Fax No. (631) 951-3317
nsbctc@optonline.net

February 8, 2019

Re: Empire Wind Project

To whom it may concern,

On behalf of Triple Five I am pleased to have the opportunity to express our support for Equinor Wind US LLC ("Equinor Wind"), as it works towards development of the Empire Wind Project.

Uniting Long Island's institutions with local businesses, will centralize the technology and innovation needed to support offshore wind. Triple Five is excited about establishing a workforce training program to assist in the development and maintenance of a skilled and diverse talent pool establishing a unique opportunity for job seekers, as well as a path toward meaningful career advancement and economic sustainability.

I particularly appreciate Equinor Wind's willingness to engage in an open dialogue with my office and keep us updated about the progress of the project. I am optimistic about the potential impact that development of the Empire Wind Project will have on establishing New York as a hub for offshore wind development. I wish Equinor Wind continued success as it pursues development of the Empire Wind Project and look forward to the project's completion.

Sincerely,

Stuart Bienenstock

Stuart Bienenstock

Director of Business Development

Stony Brook University

Office of the Dean
College of Engineering and Applied Sciences
Stony Brook, NY 11794-2200

Tel: 631.632.8380
Fax: 631.632.8205

February 5, 2019

To Whom It May Concern,

Based on our ongoing offshore wind R&D collaboration with Equinor, and in my role as the Dean of Stony Brook University College of Engineering and Applied Sciences (CEAS), I am delighted to offer my support for Equinor Wind US LLC's Empire Wind project in the New York Bight. CEAS has collaborated with Equinor on the subject for the last 1.5 years and we plan to intensify and solidify the partnership going forward.

The CEAS and Equinor's collaboration to date has focused on innovation through optimization of offshore wind farms, as well as uncertainty reduction and integration of offshore wind into the power grid. Key aspects include wind resource estimation and advanced farm control. As part of this joint research effort, Equinor has visited CEAS at Stony Brook, following which I have paid two visits to Equinor's research and technology center in Trondheim, Norway. Our joint efforts on offshore wind technology development could contribute to a more efficient and sustainable development of offshore wind resources – including in New York State – in the future.

Sincerely,

Fotis Sotiropoulos, PhD
Dean, College of Engineering and Applied Sciences
SUNY Distinguished Professor

Re: Empire Wind Offshore Wind Energy Development

To whom it may concern,

The School of Marine and Atmospheric Sciences (SUNY Stony Brook; SoMAS) is in the process of completing a study funded by BOEM and NYSDEC and lead by Professor Michael Frisk to better understand the spatial and temporal distribution of Atlantic sturgeon in the New York Bight; specifically, the New York Wind Energy Lease Area (Equinor, Lease OCS-A 0512). Equinor Wind has facilitated this effort through additional monitoring, by facilitating the installation of three of our acoustic receivers on their Metocean moorings within their Lease Area. These were installed in December 2018, with a fourth to be installed in spring of 2019, potentially resulting in up to two years of additional data beyond the original study scope.

Equinor Wind and SoMAS have also worked together to ensure there is minimal conflict between Equinor Wind's geophysical survey activities and the array of SoMAS Atlantic sturgeon moorings installed within the Lease Area. We look forward to continuing our collaboration, including potential to accommodate more of our sensors on future Equinor moorings.

We appreciate Equinor Wind's consideration for environmental data collection in the lease area and their efforts and openness to collaborate on research. We authorize Equinor Wind to include this letter in its application for Offshore Renewable Energy Certificates to NYSERDA.

Sincerely,

Michael G. Frisk

Michael G. Frisk, Ph.D.
Professor and Director of the Living Marine Resources Institute
School of Marine and Atmospheric Sciences
Stony Brook University, Stony Brook, New York
Email: michael.frisk@stonybrook.edu
Phone: 631-632-3750
http://you.stonybrook.edu/frisk/Sincerely,

Farmingdale
State College

Barbara Christe, PhD
Dean, School of Engineering Technology
Phone: 631-420-2256
Fax: 631-420-2101
Barbara.Christe@farmingdale.edu

Re: Empire Wind Project

To Whom It May Concern:

I am pleased to have an opportunity to express my support for Equinor Wind US as it works towards development of the Empire Wind Project.

As the Empire Wind team began their project development, they reached out to me regarding job training for offshore wind energy technicians. This happened just as I was working on a grant proposal to help design a robust offshore Wind Turbine Technician (WTT) program with my colleagues from SUNY Maritime. The Equinor Wind team is now serving on the steering committee for the Offshore Energy Center, helping to advise on what training their future employees will need to operate and maintain Empire Wind.

I particularly appreciate Equinor Wind's willingness to engage in an open dialogue with me and keep me updated about the progress of the project. I am optimistic about the potential impact that development of the Empire Wind Project will have on establishing New York as a hub for offshore wind development. I wish Equinor Wind continued success as it pursues development of the Empire Wind Project and look forward to the project's completion.

Sincerely,

Barbara Christe

Barbara Christe, PhD
Dean, School of Engineering Technology
Farmingdale State College

ULC
PIPELINE ROBOTICS
AERIAL SERVICES
RESEARCH AND DEVELOPMENT
ENERGY SERVICES

88 Arkay Drive
Hauppauge, NY 11788
1-631-667-9200 | ulcrobotics.com

January 29, 2019

To Whom it May Concern,

ULC Robotics, Inc. is pleased to submit this letter to express its support of Equinor US Wind's proposal to NYSERDA (ORECCRFP 18-1). Equinor is a champion for the creation of renewable energy, and a leader in the offshore wind industry. Their track record of success extends to the two largest offshore wind markets, Germany and the United Kingdom, and helps provide clean energy to over 1 million homes.

ULC encourages Equinor's intention to replicate that success in the United States, beginning with the Empire Wind project, which is located 20 miles off the cost of Long Island. Equinor's US vision based upon current and planned offshore leases has the potential to power more than 1 million homes once complete.

ULC Robotics and Equinor have been working to explore the creation of advanced, purpose-built vertical take-off and landing aircraft to support the entire lifecycle of offshore wind farms, a concept that is well-aligned with Governor Cuomo's ambitious plan to generate 9,000 megawatts of offshore energy by 2035. Equinor's experience in offshore wind project siting, planning, permitting, construction, and operations and maintenance will help establish New York as an industry leader through job creation, reduced cost and risk, and the improved safety of workers.

For over 15 years ULC Robotics has been a leader in supporting the energy industry with high-value robotic solutions and has been in discussion with offshore wind experts worldwide to develop purpose-built aircraft and robotic crawlers to support the industry. The partnership between Equinor and ULC Robotics will be well-suited to achieve NYSERDA's RFP-stated objectives, specifically Section 6.4 (Reduce risk and drive down costs) and Section 6.4.16 (New York economic benefits).

ULC Robotics looks forward to working in collaboration with Equinor US Wind to develop and deploy advanced technologies to benefit New York-based offshore wind projects and the industry as a whole.

Sincerely,

Gregory Penza
President
ULC Robotics, Inc.

February 12, 2019

Equinor Wind US LLC
120 Long Ridge Road Ste 3E01
Stamford, CT 06902

Re: Empire Wind Project

To whom it may concern,

I am pleased to express my support for Equinor Wind US LLC ("Equinor Wind"), as it works towards development of the Empire Wind Project. I particularly appreciate Equinor Wind's willingness to engage in an open dialogue with my office and keep us updated about the progress of the project. I am optimistic about the potential impact that development of the Empire Wind Project will have on establishing New York as a hub for offshore wind development. I wish Equinor Wind continued success as it pursues development of the Empire Wind Project and look forward to the project's completion.

Sincerely,

Sammy Chu

Chief Executive Officer,
Edgewise Energy

Chairman,
US Green Building Council Long Island Chapter

ALG AMATO
LAW GROUP, PLLC

666 OLD COUNTRY ROAD, 9TH FLOOR
GARDEN CITY, NY 11530
TEL: 516.227.6363 | FAX: 516.227.6367

February 8, 2019

VIA ELECTRONIC MAIL
New York State Energy Research and
Development Authority
17 Columbia Circle
Albany, NY 12203-6399

Re: Empire Wind Project

Dear Sir/Madam,

Amato Law Group, PLLC ("ALG") is delighted to be considered for the role of local real estate counsel to Equinor Wind US LLC ("Equinor Wind") in its efforts to develop the Empire Wind Project. Since October of last year, ALG has been in an active dialogue with Equinor Wind to provide legal services. ALG appreciates the opportunity to be part of the team seeking to make the Empire Wind Project a reality.

Operating since 1995, and with its twenty (20) attorneys possessing extensive experience in transactional, leasing, land use, environmental and litigation work on behalf of an array of real estate clients, ALG is well positioned to support Equinor Wind in its efforts in developing the Empire Wind Project. As a full-service real estate firm, ALG will be able to identify and resolve any and all legal issues that may arise during the permitting and construction phases of development. Given this experience, ALG looks forward to playing a role in helping the State of New York achieve its renewable energy goals. Additionally, we look forward to further developing our relationship with Equinor Wind to help them deliver the Empire Wind Project in the most efficient and cost effective manner.

ALG supports Equinor Wind's efforts to bring the offshore wind industry to Long Island. If selected, ALG will draw upon our many years of experience to deliver real estate legal services for the Empire Wind Project balancing the interests of time, budget and attention to client's needs. Once again, ALG appreciates the opportunity to be a part of Equinor Wind's team and looks forward to a fruitful relationship for all involved.

Sincerely,

Alfred L. Amato, Esq.
Manager

Attachment 40

Empire Wind Press Coverage

equinor

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Empire Wind Media Clips

December 2016 – February 2019

Wind energy project off Long Island to be called Empire Wind

Newsday
By Mark Harrington
October 23, 2017

The developer is Norwegian, but the name of the first wind-energy array off Long Island's South Shore will be distinctly New York: Empire Wind.

Officials from developer Statoil are in New York this week to attend a wind-industry event in Manhattan and on Tuesday will announce the name of the project. Empire Wind was chosen, they say, to reflect the location.

"We wanted to find something that's associated with New York, to make it local," said Christer af Geijerstam, who was recently named Statoil's project director of Empire Wind. A website, www.empirewind.com, will go live later this week.

Statoil, which is two-thirds owned by the Norwegian government, won the bidding to develop 79,000 acres of ocean off Long Island through a federal auction in December 2016. Statoil's bid was $42.5 million, besting New York State, the second-final bidder.

Geijerstam indicated that Statoil has ambitions beyond the Empire Wind project. New York State this month identified more than 1 million acres of offshore waters for future wind arrays for at least four additional wind farms beyond the Statoil project. "It's fair to say Statoil has the northeast of the U.S. as a priority area and we'll be looking at ways to increase our efforts and engagements in this area," he said.

For Empire Wind, the tentative plan is to erect 80 to 100 turbines 14 miles south of Long Beach and extending south-eastward. The project would produce up to 1,000 megawatts of energy, enough to power hundreds of thousands of homes, but Geijerstam noted production will be based on contracts the company negotiates with the state or power companies.

"At this stage we'll keep all options open" in terms of the size, he said.

INDEX

INNOVATELI
INSIDE THE NEW ECONOMY

Record $42.5M Bid Wins LI Wind-Farm Lease

Innovate Long Island
By Gregory Zeller
December 16, 2016

The U.S. subsidiary of a Norwegian energy company has placed a record $42 million bid to win the lease rights to build a wind farm 11 miles off Long Island.

Stamford-based Statoil Wind US LLC, a subsidiary of Norwegian mega-utility Statoil, topped five other bidders – including the New York State Energy Research and Development Authority – in a 33-round U.S. Department of the Interior auction that kicked off Thursday.

The auction covered 79,350 acres of ocean real estate – roughly 127 square miles – between the southern Long Island and northern New Jersey coasts, and as the saying goes, things accelerated fast: Statoil Wind's winning bid of $42.46 million was a far cry from the $158,700 (roughly $2 per acre) opening bid required by the Interior Department's Bureau of Ocean Energy Management.

Six contenders – including Oregon-based Avangrid Renewables, German energy company Innogy SE and Denmark-based companies DONG Energy Wind Power and Alpha Wind Energy – answered the bell. But by close of business Thursday, with bids pushing past the $25 million mark, only three bidders remained.

For its winning bid, Statoil Wind secures a preliminary one-year lease for the 79,000-plus acres, during which time it must submit a site-assessment plan to the Bureau of Ocean Energy Management. If the assessment plan is approved, the company will have an additional 54 months to submit a construction and operations plan, which the bureau will review – including a public-comment phase – and measure against other possible site uses.

With an approved construction plan, the company would have an additional 25 years to build and operate its wind farm, which it says could ultimately include more than 200 turbines and produce 1 gigawatt of power – roughly enough to power three-quarter-of-a-million homes.

The $42 million-plus bid – a record for an offshore U.S. lease, according to the Interior Department – gives the Norwegian parent company, which boasts operations in 30 countries, its first U.S. foothold, while wrapping up tidy bow on a 2016 marked by aggressive expansion.

Earlier this year, Statoil acquired 50 percent of the Arkona Wind Farm, located in the Baltic Sea off the German coast, which is slated to begin producing electricity in 2019. The company already held a 40 percent share in the Sheringham Shoal Wind Farm, which has been providing electricity to the UK since

2012, and expects to begin producing energy at its Dudgeon and Hywind farms – located off the western coasts of England and Scotland, respectively – next year.

Calling the United States "a key emerging market for offshore wind," Statoil Executive Vice President Irene Rummelhoff said her company was "excited to have submitted the most competitive bid in a highly attractive project."

"We now look forward to working with New York's state agencies and contributing to New York meeting its future energy needs by applying our offshore experience and engineering expertise," Rummelhoff said. "As today's announcement shows, Statoil is well positioned to take part in what could be a significant build-out of offshore wind in New York and other states over the next decade."

Although it rivaled – and ultimately defeated – NYSERDA in the Interior Department auction, Statoil Wind will "work closely with the New York State Energy Research and Development Authority on these studies and throughout the permitting process," the executive VP added.

Heather Leibowitz, director of NYC-based watchdog Environment New York, said the completion of the Bureau of Ocean Energy Management auction marked a giant leap in the global struggle against climate change – while giving New York "a great opportunity to be a national leader in tackling climate change and developing offshore wind."

"The successful lease sale of New York's first Wind Energy Area is a great step forward to tapping into this tremendous clean, pollution-free resource," Leibowitz said. "We look forward to continuing to work with local, state and national officials to bring offshore wind to New York."

Statoil Wind wins right to build wind farm off Long Island

Newsday

By Robert Brodsky and David M. Schwartz

December 16, 2016

Statoil Wind won leasing rights Friday to build an offshore wind farm in 79,350 acres of ocean 11 miles off Jones Beach with a record-setting bid of $42.46 million, the federal Bureau of Ocean Energy Management said.

Statoil Wind US LLC, an international energy company with offices in Houston, outlasted five other bidders, including the New York State Energy Research and Development Authority, in an online auction that lasted 33 rounds.

"We are excited to have submitted the most competitive bid in a highly attractive project, Statoil's first offshore wind lease in the United States," said Irene Rummelhoff, the company's executive vice president for New Energy Solutions.

U.S. Interior Secretary Sally Jewell said the auction "underscores the growing market demand for renewable energy among our coastal communities."

Statoil said it would work with the state energy authority, runner-up in the auction, as it conducts studies of the project area.

Headquartered in Norway, Statoil operates in 36 countries and has 22,000 employees worldwide focused on oil exploration and production.

Other bidders were Avangrid Renewables LLC, DONG Energy Wind Power Inc., Innogy US Renewable Projects LLC and wpd offshore Alpha LLC.

The auction began Thursday with participants agreeing to pay a minimum of $158,700, the original asking price set by the Ocean Energy Management bureau, part of the Interior Department. The number of bidders dropped to four when the price reached $14.46 million, and another dropped out when the price hit $19.46 million.

At day's end Thursday, the three participants were each bidding $25.46 million. On Friday, the field narrowed to Statoil and the state authority as the price reached $33.46 million.

"We have seen robust competitive interest for this auction, as evidenced by 33 rounds of bidding — the most we have seen for any of our lease sales to date," said Abigail Ross Hopper, the bureau's director.

The previous record for a U.S. offshore wind lease was $8.7 million, paid in 2014 to develop two ocean zones off Maryland, said Tracey Moriarty, a spokeswoman for the bureau. Auction proceeds go to U.S. Treasury Department, officials said.

The Department of Justice and Federal Trade Commission will conduct an anti-competitiveness review of the auction before the lease is executed, officials said.

Statoil also must submit a plan detailing its vision for the project, conduct an environmental review and give the public an opportunity to comment on the plans.

If its plans are approved, Statoil would have 25 years to construct and operate the project.

Fishing groups, including the largest commercial fishing association on Long Island, filed suit this month seeking to block the project, alleging the 194 turbines would hinder access to vital fishing grounds.

The auction marked the first time in six auctions for Atlantic Coast wind-energy areas that a government entity bid against private developers, Moriarty said.

The state energy authority said it "remains committed to the development of cost-effective offshore wind that will benefit all New Yorkers by producing clean, renewable energy, while growing a robust offshore wind infrastructure that supports new jobs."

Kevin Law, president of the Long Island Association, the region's largest business organization, called Statoil's win "good news" for Long Island's "renewable energy efforts."

POLITICO NEW YORK

Norwegian company tops state agency in auction for offshore wind rights

Politico New York
December 19, 2016

In a record-breaking auction of U.S. offshore wind development rights, a Norwegian oil and gas company has beaten out a New York state agency for the right to develop 80,000 acres off Long Island.

The federal Bureau of Ocean Energy Management last week declared Statoil, a state-owned company, to be the auction's provisional winner with a final bid of $42.5 million. That's more than the combined $15 million in revenue reported to the U.S. Treasury from previous lease auctions for a million acres for offshore wind development since 2013.

The New York State Energy Research and Development Authority came in second place. There were six bidders in total, two of which made it to the auction's final round of bidding.

Statoil, which is developing multiple offshore wind projects in Europe, plans to develop 1 gigawatt of electricity from turbines 11 miles off Long Island.

The high price reflects growing interest in offshore wind as development costs go down. The area is also close to high-cost, high-demand load centers in New York City and Long Island.

"This is a very good place to be with respect to wind resources," Irene Rummelhoff, Statoil's executive vice president for New Energy Solutions, said in an interview. "The combination of the natural resources and the attractive market make it very intriguing. Also for us this is a first foothold into the larger offshore wind market, which we believe will grow very rapidly."

Statoil will have to secure additional regulatory approvals, a power purchase agreement to sell the electricity and a connection to the electricity grid. NYSERDA had planned to package those additional pieces needed for offshore wind development and then re-sell it.

NYSERDA officials said this would speed up the first offshore wind project in New York and provide the best deal for ratepayers.

Statoil did have the option to step aside and let NYSERDA win the auction as the second-place bidder, according to BOEM spokeswoman Tracey Moriarty. But Statoil declined to do so.

Rummelhoff said the process would not be "straightforward" but that the company looks forward to working with NYSERDA and other state agencies.

NYSERDA also plans to continue looking for additional offshore wind development sites by working with coastal communities, the fishing industry and advocates, spokeswoman Kate Muller said in a statement.

The agency is developing a master plan for offshore wind in New York, set to be released by the end of 2017.

“NYSERDA remains committed to the development of cost-effective offshore wind that will benefit all New Yorkers by producing clean, renewable energy, while growing a robust offshore wind infrastructure that supports new jobs," Muller said.

The auction still faces a legal challenge from a group of fishing industry trade groups, businesses and communities. In a federal lawsuit, the Fisheries Survival Fund and others argue that BOEM did not consider options that would do less harm to habitats where squid, scallops and other marine life are harvested.

Clean energy and environmental advocates have said further environmental review is part of the process after the auction. Those groups praised the auction's results.

"It shows that there’s a lot of confidence in offshore wind in New York," said Anne Reynolds, executive director for the Alliance for Clean Energy New York, referring to the high bids the auction drew. "The state’s participation lent seriousness and confidence to the whole thing."

The Washington Post

The Energy Department helped start a revolution – and doesn't know who to hand it off to

Washington Post
By Chris Mooney
December 19, 2016

As the Obama administration prepares to leave office, it is seeking to underscore just how much has changed in the last eight years in the way we get energy — and to take some credit for it.

Since 2008, costs for wind and solar have plunged by 40 and 60 percent, respectively, according to an analysis provided by the Energy Department. That's even as the United States has installed 100 gigawatts, or billion watts, of generating capacity in the two technologies combined (75 gigawatts of wind, 25 of solar).

Meanwhile, we now have 500,000 electric vehicles on the road, thanks largely to a 70 percent drop in battery costs. The federal government can't take credit for all of this (industry invested too, states also promoted renewable energy, and so on), but it helped drive much of it through research investments over decades, said David Friedman, the Energy Department's acting assistant secretary for energy efficiency and renewable energy.

"The Department of Energy has really changed the world when it comes to energy, and that's part of a global competition that's underway," said Friedman. He spoke to the Post to preview remarks he planned to deliver Monday in Chicago at an event being put on by the Clean Energy Trust, the Chicago Council of Global Affairs, and Business Forward.

"Electric vehicles, we can take very I think direct credit for the lithium ion battery of today," Friedman added. "That core chemistry…was developed and improved at Argonne National Labs through DOE funding."

But the timing for this message, which overlaps heavily with a report that the Department released shortly before the 2016 election, couldn't be more challenging. In a month, a new administration will take over, guided by a president who talked extensively on the campaign trail about reviving the glory days of fossil fuels.

The transition has already been a painful one at the Energy Department in particular. A questionnaire revealed by the press showed that the Trump transition team had not only asked the agency for the names of career staffers who had worked on Obama climate policies, but also seemed to hint at plans to cut the department's funding.

One question asked, "If DOE's topline budget … were required to be reduced 10% over the next four fiscal years [does] the Department have any recommendations as to where those reductions should be made?"

Another asked, "What is the Department's role with respect to the development of offshore wind?" This technology, the next step for ramping up wind energy in the United States, is finally arriving in this country at a time when the next president has been particularly critical of offshore wind farms, having battled them in Scotland.

The U.S.'s first offshore wind farm, in Rhode Island, just became operational last week and **in a massive auction, the Norway-based oil major Statoil set a new record by laying down nearly $ 42.5 million on a bid for a huge offshore area off the coast of New York.** It was "the highest bid ever for a U.S. offshore wind energy area," according to the American Wind Energy Association.

"We believe that the area that we have now leased…has the potential to develop more than 1 gigawatt of offshore wind, which is a sizeable offshore wind park," said Irene Rummelhoff, Statoil's executive vice president for New Energy Solutions. "The biggest ones in Europe are about that size."

While this type of slow greening of the U.S. energy system should continue no matter who is president, it's less clear if the clean energy research investments that Friedman hails will remain a priority at the federal level — or if, instead, countries like China and Germany will take the next steps. (The Energy Department invested $ 2.4 billion in wind energy technology research from 1976 through 2014.)

Under Trump, the Department of Energy is set to be run by former Texas Republican governor Rick Perry, who once argued that the department shouldn't exist — and yet is credited with a wind industry expansion in Texas on his watch. Still, there are fears that his nomination suggests a realignment of department priorities towards fossil fuels and away from renewables.

It remains unclear how closely the vision implied by the memo, attributable to the Energy Department transition team rather than the incoming secretary, will also match Perry's approach.

But already, one point of sharp contrast is clear. Under Obama, the department was run by two scientists — Steven Chu and Ernest Moniz. In contrast, Perry is a politician who has repeatedly questioned a fundamental scientific reality — human-caused climate change.

Friedman, in the interview, strongly defended the career Energy employees who were viewed as being targeted in the memo.

"Energy efficiency, and being competitive in manufacturing, have been bipartisan issues for decades, and it has been the career employees who've continued pushing these technologies forward," he said. "The people who are going to be there on January 21 are the people who…have been the true engines behind all this progress."

And indeed, there is a broad U.S. bipartisan tradition — not only at the Department of Energy — of the federal government investing in scientific research, and then watching as the resulting technologies take root in this country and stoke new industries.

Yet it's just unclear how much this matters to Donald Trump, who has not yet named a White House science adviser.

“While the men tapped by the president-elect to run Energy, Interior and EPA have expressed doubts about the reality of human-caused climate change, there are hundreds of scientists in their agencies who can offer them expert advice,” said Neal Lane, a physicist at Rice University who served as a science adviser to President Bill Clinton. “But the president, who has said he has an ‘open mind’ on the subject, needs his own science adviser to help him devise a climate policy strategy.”

Friedman, an Obama appointee, was unabashed in making an argument that echoes one Hillary Clinton made in her losing campaign — if we don’t keep making the scientific and applied research investments to push green technologies forward, other countries will and they’ll eat our lunch.

“We’re facing a fundamental question in this country,” said Friedman. “Are we going to invest in the technologies that have been revolutionizing the world of energy, and that other countries are waking up to and investing in, or are we going to let that multi-trillion dollar opportunity slip by? And we’re not going to know the answer until post January 20th.”

HUFFPOST

Norway's Top Oil Company Is Building A Huge Wind Farm Off New York's Jones Beach

Huffington Post
By Alexander Kaufman
December 20, 2016

Winds off the coasts of the United States are so dependably strong, turbines built offshore could produce four times the amount of electricity that's currently generated from all sources in the country.

At least, that's what Norway's biggest oil company is betting.

Statoil, the fossil fuel cash cow that made Norway the world's seventh richest country, won a $42.5 million bid last Friday to lease 79,350 acres of federal waters starting roughly 14 miles off the coast of Long Island. There, the company's U.S. subsidiary plans to build a massive offshore wind farm to send clean energy back to New York City and its suburbs.

Before Statoil can begin construction, the firm plans to survey the waters, which go as deep as 131 feet in places. It's unclear how many turbines the project will include, but the first phase is expected to produce up to 600 megawatts. By 2030, New York Gov. Andrew Cuomo (D) wants to get half of the state's electricity from zero-emissions sources.

"New York state has really good wind conditions and, obviously, also a very attractive market close to the wind resource," Irene Rummelhoff, Statoil's top boss in charge of renewable energy, told *The Huffington Post*. "We think it's a good foothold into a potentially very exciting offshore wind market in the future."

The U.S. produces roughly 75 gigawatts of wind energy already, almost all of which comes from land-based turbines in windswept states like Texas, California and Iowa. But offshore wind, popular in Western Europe, has failed to take off until this year.

Last week, the first offshore wind farm in North America — a five-turbine operation abutting Rhode Island's vacation hub Block Island — began producing electricity. The project, which took seven years to complete, marked a historic turning point for a long-stalled subsector of the renewable energy industry. Developers had hoped a proposed 130-turbine farm off the coast of Massachusetts might jump-start the industry. But fierce opposition delayed the project, first proposed 15 years ago, and it may now never be built.

As offshore wind languished in the U.S., the industry thrived abroad. Europe added 114 commercial offshore wind turbines in the first six months of 2016 alone. Last year, nearly 1 out of every 3 new turbines built in Europe went offshore. The cost of offshore wind energy has plunged as the supply chain for building turbines improves and competition heats up. The price of a megawatt-hour of offshore wind is now between $75 and $140, compared to $67-$72 for gas and coal, according to The Guardian.

The United Kingdom alone gets about 5.1 gigawatts of electricity from 1,465 turbines operating at 27 separate wind offshore farms, according to data from the trade group Renewable UK. In 2012, Statoil completed its first commercial offshore wind farm, an 88-turbine project called Sheringham Shoal, off the eastern coast of England. That farm now powers up to 220,000 British homes. The company is building a second farm in deeper waters, roughly 20 miles off the North Norfolk coast in England, that is expected to produce enough power for up to 401,000 homes. Statoil's third British farm, set to begin production off the coast of Scotland next year, could become the world's first floating wind farm.

greentechmedia:

Statoil Wins NY Offshore Wind Rights for $42M

Greentech Media
By Katherine Tweed
December 20,2016

Norwegian state-owned oil company Statoil is the winning bidder for the right to build a wind farm across nearly 80,000 acres off the coast of New York.

The U.S. Department of the Interior's Bureau of Ocean Energy Management's auction was for an area approximately 12 miles off the west end of Long Island, which should be able to accommodate up to about 800 megawatts of wind power. A wind farm that size would rival some of the largest offshore wind farms in Europe.

There were approximately a dozen bidders that were qualified to bid, but only six took part in the auction. The bidding went through 33 rounds before Statoil ultimately emerged victorious.

Statoil's bid of $42.5 million is hardly the final price tag, as the Norwegian company still needs to go through various environmental and feasibility studies, as well as to find an offtaker for the power it will eventually produce.

The other bidder in the final rounds was the New York State Energy Research and Development Authority. NYSERDA hoped to lower the cost by winning the acreage and then bundling that with an offtake agreement. But Statoil's win suggests that an individual developer thinks it can do it for cheaper than buying the bundled package from the government. NYSERDA's approach was similar to how many offshore wind auctions work in Europe.

No matter the approach, the project will certainly be more expensive than similar ones in Europe, which has about 11 gigawatts of offshore wind. NYSERDA will also still be heavily involved, providing assistance with studies and permitting. Just last week, NYSERDA put out an RFP for expert consultants as the state finalizes its offshore wind master plan.

"We are excited to have submitted the most competitive bid in a highly attractive project, Statoil's first offshore wind lease in the U.S.," Irene Rummelhoff, Statoil´s executive vice president for New Energy Solutions, said in a statement. "We now look forward to working with New York's state agencies and contributing to New York meeting its future energy needs by applying our offshore experience and engineering expertise."

That expertise draws on Statoil's growing interest in offshore wind and long history in offshore oil and gas. It is a joint developer for a handful of wind farms off of the coast of the U.K., and is developing a floating offshore wind farm that will also be paired with energy storage.

One of the U.K. projects is Dogger Bank Wind Farm, which is more than 100 miles offshore of Yorkshire and is expected to have a target installed capacity of at least 7 gigawatts of wind power, and potentially up to 13 gigawatts.

Although NYSERDA will not lead the project, it will be critical for getting buy-in from local communities, especially the fishing community.

"NYSERDA will continue to work closely with coastal community members, the fishing and maritime industries and advocates to identify additional offshore wind energy sites to be included in New York's Offshore Wind Master Plan," the agency said in a statement.

Enthusiasm and acceptance for the project is critical not only for Statoil and New York state, but also for the larger offshore wind industry in the U.S. Europe has gigawatts of offshore wind and some of those projects are now coming in at well under $100 per megawatt-hour. By comparison, the U.S. has only a single offshore wind farm off of Rhode Island, which is delivering 30 megawatts of power to Block Island.

New York, Massachusetts and other states, however, are getting more serious about offshore wind. Massachusetts has a goal of 1.6 gigawatts of offshore wind in the next decade and New York has a goal of getting half of its electricity from clean generation sources by 2030.

To get there, the U.S. offshore wind industry will have to scale up quickly from virtually nothing. It will require larger projects and more support from state governments for permitting. But with lessons learned from Europe, many in the industry feel the time is finally right for offshore wind to become a viable market in the U.S.

"Over the past decade, there has been consistent progress toward the realization of offshore wind power's potential in America," Nancy Sopko, the manager for advocacy and federal legislative affairs at the American Wind Energy Association, said in a statement. She added that the construction of the New York project alone could produce thousands of jobs.

Statoil said the project will be a phased development, with the first phase delivering 400 to 600 megawatts.

EcoWatch

Norway's Biggest Oil Company to Build Huge Offshore Wind Farm Off Coast of New York

Eco Watch
By Lorraine Chow
December 21, 2016

If everything goes to plan, New York City and Long Island will be harnessing the Atlantic Ocean's strong and dependable winds as a source of renewable energy.

Norway's biggest oil company will be developing an offshore wind farm outside of New York. Statoil submitted the winning bid of $42.5 million to the U.S. Department of the Interior's Bureau of Ocean Energy Management last Friday to lease nearly 80,000 acres of federal waters roughly 14 miles off the coast of Long Island, the Huffington Post reported.

The company estimates that the leased area could host a 1,000-megawatt offshore wind farm, with the first phase of development expected to begin with 400 to 600 megawatts. The first plan of action is to survey seabed conditions which can be as deep as 131 feet, grid connection options and wind resources at the site.

"We now look forward to working with New York's state agencies and contribute to New York meeting its future energy needs by applying our offshore experience and engineering expertise," Irene Rummelhoff, Statoil's executive vice president for Statoil's renewable energy branch, New Energy Solutions, said in a statement.

New York state aims to generate 50 percent of its electricity needs from renewable resources by 2030 and is betting big on offshore wind to help meet that goal. The Long Island Power Authority, with the support of New York Gov. Andrew Cuomo, is slated to approve a contract for a 90-megawatt offshore wind project 30 miles northeast of Montauk.

Offshore wind is resource begging to be tapped in the U.S., which has a projected 4,223 gigawatts of electric generating potential, LEEDCo estimated.

"The U.S. is a key emerging market for offshore wind—both bottom-fixed and floating—with significant potential along both the east and west coasts," Statoil's Rummelhoff said.

Still, the U.S. lags behind other countries in utilizing this form of emissions-free electricity. U.S. offshore wind development has faced a number of stumbling blocks, such as the embattled Cape Wind Project in Massachusetts that has stalled for more than a decade.

Europe, in comparison, has embraced this form of energy and developed several offshore wind farms projects, as the Huffington Post detailed:

> "The United Kingdom alone gets about 5.1 gigawatts of electricity from 1,465 turbines operating at 27 separate wind offshore farms, according to data from the trade group Renewable UK. In 2012, Statoil completed its first commercial offshore wind farm, an 88-turbine project called Sheringham Shoal, off the eastern coast of England. That farm now powers up to 220,000 British homes. The company is building a second farm in deeper waters, roughly 20 miles off the North Norfolk coast in England, that is expected to produce enough power for up to 401,000 homes. Statoil's third British farm, set to begin production off the coast of Scotland next year, could become the world's first floating wind farm."

In fact, Europe's offshore wind is now cheaper than fossil fuels. According to The Guardian, the price for a megawatt hour is between €73-€140 ($76-$146) for offshore wind compared to €65-€70 ($68-$73) for gas and coal.

On a more positive note, America's first offshore wind farm—the 30-megawatt Block Island Wind Farm in Rhode Island developed Deepwater Wind—switched online just last week. And at least 10 other U.S. offshore wind projects are in development.

The country's renewable energy sector as a whole has been buoyed by federal tax credits that help reduce the price of developing such costly technologies such as offshore wind. For instance, the $30 million Block Island wind farm is eligible for a tax credit worth 30 percent of the project's cost.

However, under a Donald Trump presidency and a potential cabinet consisting of fossil fuel execs and climate change deniers, federal support of the country's renewable energy sector could weaken.

Wind farms, in particular, are a sore subject for the president-elect. Trump has waged legal battles against an offshore wind farm near his golf courses in Scotland because it was a "blight" on the view and once said "the wind kills all your birds."

That federal renewable energy subsidy is set to be lowered in 2019. An extension will require support from both Congress and the Trump administration.

POLITICONEW YORK

With new interest in offshore wind, state agency re-calibrates strategy

Politico New York
By Marie J. French
March 16, 2017

As a new proposal for an offshore wind project looks likely to trigger a federal auction for development rights, a state agency that was willing to spend big in a previous auction is rethinking its strategy.

German-based PNE has submitted plans for a 400 megawatt offshore wind farm off the coast of Fire Island. The project, submitted to the U.S. Bureau of Ocean Energy Management, would put as many as 50 turbines in the 40,000 acre area.

That's likely to spark competitive bidding on the area, said Alliance for Clean Energy's Anne Reynolds, and could move offshore wind along more quickly in New York.

But the New York State Energy and Research Development Authority may not be one of the bidders. The agency said in a statement it "may, but does not expect to" participate in future bidding.

"NYSERDA is executing a strategy to create competition for offtake agreements for areas that meet our standards and provide the best path to cost effectiveness for New York State consumers," the agency said. "We look forward to working with any successful winning bidder to help us achieve these goals."

The agency made an aggressive bid in a December auction of 80,000 acres 11 miles off Long Island. But the agency placed second to Norwegian oil giant Statoil, which posted a winning bid of $42 million.

NYSERDA had been willing to spend as much as $36 million to secure the leasing rights. CEO John Rhodes said the state's plan was to package the leasing rights with all necessary regulatory approvals and an agreement to buy the power.

Gov. Andrew Cuomo has committed to a goal of 2,400 megawatts of offshore wind to supply energy about 1.25 million homes by 2030. NYSERDA is leading the state's effort with the development of a comprehensive plan to locate multiple projects in the Atlantic Ocean, due out at the end of this year.

"Companies noticed how much Statoil paid for the lease and they definitely noticed the governor's commitment … and they know it's a very high-demand place close to New York City," Reynolds said. "What we need in New York is competition between different offshore wind developers to push down the price and get the best deal for New York."

PNE cited political support for offshore wind in New York, high electricity costs for energy in Long Island and New York City, constraints of on-shore generation and planned retirements of plants as reasons for its interest. While praising the state's support for offshore wind, the company's application says more work is needed.

"PNE is convinced of offshore wind's long-term potential in meeting New York's generation needs," the application states. "Going forward, however, what is essential is developing a viable policy framework and an established process that mandates the procurement of offshore wind capacity in New York, as implemented to date in states such as Maryland and Massachusetts."

Maryland and Massachusetts have specific requirements for utilities to buy credits from or directly procure offshore wind energy.

New York's Clean Energy Standard, which supports a goal of 50 percent renewables by 2030, is "agnostic" on technology but requires utilities to buy credits linked to renewable energy projects. Utilities can also directly buy energy from renewable projects, including offshore wind, to lower the amount of credits they must buy.

The PNE project, or one by another developer in the same area, would ostensibly be the third offshore wind farm for New York. The company predicts it could be completed by 2027.

Besides the Statoil lease, which is facing a legal challenge and requires numerous regulatory approvals, the Long Island Power Authority approved a 90-megawatt project off the coast near Montauk in January.

All of this action, with rave reviews from environmental groups, does not come without its detractors. Long Island's commercial fishing industry fears the placement of dozens of wind turbines in waters that have been fishing grounds for hundreds of years will devastate their way of life.

"You don't destroy the ocean environment to save the environment," said Long Island Commercial Fishing Association executive director Bonnie Brady. "If they keep selling off these portions of the ocean indiscriminately without determining first where they shouldn't be going, it'll be too late… You'll be bankrupting these coastal communities."

Brady said the area where PNE wants to build includes fishing grounds for scallops, squid, black sea bass and many other species of fish.

The fishing industry and some coastal municipalities in Long Island have filed a legal challenge to the sale of leasing rights to Statoil. They argue the environmental review should not just consider the effects of building a wind farm but whether other sites would be less harmful to marine life or if it should be built at all. That lawsuit is pending.

NYSERDA has said it plans to consider the concerns of all stakeholders, including the fishing industry, as part of the master plan for offshore wind.

Newsday

Norwegian energy company seeks beachhead in New York area

Newsday
By Mark Harrington
April 29, 2017

Statoil, the Norwegian energy conglomerate that won lease rights to build a wind-energy array off the coast of southwestern Long Island, is establishing a beachhead in the metropolitan area as it marches toward development of more than a gigawatt of wind power here beginning in 2024.

The company, which spent $42.5 million to outbid a contingent of energy conglomerates and New York State in December to advance its first U.S. wind project, has begun staffing here as it begins the four- to five-year process of acquiring the more than two dozen state and federal permits needed before construction can begin.

Irene Rummelhoff, executive vice president of new energy solutions for Statoil, said the company is still deciding whether to approach construction for the 79,000-acre lease area about 14 miles south of Long Beach in phases or all at once.

Under the first scenario, 400-600 megawatts could be developed by 2024, with the remaining number phased in over the next several years. Statoil expects to develop more than 1,000 megawatts of wind energy in the area, using turbines that can produce at least 10 megawatts or more each. That would amount to about 100 turbines in all. A megawatt of wind energy can power at least 360 homes.

"We're a big company with a serious interest and intent on developing this lease as quickly as possible," Rummelhoff said in an interview in Manhattan Wednesday. "We could build it quicker, but we need to do it the right way."

The company, which has offshore wind projects in the United Kingdom and Germany, has also expressed ambitions for wind-energy arrays in California and Hawaii, said Michael Olsen, senior director of business development. Its vast holdings in offshore oil and gas exploration and production have given it expertise in offshore work that will benefit the new renewable energy plans, Rummelhoff said. Statoil is two-thirds owned by the Norwegian government.

The Long Island project, while supported by environmentalists, has already run into opposition from commercial fishing groups that charge it will reduce access to, and potentially destroy, vital fishing grounds, particularly for scallops, squid and other groundfish. They have filed suit in federal court seeking to block the lease award, an effort that initially failed, though the suit is pending.

"Our industry is being ambushed," said Bonnie Brady, director of the Long Island Commercial Fishing Association, one of the plaintiffs in the suit. "If everyone put solar panels on their roofs, there would be no reason to destroy the fishing grounds" for wind turbines.

Rummelhoff said the company plans to have an "informative and respectful dialogue" with fishing groups. She allowed that there could be impacts during the construction phase, but said "after that it's quite possible" that fishing could continue around the turbines. Fishermen have expressed doubt about the claim.

Fishing, Rummelhoff noted, is a big industry in Norway. "We've learned how to co-exist," she said. "We think we can manage this by approaching stakeholders with an open mind and listening." Officials also broached the notion that some of the 79,000 acres "will not be developed."

Rummelhoff said the company has already begun the work of meeting with local and state officials to inform them of the plan and address concerns. She and her team visited with state lawmakers in Albany on Tuesday, and have plans to meet with Long Island groups, including fishing groups, in coming weeks and months.

At 14 to 30 miles from shore, she said, the turbines for the Long Island project aren't expected to be seen on the horizon. "We'll try very hard not to make them visible," she said. The company has a floating platform technology that can allow for siting the turbines in much deeper water than currently feasible, she said.

Rummelhoff said the company has been encouraged by the increased activity for offshore wind in the United States, after Europe has carried the offshore wind flag for more than a decade. The Trump administration, despite telegraphing doubts about climate change and green energy, last month completed a successful offshore lease for waters off North Carolina. Meanwhile, a German developer, PNE Wind, has made an unsolicited offer for a wind farm just east of the proposed Statoil project in waters 12 miles from Bayport. LIPA already has signed a separate contract for a 90-megawatt wind farm with Deepwater Wind off the Rhode Island coast.

Statoil has been encouraged by state and Long Island energy plans, which anticipate renewable energy playing a greater role in the next dozen years, Rummelhoff said. The company is working on a study "to understand the Long Island market and beyond," including how to reach the markets that demand new energy sources. A plan by Gov. Andrew M. Cuomo to shutter the Indian Point nuclear plant in Westchester by 2021 could further create a need for Statoil's wind energy, she said.

Newsday

Long Island's energy future may be blowin' in the wind

Newsday
By Editorial Board
May 6, 2017

Diesel generators that date to 1925 were shut down on Block Island last week as the nation's first offshore wind plant, a few miles off its coast, began providing full power to the island's electrical grid.

Earlier this year, final agreement was reached between the Long Island Power Authority and that same wind plant's developer, Deepwater Wind, to provide power to Long Island's South Fork. The electricity from 15 turbines at the wind farm, about 30 miles off Montauk, could begin flowing in six years.

Statoil, a Norwegian firm that won an astonishingly high-priced federal auction in December to lease 79,000 acres in the Atlantic Ocean 14 miles off Long Beach, is gearing up to face regulatory battles and to build community support it needs to start its own wind project. Statoil says it could be producing power for this region as soon as 2024. In addition, LIPA might have other choices for wind generation; a German company is getting ready to propose an offshore project south of Bayport.

Wind power from inland?

And it's not just sea breezes that could be a power source. LIPA is expected next month to choose among bidders offering renewable generation to replace small aging gas plants known as peakers. One of the bidders, Invenergy, offers an ambitious proposal to build wind and solar farms in rural Ohio, West Virginia, Pennsylvania and North Carolina, and to send us that power via the existing grid and a new underwater cable. Land is so expensive and solar arrays need so much space that it's unlikely there will be any new large-scale solar projects built on the Island.

Gov. Andrew M. Cuomo greatly expanded this market for renewable energy by setting a goal that the state will draw 50 percent of its power from green sources by 2030, and Long Island will be the centerpiece of that effort. New York stands with California, Oregon, Vermont and Hawaii as states with the highest standards for renewable energy.

Yet it was quite a torturous, if not ironic, path that got us to this point.

The failed Shoreham nuclear plant resulted in the state taking control from a private utility, the Long Island Lighting Co., 29 years ago. Instead of profits, however, it was politics that ruled local decision-making until superstorm Sandy exposed inadequacies and new state legislation overhauled LIPA's governing structure in 2013. Often those politics were designed to appease local officials, resulting in bad decisions, such as not challenging assessments on overtaxed plants or awarding too-generous community payments in lieu of property taxes. Now that state control can be turned into a benefit if the political decisions support enlightened policy that embraces new technology and moves away from outsized dependence on fossil fuels.

Long Islanders will still have the same basic concerns about reliability and affordability, which must always be at the center of the conversation. But the moldy focus on how to salvage the oil- and gas-fueled baseload power plants of the last century must evolve. The latest study from LIPA, its long-awaited Integrated Resource Plan, and an independent review of a PSEG Long Island analysis of existing generation, must start a new dialogue.

The resource plan, as well as the PSEG review by the Brattle Group, a consultancy, confirm that Long Island and the nation are consuming less electricity, due in part to more efficient appliances, light bulbs and sustainable design. At the same time, the New York Independent Service Operator, which manages the flow of high-voltage power on the state's grid, has reduced requirements for how much backup power LIPA needs to have at the ready and how much of that must be produced on the Island.

As a result, there is widespread agreement that no additional generation is needed until 2030. The current open bids are to replace aging peakers with renewables and more efficient plants. And when the decision is made in five to seven years about what should be built to meet new needs, it certainly won't be enormous plants using fossil fuels. Even now, 54 percent of LIPA's generation is idle at any given time; the national average is 44 percent.

Another reason for reduced power need is rapidly changing energy markets — from competitively priced renewables to plentiful and low-cost natural gas. The studies conclude that there is no need to rebuild — euphemistically called repowering — the older plants at Port Jefferson and Island Park. The plants are still used, but sparingly, and their value has depreciated. Contracts with owner National Grid on those plants, as well as the workhorse of the system in Northport, expire in 2028 and shouldn't be renewed. The studies also confirmed that there is "no compelling reason" to build a second Caithness plant in Yaphank. LIPA says going forward with repowering and a second Caithness plant would increase customer bills by $5 billion through 2030.

These findings are going to make some communities on Long Island and their elected officials very displeased because the $189 million LIPA customers pay for the taxes on these old plants only benefit the jurisdictions in which they are located. But the time for stalling and maneuvering is over. Incredibly, one of the reports that buries the dream of repowering was requested by the State Legislature, hoping it would prove the opposite.

LIPA's tax grievance litigation against Nassau County, and Brookhaven and Huntington towns, should be settled so plans for other uses of the sites of those aging plants can move forward. Port Jefferson, for example, is ideally situated for one of the new and more efficient peaker plants LIPA will need in the near future.

Will the findings of today change? Of course. The key assumption in these studies, that the trend toward reduced consumption will continue, must be closely monitored. If it changes, LIPA will need to have new power sources in place before 2030. The premise that the massive wind project off Long Beach will soon supply bountiful renewable energy could dissolve if state and federal regulatory hurdles mount and if there are construction delays.

Keeping the old standards, the old thinking and the old politics will lead to costly mistakes. Almost half of a LIPA bill, the charges called "power supply," rest on these decisions. Managing them smartly can not only keep our already high cost of electricity in check, but power Long Island into the future.

THE WALL STREET JOURNAL.

Plans for U.S. Wind Farms Run Into Headwinds

Wall Street Journal
By Erin Ailworth
July 19, 2017

After two decades spinning power from the gusts that sweep Europe's North Sea, the offshore wind industry is finally turning to the U.S. A big hurdle: getting its giant turbines to American waters.

No one in the U.S. currently makes turbine towers sizable enough for use in deep waters—one of the many challenges impeding the buildup of offshore wind on the other side of the Atlantic Ocean.

The first offshore wind installation in the U.S., a $300 million, 30-megawatt project off Rhode Island, began turning six months ago. Companies including Denmark's Dong Energy AS , Norway's Statoil AS A and Spain's Iberdrola SA IBDRY -1.13% are now pursuing more than a dozen projects that would dwarf it.

But the Block Island wind farm in the U.S. currently generates power for 24.4 cents per kilowatt-hour, while offshore wind projects in Europe can come in well under 10 cents per kilowatt-hour. Developers are optimistic that, as occurred in Europe, prices will go down as more projects begin and a supplier network takes shape in the U.S.

"They are really viewing this as a real market if you are attracting players like Dong and Iberdrola and Statoil," said Maxwell Cohen, a senior research analyst at IHS Markit . "I've heard some pretty major companies that are not in offshore at least being asked, 'Why not?'"

If all 17 of the proposed farms are built, the wave of U.S. offshore wind projects, primarily concentrated in the Northeast, would add 9.1 gigawatts of generating capacity, according to the American Wind Energy Association. That is enough to power 3 million homes.

Offshore wind farms require hundreds of millions to billions of dollars to construct depending on their scale, and analysts say not all of the proposed U.S. farms will be built. But state-level policies that promote renewable energy are providing momentum.

Earlier this year, New York Gov. Andrew Cuomo, a Democrat, called for 2.4 gigawatts of offshore wind to be developed by 2030. Massachusetts Gov. Charlie Baker, a Republican, signed legislation last year to have the state add 1.6 gigawatts of wind power offshore by June 2027.

Statoil won an auction late last year for the right to build a wind farm 14 miles off the New York coastline. Dong, meanwhile, has two proposed U.S. projects: one about 15 miles off Martha's Vineyard that it has teamed with Eversource Energy , a Northeast utility, to build; and another off the coast of New Jersey.

"I can really feel the appetite and the interest in the market now," said Thomas Brostrom, president of North American operations at Dong, which has built 22 offshore wind farms in Europe. "This is the moment."

Avangrid Renewables, an Iberdrola subsidiary, has joined with developer Copenhagen Infrastructure Partners to also build a separate wind farm off Martha's Vineyard.

Most of the 17 proposed projects are in federally designated wind energy areas. Such zones were created to help cut through some of the red-tape and community opposition that for more than a decade has blocked Cape Wind, a more than 400-megawatt project proposed for federal waters off Martha's Vineyard.

Jim Gordon, the man behind Cape Wind, is unwilling to concede defeat, saying the wind farm's lease is still active and that he hopes to see it built one day.

Block Island didn't have the same troubles, in part because it was much smaller and developer Deepwater Wind built it in state waters, which required fewer federal permits. But hurdles remain for large offshore wind projects in the U.S., including how to build out a supply chain that can regularly ship giant turbine towers from Europe.

Components like the enormous stands that anchor offshore turbines will have to be brought up from places like the Gulf Coast. That is because many U.S. Atlantic ports are small, and large vessels need to navigate busy shipping lanes, hurricane barriers and bridges.

This proved a challenge for the Block Island farm, said Meaghan Wims, a spokeswoman for Deepwater Wind. Its stands were brought up on barges from the Gulf Coast. The turbine towers and blades were shipped from France.

A Norwegian ship carrying the nacelles—the housing that holds the main generating machinery—couldn't fit under the Newport Pell Bridge that spans Narragansett Bay in Rhode Island, so it skipped coming into port and went straight to the construction site offshore.

It can also still take considerable time to get the necessary permits and approvals for offshore wind farms from state and federal regulators. Mr. Cohen of IHS Markit said he doesn't expect to see the industry really ramp up in the U.S. until the mid-2020s.

Still, developers are confident that manufacturers and other suppliers will set up shop in the U.S., and costs will come down, once sizable projects are built.

"We've done this in Europe and we have absolutely the same opportunity in the U.S.," said Stephen Bull, Statoil's senior vice president for offshore wind.

State launches public hearings on site of offshore wind farm

Long Island Herald
By Bridget Downes
July 20, 2017

The New York State Energy Research and Development Authority launched a series of public meetings at the Long Beach Public Library on July 11 as part of an outreach effort as the state moves forward with a plan to build wind farms off the South Shore.

The meeting engaged the public, as well as stakeholder groups such as fishermen and the maritime industry in order to generate feedback as early as possible in the planning process for wind farms that would be located 14 miles off the coast of Long Beach, according to state officials.

The efforts coincide with Gov. Andrew Cuomo's goal to pursue options like offshore wind to produce 50 percent of the state's electricity needs from renewable energy sources by 2030.

Cuomo announced in his 2017 State of the State address that New York aims to develop up to 2.4 gigawatts of offshore wind in 13 years off the Atlantic coast — enough to power 1.25 million homes.

Doreen Harris and Greg Matzat, of the large-scale renewables team at NYSERDA — a state agency that is leading the effort to develop offshore wind — offered information about their Offshore Wind Master Plan, which is expected to be completed and released by the end of the year.

As part of the plan, state officials said, NYSERDA is conducting more than 20 studies in a 16,740-square-mile area of the Atlantic Ocean. Only 2 percent of the study area, though, would be needed to meet the state's goal of 2.4 gigawatts by 2030. According to Matzat, that would require 240 to 300 turbines.

The results of the studies will be available to project developers and various stakeholders, and will suggest the best possible sites for wind development and establish guidelines for developers.

"That's really the point of the master plan — to advance offshore wind for the state in a way that is responsible and takes into account the varying uses of our ocean in our planning activities," Harris said. There are "three major components: identify sites that are best suited for the development; create guidelines as a state; advance offshore wind to the point where it's competitive."

Additionally, the offshore wind industry is expected to support 160,000 jobs over the next 30 years, according to the U.S. Department of Energy, and help protect the environment by reducing harmful emissions by 5 million tons per year.

Harris and Matzat also explained that the turbines would not be visible from the shoreline. The state plans to set guidelines that developers must abide by, which will include a minimum distance from the shore that turbines can be constructed.

The fishing industry won't be impacted, either, according to NYSERDA, because the state does not plan to impose any restrictions on fishing around the wind turbines, which will likely be about a mile apart. The aim is to allow the wind farms and the fishing industry to co-exist.

So far, wind farms off the coast of Long Island are in their early planning stages.

"To date, the [U.S. Department of the Interior's Bureau of Ocean Energy Management] has leased six areas for offshore wind between New Jersey and Massachusetts," Matzat said. "All these leases have been awarded to companies through competitive auctions that the BOEM has had. The leases give these companies the rights to do site assessments and propose projects for construction.

The Long Island Power Authority recently approved a contract submitted by Deepwater Wind for operation of the South Fork Wind Farm, a 90-megawatt development 30 miles west of Montauk that is in its early planning stages, according to state officials.

"These megawatts are the first towards our 2,400-megawatt goal," Matzat said. He added that the South Fork Wind Farm is expected to be completed in 2022 and operational in the mid-2020s.

Last week's meeting came after another company won a lease off the Long Beach coast in February. With a bid of $42.5 million at an auction held by the federal government, a Norwegian energy company, Statoil Wind US LLC, won the lease for an area that would provide the state with about 800 megawatts of offshore wind power.

Cuomo called on NYSERDA to work with Statoil to ensure that the project delivers power "cost-effectively and responsibly." Last year, the governor rejected plans to build a liquefied natural gas terminal about 16 nautical miles off the coast of Jones Beach because it would have conflicted with the site of potential wind farms.

"This is part of a much longer trajectory, and we in Long Beach and on the South Shore stood against the Port Ambrose liquefied natural gas terminal a year and a half ago to make room for a project just like this," said State Sen. Todd Kaminsky.

"We're really excited that we're moving forward with our energy goals, that we're being progressive in promoting renewable energy. You can count on one hand the amount of big renewable wind projects in the United States, and for us to be the home for one of them I think is tremendous."

"It's a very inclusive and very exhaustive process because it needs to be done right," said George Povall, director of a local environmental group called All Our Energy. "As an environmental group, we really support that. We'd like to see it done faster, but it's not going to happen. We want to make sure it's done right."

New York Seeks to Lead US in Offshore Wind

RTO Insider
By Michael Kuser
August 7, 2017

New York state wasn't the first out of the gate on offshore wind, but it will be the biggest player if it meets Gov. Andrew Cuomo's 2,400-MW target. State policymakers are embracing offshore wind for its utility-scale generation, its ability to be developed close to the major load centers of New York City and Long Island — and its potential jobs.

"Right now, there are over 300,000 jobs in the offshore wind industry in Europe," Sierra Club Senior New York Representative Lisa Dix said last week when she moderated a panel at the Infocast New York Energy REVolution Summit at Times Square.

The federal government has identified more than 100 GW of offshore wind potential off the Atlantic coast, and the Bureau of Ocean Energy Management has moved forward with the offshore wind lease process in New York and seven other states. **The first offshore wind lease for New York, a nearly 80,000-acre site off the Rockaways in Queens, went to Norway-based Statoil last December.**

"Offshore wind provides power when it's needed the most, at peak times," Dix said. "And it's at a scale that the state needs not only to fulfill its renewable energy policy goals, but also to help combat climate change, where New York City and Long Island are really on the front lines."

State and Stakeholder Support

Chris Wissemann represents the U.S. activities of Germany-based offshore wind developer Innogy, which he characterized as being four times the size of Consolidated Edison and generating enough electricity to serve the entire load of New York state.

"Long-term, stable policy is what makes this become cost-effective," Wissemann said. "Along those lines is the corollary, which is the four P's: politics-proof purchase program. Look at Cape Wind, several years ago: The minute their benefactor was out of office, they lost their [power purchase agreement]. New Jersey's OSW economic development program was never implemented because of politics."

Cuomo in January called for 2,400 MW of offshore wind projects by 2030, starting with the 90-MW South Fork Project off Montauk, Long Island.

The growing breadth and depth of support for offshore wind is spectacular, but not surprising, said New York Offshore Wind Alliance director Liz Gordon. All the different interest groups don't necessarily have the same reasons to support OSW, she said.

"Environmental groups clearly see clean, reliable offshore wind power as a climate change solution, or at least a mitigation," Gordon said. "Labor in New York state is all-in; they're vocally supporting offshore wind because they see massive job potential — good jobs, quality jobs. That will depend on there being a reliable pipeline of projects and ideally a port or two here in New York."

Leasing Moves Forward

Greg Matzat, senior adviser on large-scale renewables at the New York State Energy Research and Development Authority, said: "New York has the largest goal for offshore wind in the country of 2,400 MW. Massachusetts is behind us at 1,600. But we're the only state that doesn't have enough areas currently leased to support our goal. Massachusetts has more than 1,600 MW [in leased sites] available, so it's really important for us to identify sites that make sense for New York and hopefully work for BOEM too … so we can move forward with more leases."

The Statoil site has room for about 800 MW, only one-third of New York's target.

James F. Bennett, chief of renewable energy programs at BOEM, described the 13 commercial OSW leases contracted so far, extending from Cape Cod to Cape Hatteras.

"There's at least one off of every state, from Massachusetts to North Carolina, and obviously where the greatest demand would be," Bennett said. **"New York is one of these areas, obviously, where that demand is indeed great. In particular for New York, we have the one area that was leased in December of last year to Statoil for $42 million, which was an incredible milestone for the program.** And we also had a sale in North Carolina in March of this year that went for $9 million to Avangrid. **Both of those are indicators that the industry, if it hasn't arrived, it's arriving. We're very optimistic about activities in the future."**

According to Bennett, New York has great OSW potential because it has all the factors that make a wind project succeed: wind resources are prime; shallow water off the continental shelf supports seafloor foundations; strong demand that constitutes a good market; and state support.

"I don't know if there is a stronger demand than immediately from New York," Bennett said. "All of these leases have occurred with state involvement and state input, and in particular New Jersey and Massachusetts are great examples of states that have put the time and effort into putting the environmental and stakeholder interests together, and that's the lead that New York is following."

NYSERDA is drafting a master plan that will include a plan for transmission to get wind-generated power to shore. "Some of this you'll see in our Public Service Commission filings," said Matzat, "but the master plan will include recommendations on how to move pre-permit forward for OSW and a timeline on how we see this going."

BOEM manages the lease process and step one is planning and analysis to identify a wind-energy area, "which is where we are now in the process for New York," Bennett said. "It's obvious that the biggest one [lease area] is the one to the north, from New York to Nantucket, and right now that probably will include a couple leases off Martha's Vineyard, which went unleased just two years ago, and we expect very high demand for those areas and are looking to 2018 for an auction for that. Beyond that, and we're always hesitant to get nailed down to a date, but after that we think we're in a position to go forward with another sale in New York."

Docks and Dolphins

NYSERDA applies a similar evaluation process to ocean areas and to the shoreline for the ports needed to fabricate the huge turbine blades and host the purpose-built vessels used in building OSW installations. The authority is looking at 75 sites. The turbines off Block Island, which are 6 MW each, stand 600 feet above the water. The turbines NYSERDA is looking at will average 10 MW and approach 700 feet tall, plus their 200-foot foundations.

"We're looking at the whole supply chain, so we're not just looking at New York Harbor and the Port of New York and New Jersey, but we're looking around Long Island and we're looking up the Hudson too," Matzat said.

Certain activities should be done as close to the wind farm as possible, such as staging for assembly, but other parts of the supply chain, such as manufacturing cables or blades, can be done farther away, he said. Most parts cannot be put on a truck and must be put on a ship, so a large part of the supply chain has to be on the water.

"But that doesn't mean you couldn't build up on the Hudson, where there are areas of labor that might fit a particular part of the supply chain, and bring that down on a barge to an assembly area," Matzat said.

NYSERDA is now conducting public comment sessions, with four for the fishing industry alone this month.

"Another big group that isn't 100% on board with us is the fishing industry, so we've really made a point of reaching out to the fishermen, and we've had a dedicated fishing liaison who just goes around to docks, not just in New York but in other states too, to talk to fishermen and understand their concerns," Matzat said.

The master plan also includes intensive surveys of the shoreline and coast.

The authority has a survey vessel about 15 miles south of New York City doing sediment profiles and sediment samples of the sea bottom over a couple million acres so planners can understand the habitat on the seafloor and what the seafloor is made of, which has environmental as well as construction-planning value.

"I don't believe any state has ever done that in advance of identifying areas for offshore wind," Matzat said. "Usually that's done later by developers."

NYSERDA also is conducting a digital aerial wildlife survey, using a plane with high-resolution cameras to photograph more than 12,000 square miles of ocean four times a year over three years. It has already completed the first year.

New York a leader in wind energy, feds say

Newsday
By Mark Harrington
August 8, 2017

New York is ahead of most other states in wind-energy production and planning, ranking third in small land-based wind arrays and planning for potentially hundreds of offshore wind turbines over the next decade, the federal government said.

In a series of reports released Tuesday, the U.S. Department of Energy noted the state in 2016 added 13.3 megawatts of small wind-energy installations — arrays of less than 100 kilowatts — primarily upstate.

New York also added 78 megawatts of larger, utility-scale turbines last year, increasing that sector's total to 1,827 megawatts statewide — 13th in the nation.

Long Island's handful of land-based wind farms are primarily single turbines on East End farms, including vineyards in Peconic, Mattituck and Cutchogue.

The reports take note of the whirlwind of offshore wind activity around Long Island.

LIPA announced a 90-megawatt project off the coast of Rhode Island last year, and **Norwegian-based energy company Statoil is planning a 1,000-megawatt array off Long Island's coast.**

"When you look at the state of New York it has been a leader in all aspects of wind," Jose Zayas, director for the Wind Energy Technologies Office in the Office of Energy Efficiency and Renewable Energy at the U.S. Energy Department, said in an interview.

He cited state incentives, a strong wind source and economics as the primary drivers for the state's growth.

"It's a little bit of everything," Zayas said.

The New York State Energy Research and Development Authority has identified a large study area for other offshore wind installations. Nearly all of it is off Long Island's South Shore.

NYSERDA has been holding briefings in recent weeks to formulate an offshore wind blueprint by year's end.

The energy department's optimism about wind energy is noteworthy as the administration of President Donald Trump has placed greater public focus on development of fossil fuels such as coal.

Zayas said the administration has an "all of the above" attitude on energy, "looking at all these options and letting the market pick" which to advance.

The federal reports make note of the large gains by wind-energy overall.

Led by Texas, Iowa and Oklahoma, the U.S. wind industry added 8,200 megawatts in 2016, accounting for 27 percent of all new-energy additions for the year. Wind now supplies about six percent of the nation's total electricity.

In New York, a megawatt of wind is estimated to power 360 to 500 homes.

Nationwide, small-scale wind installations produced 992 megawatts of capacity last year from 77,000 turbines in the 50 states, Puerto Rico, Guam and the Virgin Islands.

The report singles out New York as the number-three state for wind-energy projects installed since 2003 using U.S. Department of Agriculture incentives, behind Iowa and Minnesota.

Federal tax incentives for wind power that once covered a third of project costs are set to expire Dec. 31, 2019. Zayas noted, "There will be an impact, the question is how much of an impact?"

north american WINDPOWER®

Statoil's New York Offshore Development Now Known As Empire Wind

North American Wind Power
By Betsy Lillian
October 24, 2017

Empire Wind has been selected as the project name for Statoil's offshore wind site off the southern coast of Long Island, N.Y.

The 79,350-acre site, secured by Norway-based Statoil in a federal auction in December 2016, has the potential to generate up to 1 GW of offshore wind power, making it a key part of New York State's plan to deploy renewable energy sources to meet the state's electricity needs, says Statoil.

Statoil has also launched an Empire Wind website, where members of the public can obtain information on the project and register to receive updates.

"The name Empire Wind captures the pivotal role that this important project will play in helping New York achieve its ambitious renewable energy goal," says Statoil's Empire Wind project director, Christer af Geijerstam. "Empire Wind also speaks to the leading role that New York State is taking in advancing the deployment of offshore wind technology in North America."

Statoil is in the early stages of developing the facility. The Empire Wind project team is currently conducting an extensive evaluation process by gathering detailed information about the seabed conditions, grid-connection options and wind resources characteristic to the area. Statoil currently has seven offshore wind projects online or under development in Europe.

New York's Clean Energy Standard mandates an increase in the share of renewables in its energy mix to 50% by 2030. As part of that effort, Gov. Andrew Cuomo has called for the development of up to 2.4 GW of offshore wind power by 2030.

"Statoil looks forward to working with all stakeholders as we move forward with the job of bringing offshore wind energy to New York," adds Geijerstam. "We are committed to working with other developers, state officials, unions and the business community to develop a U.S. supply chain for this and other offshore wind projects. Our goal is to help make offshore wind a leading option for generating clean and affordable energy in New York."

WORKBOAT

Statoil launches Empire Wind project off New York

Work Boat
10/24/17

Norway-based Statoil ASA announced it will develop its 79,350-acre federal lease off New York as the Empire Wind project, with the potential to generate up to 1 gigawatts of power toward the state's plan for shifting to renewable power sources.

The company also launched a new website, www.empirewind.com, to promote its project to the public. Offshore wind developers like Statoil and Rhode Island-based Deepwater Wind have powerful political backing from state leaders – New York Gov. Andrew Cuomo wants up to 2.4 gigawatts of offshore wind power by 2030 – but siting plans around Long Island are getting intense scrutiny from maritime and fishing industry groups.

"The name Empire Wind captures the pivotal role that this important project will play in helping New York achieve its ambitious renewable energy goal," said Christer af Geijerstam, Statoil's Empire Wind project director, in announcing the formal launch. "Empire Wind also speaks to the leading role that New York State is taking in advancing the deployment of offshore wind technology in North America."

The project is in its very early stages of evaluating the site, a triangular patch of ocean south of Long Beach, N.Y., flanked by shipping traffic separation lanes to the port of New York and New Jersey. Statoil officials say their team is gathering detailed information about the seabed conditions, grid connection options and wind resources.

"Statoil looks forward to working with all stakeholders as we move forward with the job of bringing offshore wind energy to New York," said Geijerstam of Statoil. "We are committed to working with other developers, state officials, unions and the business community to develop a U.S. supply chain for this and other offshore wind projects. Our goal is to help make offshore wind a leading option for generating clean and affordable energy in New York."

Statoil currently has seven offshore wind projects online or under development in Europe, including the Hywind offshore wind project in Scotland that is using the world's first operational 30 mW array of floating, anchored wind turbines. Statoil is betting the technology could open deepwater wind areas farther offshore, including the U.S. west coast and Hawaii.

New York sets high bar for wind energy

United Press International
By Daniel J. Graeber
October 26, 2017

The state of New York aims to become a new hub for the wind energy industry with its unique geographical position and ambitions goals, a state leader said.

New York ranks 11th in the nation in terms of installed wind energy capacity and is the 15th windiest. As of 2014, the state had 20 wind energy projects in service, with a total capacity of 1.8 gigawatts of capacity. The state set a goal of 2.4 GW by 2030.

"New York intends to be the preeminent global hub for the next generation of the wind industry," Lt. Gov. Kathy Hochul said during the opening remarks of a wind energy conference. "We're making unprecedented investments in infrastructure and laying the groundwork for the offshore wind industry, which is primed to benefit from New York's talented, ambitious workforce."

A clean energy mandate in New York states that renewable energy should account for half of the installed capacity on the state grid by 2030. This week, managers at Norwegian energy company Statoil named their early-development project off the Long Island coast Empire Wind.

Statoil secured the 79,000 acre plot during a federal auction in December and said the facility has a design capacity of 1 GW of offshore wind.

The Board of Trustees of the Long Island Power Authority voted in favor of the 90-megawatt South Fork Wind Farm in January. Gov. Andrew Cuomo's broader state energy vision calls for a reduction in greenhouse gas emissions and includes a $5 billion investment in clean-energy technology.

There are more than a dozen offshore wind energy projects in various stages of development in the United States, representing more than 9.1 GW of installed capacity. One GW is enough to power 100 million LED light bulbs.

"Unlocking America's vast offshore wind potential will reliably deliver large amounts of clean power, grow jobs, and cement American energy dominance," Tom Kiernan, the CEO of the American Wind Energy Association, said.

The AWEA hosted the New York wind energy conference.

Statoil Christens NY Offshore Wind Project

Oil And Gas Facilities
By Pam Boschee
November 1, 2017

Statoil selected the name "Empire Wind" for its offshore wind site located off the southern coast of Long Island, New York. The 79,350-acre site, secured by Statoil in a US Department of the Interior's Bureau of Ocean Energy Management (BOEM) auction in December 2016, has the potential to generate up to 1 GW of offshore wind power. It will be constructed by private investors, and the company said investments for a 1-GW project are typically about $3 billion.

The name Empire Wind captures the pivotal role that this important project will play in helping New York achieve its ambitious renewable energy goal," said Statoil's Empire Wind Project Director Christer af Geijerstam. "Empire Wind also speaks to the leading role that New York State is taking in advancing the deployment of offshore wind technology in North America."

The company is in the early stages of developing the offshore wind farm with the potential to provide New York City and Long Island with a significant, long-term source of renewable electricity. The project team is currently conducting an extensive evaluation process, gathering detailed information about the seabed conditions, grid connection options, and wind resources characteristic to the area.

Statoil will submit a Site Assessment Plan to the BOEM, and site assessment and characterization studies and surveys are scheduled to start spring 2018. The results of these studies and surveys will provide the data necessary to compile a Construction and Operations Plan (COP) for the project. BOEM requires submission of a COP within 5 years. Statoil said Empire Wind can generate power as early as the mid-2020s.

New York's Clean Energy Standard mandates an increase in the share of renewables in its energy mix to 50% by 2030. As part of that effort, Governor Andrew Cuomo recently called for the development of up to 2.4 GW of offshore wind power by 2030.

Wind Portfolio Grows

Statoil currently has seven offshore wind projects online or under development in Europe, including the world's first floating offshore wind project, Hywind Scotland. The 30-MW installation, located 25 km from Peterhead in Aberdeenshire, Scotland, began producing power in September, and started delivering electricity to the Scottish grid in mid-October. At peak capacity, the wind farm will produce enough electricity to power 20,000 homes. The company's website characterizes this as a technology which could prove pivotal in generating offshore wind power for the US west coast and Hawaii.

First Step into Solar

Statoil also recently announced its first solar investment in the 162-MW Apodi solar asset in Brazil. The company signed an agreement in October to acquire a 40% share in the construction-ready asset from Scatec Solar, a Norwegian independent solar power producer. The project will provide approximately 160,000 households with electricity. Statoil and Scatec Solar have also agreed on an exclusive cooperation to jointly develop potential future solar projects in Brazil.

Statoil will also acquire a 50% share in the project execution company, enabling it to participate in building and operating solar projects in the future.

"Brazil is a core area for Statoil where our ambition is to deliver safe and sustainable growth in a significant energy market. Entering into solar in Brazil adds to the positions we have already in the producing Peregrino oil field and in the offshore licenses BM-S-8 and BM-C-33 which include the yet to be developed discoveries Carcará and Pão de Açúcar, respectively. We are excited to have entered our first solar project with an experienced partner like Scatec Solar," said Irene Rummelhoff, executive vice president of New Energy Solutions in Statoil.

Statoil will pay a combined acquisition price of $25 million for access to the Apodi solar asset and the project execution company. Construction of the solar plant was targeted to begin in October, aiming to deliver electricity from the end of 2018. Total project capex is estimated to $215 million. The Apodi asset will be funded 65% by project financing and 35% equity contribution, of which Statoil's equity share will be approximately $30 million.

The Apodi asset, located in the municipality of Quixeré, Ceará State in Brazil, is fully permitted with grid connection. The asset holds a 20-year power purchase agreement awarded in 2015 at an auction organized by the Brazilian government.

The construction and operations phase for this project will be led by Scatec Solar with Statoil contributing with staff and services from Brazil as well as Norway.

The Wave

Residents Slam Latest Pipeline Proposal

The Wave
By Ralph Mancini
November 23, 2017

Local activist groups and residents banded together in the fight to thwart an energy company's proposal to build a controversial 23-mile gas pipeline that would connect to the Rockaway Lateral, at a Thursday, Nov. 16 information session at the Knights of Columbus Hall.

Noelle Picone of Surfrider Foundation NYC briefed listeners on an application filed earlier this year by The Williams Companies to a federal agency for approval to build a pipeline system, known as the Northeast Supply Enhancement Project (NESP), extending from Raritan Bay, New Jersey to the lateral area just south of the Marine Parkway Bridge.

Picone and representatives from groups, such as the Sane Energy Project (SEP), New York Communities for Change (NYCC) and Food and Water Watch (FWW) argued that adding another pipeline would be unnecessary in light of a diminishing need for natural gas over the next 10 years.

In fact, SEP Director Kim Fraczek clued attendees in on the renewable energy solutions coming to New York in the near future.

Gov. Andrew Cuomo, according to Fraczek, recently made a commitment to purchase 2,400 megawatts of offshore wind operating about 12 miles off the Rockaway shore.

"The developer's name is Statoil. They are moving into renewable energy and we're happy that they are doing this," said the wind farm advocate, as she delved into the 'Reforming the Energy Vision' program (REV) endorsed by New York State.

"There's a plan from Gov. Cuomo to move us on to renewable energy. In my opinion, he's not being aggressive or fast enough. We want to be 100 percent into renewables and ditch fossil fuels," said Fraczek.

The meeting also brought to light the potential harm the pipeline could inflict to both human and marine life. As noted by environmental spokesperson JK Canepa, The Williams Companies' construction endeavor would entail the excavation of a large trench across New York Harbor – one that would churn up an assortment of toxins, including lead, arsenic, cadmium and zinc, into the water.

Reportedly, those contaminants would eventually be washed ashore by tidal activity and poison various forms of marine life. What's more, it was pointed out that turbulence and vibrations produced by the digging would interfere with the migratory patterns of local whales, seals, turtles and birds.

Pete Sikora, an NYCC senior advisor, painted a dire picture for beach communities – Rockaway included – if companies like Williams are afforded free rein to continue installing miles of pipeline infrastructure.

He informed the crowd on how the enhancement project would only perpetuate thermal expansion that has already resulted in stronger winds and increased storm surge witnessed during Superstorm Sandy.

Siroka cautioned: "The Rockaways are not going to survive change if we don't do something. It's that serious [of] a situation. So, the mainstream science on this [forecasts] a two-to-six-foot sea-level rise coming. That gap means life or death for this area and the difference is what do we do with fossil fuels right now?"

Also weighing in on the topic of pipeline safety was Rockaway Park-based activist and local board member Danny Ruscillo, who brought attention to the fact that Wikipedia has a 73-page list of pipeline accidents, ranging from rupture and leak-induced fires to recent explosions, from 2000 to 2017 alone.

"Many of us here in Rockaway fought hard to make sure the LNG Platform was not placed off our shores. If an accident occurred, it would have caused major environmental damage," offered Ruscillo. "Well folks, the same goes for Williams Transco Pipeline; it's just another accident waiting to happen."

Furthermore, the one-time 100th Precinct Community Council President admonished attendees not to fall for the natural gas producer's charitable tactics, such as doling out community grants and buying scoreboards for Little League ball fields.

"Do you really think they care or have your best interest in mind? People, it's the money and their big profits they care about," Ruscillo professed.

The business aspect of another pipeline being "forced down the throats" of Rockaway residents was a primary concern among both the speakers and spectators, as more than one protestor referenced a previously-built 2.3-mile structure that went live in 2015.

Sara Gronim of 350 Brooklyn, an organization that works to reverse climate change and achieve climate justice through local action, declared that Williams would recoup the dollars spent on pipeline installation by selling their gas to National Grid, along with applying a 14-percent interest and/or surcharge.

Those fees to recover the approximately $924.5 million being spent by the Oklahoma-headquartered energy conglomerate would ultimately trickle down to individual residents, who will invariably be hit with mark-ups, according to Gronim.

"There's no skin off National Grid's nose," she concluded. "It's our pockets that will pay for this pipeline and it's a pipeline we don't need."

Although Williams' Companies personnel weren't invited to give their side of the story at the meeting, Chris Stockton, a media relations representative, reached out to The Wave to challenge specific claims.

In addition to stating that the firm's Transco pipeline system has safely and reliably met the city's natural gas needs since the 1950s, Stockton purported there's a growing demand for natural gas in New York City to heat, cool and power buildings.

To make his case, Stockton referenced a 2017 New York Building Congress report indicating the need for added pipelines due to the planned closure of the Indian Point nuclear plant.

He went on to cite natural gas' lower cost and environmental benefits compared to oil as a major factor influencing customers to obtain their services from National Grid. A Con Edison study, moreover, estimates a 25-percent surge among local inhabitants in favor of gas heat.

In terms of safety, the corporate communications spokesperson related that the company's 2015 pipeline installation was performed without incident and was even lauded by environmental groups, such as the Jamaica Bay Ecowatchers.

But while Stockton mentions "increased demand" as a primary reason for the project in question, West Hempstead (Long Island) resident Joseph Varon highlighted other corporate incentives in play.

He opined that the pipeline would be added not so much to service local citizens, but rather to export fracking gas from the east coast to Europe since gas prices are higher in that part of the world.

Others who vehemently opposed the proposal were former firefighter Joe Hartigan, who expressed concern over the pipeline's proximity to three major airports (Newark, LaGuardia and JFK International), and civic leader John Cori, who described The Williams Companies as being "relentless."

"They're going to keep on doing it. You have to be eternally vigilant…and we will be," promised Cori. "This is an appeal to everybody to come out and fight with us. If you can lead, lead. If you can follow, follow. But if you can't do either, then get the hell out of the way."

Echoing Cori's passion and sentiments was New York Organizer for Food and Water Watch Laura Shindell, as she encouraged everyone at the conference to vent their frustrations by calling the governor at 888-997-5380. She also pushed residents to sign a petition on the matter.

The various members of the coalition against the Williams Companies' initiative seemed to agree that the only way to win their battle is to get Cuomo to throw down the gauntlet on the project, instead of relying on the federal government to take action.

SITE SELECTION MAGAZINE

Norway's Trump Card

Site Selection Magazine
By Adam Bruns
January 1, 2018

"What's so great about Norway?" some are asking in the wake of President Trump's stated immigration preference.

A lot of things, it turns out. (Which might prompt some to wonder just how badly Norwegians would really want to emigrate.) And many of the nation's positives come thanks to the fortunes of state-owned energy company Statoil, the second-largest gas exporter to Europe and the world's largest offshore operator.

Arctic Now in December reported on the €5-billion (US$6.1-billion) investment by Statoil in an Arctic oil project called the Johan Castberg that will produce between 450 million and 650 million barrels of oil over 30 years. First oil from the project is scheduled for 2022, as the company's oil and gas plays venture north — the Castberg project is at the 72nd parallel.

It's one of over 40 Statoil assets spread across 30 fields on the Norwegian Continental Shelf, which includes the North Sea, Norwegian Sea and Barents Sea. Statoil is responsible for over 70 percent of all oil and gas production on the NCS, and since 2010 has increased its annual investments there by 75 percent.

Statoil's projects play out in other directions too, with 20,000 employees in more than 30 countries. Its portfolio includes a 100,000-bpd oil field offshore Brazil; exploration and development in the Gulf of Mexico from shale and tight rock formations throughout the US. The company manages upstream activities from a base in Houston, and midstream, marketing and trading activities from Stamford, Connecticut, not far from where the company in October named a new wind farm offshore Long Island, New York, the Empire Wind project.

The 79,350-acre (7,372-hectare) site, secured by Statoil in a federal auction in December 2016, has the potential to generate up to 1 gigawatt (GW) of offshore wind power — enough to power about 1 million homes, or the equivalent of the number of homes that could be powered by the company's European wind farms combined.

New York's Clean Energy Standard mandates an increase in the share of renewables in its energy mix to 50 percent by 2030. As part of that effort, Governor Andrew Cuomo recently called for the development of up to 2.4 GW of offshore wind power by 2030.

"Statoil looks forward to working with all stakeholders as we move forward with the job of bringing offshore wind energy to New York," said Statoil's Empire Wind Project Director Christer af Geijerstam.

"We are committed to working with other developers, state officials, unions and the business community to develop a US supply chain for this and other offshore wind projects."

Statoil currently has seven offshore wind projects online or under development in Europe, including the world's first floating offshore wind project in Scotland — "a technology which could prove pivotal in generating offshore wind power for the U.S. west coast and Hawaii," says the company. Statoil also recently announced its first solar investment in the 162-MW Apodi solar asset in Brazil, which will provide approximately 160,000 households with electricity. Another 385-MW wind farm, Arkona, is being constructed in the Baltic Sea by Statoil and Germany's E.ON.

Underwater Factories

But the billions that have long provided the ballast for the Norwegian economy continue to come from the growing clusters of rigs proceeding from Norway's coastline further and further into the Arctic, such as the Johan Castberg. The firm was called "The Norwegian Paradox" by The New York Times last year because of its vaunted clean energy push above-ground while the drilling for oil and gas continues underneath. And even as the nation's $1-trillion investment fund considers a proposal to divest from petroleum companies, the oil and gas work continues.

"This is a great day! We have finally succeeded in realizing the Johan Castberg development," said Margareth Øvrum, Statoil's executive vice president for Technology, Projects and Drilling, in December when the company, along with Eni and Petoro, submitted a PDO (plan for development and operation). "Johan Castberg has brought challenges. The project was not commercially viable due to high capital expenditures of more than NOK 100 billion [US$12.7 billion] and a break-even oil price of more than US$80 per barrel. We have been working hard together with our suppliers and partners, changing the concept and finding new solutions in order to realize the development. Today we are delivering a solid PDO for a field with halved capital expenditures and which will be profitable at oil prices of less than US$35 per barrel."

"Johan Castberg will be the sixth project to come on stream in Northern Norway," added Arne Sigve Nylund, Statoil's executive vice president for Development and Production Norway. "The field will be a backbone of the further development of the oil and gas industry in the North. Infrastructure will also be built in a new area on the Norwegian continental shelf. We know from experience that this will create new development opportunities."

The Johan Castberg field will have a supply and helicopter base in Hammerfest and an operations organization in Harstad. Together with other operators of oil discoveries in the Barents Sea, Statoil is investigating the possibility of finding a profitable oil terminal solution at Veidnes.

Statoil has developed a strong specialist environment in Harstad based on 40 years of experience from operation in the north. Finnmark is another area the company will look to for workforce for the offshore component, which will require 90-100 professionals spread across three shifts.

"To ensure a long-term development of petroleum-related specialist jobs in Finnmark, Statoil will, in collaboration with other operating companies, suppliers and local authorities before the plan for development and operation is submitted to the authorities, look at possible initiatives to upgrade the general petroleum competence level in Hammerfest and Finnmark," said Siri Espedal Kindem, senior vice president for the operations north cluster in Statoil, in December. "In the longer term this will lead to more local recruitment to the industry, and Finnmark may strengthen its position in the technology-driven development of the Barents Sea."

The costs of operating the field are estimated at some NOK 1.15 billion (US$146 billion) per year. "This will represent about 1,700 man-years nationwide, some 500 of which will be located in Northern Norway," said the company, counting both direct and indirect employment effects. The subsea development includes 30 wells, 10 subsea templates and two satellite structures. Aker Solutions will do much of the work. "We are pleased to see that Norwegian suppliers again demonstrate their competitiveness and will play a key role in the development of Johan Castberg. The jobs generated nationwide during the development are estimated at almost 47,000 man-years," Øvrum said.

The Undiscovered

According to the Norwegian Petroleum Directorate and the Norway Ministry of Petroleum and Energy, the Norwegian continental shelf covers an area of 2,039,951 sq. km. (787,625 sq. miles), with oil exploration expanding from the North Sea to the Norwegian Sea and Barents Sea since 1980. "The North Sea is still the powerhouse of the Norwegian petroleum industry with 62 fields in production at the end of 2016," says the directorate. "In addition, there are 16 fields in production in the Norwegian Sea and two (Snøhvit and Goliat) in the Barents Sea."

The Norwegian part of the Barents Sea covers an area of 313,000 sq. km. (120,850 sq. miles), and is the largest sea area on the Norwegian continental shelf. The Barents Sea — home to only the Snøhvit and Goliat fields thus far — is also the sea area with the largest hydrocarbon potential. Only the area south of 74° 30' N is open for petroleum activities.

Currently, gas from Snøhvit is transported by pipeline to the Melkøya onshore facility, where it is processed and cooled down to produce liquefied natural gas (LNG), which is delivered to the markets on special LNG vessels, Statoil explains. "Produced oil and gas from Goliat are transported onto a Floating Production Storage & Offloading (FPSO), where the oil is processed, stabilized and stored for further export in tankers, while the gas is reinjected into the reservoir."

"Most of the Barents Sea is considered to be a frontier petroleum province, even though there have been exploration activities here for more than 30 years, and the first discovery was made in the early 1980s," says the company. "It is estimated that approximately half of the undiscovered resources on the Norwegian continental shelf are in the Barents Sea."

Oil Giants See a Future in Offshore Wind Power. Their Suppliers Are Investing, Too.

Inside Climate News
By Lyndsey Gilpin
January 11, 2018

Transporting an offshore wind array from the factory floor to the ocean floor is no easy feat. Giant, specialized marine vessels must carry the blades and turbines—which sit atop rigs hundreds of feet tall—out miles from shore. Steel or concrete foundations are built to hold them in place, and underwater cables are laid on the seabed to transfer the power to land.

One other industry has spent decades constructing and maintaining such massive energy infrastructure that can survive the storms of the open ocean: oil and gas. Now, with global demand for wind power growing, major oil and gas companies like Shell and Statoil are diversifying their portfolios by developing offshore wind, and the companies that provide services to offshore fossil fuel platforms are seeing a new market rising in their wake.

"Offshore wind developing seemed like a natural skill set for offshore oil and gas companies," said Stephen Bull, senior vice president of wind and carbon capture storage for Statoil, a Norwegian oil and gas company. "From the Gulf of Mexico to Brazil and beyond, we see a similar supply chain and skill set and can grow within this area."

Statoil, which is building the world's first floating wind farm near Scotland, is planning development for its first offshore wind lease in the U.S., an 80,000-acre area off the coast of New York that could generate more than a gigawatt of power. Ørsted (formerly DONG Energy, short for Danish Oil and Natural Gas), has a 1.3 gigawatt wind farm under construction off the UK and is exploring developments off Massachusetts and New Jersey. Shell is leading the development of two wind farms in the Dutch North Sea.

Globally, 17.6 gigawatts of wind power capacity have been installed offshore, with most of it in Europe, and the industry is growing. Bloomberg New Energy Finance raised its offshore wind forecast this week, with an expectation that it will reach 115 gigawatts worldwide by 2030.

The U.S. market, however, has gotten off to a slow start.

Cape Wind, a large-scale offshore wind project planned near Massachusetts, was officially killed late last year, leaving only one small working offshore wind farm in the U.S., and 13 offshore leases from Massachusetts to North Carolina, according to the Bureau of Ocean and Energy Management (BOEM). Other projects are in various stages in the South Atlantic and Pacific Ocean.

According to a 2017 Wood Mackenzie study, annual revenues from wind and solar could represent one-twelfth of the revenues in oil and gas by 2035. As major global oil and gas companies and supply chain companies are moving into the offshore wind game, the market is ripe for large-scale projects that could not only generate more wind power in the U.S. but bring costs down and create jobs in local communities.

"Building on the success of the oil and gas industry and their work in the open ocean for several decades now, we think it's a great business opportunity for them," said Nancy Sopko, director of offshore wind and federal legislative affairs at the American Wind Energy Association. "And it's a great starting point for offshore wind to utilize the skilled workers, infrastructures, the vessels and the body of expertise that comes from oil and gas to catapult another new ocean industry resource."

Using Oil and Gas Industry Strengths

Just south of Rhode Island, the only working offshore wind farm in the U.S. has been successfully supplying power from five turbines to about 2,000 customers for just over a year. Years ago, Europe started with small projects like that, Bull said. But as oil and gas giants entered the market, they have been able to take on larger projects that generate more electricity. Since then, Europe has become the world leader in offshore wind, with about 13 gigawatts installed and more in the works.

"What we see now has scaled dramatically on the industrial level—turbines are much larger and farther from shore to capture better resources," Bull said. "Oil and gas companies are used to carrying that kind of investment."

Oil and gas supply chain companies are also getting into the market.

Gulf Island Fabrication, based in southern Louisiana, manufacturers foundations for offshore oil rigs—and for offshore wind turbines. The company built foundations modeled after oil platforms for the Block Island Wind Farm.

The Houston-based engineering firm Zentech, which specializes in rig platforms and offshore oil drilling and construction vessels, announced plans this summer to tackle another hurdle facing the wind industry: with Renewable Energy Resources International of Virginia, the company is building the first U.S. offshore wind-turbine installation vessel. Under the Jones Act, only U.S.-built, U.S.-based ships with U.S. crews can carry goods between U.S. ports. When the Block Island Wind Farm was built, a European ship had to be used, and it wasn't allowed to dock in the U.S. before delivering supplies. After some "fine-tuning" of the designs, the new U.S. vessel is on track to be completed by mid-2019, Zentech Vice President Sundaram Srinivasan said.

The wind industry provides an opportunity for companies to reinvent themselves and diversify, Bull said, and for employees to find work in a new market. "These workers have been building things for open ocean use for decades," he said, adding that he's hoping American offshore oil supply chain companies will get into the offshore wind industry to help create local jobs.

"That will be essential for us to win the hearts and minds, not just with politicians, but with local people," he said.

Statoil is interested in utilizing the oil and gas supply chain along the Gulf Coast to build foundations, vessels and turbines, and using port authorities in New Jersey and New York and other local vendors to help with the New York project.

"It's a true redeployment of the American workforce," Sopko said. "It will create great-paying jobs and increased energy independence and attract investment in infrastructure and manufacturing."

Streamlining the Process

There has been a surge in demand for offshore wind from many coastal states, with about 14 gigawatts of leased wind energy area capacity in the Northeast alone. Several states have set goals for offshore wind power:

- New Jersey's incoming governor has pledged 3.5 gigawatts by 2030.
- New York's governor has a goal of 2.4 gigawatts by 2030.
- Massachusetts is calling for 1.6 gigawatts by 2027.

California has been pushing for offshore wind, too. Floating wind farms, which are now being tested off Europe, have more potential near California and Hawaii, where the seafloor drops off quickly, Bull said.

But an offshore wind project can take up to a decade to complete. After the long bidding process, it takes time to choose and assess a site, figure out financing, and do an environmental impact analysis—all before a developer begins construction.

"The key thing about renewables is that we need and want to develop as fast as we can but the regulatory process stops it for so many years," Bull said.

There are ways to streamline the process at the federal level, Sopko said, and AWEA has been lobbying the Department of Interior and BOEM to do so. For instance, she said, a floating wind farm doesn't have the same environmental impacts as one on the seafloor, so it shouldn't be held to the same environmental assessment requirements.

"That could shave two years off process for a developer," Sopko said, "which is going to keep attracting investment."

There are also hold-ups at the state level, where some lawmakers and communities have pushed back against offshore projects. Along the East Coast, fishermen groups are fighting plans for offshore wind projects; Cape Wind was set back for years because of political opposition from the Kennedy and Koch families.

"Each developer must demonstrate safe and responsible development plans to the regulators as well as to a plethora of other agencies and local stakeholders," said Walt Musial, manager of offshore wind at the National Renewable Energy Laboratory.

However, as those processes are smoothed out and fossil fuel companies scale up offshore wind projects, he said, the costs will likely come down. "The oil and gas industry is in an excellent position to capitalize on this nascent industry," Musial said. "It possesses the skills and know-how to step into this business, which could see revenues of well over $20 billion in the next decade."

The Wave

Dancing With The Wind

The Wave
By Ralph Mancini
October 4, 2018

A Thursday, Sept. 27 presentation on the part of New York State Research and Development Authority (NYSERDA) representatives offered lots of sizzle, but a scarcity of concrete plans for wind energy supporters to sink their teeth into.

Though the information session provided a glowing report of the host of environmental and economic benefits that could result from the development of renewable offshore wind energy, agency experts were unable to communicate a firm date for its implementation with proposed siting areas awaiting state and federal approval.

In fact, during a half-hour Q&A period following the walkthrough of NYSERDA's Offshore Wind Master Plan, one spokesperson claimed that it wouldn't be until sometime in the mid-2020's at the "earliest" before the installation of any turbines and/or any other steel components would break ground.

"Our Clean Energy Standard mandate requires that 50-percent of our energy come from renewables by 2030, which is very substantial [and] one of the leading commitments to renewables in the nation," said NYSERDA's Director of Large-Scale Renewables Doreen Harris.

"It's accompanied by an equally aggressive goal of offshore wind development. New York State's goal of 2,400 megawatts of offshore wind by 2030, which places us in a position of leadership in advancing what we believe is a resource that can not only benefit New Yorkers from an environmental perspective, but from an economic perspective as well."

NYSERDA's Principal Engineer for Offshore Wind Adrienne Downey detailed a few of the environmental dividends of achieving the state's wind energy goal, including the reduction of greenhouse gas emissions by more than five million tons, which she estimated to be tantamount to removing about one million cars from the road.

Improved air quality, she added, would result in 8 to 18 fewer premature deaths annually.

As for the economic rewards, she cited the Workforce Opportunity of Offshore Wind in New York study, which forecasts that the state would benefit from more than $6 billion in investments and approximately 5,000 new jobs in installation, operations, maintenance and manufacturing.

Joining Downey to touch on NYSERDA's public engagement and outreach efforts was Greg Lampman, the group's program manager for its environmental research program, as he recounted how he and his colleagues have met with several fishing organizations to understand what their concerns are.

"We've been developing a commercial recreational fishing technical working group, the core of which is going to be comprised of fishing organizations. They represent the regional states of Massachusetts, Rhode Island, New Jersey and New York and we're working with that group to expand that list to include more," informed Lampman.

Prior to NYSERDA's master plan presentation, The Wave spoke to Julia Bovey, a corporate rep from Equinor U.S. Wind (a Norway-based wind energy provider, formerly known as Statoil, that will be bidding into the procurements of local offshore wind projects) on the subject of the impacts of wind power infrastructure on the fishing industry.

The external affairs director stated that the American Wind Energy Association has spoken to numerous fishermen who ply their craft in the surrounding waters of Block Island (the location of the first offshore wind farm in the United States) who "seem happy" with the work done by Deepwater Wind to complete the steel construction and turbine installation.

"They can fish right up to the turbines…and there's certainly fears in the fishing community that their access will be restricted, but the plan is it absolutely not be. We don't even have the right to restrict their access. During construction, if there's a safety issue, that's one thing, but once the project is up and operating, anyone with a boat can [fish]," she said.

Currently, New York State is proposing six sites along the northern east coast as existing lease areas for offshore wind, including three in New England, one off the coast of New Jersey and one in the New York City area.

The Bureau of Ocean Energy Management (BOEM), an agency within the United States Department of the Interior, is reportedly considering siting areas that go beyond New York State's recommended locations.

While many local activists, such as John Cori of the Rockaway Beach Civic Association, JK Canepa of Sane Energy and Joan Flynn of the Rockaway Women for Progress among others, have fully endorsed the move to wind energy, others had questions about the number of ways the Rockaway peninsula could be affected by an advent of wind farms.

Animal communicator Jill Lauri, in particular, voiced her quality-of-life concerns for the Rockaway community when asking if her hometown's "laid back" character would change with all the incoming economic activity that will be one of the byproducts of offshore wind infrastructure once it's in full operation.

"I think it's important to note also that any siting of activity here in the Rockaways, where the intention would be to bring jobs and to bring economic activity into the region, would also likely go through rounds of local permitting certainly," replied NYSERDA Technical Advisor Matt Vestal. "I think that effectively what I'm telling you is before any type of facility is placed locally, there would be additional engagement with the local community to ensure that it is in alignment with the ambitions of the people who live here."

Similarly, Rockaway Waterfront Alliance's Director of Planning and Development Ana Fisyak expressed her own set of apprehensions about New York State's bold energy agenda, as she implored the guest speakers to expound on the windmill components in terms of where they'll be produced, their life cycle, maintenance and disposal plan when parts will eventually have to be replaced.

Vestal and BOEM Energy Program Specialist Luke Feinberg tackled the issue with the former mentioning that the offshore wind industry is grounded in Europe, but predicted that the "seismic shift" in the attention that the renewable energy source is gaining in the U.S. will soon lead to the domestic manufacturing of infrastructure components.

Feinberg, on the other hand, addressed the other topics by conceding that there would certainly be oil lubricants involved in the process of maintaining and operating a wind farm, but noted that the federal government has no jurisdiction over the equipment and/or materials used by providers.

"If they need to change a blade, for example, that's not something that I'm aware of that we would play a part in," he said.

In addition, Feinberg offered insight on leasing agreements with wind energy developers by pointing out that as the landlord of the siting areas that will be selected, BOEM requires stipulations and regulation in their leases that mandate everything be restored to the original conditions after the expiration of their lease agreements.

"If we grant a lease to a project and it's installed, if for some reason, the developer is not able to live out the entirety of that lease, the taxpayer is not stuck with the liability of deconstructing it," he said.

YaleEnvironment360

After an Uncertain Start, U.S. Offshore Wind Is Powering Up

Yale Environment 360
By Roger Drouin
January 11, 2018

This summer, the Norwegian energy company, Statoil, will send a vessel to survey a triangular slice of federal waters about 15 miles south of Long Island, where the company is planning to construct a wind farm that could generate up to 1.5 gigawatts of electricity for New York City and Long Island — enough to power roughly 1 million homes.

Construction on the "Empire Wind" project, with scores of wind turbines generating electricity across 79,000 acres of leased federal waters, is scheduled to begin in 2023, with construction completed in 2025.

Farther south, 27 miles off the coast of Kitty Hawk, North Carolina, Avangrid Renewables, an Oregon-based company, has already begun planning for a major wind energy farm on 122,000 acres of federal waters, a project that could eventually generate 1.5 gigawatts of electricity.

And about 10 miles off the New Jersey coast, between Atlantic City and Cape May, Danish clean-energy giant Ørsted, which has a large portfolio of offshore wind farms across Europe, is talking with local officials, securing state permits, and doing seafloor surveys on a 160,000-acre site, where it plans to build its 1–gigawatt Ocean Wind project. Company officials say they are hopeful that the wind farm will come online between 2020 and 2025.

After years of false starts and delays, the offshore wind industry in the United States finally seems to be gaining some momentum. Although far behind the burgeoning offshore wind energy industry in Europe, companies such as Statoil, Avangrid, and Ørsted are joining other wind energy developers — both from the U.S. and Europe— to pursue a slate of projects along the U.S. coast.

According to the U.S. Department of Energy, more than 25 offshore wind projects with a generating capacity of 24 gigawatts are now being planned, mainly off the U.S. Northeast and mid-Atlantic coasts. And although some of these projects may not be built, and only one commercial offshore wind farm has actually been constructed —the tiny, five-turbine "Block Island Wind" project off Rhode Island — analysts say that U.S. offshore wind is expected to enjoy significant growth in the coming decade.

"The real nuts-and-bolts of making this industry happen are going to come together in 2018," says Stephanie McClellan, director of the University of Delaware's Special Initiative on Offshore Wind.

Several key factors are driving the long-awaited takeoff of U.S. offshore wind: Sophisticated turbine technologies and economies of scale are driving down costs; advances in construction are allowing wind farms to be built in deeper water farther offshore, significantly lessening the public's concern about seeing turbines close to the coast; states across the Northeast and the mid-Atlantic, as well as California and Hawaii, are pushing development of offshore wind projects; and some European wind turbine manufacturers, as well as several U.S. firms, have decided to locate research, development, and wind turbine production facilities in the U.S.

And to the surprise of some companies and renewable energy analysts, the Trump administration — which has aggressively promoted the development of fossil fuels over renewable energy — seems to be supporting the offshore wind energy sector.

Interior Secretary Ryan Zinke, whose department oversees the federal Bureau of Ocean Energy Management, endorsed offshore wind in his proposed fiscal year 2018 budget and praised the leasing of federal waters to Avangrid for the Kitty Hawk project as a "big win." In December, U.S. Secretary of Energy Rick Perry announced the creation of a consortium to develop innovative offshore wind technologies. Ninety percent of the announced $18.5 million in federal funding for the consortium will go to research and development, largely to decrease turbine costs and improve turbine efficiency.

President Trump, who once disparaged many aspects of wind power, could still decide to throw up roadblocks to the offshore wind industry. But for now, analysts are cautiously optimistic about the sector's prospects, especially since Congress's recently passed tax reform bill preserves tax credits for the wind energy industry for several more years.

Bruce Hamilton, director of energy practice at the consulting firm Navigant, has been skeptical of the prospects for U.S. offshore wind energy, in large measure because establishing wind farms offshore has been far more expensive than building onshore facilities. But he now sees encouraging signs of life in the sector, as offshore wind costs have fallen substantially. "European developers, major companies, are interested in participating, and that is telling," says Hamilton.

Stephen Bull, Statoil's senior vice president for offshore wind, told *The Wall Street Journal* last year, "We have done this in Europe, and we have absolutely the same opportunity in the U.S."

Europe now has a total installed offshore wind capacity of more than 12,600 megawatts (12.6 gigawatts), generated by 3,589 grid-connected wind turbines in 10 countries. The U.K. is the world's most developed offshore wind market and accounts for about 36 percent of installed capacity, followed by Germany in the second spot, with 29 percent, according to the Global Wind Energy Council. In 2016, China passed Denmark to achieve third place in the offshore rankings with 11 percent. Denmark, now in fourth place, accounts for 8.8 percent of installed global offshore wind capacity. The Netherlands has 7.8 percent, Belgium 5 percent, and Sweden 1.4 percent.

The capital costs of offshore wind generation in Europe are falling sharply, from $3.8 million per megawatt of electricity in 2016, to $2.2 million per megawatt at the end of 2017. The primary driver for these reductions is the increase in turbine capacity, and this ongoing advancement in turbine and platform technology will continue to drive down the cost of offshore wind, according to Hamilton.

"It is incredible how much the costs per megawatt [for offshore wind-generated electricity] have dropped this year alone in Europe," says Hamilton. "As a result, two projects were bid with zero subsidies that will be built in the mid-[20]20s. That kind of cost improvement will come here, too."

The nascent offshore wind energy sector in the U.S., at least initially, is expected to produce more expensive electricity. According to the U.S. Energy Information Administration, the projected cost of electricity per megawatt-hour in the U.S. in 2022 will be $140 for coal, $110 for natural gas, and $157 for offshore wind — excluding any tax credits, which boost wind power's competitiveness.

Laura Beane, the CEO of Avangrid Renewables, which is the developer of the Kitty Hawk wind project, says the offshore industry has been preparing to move ahead with offshore wind growth without incentives, such as the federal Production Tax Credit, which is scheduled to be phased out over the next three years under the 2017 federal tax overhaul. Yet Beane says the offshore wind industry is aiming to soon produce electricity at a cost equal to, or lower than, coal or natural gas.

Offshore wind turbines and other components are primarily being produced in Europe and China — with the notable exception of G.E. Renewable Energy, the U.S. turbine manufacturing leader, which has facilities in South Carolina, Florida, and California.

But some companies are beginning to develop advanced offshore wind power technologies in the U.S. For instance, Louisiana-based Keystone Engineering is experimenting with the newest platform foundations designed to anchor turbines at U.S. offshore wind farm sites. The company, rooted in the oil and gas industry, has designed a structure called the "Twisted Jacket" foundation that reduces costs and storm risk compared to other foundations.

Other companies in Texas, Louisiana, and South Carolina are already interested in participating in the new offshore wind industry, according to James F. Manwell, director of the Wind Energy Center at the University of Massachusetts, Amherst. Furthermore, a Denmark-based turbine maker, MHI Vestas, is developing a groundbreaking 9.5-megawatt turbine — reportedly the world's most powerful — in South Carolina at Clemson University. This powerhouse prototype would likely be used in the first batch of large offshore wind projects built in the U.S., and according to the University of Delaware's McClellan, the South Carolina facility is an important sign that the offshore wind industry is poised for steady growth in America.

Meanwhile, numerous states — including New York, New Jersey, Massachusetts, Delaware, Maryland, Rhode Island, Hawaii, and California — are moving aggressively to develop offshore wind projects:

In New York, the state's Clean Energy Standard mandates a significant increase in the share of renewables in its energy mix. As part of that effort, Governor Andrew Cuomo has called for up to 2.4 gigawatts of offshore wind power by 2030, a move that helps create a reliable market for offshore wind-generated power, says Statoil's Empire Wind project director, Christer af Geijerstam.

In New Jersey, Democratic Governor-elect Phil Murphy has proposed a strong plan to advance offshore wind initiatives sidelined during the tenure of his predecessor, Republican Chris Christie. During his campaign, Murphy, who takes office January 16, called for developing "the most ambitious offshore wind target in the country" and promised to bring 3.5 gigawatts of offshore wind to the state by 2030.

Last May, Maryland utility regulators approved two offshore wind farm projects, to be constructed respectively by U.S. Wind and Deepwater Wind, the developer of Block Island Wind. State utility regulators have approved subsidies for these projects.

In Massachusetts, where the controversial Cape Wind project in Nantucket Sound was recently abandoned, the state has been actively trying to develop offshore wind projects. About 15 miles off Martha's Vineyard, Avangrid, in partnership with Copenhagen Infrastructure Partners, is vying for another federal lease. The state of Massachusetts is requesting utility providers to submit proposals to purchase power from the project, which will be connected to the mainland via buried transmission lines. Massachusetts and Rhode Island have both passed laws that require utilities to enter into long-term contracts, known as power purchase agreements, with economically competitive offshore wind projects. In California and Hawaii, efforts are now underway to identify the best locations for offshore wind farms. Statoil is marketing its floating wind turbine technology — already in use globally — to both states. Hawaii is eyeing offshore wind as part of its effort to power the island with 100 percent clean energy by 2045.

Although exploratory at this time, the Gulf of Mexico is an area of interest for offshore wind development because of the design, infrastructure, and workforce synergies between offshore wind and the Gulf's oil and gas industry. The region has less-powerful winds than the Atlantic, but it offers a number of advantages for offshore wind, including shallow water that makes turbine installation easier and higher accessibility because of close proximity to existing offshore oil and gas infrastructure.

The Trump administration's policies on energy and utilities have the potential to impact offshore wind. For instance, Energy Secretary Perry recently put forth a measure that would have tipped U.S. electricity markets in favor of coal and nuclear power by subsidizing struggling coal and nuclear plants. But this week, the Federal Energy Regulatory Commission, which oversees those markets, rejected Perry's proposal.

Offshore wind proponents remain cautiously hopeful that Trump, as well as Republican governors in coastal states, will warm to what they see as the immense potential of offshore wind-generated electricity. "There is an opportunity to create a new American heavy industry," says McClellan.

Running With The Wind

The Wave
By Ralph Mancini
February 15, 2018

In its ongoing mission to promote sustainable power sources on the Rockaway peninsula and beyond, the Sane Energy Project (SEP) recently hosted an information session that saw the group sing the virtues of building a wind farm along local shores to replace hazardous fossil-fuel methods.

Renewable energy advocates Kim Fraczek and JK Canepa appeared at the Challenge Preparatory Academy's Central Avenue campus on Feb. 9 to fill in community members on their partnership with the New York State Energy Research and Development Authority (NYSERDA) to lay the groundwork for the installation of wind turbines on Rockaway's coastal waters.

Fraczek detailed a commitment on the part of Gov. Andrew Cuomo to procure two separate 400 milliwatt installments of offshore wind in 2018 and 2019 in his effort to make New York an increasingly renewable state.

"The process is going to get started this year. Right now, we're doing a big study of this area. We know we can do better than fossil fuels. We need to move into the future and New York is poised to be a leader," said Fraczek.

The Brooklyn-based activist referenced a wind-energy pilot project that was recently developed and currently in service on Block Island, located just south of mainland Rhode Island, as evidence that this alternative power source is indeed viable.

She stated that five turbines are supplying the entire island area that is no longer using diesel generators that have since been placed out of commission.

In addition to highlighting the fact that wind energy doesn't pollute the air like traditional power plants that continue to rely on fossil fuels, such as coal and natural gas, the speaker touched on the economic benefits of the sustainable power option in the form of jobs.

"We want to make sure there are jobs created right here. We want to [secure] the $15 million Gov. Cuomo has promised for those offshore wind farms right here on the Rockaway peninsula. This is a frontline community of this offshore wind farm."

However, it was noted that that SEP's affiliation with the international energy firm Statoil will be key in converting the environmental coalition's vision into a reality. Statoil's commitment to opening new renewable energy opportunities, according to Fraczek, would provide the necessary training to allow individuals to switch careers and enter the wind power industry.

The Wave caught up with Fraczek and Canepa after the meeting to ask about how wind-generated energy would impact residents in terms of their monthly dues; they replied that it's too early to forecast any kind of rate decrease. So, while wind power is inherently cost-effective, the "system" is currently stacked in favor of nuclear and fossil fuel sources that are extending public subsidies, as per Fraczek.

“We are actively working on esoteric policy with the Public Service Commission to have renewable energy benefit low to moderate income New Yorkers. Cuomo needs to hear from the people that we won’t stand for it anymore, as he controls the PSC,” indicated Fraczek in a subsequent email. “We have a big fight ahead of us and need all hands on deck to make sure the renewable revolution functions in favor of the people and no longer the corporate model.”

In the meantime, SEP is leading the fight to oppose a request submitted to the Federal Energy Regulatory Commission (FERC) by The Williams Companies to install a 23-foot pipeline transporting fracked natural gas from a compressor station in York County, Pennsylvania through the waters of Rockaway and into additional valves and facilities along the east coast.

The new pipeline would reportedly feed into the Rockaway pipeline which travels under the Gateway National Park through Jamaica Bay and into Floyd Bennett Field, where it would then be metered back onto Flatbush Avenue and into the National Grid network.

Canepa encouraged those protesting the plan, also known as the Northeast Supply Enhancement Project (NSEP), to register with FERC and become intervenors, which would empower them to develop a stronger stance on the issue and subsequently comment on it. The steps require that individuals create an account at ferc.gov/multimedia/efile.asp and visit ferconline.ferc.gov/FERCOnline.aspx to file their concerns.

Forbes

New York Is Moving Aggressively To Harvest Its Offshore Wind

Forbes
By Peter Kelly-Detwiler
March 9, 2018

The East Coast of the United States is about to become a major offshore wind hub, with 7,500 megawatts (MW) being committed by Massachusetts (1,600 MW), New York (2,400 MW), and New Jersey (3,500 MW). Other states such as Connecticut, Maryland, and Rhode Island are likely to get into the game as well.

For years, the harvest of this resource seemed somewhat of a pipe dream, especially as observers watched the lengthy, contentious, and ultimately unsuccessful travails of Cape Wind. All that seemed to change once Deepwater Wind successfully installed its 30 MW project off Block Island. Suddenly, these projects began to look a lot more feasible. In fact, within a few short years, the East Coast of the United States may find itself a bustling hub for offshore wind development, much the same way the European countries around the North Sea – with over 11,000 MW of offshore wind installed – are today.

A conversation with NYSERDA's CEO Alicia Barton: the role of NYSERDA

Of the states with articulated offshore targets, none is moving faster than New York State. In his 2018 State of the State address, Governor Cuomo set a goal of procuring no less than 800 MW of offshore wind in two solicitations this year and next.

In an effort to better understand the implications of this commitment, and the potential of offshore wind for the Empire State, I lined up a conversation with Alicia Barton, president and CEO of the New York State Energy Research and Development Authority (NYSERDA). Barton is quite familiar with the issues at hand: some years ago she was CEO of the Massachusetts Clean Energy Center when the Commonwealth was architecting its initial plans for developing the offshore wind resource.

Barton noted that while the near-term 800 MW goal is going to require a concerted effort, New York has actually been preparing for this for many years. Her agency has helped lay the groundwork for this effort, coordinating a 'War and Peace' length Master Plan complete with 20 supporting studies. These cover everything from the obvious impacts on wildlife, commercial fisheries and navigation, to the assessment of ports and infrastructure capable of supporting these massive projects, and the economic impacts of developing the wind resource. The studies also examine some perhaps less obvious areas including cultural resources (such as shipwrecks and underwater archaeological sites) to the impact on potential future underwater sand and gravel mining sites (an $8.2 bn U.S. industry). In other words, they have tried to thoroughly address all possible relevant aspects of the proposed projects.

NYSERDA has many responsibilities related to promoting energy efficiency and renewables, but the offshore wind challenge is one of the bigger ones. Here, its main job is to move the process along and coordinate the alphabet soup of agencies that are tasked with supporting and regulating these complex projects. Barton's goal for the state is to help make it a leader, "positioning ourselves at the forefront of an industry that is taking shape in the United States" and observes that the Master Plan is "the most comprehensive effort any state has taken to date in looking at offshore wind across the board in terms of siting cost, economic development and workforce needs."

East Coast commitments will create industries and drive economies of scale Barton is optimistic that the combined commitments of the East Coast states will lead to economies of scale that will drive costs down, and she points to Europe, where thousands of megawatts of projects have helped create a supply chain that has created numerous efficiencies and lower costs.

That's a big part of what gives us confidence that this is a good investment for NY State. Those rapid cost declines in Europe. The U.K. auction last fall with prices at half what they were two years prior is very heartening about the industry's ability to deliver a cost-effective resource.

Those cost declines follow an increasingly positive trend: according to Wind Europe, the December 2013 levelized costs of European offshore wind energy were €140 (roughly $174 U.S., as of this writing). By late 2016, they had plummeted to €40 ($49.60).

NYSERDA's CEO sees similar dynamics eventually coming into play in the United States, once the commitment is large enough and the supply chain migrates from Europe to the U.S. In NYSERDA's analysis, she observes, we concluded that over the course of that 2,400 MW and the time horizon between now and 2030, we would expect offshore wind to be cost-competitive with land-based renewables. We see offshore wind as being cost-competitive with onshore wind in the U.S. based on the experience in Europe.

As far as the size of the commitment necessary to create a robust and cost-competitive supply chain on the East Coast, Barton indicates that it could be around 1,000 MW although different suppliers give different numbers. But with many of the East Coast states in the offshore game, we will see economies of scale…collectively we have 7,500 MW of commitments, which means we will be much better positioned to optimize the supply chain and bolster the ability of domestic businesses to collaborate.

The big developers have signaled interest, and they will deploy massive machines

As of the end of 2017, Europe boasted nearly 16,000 MW of offshore wind. So 7,500 MW of East Coast offshore wind is a pretty attractive prize. As a result, Barton indicates, all of the major players are eyeing the potential, evaluating the opportunity, and communicating with NYSERDA.

"We engage all developers, and those that hold leases in particular, whether Statoil, Deepwater Wind, Orsted, or Copenhagen Offshore Wind. We have engaged with all those folks, and we see a robust appetite from other European companies that don't hold leases to seek leases from the government."

These include major enterprises such as Shell and BP, as well as U.S. companies like Avangrid (the latter holds a lease off North Carolina).

These companies are quite comfortable in the world of big money, complex undertakings, and big machines. They will need to be: Barton indicates NYSERDA made assumptions for their cost analysis that turbines would be in the 8 MW range (those machines have started going into European projects over the past year and will soon be commonplace). Indeed, this assumption may turn out to be modest: just this month GE announced a 12 MW turbine for offshore deployments, expected to hit the market in 2021. It may be too late to be included in the earliest offshore projects, but GE has indicated it is eyeing the East Coast as a market for this new machine.

This is all good news for Barton, who notes that “As those machines get bigger, as we expect they will, costs will come down faster than they otherwise would.”

The next moves to getting turbines on the water

The next steps, Barton indicates, have to do with actual procurement, and they must happen soon to meet the Governor’s near term goals.

We need to procure no less than 800 MW in 2018/19 to send a signal that NY is serious about moving ahead. Now we have to figure out what’s the mechanism for procurement… That’s where the policy discussion is and where the workflows for New York and NYSERDA will be.

This process will involve a technical conference, followed by requests for public comments from the Public Service Commission (PSC), ultimately leading to a PSC decision later in 2018 that will specify how to move forward. The process may likely involve NYSERDA, since the agency manages solicitations for other large-scale renewables.

Led by NYSERDA, the state will also continue to evaluate the capabilities of its ports and existing industries. These ports may include not only the obvious ones like those in New York City, but also other facilities further up the Hudson River. Some are already being used for staging of large infrastructure projects like the new Tappan Zee Bridge and may be adapted for the offshore wind endeavor.

Ultimately, Barton concludes, the East Coast is likely to be one of the next big global frontiers for wind energy. Given the size of the prize and the implications for both the State’s ambitious clean energy goals and its long-term economic development, it’s important to get this right. “We concluded this is a pretty substantial opportunity for the State, with up to 5,000 jobs and $6 billion in investment.”

E&E NEWS

U.S. can replicate Europe's wind build-out, executives say

E&E News
By Saqib Rahim
March 28, 2018

The CEO of a U.S. offshore wind company says project costs in America could one day approach the low costs seen in Europe.

It just takes three things, said Deepwater Wind CEO Jeff Grybowski: "projects, projects and projects."

Speaking at an energy conference in New York City, Grybowski, whose company has built the only offshore wind farm in the United States to date, lauded the states trying to hurry up and build projects. He said that's the same way solar and onshore wind slid down the cost curve.

"There's no reason that offshore wind is going to have any different of a story," he said on a panel at the Advanced Energy Conference. "There's no reason why offshore wind ought to be really cheap in Europe and not so cheap in the United States. There's no magic here the U.S. can't replicate."

"What will get us there? It's not engineering; that's not the issue. It's projects," he said.

Grybowski's European rivals agree. "The fundamentals are as good here in the Northeast as anywhere in the world," said Lars Thaaning Pedersen, an executive with Copenhagen Infrastructure Partners who heads up its North American offshore wind portfolio. He estimated the United States could approach European project costs in the next decade.

The comments came as policymakers prepare policies that could establish offshore wind as a utility-scale energy resource in the next few decades.

So far, only one project, a five-turbine installation off Rhode Island, exists in the United States. With that demonstration-scale achievement, policymakers in Maryland, Massachusetts, New Jersey and New York are advancing policies meant to erect wind farms in the hundreds of megawatts. By some estimates, their current commitments add up to a 4-gigawatt "pipeline" of projects.

Europe has built 15.8 GW to date. Grybowski, and his European competitors now eyeing the U.S. market, are trying to persuade policymakers that the bigger they go, the bigger the benefits will be, in terms of both project costs and job creation.

"It's basically the amount of projects that's going to determine how much supply chain you're going to get in the U.S.," said Christer af Geijerstam, project director for Statoil ASA's proposed project off New York. "So if the supplier sees a pipeline of, say, 10 GW of projects in the next X number of years, they can make the investment to put manufacturing capabilities in the U.S."

For now, states are tiptoeing carefully at the top of the cost curve.

Maryland regulators have awarded subsidies to 368 megawatts of offshore wind projects, expecting them to be up and running by 2022. Last year, Massachusetts held its first solicitation for projects going toward its 1,600-MW mandate. New York hopes to launch an 800-MW solicitation by next year. New Jersey regulators are currently designing an 1,100-MW solicitation.

One key issue is financing. Developers say they cannot build offshore wind without some form of state support, but states have been wary of overpaying. Officials are exploring creative financing tools that can get the maximum projects built but with minimum ratepayer ask.

Grybowski is a fan of power purchase agreements (PPAs), long-term contracts for power, because it's the gold standard in the electricity industry and is easy to finance.

Maryland and New Jersey have so far favored the OREC, or offshore renewable energy credit — a direct subsidy to the project developer. For the projects awarded in Maryland, an OREC is worth $131.93 per megawatt-hour, for 20 years.

But as Grybowski said, and his competitors agreed, coming up with the precise financing tool isn't the most pressing issue before U.S. policymakers. It's putting up windmills.

New York regulators currently have seven financing options before them, and they're taking public comments on each. But time is of the essence; the state's goal is to launch its first-ever offshore wind solicitation by the end of this year.

Speaking at the conference, one state official said the Public Service Commission may prefer the ORECs now and another tool later.

"It's unlikely that the commission will pursue a PPA at this point for phase one," said Thomas Rienzo, a staffer at the state's Department of Public Service. "This is very time-sensitive, and we don't want to propose an option that's going to be challenged in court."

WORKBOAT

New York City to reactivate South Brooklyn Marine Terminal

Work Boat
By Kirk Moore
May 14, 2018

A 64.5-acre block at the South Brooklyn Marine Terminal is being reactivated, as the first step in what New York City officials say will be a new cluster of maritime activity and waterfront industry.

More than 250 jobs are expected in the near term as the city's selected Brooklyn-based property operators, Red Hook Container Terminal and Industry City, open up what's being dubbed the Sustainable South Brooklyn Marine Terminal, according to the city Economic Development Corporation.

With a long-term lease through 2054, operators will move over 900,000 metric tons of material annually through the port, including waste paper recycling and export, lumber imports, salt and aggregate material. South Brooklyn will also become a new hub for the same kind of container-on-barge (COB) operations that Red Hook Container Terminal now hosts at its namesake Brooklyn location to the north. RHCT will be the new terminal operator and stevedore.

The 72-acre South Brooklyn terminal has lain fallow for too long, and "our partnership with Industry City and NYCEDC will transform the terminal into a vibrant cluster of industrial maritime activity over the coming decades," said Mike Stamatis, RHCT president and CEO, in a joint statement with the EDC.

The Economic Development Corporation worked with the neighborhood Sunset Park Task Force and other local Brooklyn leaders on revitalizing the terminal, with the goal of maintaining its industrial waterfront and creating good-paying maritime jobs. Gentrification is a major issue in the borough, driving up housing costs and converting what once were job-generating business locations.

"New York City's working waterfront has long been a source of economic vitality, fueling industries and good-paying careers for over a century. Sustainable South Brooklyn Marine Terminal will build on that legacy to advance the future of the New York Harbor," said James Patchett, the EDC president and CEO.

So far the city has spent $115 million to upgrade the South Brooklyn property, including improved rail connections. Goals include making it the one location on the east side of New York Harbor that can accommodate deep-draft bluewater cargo vessels, and using its container-on-barge capacity to help reduce truck traffic, congestion and air pollution on the port's crowded highways.

"By reducing the use of trucks for long-haul movement of freight and moving cargo across water, we can reduce emissions, while helping diminish traffic congestion on local highways and bridges," said Rep. Nydia M. Velázquez, D- N.Y.

South Brooklyn is also a potential future hub for building and servicing offshore wind energy arrays, which would bring in a whole new industrial base, Velázquez said. One of the first planned wind turbine developments is Statoil's Empire Wind project just outside the harbor approaches, and New York State energy planners say there could be 2.4 gigawatts of energy coming from offshore wind by the 2030s.

"Establishing a home for the emerging offshore wind industry on our working waterfront is a once-in-a-generation opportunity," said Ben Margolis, executive director of the Southwest Brooklyn Industrial Development Corporation.

WORKBOAT

Washington must come to grips with offshore wind conflicts

Work Boat
By Kirk Moore
May 16, 2018

Offshore wind energy developers have momentum building for them in East Coast waters. But other maritime industries want to ease up on the throttle.

The federal Bureau of Ocean Energy Management recently held another round of public meetings in New Jersey and New York, gathering information for what could be a future round of lease offerings in the New York Bight. Secretary of Interior Ryan Zinke has promised to help fast track future permitting.

Already Statoil has plans for its Empire Wind turbine array, tucked into a 79,350-acre federal lease near the apex of ship traffic separation lanes near the entrance to New York Harbor. That could mean a lot of new maritime jobs, along with a new kind of navigational risk.

The Maritime Association of the Port of New York and New Jersey supports renewable energy, said Edward Kelly, the association's executive director, at a May 9 meeting BOEM hosted in Newark, N.J.

"Our ultimate goal is safety," Kelly stressed. The port gets more than 10,000 deep draft vessels calling every year, he said, and handles the largest volume of petroleum products of U.S. ports.

For separating turbines from ship traffic, "we feel the setbacks are absolutely essential…we would like them to be at least one nautical mile," said Kelly.

Others have argued there needs to be much more space now, with the arrival of 1,200'x140' ultra-large containerships that need more like 2.5 miles to stop.

Those final decisions are up to BOEM. The Coast Guard is busy in an advisory role to the agency, while also starting work toward what could be a new East Coast routing system that would create shipping safety fairways.

"Each wind farm is different, each port is different," said Chris Scraba, deputy waterways chief with the Coast Guard Fifth District headquartered in Virginia. That will affect how wind farm buffers and setbacks are established, he said.

State governments in the Northeast and Mid-Atlantic are promoting big plans for offshore wind energy, even as they oppose the Trump administration's wishes to open Atlantic waters to oil and gas drilling. But wind turbines in the wrong place could pose their own danger of a spill.

"If we have one accident, one spill, that potentially could have generational impact," said Scraba. "It's critical we get this right."

Commercial fishermen have a case in federal court over the Statoil lease, and litigation seems certain to reignite. The arrival of foreign-flagged survey vessels in New Bedford, Mass., to explore sites leased by European wind developers energized fishermen opponents.

"We have the Magnuson Act (federal fisheries law) because we want to have American fishing grounds for American fishermen," said Meghan Lapp, fisheries liaison for fishing company Seafreeze Ltd., North Kingstown, R.I. "BOEM is plowing ahead regardless. They have not slowed down."

Skeptics may be getting some traction. A day after BOEM's meeting there, New Jersey Gov. Phil Murphy, a strong proponent of wind energy himself, asked the agency for a six-month extension of its information-gathering stage to absorb concerns of the fishing industry.

In lengthy comment letters April 30, the National Marine Fisheries Service and Massachusetts Division of Marine Fisheries weighed in, pointing out shortcomings in BOEM's environmental analysis so far and providing laundry lists for new research.

"It's going to take more than a one-year NEPA (National Environmental Policy Act) analysis," said Lapp. "You can't fast-track the analysis of something that's never been done before."

Competition, Cooperation and Costs the Talk at OSW Conference

RTO Insider
By Michael Kuser
June 11, 2018

Competition among states to set the highest offshore wind energy targets and to secure supply chain jobs is gradually giving way to a regional cooperation, the head of the Bureau of Ocean Energy Management said last week.

"In our view, all of the federal leases, they don't belong to any particular state, and we need to be thinking about how to manage those assets on a regional community basis," acting BOEM Director Walter Cruickshank said at New Energy Update's U.S. Offshore Wind Conference, held June 7-8.

"And we're certainly seeing that already," Cruickshank added. "We've seen projects that were leased off of one state getting agreements with neighboring states."

He cited the collaborative development efforts of Massachusetts and Rhode Island, of "Virginia and the Carolinas, and obviously in the New York Bight, where there are a lot of states that have stakeholder interest."

In May, Vineyard Wind, a partnership between Avangrid Renewables and Copenhagen Infrastructure Partners, won a contract to supply Massachusetts with 800 MW of offshore wind energy. In the same solicitation, Rhode Island picked Deepwater Wind to build a 400-MW version of its Revolution Wind proposal.

Picking up the Pace

Panelists at the conference also discussed ways to reduce costs and speed up permitting.

The Department of Energy's 2015 Wind Vision report set a goal of deploying 86 GW of offshore wind by 2050. The U.S. would need to use about 4.2% of the total technical resource area to reach the goal, according to the National Renewable Energy Laboratory's September 2016 Offshore Wind Energy Resource Assessment. The technical resource area includes areas of the Great Lakes and the Atlantic and Pacific coasts with wind speeds of at least 7 meters/second and water depths of less than 60 meters (Great Lakes) or 1,000 meters (the oceans).

The 11 BOEM leases issued so far could produce 20 GW by 2030 "based on the physical capacity of these leases," said Tom Harries of Bloomberg New Energy Finance. The typical timeline from lease to operation is five to seven years.

Stephen Bull, senior vice president at Norway-based Equinor (formerly Statoil), said he'd like "to see BOEM interact more at the state level, to really try to fast-track or work quicker to get wind energy areas out there."

Conference chair Stephen Pike, CEO of the Massachusetts Clean Energy Center, a state agency in charge of offshore wind development, asked about having BOEM pre-permit the leases to speed up development, as is done in Europe.

"That's not the way the federal government works," said Cruickshank, explaining that the bureau has no funding for capital-intensive marine surveys.

Although BOEM's leases to date have been off the Atlantic Coast, BOEM is also looking to the Pacific, which will require floating wind technology because of the much greater water depths, Cruickshank said.

"We're cautiously optimistic we'll be able to move ahead with some of those leases later this year."

Daniel Simmons, principal deputy assistant secretary for DOE's Office of Energy Efficiency and Renewable Energy, said improving floating platforms "is an important area for us just because so much of our wind resources offshore is in deep water."

Walter Musial, manager of offshore wind at the National Renewable Energy Laboratory, who explored the levelized cost of energy for floating turbines, said about 58% of potential offshore wind areas are deeper than 60 meters.

"Floating obviously starts out a bit more expensive, but it's a maturity thing, so fixed and floating turbine costs converge over time," Musial said. "Actual costs are confidential — they don't report them in the newspaper."

Manufacturers need to see the market demand in order to develop optimized turbine systems for floating platforms, he said. "Up till now, every single deployment has been with a turbine that was actually designed for a fixed bottom system, so we're sub-optimum," he said.

But the industry is now moving beyond the floating prototype phase. "I've counted about 11 projects totaling 229 MW," Musial said. "These are going in with some subsidies, but also with regular financing, and they're going in all over the world."

NREL wind analyst Garrett Barter agreed, saying the current design paradigm of offshore turbines "won't give you a cost-competitive floating system."

Engineering and design are just a fraction of the total cost for a floating wind turbine. Most of the costs are the operational expenses, logistics, assembly and installation, and financing, he said.

"So you really need a systems approach that can tackle all these complexities at the same time, and not just focus on the turbine itself," Barter said. He recommended multidisciplinary analysis and optimization, which is "a tool and also a state of mind where you connect the whole power production process, the whole load path, the controls that sit in between those two, and the whole balance sheet over the lifecycle of the plant."

He said the offshore industry may have to evolve into a structure like that of the aerospace industry, where a global supply chain serves a system owned by the prime contractor.

Driving Down Costs

Experts say it will take several years for the U.S. market to mature before it matches the separate cost curves for the established European market

“We think the transition happens around 3 to 4 GW of installed capacity, which should be in 2028 in the U.S., and the industry will move onto the established cost curve and really see price reductions,” Harries said. “The regulatory route gets simplified, and then gradually you build your experience and you move down this cost curve. Supply chains gain experience, and routes to market become very clear.”

Jonathan Cole, managing director of offshore for Avangrid parent Iberdrola’s renewable business, wants to see nearly that much capacity entering the pipeline each year.

“As soon as possible, get to a place where this market is being fed with 2 to 3 GW of new projects every year, which means you’ve got enough volume to support a local supply chain,” Cole said. “That’s when you’ll truly see cost reductions and the industrialization happening.”

Cole said that so far, they’ve been able to lower development costs through tax credits, which are now being phased out.

“We’re hoping that the downside of removing the tax credits is going to be more than compensated by the positive … making a more efficient and optimized installation,” he said.

Northeast Advantage

Vineyard Wind CEO Lars Thaaning Pedersen said tax credits are an important part of the price structure in Massachusetts, but “the benefits … these projects will bring to the southeast coast” of New England may be more important, such as avoiding the high cost of building transmission lines to bring hydropower from Canada.

The state “has taken a bold step already … and I’m confident that Massachusetts will be at the center of the industry,” Pedersen said.

Francis Slingsby, head of strategic partnerships at Orsted, congratulated Pedersen. Despite not winning the first round of the Massachusetts-Rhode Island solicitation, Slingsby said Orsted is committed to developing its Massachusetts lease areas, “which in our estimation are superb.”

“Wind speeds increase as you move farther north along the coast, which gives New England an innate advantage,” he added.

Massachusetts Energy Secretary Matthew Beaton referred to the previous day’s tour of the New Bedford Marine Commerce Terminal, which was built for the deployment of offshore wind, as evidence of the state’s chance to lead the industry.

"To see international companies come in with Massachusetts companies made me realize … this thing's for real, this thing's happening, and we have all the pieces that we need," Beaton said. "Eight hundred megawatts is just the starting point."

Bill White, MassCEC director of offshore wind development, said, "Growth in Massachusetts is really about … what it will cost to ratepayers."

John B. Lavelle, head of offshore wind for GE Renewable Energy, said volume will be the biggest driver of cost reductions. Lavelle said GE will "compete in the U.S. with our 12-MW platform that we just announced."

Operating costs will come down partially through "a lot of automation," Lavelle said. "You don't want to send people 15 miles off the coast if you don't have to."

NY, NJ, Md. Moving Forward

Elisabeth Treseder, senior regulatory adviser for Orsted, said New Jersey's commitment in May to build 3,500 MW of offshore wind by 2030 — surpassing New York's target of 2,400 MW — "provides a lot of certainty and reassurance" to the market. (See Gov. Signs NJ Nuke Subsidy, Renewables Bills.)

"We're still waiting for the New Jersey Board of Public Utilities to finish its plan, which for us means focusing on the local supply chain and workforce development," Treseder said. "New Jersey was very wise in passing a $100 million tax break for offshore wind manufacturing, which left them an additional pool [of incentives] for suppliers."

Kenneth J. Sheehan, director of economic development and emerging technologies at the BPU, said the state is working to develop its master plan and its first solicitation.

"We are looking for suppliers, transmission, for all the factors that go into it, and the OREC [offshore wind renewable energy credit], the single price, up-front method of funding, takes all this into consideration," Sheehan said.

Jim Lanard, CEO of Magellan Wind, asked Sheehan what his state's position is regarding wind energy areas that could serve both New York and New Jersey.

"Half the New York Bight is in New Jersey, so we're not practically upset about additional project development off our shore," Sheehan said, referring to the Atlantic Coast region between Cape May, N.J., and Montauk Point on Long Island. "At the start, it's every state for itself. … Everything could be supplied from New Jersey. And New York thinks the same of itself."

Kevin Knobloch, president of transmission developer Anbaric's New York Ocean Grid, said that particularly with New Jersey's goal of 3,500 MW, there's a sense of great urgency to get the first turbines in the water.

"We believe the wise approach is from the very first solicitations to separate generation from transmission, and open it up to competition," Knobloch said. "In so doing, the state decision-makers still reserve the right to go with an offer that's bidding on both attributes."

Doreen Harris, director of large-scale renewables at the New York State Energy Research and Development Authority, said the agency is also identifying new wind energy areas off New York City. There is a proceeding before state regulators now "to make the first utility-scale procurement later this year," she said.

Christer Geijerstam, director of the Empire Wind project for Equinor, which bought the first New York lease in 2016, said that aside from preparing for a state bid, the company is "focused on project technical issues to reduce asset risks" prior to the hoped-for start of construction.

John Hartnett, business opportunity manager of U.S. offshore wind for Shell Wind Energy, said his company "had really jumped into the U.S. markets driven by the evidence of the northeast. Right now, we are investigating the upcoming lease opportunities, both in Massachusetts and New York, and are very hopeful to have site control in time to participate in the upcoming auctions."

The Maryland Public Service Commission approved two offshore wind projects totaling 368 MW in May 2017, allowing the developers to receive ORECs. The projects are estimated to create 9,700 full time equivalent jobs and result in more than $2 billion of economic activity in Maryland, including $120 million of investments in port infrastructure and steel fabrication facilities.

Samuel Beirne, wind energy program manager for the Maryland Energy Administration, said that "most offshore wind developers have to contract through the state Public Service Commission [to obtain ORECs] … and most use a third-party consultant to help them."

Aileen Kenney, senior vice president of development for Deepwater Wind, said the company's 120-MW Skipjack project off Maryland will start construction in 2021 and go online the following year.

"Right now we're mapping all the seafloor, doing bathymetry analysis," Kenney said.

Production Tax Credit

According to DOE, the federal renewable electricity production tax credit is an inflation-adjusted 1.9 cent/kWh tax credit for wind for the 2017 calendar year. The credit lasts 10 years after the date the facility is placed in service.

The tax credit is phased down for wind facilities as a percentage reduction: for wind facilities beginning construction in 2017, the PTC amount is reduced by 20%; for 2018, 40%; and for 2019, 60%.

State talks plans for wind power

Long Island Herald
By Bridget Downes
October 11, 2018

New York State Energy Research and Development Authority officials announced last month that the agency was seeking feedback on a draft request for proposals from potential offshore wind developers.

More than 50 people gathered on the sixth floor of City Hall on Sept. 26 to learn more about the state's efforts to advance offshore wind energy and ask questions about the RFP process. NYSERDA sought comments from potential offshore wind developers and other stakeholders in the hope of finalizing the RFP, which would be issued this winter.

On Monday, a report from the United Nations' Intergovernmental Panel on Climate Change said that if greenhouse gas emissions continue at the current rate, the world could see intensified droughts and flooding, disappearing coastlines and extreme heat that could lead to food shortages by 2040, according to The New York Times. The United States is the world's second-largest greenhouse gas emitter, behind China.

NYSERDA's efforts coincide with Gov. Andrew Cuomo's goal of producing half of the state's electricity needs — up to 2,400 megawatts, enough to power 1.2 million homes — from renewable energy sources by 2030.

Agency representatives said the benefits of offshore wind energy include clean, locally produced power, support for investment in coastal infrastructure and the creation of thousands of short- and long-term construction, manufacturing and operations jobs.

NYSERDA has led the way in promoting the New York State Offshore Wind Master Plan, which encourages the development of offshore wind power in a way that is mindful of the environment and the maritime industry as well as economic and social issues, according to the agency. Since 2016, it has conducted 20 studies, officials said, and engaged with stakeholders and the public to "ensure the responsible and cost-effective development of offshore wind."

The state and federal governments have collaborated on the plan: The Department of the Interior, through the Bureau of Ocean Energy Management, identifies areas for offshore wind development, while the state commits to buying the power from those projects.

There are currently six areas in New York waters that the federal government is leasing to wind developers: three east of Long Island, near Massachusetts, owned by Deepwater Wind, Orsted and Vineyard Wind; **one south of Manhattan, owned by Equinor (formerly Statoil);** and two southwest of Long Island, near the New Jersey coast, owned by US Wind and Orsted. On Monday, Orsted, which is based in Denmark, acquired Deepwater Wind for $510 million, according to Orsted, and the two companies plan to merge.

“We think the work that the master plan has advanced really serves as a solid foundation for the federal government’s decision-making,” said Doreen Harris, NYSERDA’s director of large-scale renewables. “And further, again, to realize this very exciting and robust industry for us as a state, we think we need more areas to help us do so.”

Last year, NYSERDA officials recommended areas that they thought were best suited for offshore wind development to the federal government. The Bureau of Ocean Energy Management then began work on identifying more lease areas for potential developers, and NYSERDA officials said they would like to see that development happen as soon as possible.

“We see these new lease areas as being critical to our future development,” Harris said, “but in the meantime, we’re really excited to say that we are advancing New York’s first solicitations for offshore wind in the very near future.” The agency was recently awarded an $18.5 million grant from the Department of Energy to lead an offshore wind research and development consortium.

At the Sept. 26 meeting at City Hall, representatives of NYSERDA and BOEM invited audience members’ questions. “I was very pleased to see that a project labor agreement is a requirement of the RFP,” City Council President Anthony Eramo said. “I greatly appreciate that for the workforce for New York state.”

He asked if a change in the state’s political administration would affect the rollout of the wind development process. “All of the actions that have been taken in terms of the effectuation of the governor’s goal are actually through the New York Public Service Commission, through the orders of the Public Service Commission,” Harris explained. “So, in fact, these orders hold. They aren’t governed particularly by who is in office [at] that particular point in time. We’ve been working on renewables as a state for a very long time, and we’ve done it through many administrations. NYSERDA’s agreements stay in force.”

“I was kind of surprised to find out this has gone as far as it has,” said East Hills resident Cary Ratner, “because I don’t think that the public really understands what they’re getting for their money. My question is, What concern do you have to address the actual cost? Because everything you people have touched in the power industry in this state has been nothing but crap.”

A handful of audience members repeatedly yelled, “Time!” to cut Ratner off from speaking any longer than the allotted two minutes.

NYSERDA “did study, quite extensively, the cost of offshore wind,” said Matt Vestal, a technical adviser for the agency. “The cost of offshore wind has come down dramatically over the last even 12 to 18 months across the world. We saw the cost of offshore wind basically be cut in half in Europe from 2016 to 2018. This is obviously an issue that NYSERDA is taking very seriously. . . . The premiums associated with offshore wind above conventional fuel technology [are] rapidly diminishing over time, and this is great news for the industry and for New York ratepayers.”

NYSERDA accepted public comments on the draft RFP until last week, and is reviewing the input and working to finalize the document.

POLITICONEW YORK

New York offshore wind call draws record amount of interest

Politico New York
By Marie French
January 3, 2019

Five developers have told New York they will submit bids in the state's current solicitation for offshore wind projects targeting 800 megawatts of new capacity.

The level of interest is greater than in several other states seeking to take the lead on offshore wind and is expected to support Gov. Andrew Cuomo's goal of securing 2,400 megawatts of offshore wind by 2030. It also highlights the growing momentum for the industry in the U.S. as big-name players in the European offshore wind market step up their efforts here.

"We've seen this coming and we know that New York will be the center of gravity with regards to offshore wind development," said Doreen Harris, director for large-scale renewables for the New York State Energy and Research Development Authority. **"The five companies that have submitted … represent not only a significant scale — a larger scale than any other state has seen with regard to participation — but also these are very significant, major developers who are going to bring this industry to the U.S. even more quickly than some had expected."**

The five developers expressed interest by the notice of intent deadline on Dec. 20. NYSERDA will pay subsidies collected from ratepayers for electricity produced by selected projects.

The interested developers control 700,000 acres of federal lease areas and could accommodate as much as 7,000 megawatts worth of turbines, according to NYSERDA. Three of the lease areas are off the coast of Massachusetts: Bay State Wind LLC, a joint venture of Denmark power company Ørsted A/S and Northeast utility owner Eversource Energy; Vineyard Wind LLC, backed by Copenhagen Infrastructure Partners and Avangrid Renewables; and Mayflower Wind Energy LLC, a joint venture of Shell New Energies and EDPR.

Massachusetts, Connecticut and New Jersey received only three bids from interested developers in recent offshore wind solicitations. The last two interested developers are **Equinor, formerly Statoil, offering the area it won in November 2016 that's south of Long Island and east of Sandy Hook, N.J.,** and Atlantic Shores Offshore Wind LLC, a joint venture of EDF Renewables and Shell New Energies, which holds a lease off the New Jersey coast.

There is some overlap of projects among the various states. Vineyard Wind has already secured an 800 megawatt power purchase agreement through Massachusetts' procurement.

Mayflower Wind, Atlantic Shores and Equinor have all submitted bids in New Jersey's solicitation. The state has a goal of 3,500 megawatts of offshore wind by 2030 and is currently conducting an 1,100 megawatt solicitation. Bids were due on Dec. 28 and the Board of Public Utilities has said it will act by July 1.

Harris said it would be a benefit for New York if projects were expanding to serve multiple states because of the potential for economies of scale.

“These are very large areas that can support delivery to multiple markets,” Harris said. "We don't see it as a one or the other... If a developer is building a project for location A and expands it to serve New York, the unit cost for New York ratepayers will be less."

Final bids for NYSERDA's process are due by Feb. 14. Awards are expected in April with contracts finalized in June, allowing developers to take advantage of expiring federal tax credits. If NYSERDA awards 800 megawatts or more, the agency would need approval from the Public Service Commission to conduct another solicitation in 2019.

The state is splitting its offshore wind effort into two phases, with a fierce debate ongoing about which form the second phase should take to achieve the balance of Cuomo's goal. Much of the focus among stakeholders has been on how to deal with transmission in the most cost-efficient manner.

The initial request for proposals requires bidders to provide both a fixed price offshore renewable energy credit, or OREC, price and an indexed one that will fall as energy prices rise. But NYSERDA is not only accounting for price in its bid evaluation, requiring developers to offer information on what investments in jobs and the supply chain they plan to make in the state.

“What we see is all of them are taking quite seriously the fact that we’re looking for a New York project with New York benefits, which may include a New York interconnection as well,” Harris said.

Only one wind project proposed in waters off LI, filings show

Newsday
By Mark Harrington
January 12, 2019

Only one of five developers who intend to vie for a New York State contract for off-shore wind energy is proposing its project off Long Island waters. The rest would be off Massachusetts/Rhode Island or the New Jersey coast, according to recent state filings.

The New York State Energy Research and Development Authority, or NYSERDA, which is overseeing the bids and will award contracts for upward of 800 megawatts of offshore wind energy this year, said the five notices of intent to participate in the state bid represented the strongest response to any state solicitation to date. One megawatt of offshore wind powers around 360 homes. Formal bids are due Feb. 14.

The project located in the New York wind-energy area is off Long Island's South Shore in waters previously identified by the federal agency responsible for leasing water rights. Another possible developer has offered a project off the New Jersey coast. A state official said all projects would get careful review, and downplayed the notion of their distance from New York.

"I think you have to look beyond the geography," said Doreen Harris, director of large-scale renewables for NYSERDA, noting that all projects will be reviewed based on their proposed price of energy but also their benefits to the New York economy. She also noted that studies have shown a greater wind-energy resource from the Massachusetts/Rhode Island offshore area and other factors which could offset the potential higher cost to transmit power from the distant turbines.

New York wants to become a major East Coast hub for the wind-energy industry, and even the bids for projects more than 50 miles from Long Island are expected to include ways to involve the state in wind-energy employment, development, manufacturing and maintenance.

The closest proposal for the waters off Long Island is by Norwegian energy giant Equinor called Empire Wind off the coast of Long Beach. Equinor, formerly known as Statoil, in 2016 won an auction for 80,000 acres of offshore wind water rights to erect a wind farm it expects to produce up to 2,000 megawatts, enough to power 1 million homes, at a cost of some $6 billion.

The former Deepwater Wind, the Rhode Island-based company recently acquired by Danish energy company Orsted, already has a contract for 90 megawatts of wind energy it expects to deliver to Long Island Power Authority by the end of 2022, and is bidding in another project in the area in a joint venture with Eversource Energy called Bay State Wind. The company also won authorization by LIPA to increase the size of the project to 130 megawatts.

Two other potential bidders in the Massachusetts area are Vineyard Wind and Mayflower Wind Energy. Atlantic Shores Offshore Wind has proposed the project off New Jersey.

Harris explained that the major reason the projects were based in the Massachusetts/Rhode Island area was that the U.S. Bureau of Ocean Energy Management, or BOEM, had not completed a lease auction for the other areas in the waters off New York, and may not until this year's end or next year.

The current New York bid solicitation required that developers currently hold lease rights to their proposed projects.

And while it's not an ideal situation for those proposing New York projects to have operations more than 50 miles away, Harris said NYSERDA was keeping an open mind about the projects. She said the state viewed all the projects as "regional."

"I had to rethink my view of these large areas of being beholden to one particular state," she said. "They're really regional projects."

Some of the developers have filed applications to bring their energy to the state using a variety of connections, from the LIPA grid to interconnections owned by Con Edison. Some may even connect to grids using the nearby New England grid system, Harris said, and transport energy over interstate transmission lines to New York. Others could enter through the Mid-Atlantic grid known as PJM.

One other complication about using New York as a hub of operations is the limitations caused by bridges, particularly the Verrazano Bridge linking Brooklyn and Staten Island. Harris noted there were "air-draft constraints" for getting particularly tall wind-farm parts to and from Brooklyn ports because of the bridge height limitation, but noted that New York wasn't the only state dealing with such issues.

And she said companies were looking for ways to creatively deal with it, including shipping tall parts horizontally rather than vertically and considering certain ports that didn't have air-draft constraints.

In the end, she said, the cost of energy from a project will be the major deciding factor in awarding a contract. Around 70 percent will be based on the price of energy in the company's offer. Twenty percent will be factored for economic benefits for the New York economy, and 10 percent project viability, Harris said, quoting a Public Service Commission order.

The MARITIME EXECUTIVE
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Equinor Moves Forward with Planning for Empire Wind

Maritime Executive
February 8, 2019

Norwegian energy company Equinor is moving forward with planning for a giant offshore wind farm in the "New York Bight," an 80,000 acre lease area just off the entrance to New York Harbor. It has deployed a high-tech buoy to measure wind speed, direction, wave conditions and other characteristics on site to determine the resource potential of the site. The floating LiDAR buoy device uses laser light detection and ranging to take wind measurements, and its solar panels, onboard wind turbines and batteries allow it to operate for extended periods without intervention.

“The deployment of this specialized buoy marks another step forward in the multi-year process of bringing a reliable source of renewable energy to the New York / New Jersey area,” said Christer af Geijerstam, President, Equinor Wind US. “Offshore wind power today is made possible by a host of innovative technologies, from larger and more efficient turbines to sophisticated LiDAR systems like this that enable us to gauge invaluable information about the characteristics of this offshore lease area.”

Equinor won the federal lease auction for 80,000 acres south of New York and east of New Jersey in 2016. The company is currently working on two potential projects at the site - Empire Wind for New York and Boardwalk Wind for New Jersey. Late last year, it also paid $135 million for a giant lease area off Massachusetts in the highest-value wind auction in U.S. history.

Equinor (formerly Statoil) derives almost all of its revenue from oil and gas, but it is moving to expand into renewables. It holds four projects in the UK and Germany, generating enough electrical power for one million homes, and it recently commissioned the world's first commercial floating offshore wind installation off Scotland. Floating wind platforms are a technological solution borrowed from offshore oil and gas, and could expand wind's potential into much deeper waters.

Equinor deploys floating lidar at its "New York Bright" offshore wind lease site

Windpower Engineering & Development
By Michelle Froese
February 8, 2019

Equinor Wind US has deployed specialized buoy that's designed to gather information, an important step in the development of its offshore wind lease site in the "New York Bight." This area is expected to provide wind energy to the New York and New Jersey regions and help achieve the renewable energy goals recently set forth by Governor Andrew Cuomo.

The Floating LiDAR (Light Detection and Ranging) device will measure wind speed, wind direction, wave conditions, and several other marine characteristics that help inform critical decisions in regard to the resource potential and eventual development of the wind farm. It will be deployed to record this information for two years.

"The FLiDAR itself is an example of renewable energy innovation," Christer af Geijerstam, President, Equinor Wind US, said. "The floating system, using solar panels, wind turbines and large batteries in its hull, can operate autonomously throughout a full winter season offshore New York. Access to good quality wind recordings like those provided by the FLiDAR system is essential to the development of any wind energy project today."

Equinor Wind US won the federal lease auction of 80,000 acres south of New York and east of New Jersey in 2016. The company is currently developing projects in the lease area for the offshore-wind markets in New York and New Jersey, with the projects named Empire Wind in New York and Boardwalk Wind in New Jersey.

In December 2018, Equinor submitted a winning bid of $135 million for a lease area offshore Massachusetts in an auction held by the US Department of the Interior's Bureau of Ocean Energy Management. The new lease, located south of Massachusetts and east of New York, gives Equinor a strong strategic position in the region.

The company now holds leases within reach of some of the most important markets for offshore wind in the U.S., with the potential to provide over two million homes with clean, renewable power.

"The deployment of this specialized buoy marks another step forward in the multi-year process of bringing a reliable source of renewable energy to the New York and New Jersey area," Christer af Geijerstam, President, Equinor Wind US, said. "Offshore wind power today is made possible by a host of innovative technologies, from larger and more efficient turbines to sophisticated LiDAR systems like this that enable us to gauge invaluable information about the characteristics of this offshore lease area."

reNEWS.BIZ

Equinor lidar lights up New York offshore

ReNews Biz
February 8, 2019

Equinor has deployed a floating lidar buoy in the New York Bight to gather data to help with the development of the company's offshore wind lease area.

The device will measure wind speed and direction, wave conditions and several other marine characteristics that will help inform decisions on the resource potential and eventual project development.

The company said the device will be deployed for two years.

Equinor Wind US won the 32,370-hectare federal lease south of New York and east of New Jersey in an auction in 2016.

The company said it plans to develop two projects called Empire Wind and Boardwalk Wind in the area.

Equinor Wind US president Christer af Geijerstam said: “The deployment of this specialised buoy marks another step forward in the multi-year process of bringing a reliable source of renewable energy to the New York/New Jersey area.

“Offshore wind power today is made possible by a host of innovative technologies, from larger and more efficient turbines to sophisticated lidar systems like this that enable us to gauge invaluable information about the characteristics of this offshore lease area.”

He added that the lidar itself is an example of renewable energy innovation.

“The floating system, using solar panels, wind turbines and large batteries in its hull, can operate autonomously throughout a full winter season offshore New York.

“Access to good quality wind recordings like those provided by the flidar system is essential to the development of any wind energy project today.

“It’s yet another example of the technological innovation that Equinor is bringing to offshore wind development in New York.”

Equinor Launches High-Tech Buoy

World Energy News
By Michelle Howard
February 8, 2019

Equinor Wind US has announced deployment of a cutting-edge, specialized buoy designed to gather information, an important step in the development of its offshore wind lease site in the “New York Bight,” which will provide wind energy to New York and the region to help achieve the renewable energy goals recently set forth by Governor Andrew Cuomo.

The Floating LiDAR (Light Detection and Ranging) device will measure wind speed, wind direction, wave conditions and several other marine characteristics that help inform critical decisions in regard to the resource potential and eventual development of the wind farm. It will be deployed to record this information for two years.

“The deployment of this specialized buoy marks another step forward in the multi-year process of bringing a reliable source of renewable energy to the New York / New Jersey area,” Christer af Geijerstam, President, Equinor Wind US, said. “Offshore wind power today is made possible by a host of innovative technologies, from larger and more efficient turbines to sophisticated LiDAR systems like this that enable us to gauge invaluable information about the characteristics of this offshore lease area.”

“The FLiDAR itself is an example of renewable energy innovation,” af Geijerstam said. “The floating system, using solar panels, wind turbines and large batteries in its hull, can operate autonomously throughout a full winter season offshore New York. Access to good quality wind recordings like those provided by the FLiDAR system is essential to the development of any wind energy project today. It’s yet another example of the technological innovation that Equinor is bringing to offshore wind development in New York.”

Strong Presence on the East Coast

Equinor Wind US won the federal lease auction of 80,000 acres south of New York and east of New Jersey in 2016. The company is currently developing projects in the lease area for the offshore-wind markets in New York and New Jersey, with the projects named Empire Wind in New York and Boardwalk Wind in New Jersey.

In December 2018, Equinor submitted a winning bid of $135 million for a lease area offshore Massachusetts in an auction held by the US Department of the Interior's Bureau of Ocean Energy Management. The new lease, located south of Massachusetts and east of New York, gives Equinor a strong strategic position in the region.

The company now holds leases within reach of some of the most important markets for offshore wind in the U.S., with the potential to provide over two million homes with clean, renewable power.

Growing Renewable Energy Portfolio Worldwide

Equinor is building a material position in renewable energy and evolving into a broad energy company. Equinor now powers more than one million European homes with renewable wind power from four projects in the United Kingdom and Germany. Equinor commissioned the world's first floating offshore wind farm last year, off the coast of Scotland, a technology essential to the development of offshore wind in many locations around the world, including the west coast of the US. Equinor is also developing offshore wind in Poland, as well as solar energy in Brazil and Argentina.

WORKBOAT

Equinor deploys data buoy for New York offshore wind energy

Work Boat
By Kirk Moore
February 8, 2019

Offshore wind energy developer Equinor has deployed a high-tech buoy to gather data to help design the Empire Wind turbine array near the approaches to New York Harbor.

The buoy carries a FLiDAR (floating light detection and ranging) system, using laser technology to measure wind direction and speed, wave conditions and other weather and oceanographic conditions over the next two years.

The buoy was launched in New York Harbor and towed to the Empire Wind site, a 79,350-acre federal lease that Norway-based Equinor (formerly Statoil) acquired in 2016. It is the latest in a series of data collection projects, from Martha's Vineyard off Massachusetts to the New Jersey coast, as developers work on designing turbine arrays.

"The deployment of this specialized buoy marks another step forward in the multi-year process of bringing a reliable source of renewable energy to the New York-New Jersey area," said Christer af Geijerstam, president of Equinor Wind US, which is developing Empire Wind and the planned Boardwalk Wind project off New Jersey.

"Offshore wind power today is made possible by a host of innovative technologies, from larger and more efficient turbines to sophisticated LiDAR systems like this that enable us to gauge invaluable information about the characteristics of this offshore lease area."

"The FLiDAR itself is an example of renewable energy innovation," said af Geijerstam said. The buoy is powered by small wind turbines and solar panels that charge its battery banks, so the system can operate autonomously throughout a full winter season offshore from New York, he said.

"Access to good quality wind recordings like those provided by the FLiDAR system is essential to the development of any wind energy project today," said af Geijerstam. "It's yet another example of the technological innovation that Equinor is bringing to offshore wind development in New York."

Equinor's latest lease acquisition was a successful bid of $135 million In December 2018 for one of three areas south of Massachusetts that were offered by the federal Bureau of Ocean Energy Management. The bid was more than three times as much that Equinor paid for its Empire Wind tract, a signal of escalating interest in the U.S. offshore wind industry, according to BOEM officials.

The company says its leases now are "within reach of some of the most important markets for offshore wind in the U.S., with the potential to provide over two million homes with clean, renewable power."

Attachment 4M

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equinor

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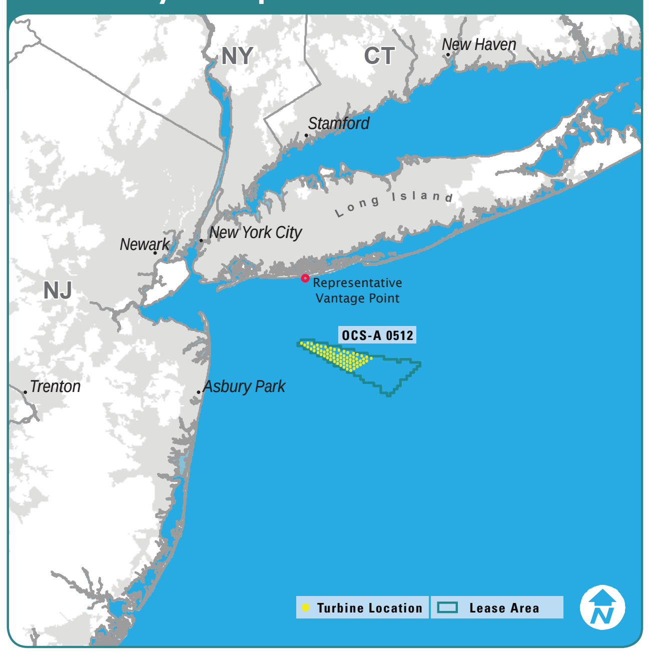
Panoramic Photograph

Vicinity Map



Viewpoint Information

Photograph Information

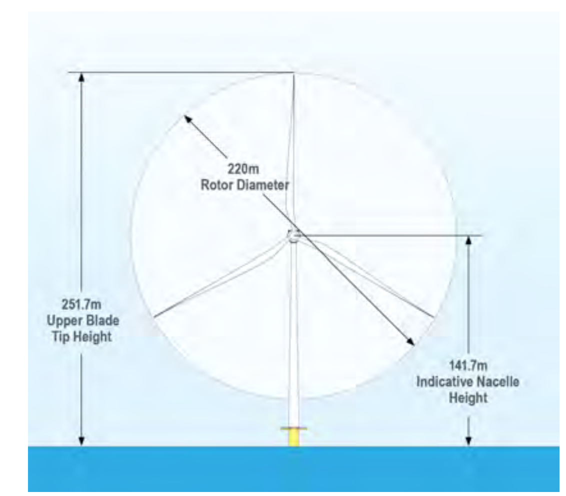
Viewing Direction: South-Southeast
Latitude: 40° 34’ 49.60” N
Longitude: -73° 33’ 23.19” W
Viewpoint Location: Short Beach at Jones Beach State Park, approximately 0.5 mile south of New York State Route 909E.
Distance to Closest Turbine: 14.4 miles

Viewing Instructions

The single-frame simulations on the following pages should be printed at 11-by-17 inches; full size with no scaling; and viewed at arm’s length (24 inches).

If viewed on a computer monitor, the document should be scaled to 100 percent and viewed at arm’s length (24 inches).

12MW Turbine Model Dimensions



EMPIRE WIND

Short Beach at Jones Beach State Park

equinor

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Short Beach at Jones Beach State Park
Existing Condition

equinor

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Short Beach at Jones Beach State Park
816MW Layout
Simulated Condition: Early Morning/Clear

equinor

Short Beach at Jones Beach State Park

816MW Layout

Simulated Condition: Early Morning/Partly Cloudy

equinor

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Short Beach at Jones Beach State Park
816MW Layout
Simulated Condition: Early Morning/Overcast

equinor

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Short Beach at Jones Beach State Park
816MW Layout
Simulated Condition: Mid-Afternoon/Clear

equinor

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Short Beach at Jones Beach State Park
816MW Layout
Simulated Condition: Mid-Afternoon/Partly Cloudy

equinor

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Short Beach at Jones Beach State Park
816MW Layout
Simulated Condition: Mid-Afternoon/Overcast

equinor

Short Beach at Jones Beach State Park
816MW Layout
Simulated Condition: Late Day/Clear

equinor

Short Beach at Jones Beach State Park
816MW Layout
Simulated Condition: Late Day/Partly Cloudy

equinor

Short Beach at Jones Beach State Park

816MW Layout

Simulated Condition: Late Day/Overcast

equinor

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Short Beach at Jones Beach State Park
816MW Layout
Simulated Condition: Night/Clear

equinor

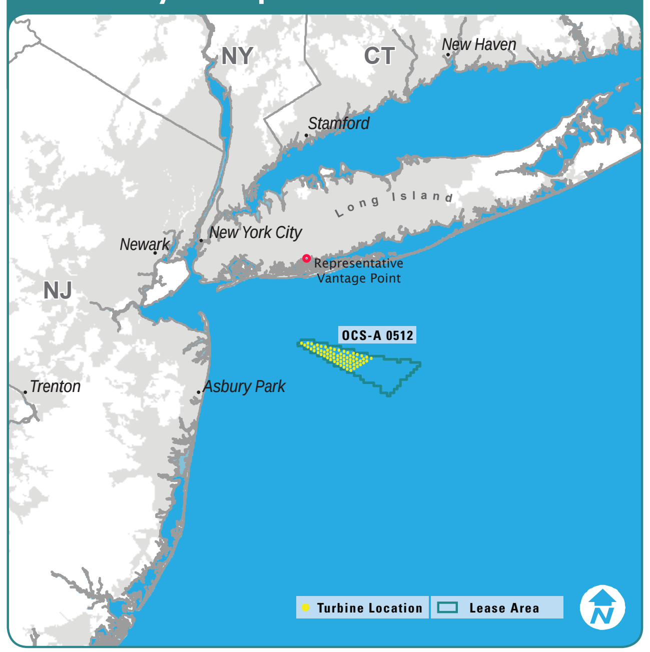
Short Beach at Jones Beach State Park

816MW Layout

Simulated Condition: Night/Clear

Panoramic Photograph

Vicinity Map



Viewpoint Information

Photograph Information

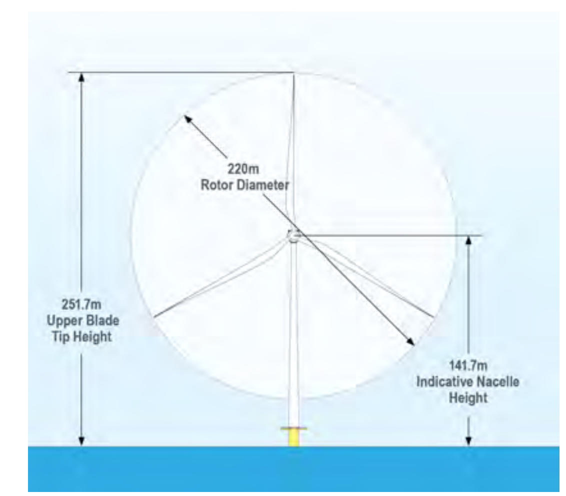
Viewing Direction: South
Latitude: 40˚ 38' 47.88" N
Longitude: -73˚ 33' 46.29" W
Viewpoint Location: Norman J. Levy Park and Preserve, approximately 0.5 mile south of Merrick Road.
Distance To Nearest Turbine: 18.7 miles

Viewing Instructions

The single-frame simulations on the following pages should be printed at 11-by-17 inches; full size with no scaling; and viewed at arm's length (24 inches).

If viewed on a computer monitor, the document should be scaled to 100 percent and viewed at arm's length (24 inches).

12MW Turbine Model Dimensions



EMPIRE WIND

Norman J. Levy Park and Preserve

equinor

Norman J. Levy Park and Preserve

Existing Condition

equinor

PUBLIC COPY - CONFIDENTIAL INFORMATION REMOVED

Norman J. Levy Park and Preserve

816MW Layout

Simulated Condition: Early Morning/Clear

PUBLIC COPY - CONFIDENTIAL INFORMATION REMOVED

Norman J. Levy Park and Preserve

816MW Layout

Simulated Condition: Early Morning/Partly Cloudy

equinor

Norman J. Levy Park and Preserve

816MW Layout

Simulated Condition: Early Morning/Overcast

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Norman J. Levy Park and Preserve

816MW Layout

Simulated Condition: Mid-Afternoon/Clear

equinor

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Norman J. Levy Park and Preserve

816MW Layout

Simulated Condition: Mid-Afternoon/Partly Cloudy

equinor

Norman J. Levy Park and Preserve

816MW Layout

Simulated Condition: Mid-Afternoon/Overcast

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Norman J. Levy Park and Preserve

816MW Layout

Simulated Condition: Late Day/Clear

equinor

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Norman J. Levy Park and Preserve

816MW Layout

Simulated Condition: Late Day/Partly Cloudy

equinor

Norman J. Levy Park and Preserve

816MW Layout

Simulated Condition: Late Day/Overcast

equinor

Norman J. Levy Park and Preserve

816MW Layout

Simulated Condition: Night/Clear

equinor

PUBLIC COPY - CONFIDENTIAL INFORMATION REMOVED

Norman J. Levy Park and Preserve

816MW Layout

Simulated Condition: Night/Clear

equinor

PUBLIC COPY - CONFIDENTIAL INFORMATION REMOVED

Panoramic Photograph

Vicinity Map

Viewpoint Information

Photograph Information

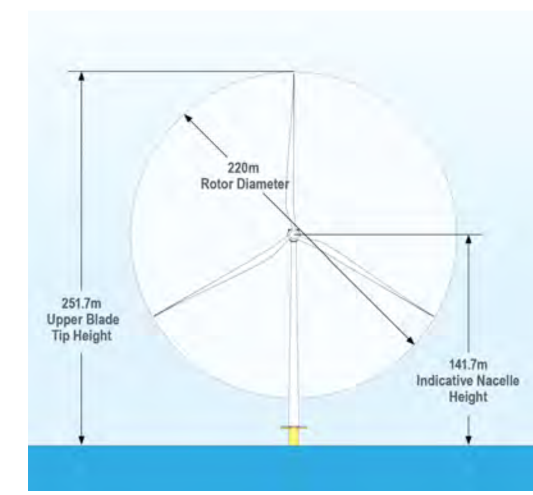
Viewing Direction: South-Southeast
Latitude: 40˚ 33’ 54.10” N
Longitude: -73˚ 52’ 23.15” W
Viewpoint Location: Jacob Riis Park Promenade, approximately 400 feet south of Rockaway Beach Boulevard.
Distance to Closest Turbine: 20.2 miles

Viewing Instructions

The single-frame simulations on the following pages should be printed at 11-by-17 inches; full size with no scaling; and viewed at arm’s length (24 inches).

If viewed on a computer monitor, the document should be scaled to 100 percent and viewed at arm’s length (24 inches).

12MW Turbine Model Dimensions



EMPIRE WIND

Jacob Riis Park

equinor

Jacob Riis Park
Existing Condition

equinor

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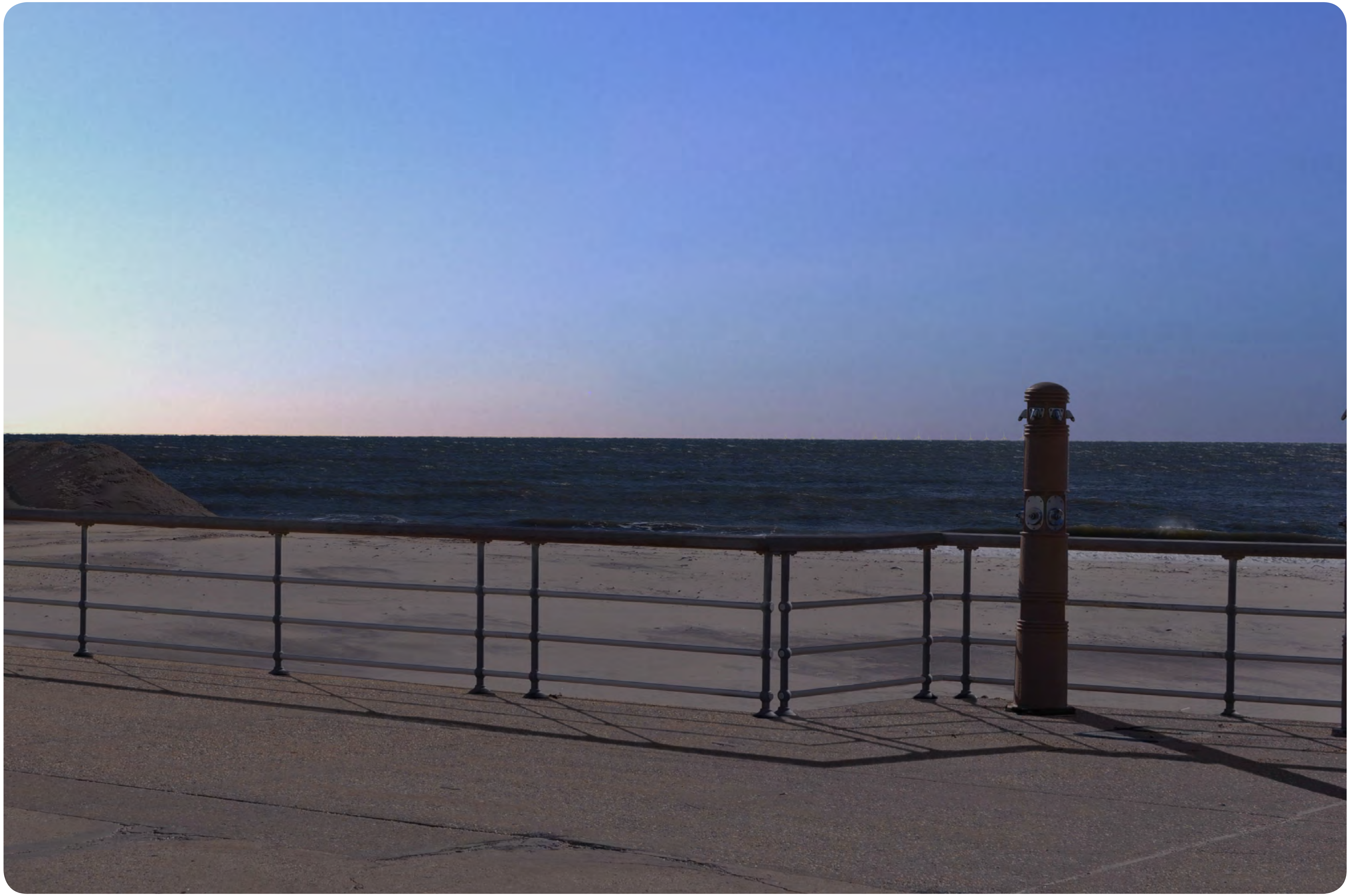

Jacob Riis Park

816MW Layout

Simulated Condition: Early Morning/Clear

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Jacob Riis Park

816MW Layout

Simulated Condition: Early Morning/Partly Cloudy

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Jacob Riis Park
816MW Layout
Simulated Condition: Early Morning/Overcast

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Jacob Riis Park

816MW Layout

Simulated Condition: Mid-Afternoon/Clear

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Jacob Riis Park

816MW Layout

Simulated Condition: Mid-Afternoon/Partly Cloudy

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Jacob Riis Park

816MW Layout

Simulated Condition: Mid-Afternoon/Overcast

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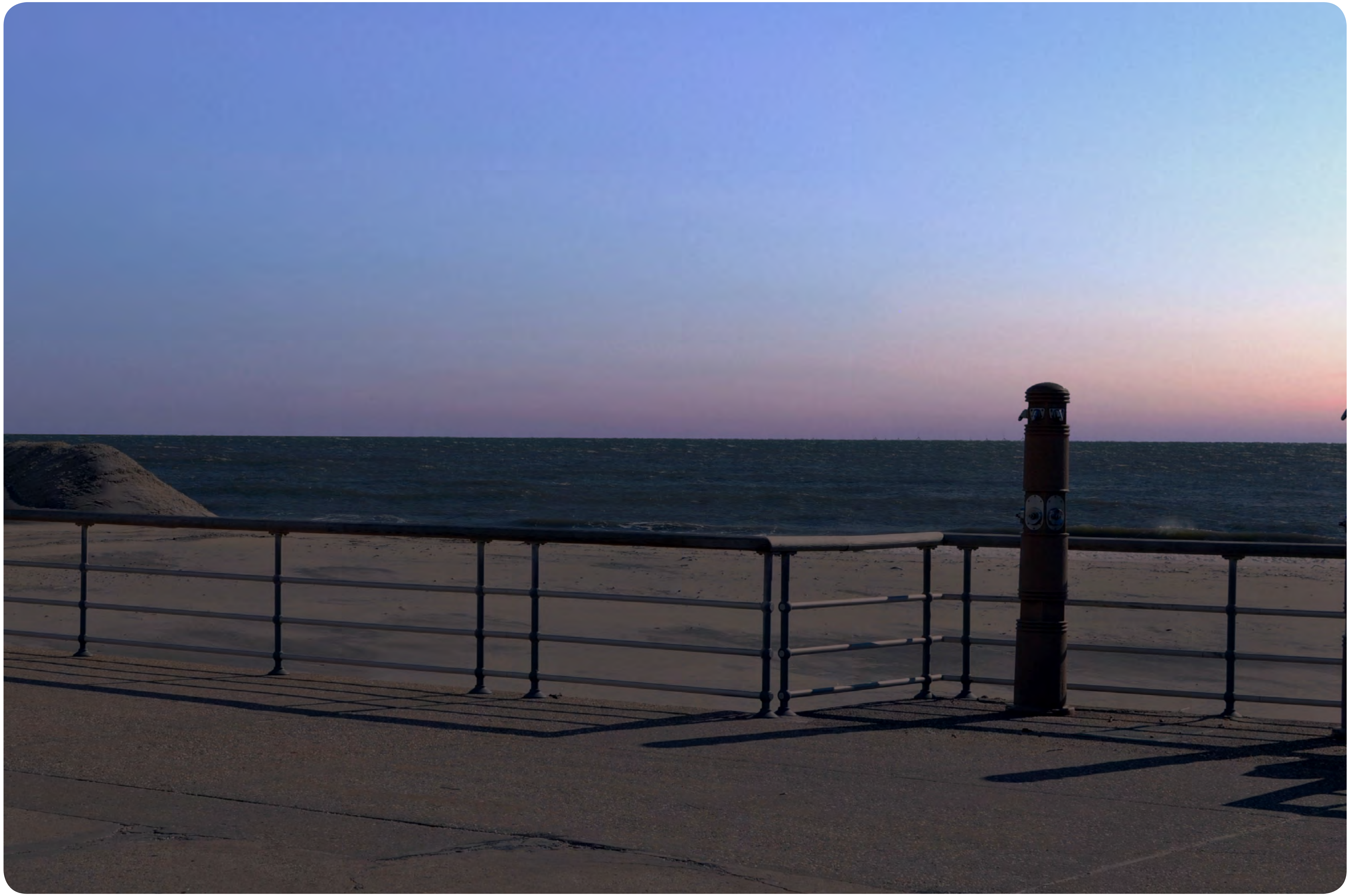

Jacob Riis Park

816MW Layout

Simulated Condition: Late Day/Clear

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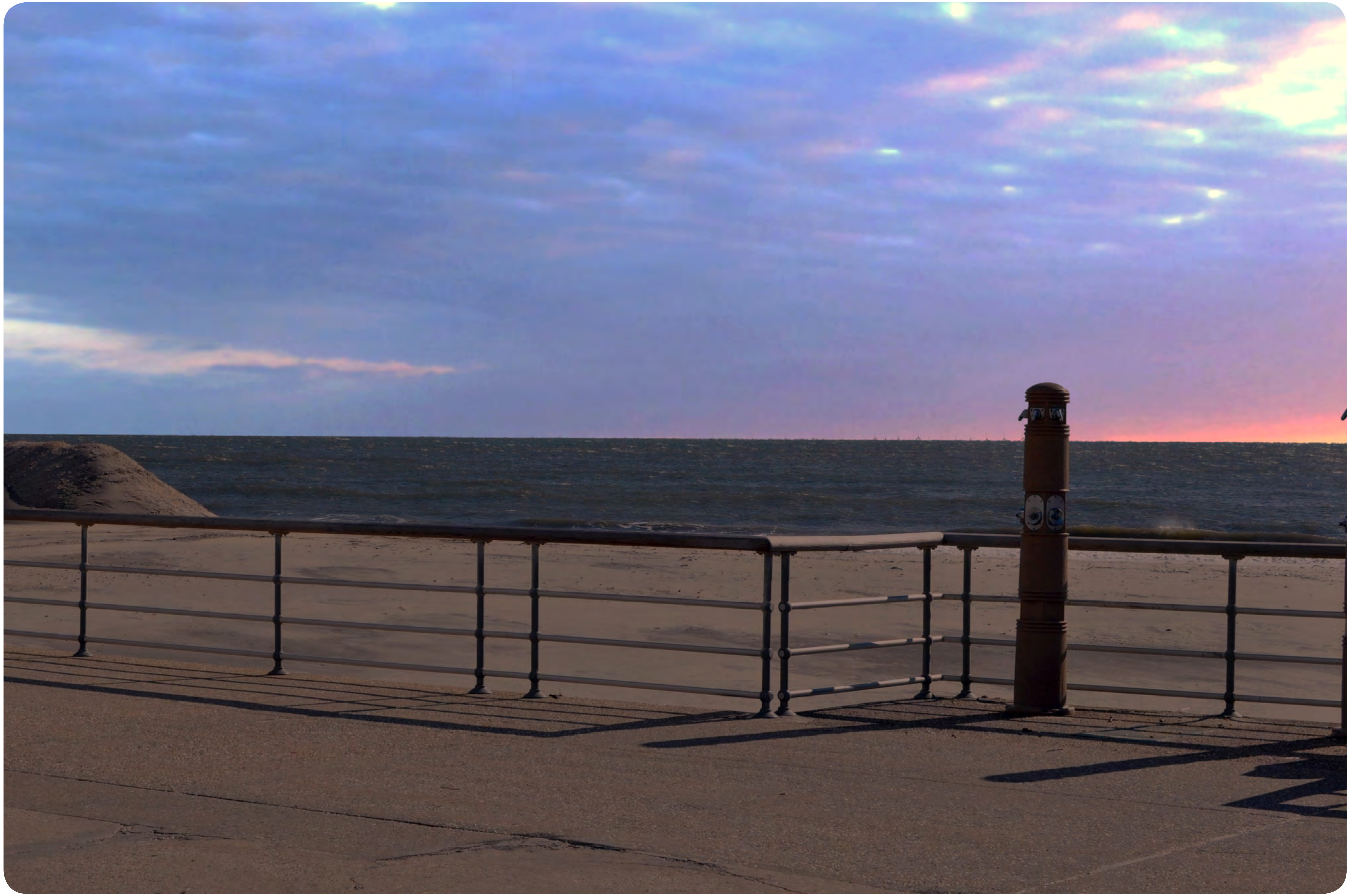

Jacob Riis Park

816MW Layout

Simulated Condition: Late Day/Partly Cloudy

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Jacob Riis Park

816MW Layout

Simulated Condition: Late Day/Overcast

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Jacob Riis Park

816MW Layout

Simulated Condition: Night/Clear

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Jacob Riis Park

816MW Layout

Simulated Condition: Night/Clear

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Attachment 42

GIS Shape Files

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Attachment 43

ICF Economic Benefits Study

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Attachment 44

Supplier Estimates of Job Creation

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Attachment 45

Redline of OREC Purchase and Sale Agreeement

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