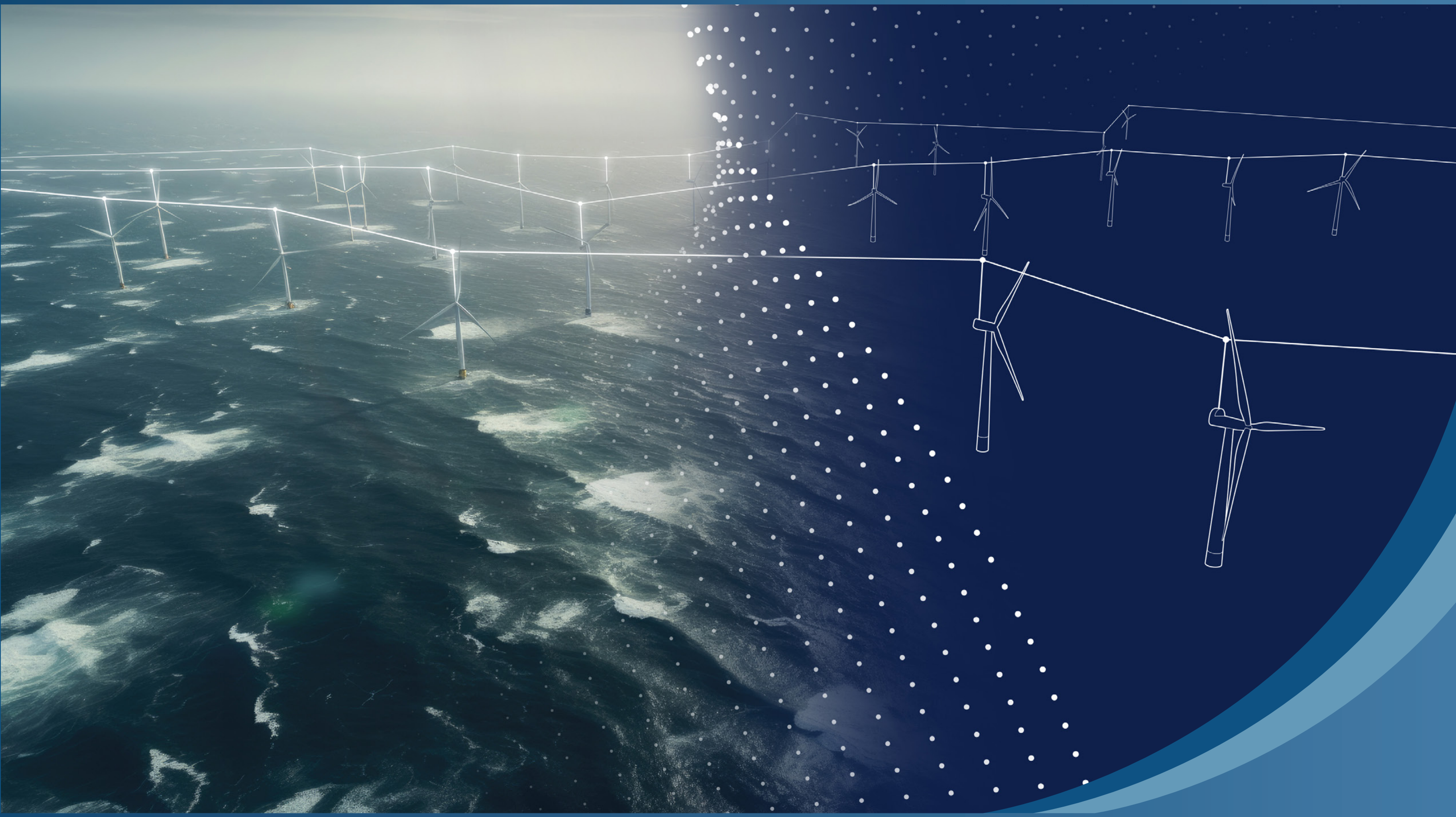
NYSERDA's Metocean Campaign: Hudson Central and Hudson South Lease Areas Offshore Wind Farm



Final Report | Report Number 24-14 | March 2024

NEW YORK STATE | NYSERDA New York State Energy Research and Development Authority

NYSERDA's Promise to New Yorkers:

NYSERDA provides resources, expertise, and objective information so New Yorkers can make confident, informed energy decisions.

Our Vision:

New York is a global climate leader building a healthier future with thriving communities; homes and businesses powered by clean energy; and economic opportunities accessible to all New Yorkers.

Our Mission:

Advance clean energy innovation and investments to combat climate change, improving the health, resiliency, and prosperity of New Yorkers and delivering benefits equitably to all.

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NYSERDA's Metocean Campaign: Hudson Central and Hudson South Lease Areas Offshore Wind Farm

Final Report

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NYSERDA Report 24-14 NYSERDA Contract 130227 March 2024

Notice

Preferred Citation

New York State Energy and Research Development Authority (NYSERDA). 2024. "NYSERDA's Metocean Campaign: Hudson Central and Hudson South lease areas Offshore Wind Farm" NYSERDA Report Number 24-14. Prepared by DNV Energy USA, Inc., Medford, MA. nyserda.ny.gov/publications

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Abstract

This report, prepared by DNV Energy USA, Inc., for the New York State Energy Research and Development Authority (NYSERDA), presents the findings from a comprehensive metocean data collection campaign in the New York Bight. The campaign involved deploying two floating lidar buoys to gather high-quality wind and wave data crucial for offshore wind project development. The collected data, spanning over two years, provided valuable insights into the wind resource potential and wave conditions in the region. This information significantly reduced the uncertainty for project developers, aiding in the planning and design of offshore wind farms. The report details the deployment process, data analysis, and the impact of the findings on the offshore wind industry, highlighting the importance of accurate metocean data in reducing project risks and supporting the responsible development of renewable energy resources. The net capacity factors estimated from the data are 48.9% for the Hudson Central area and 48.3% for the Hudson South area

Keywords

metocean data, offshore wind, floating lidar, wind resource assessment, New York Bight, renewable energy, wind speed measurement, wave data, offshore wind development, NYSERDA, wind energy analysis, environmental monitoring, data management, wind turbine siting, energy production estimation about DNV

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Acronyms and Abbreviations

°C	degrees Celsius
AC	acceptance criteria
ADCP	acoustic Doppler current profiler
AIS	automated information system
ASIT	Air-sea Interaction Tower
CFD	computational fluid dynamics
D	diameter
DC	direct current
DNV	DNV Energy USA, Inc.
ECMWF	European Centre for Medium-Range Weather Forecasts
ECN	Energy Research Centre of the Netherlands
ERA5	European Reanalysis 5
FLD	floating lidar device
FLS	floating lidar system
FLSS	Floating Lidar Sensor Solutions
GEOS-5	Goddard Earth Observing System Data Assimilation System, version 5
GPS	Global Positioning System
GWh/a	gigawatt-hours per annum
HVDC	high-voltage direct current
IEA	International Energy Agency
IEC	International Electrotechnical Commission
km	kilometers
kg/m3	kilograms per cubic meter
kV	kilovolt
KPI	key performance indicator

lidar	light detection and ranging
MMIJ	Measurement Mast Ijmuiden
MERRA-2	Modern-Era Retrospective analysis for Research and Applications, version 2
m	meter
MSL	mean sea level
m MSL	meters above mean sea level
m/s	meter per second
MW	megawatt
NASA	National Aeronautics and Space Administration
Narec	National Renewable Energy Centre
NOAA	National Oceanic and Atmospheric Administration
NOAH	Narec Offshore Anemometry Hub
NYSERDA	New York State Energy Research and Development Authority
O&M	operations and maintenance
OTS	Ocean Tech Services USA
OWA	Offshore Wind Accelerator
RMM	Reference Met Mast
SAT	site acceptance test
TI	turbulence Intensity
VMD	Virtual Met Data
VSC	voltage source converter
WHOI	Woods Hole Oceanographic Institution
WRF	Weather Research and Forecasting

Summary

Offshore wind energy could become a major source of affordable, renewable power for New York State, particularly on Long Island and in the New York City metropolitan area, where electric grid is highest. Wind turbines off New York's Atlantic coast could generate up to 39,000 megawatts (MW) of clean power for the State, enough to power 15 million homes.

Designing and operating offshore wind installations safely and efficiently requires a strong knowledge of meteorological and oceanographic (metocean) conditions. Previously, limited metocean data had been collected in the region, with much of our understanding of wind speeds and other conditions relying on modeled data. This uncertainty in physical conditions increases development risk and offtake bid prices. Improved characterization of wind, wave, and ocean current conditions within the offshore wind study areas can enhance the certainty of development conditions. This aids in planning activities such as refining project layouts, turbine siting, critical variables in lease auctions, and offtake.

In 2019, the New York State Energy Research and Development Authority (NYSERDA), in collaboration with DNV Energy USA, Inc. (DNV), and Ocean Tech Services (OTS), deployed two floating light detection and ranging (lidar) systems (FLS) approximately 70 kilometers (km) off the Atlantic coast of New York State, in the New York Bight. The FLS units have collected data for approximately two years, helping to better understand the metocean conditions for developing future offshore wind farms in the region. This data collection is part of NYSERDA's broader initiative to promote offshore wind development while addressing environmental, maritime, economic, and social issues, and overcoming market barriers to offshore wind technology to reduce electricity costs for consumers.

NYSERDA retained DNV to conduct independent assessments of the wind climate and energy production for six hypothetical offshore wind farms in the Hudson Central and Hudson South Lease Areas in the New York Bight. Based on the first three years of measured wind data, this energy assessment is one of several studies prepared for NYSERDA to support New York State's offshore wind target of 9,000 MW by 2035. Tables S-1 and S-2 summarize the projects and the wind resource and energy production analysis results.

Table S-1. Hudson Central Lease Area Project Summary

Project Summary			
Study year	2027	2030	2033
Turbine make and model	Theoretical 14 MW turbine	Theoretical 18 MW turbine	Theoretical 22 MW turbine
Turbine hub height (m)	140	155	165
Turbine rated power (MW)	14	18	22
Number of turbines	62	48	39
Installed capacity (MW)	868	864	858

Wind Resource Summary			
Average air density (kg/m^3)	1.22		
On-site measurement period (years)	2.4		
Long-term reference period (years)	23.2		
Average turbine hub-height wind speed (m/s)	10.1	10.2	10.3

Energy Assessment Summary			
Evaluation period (years)	30		
Gross energy (GWh/year)	4438.2	4442.9	4411.0
P50 loss factors			
- Turbine interaction effects (wakes and blockage)	94.4%	93.8%	93.0%
- Availability	94.9%	94.9%	94.9%
- Electrical	97.0%	97.0%	97.0%
- Turbine performance	96.7%	96.5%	96.4%
- Environmental	100.0%	100.0%	100.0%
- Curtailment	100.0%	100.0%	100.0%
Total losses	83.9%	83.2%	82.4%
Effect of asymmetric production	99.9%	99.9%	99.8%
P50 net energy (GWh/year)	**3722.9**	**3697.1**	**3632.9**
P50 net capacity factor	**48.9%**	**48.8%**	**48.3%**
P50 net energy per turbine (GWh/turbine/year)	**60.0**	**77.0**	**93.2**
1-year P99 net energy (GWh/a)	2854.6	2841.0	2792.1
1-year P99 net capacity factor	37.5%	37.5%	37.1%

Table S-2. Hudson South Lease Area Project Summary

Project Summary			
Study year	2027	2030	2033
Turbine make and model	Theoretical 14 MW turbine	Theoretical 18 MW turbine	Theoretical 22 MW turbine
Turbine hub height (m)	140	155	165
Turbine rated power (MW)	14	18	22
Number of turbines	62	48	39
Installed capacity (MW)	868	864	858

Wind Resource Summary			
Average air density (kg/m^3)	1.22		
On-site measurement period (years)	2.4		
Long-term reference period (years)	23.2		
Average turbine hub-height wind speed (m/s)	10.0	10.1	10.2

Energy Assessment Summary			
Evaluation period (years)	30		
Gross energy (GWh/year)	4383.9	4382.0	4350.0
P50 loss factors			
- Turbine interaction effects (wakes and blockage)	94.5%	93.8%	93.0%
- Availability	94.9%	94.9%	94.9%
- Electrical	97.0%	97.0%	97.0%
- Turbine performance	96.6%	96.5%	96.5%
- Environmental	100.0%	100.0%	100.0%
- Curtailment	100.0%	100.0%	100.0%
Total losses	83.8%	83.2%	82.4%
Effect of asymmetric production	99.8%	99.9%	99.8%
P50 net energy (GWh/year)	**3674.8**	**3645.8**	**3586.1**
P50 net capacity Factor	**48.3%**	**48.1%**	**47.7%**
P50 net energy per turbine (GWh/turbine/year)	**59.3**	**76.0**	**92.0**
1-year P99 net energy (GWh/a)	2818.1	2800.9	2755.1
1-year P99 net capacity factor	37.0%	37.0%	36.6%

The analysis reveals several key findings and factors affecting the results:

- The wind resource campaign used two FLS units: two EOLOS FLS-200 buoys each with one ZephIR ZX300M lidar unit onboard. After collecting two years of data, one FLS was relocated. This energy assessment relies on approximately two years of measured wind data from two buoy locations and one year from the new location. Each FLS location represents the lease area wind regimes.
- DNV derived hypothetical power curves for each study year based on current and expected trends in turbine technology.
- Offshore wind projects typically show lower energy sensitivity to changes in wind speed (sensitivity ratio) for offshore wind projects due to the higher wind speeds, although this also depends on turbine characteristics such as swept rotor size and rated power. Given the high wind speeds in the Hudson Central and Hudson South lease areas and the assumed turbine characteristics of the hypothetical turbines modeled for this preliminary assessment, the net energy is less sensitive to changes in wind speed and the sensitivity ratio approaches unity for this preliminary assessment. DNV notes that the sensitivity ratio and project uncertainty could change significantly depending on the final commercially available turbines selected.
- NYSERDA requested DNV to design hypothetical wind farm layouts for each study year in both the Hudson Central and Hudson South lease areas, totaling six layouts. While alternative, nongridded layouts are possible, the preliminary assessment uses gridded layouts for simplicity. The gridded layouts do not reflect New York State policy on layout preferences. Project capacities for each study year, set at approximately 860 MW, serve purely hypothetical purposes and do not represent DNV or New York State's opinion regarding project sizing.
- By assuming consistent distances between turbines within each row and column for each study year, the relative spacing as a function of the rotor diameter decreases as turbine sizes increase. For example, turbine spacing is 10.2 rotor diameters and 8.2 rotor diameters in study years 2027 and 2033, respectively, based on a fixed distance of 2,250 meters (m) distance between turbines. In practice, DNV anticipates wind farm developers to base turbine layouts on rotor diameter rather than fixed distances. As such, the layouts assumed for the later study years based on larger turbine technology may not necessarily reflect typical future layout designs. However, this approach is considered reasonable for this preliminary and generalized study. New York State continues to support strategic planning and stakeholder consultation for specific offshore wind project layouts.
- DNV predicted wind speed variation in the Hudson Central and Hudson South lease areas using the Virtual Met Data (VMD) mesoscale model, which is consistent with on-site measurements. The uncertainty analysis accounts for this variation.
- The assessment did not model a wind sector management strategy, and DNV has not included any losses that may be associated with this. Given the large interturbine spacings assumed, DNV considers a wind sector management strategy unlikely. For future projects, DNV recommends early engagement with the turbine supplier for layout approval and review by an independent engineer as part of thorough due diligence.

- The proposed Ocean Wind 1 (Lease 498) and Ocean Wind 2 (Lease 532) Offshore Wind Farms are distant from the Hudson Central and Hudson South turbines, making potential external wake effects negligible and, therefore, have not been considered in this assessment.
- Due to the unavailability of detailed information on other proposed wind farms, accurate modeling of their wake effects on the Hudson Central and Hudson South lease areas is not possible. DNV estimated future wake effects using a theoretical 14 MW turbine model at 140 m for these wind farms. DNV recommends reassessing the impacts of the proposed wind farms when more information becomes available.
- Aside from interannual variability, analysis uncertainty stems from loss factor uncertainty and measurement uncertainty. Reducing this uncertainty could involve obtaining commercially available turbine power curves and assessing electrical systems and access strategies for more refined estimates of electrical loss and turbine availability.

All these factors were considered in the analysis.

1 Introduction

New York State Energy Research and Development Authority (NYSERDA) retained DNV Energy USA Inc. (DNV), to manage and quality-check data for the on-site floating light detection and ranging (lidar) system (FLS) units through DNV's Resource Panorama service. DNV also completed independent analyses of the wind regime and energy production for two hypothetical offshore wind farms in the Hudson Central and Hudson South lease areas in the New York Bight.

DNV's scope of work included:

- Reviewing the FLS type validation and the predeployment validation of the units
- Commissioning the FLS commissioning
- Managing and analyzing data throughout the campaign
- Assessing the energy yield of generic offshore wind projects at the FLS location
- Reporting
- Making the data publicly available

This report, issued to NYSERDA under written agreement number 130227, dated August 16, 2018, compiles findings pertinent to this agreement. Although this document does not include the large amount of data generated during this campaign, the data is accessible on DNV's online platform: https://oswbuoysny.resourcepanorama.dnv.com/. The report covers the deliverables and findings related to the lidar validation, FLS commissioning, and energy assessments.

2 Campaign Overview

2.1 Floating Lidar Systems

Ocean Tech Services USA (OTS) supplied and installed the FLS units for this campaign using EOLOS FLS-200 buoys equipped with ZephIR ZX300M lidars.

Figure 1. EOLOS FLS-200 Used in the Campaign

Resource measurements from three locations were taken using two FLS units from August 2019 to January 2023. Table 1 summarizes the characteristics of the measurement campaign.

2.2 Floating Lidar System Locations

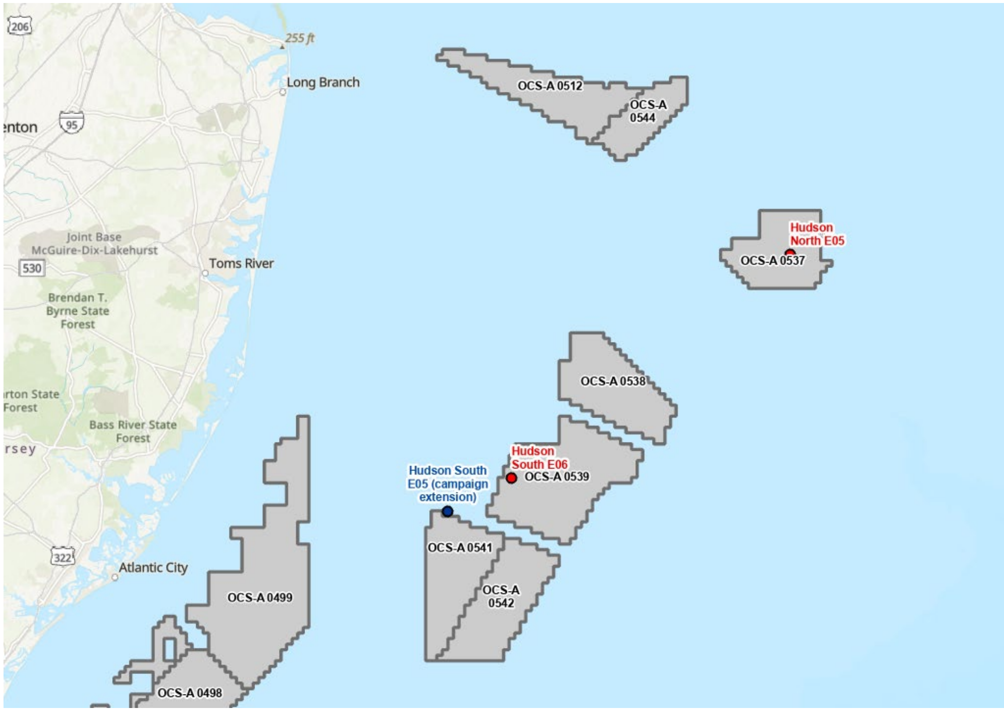
Table 1. Remote Sensing Campaign Summary

FLS	Buoy Reference	Lidar Make and Model	Measurement Heights (m MSL)	Measurement Period	Stage Maturity According to the OWA Roadmap[a]
EOLOS FLS-200	E05_N	ZephIR ZX300M	20, 40, 60, 80, 100, 120, 140, 160, 180, 200	August 2019 to September 2021	Stage 3
EOLOS FLS-200	E05_SW	ZephIR ZX300M	20, 40, 60, 80, 100, 120, 140, 160, 180, 200	January 2022 to January 2023	Stage 3
EOLOS FLS-200	E06_S	ZephIR ZX300M	20, 40, 60, 80, 100, 120, 140, 160, 180, 200	September 2019 to March 2022	Stage 3

[a] Carbon Trust Offshore Wind Accelerator Roadmap (Carbon Trust 2018).

Figure 2 shows the FLS locations.

Figure 2. Map of Floating Lidar System Locations



In September 2021, buoy E05, installed in Hudson North, completed two full years of measurement. Technicians brought the buoy back to shore for overall maintenance and then redeployed it for an additional year of measurement in the western part of the Hudson South call area (see location in Figure 2). This measurement campaign extension began in January 2022 and concluded in January 2023.

Appendix B provides full details of the history of each data source and its instrumentation. The documentation standard is reasonable and sufficient to ensure traceability of the instrumentation throughout the monitoring campaign for the E05_N, E05_SW, and E06_S FLS units. This consideration has been incorporated into the uncertainty analysis in section 5.4.

2.3 Floating Lidar System Deployments

DNV recognizes that the EOLOS FLS-200 has reached stage 3 maturity according to the "Carbon Trust OWA [Offshore Wind Accelerator] Roadmap for the Commercial Acceptance of Floating Lidar Technology." At the time of reporting, DNV had not received copies of the independent stage 3 validation reports that include the classification uncertainty for Fugro's Seawatch Wind Lidar Buoy. Previously, a type verification of the EOLOS FLS-200 buoy system occurred against a tall offshore meteorological mast at Measurement Mast Ijmuiden (MMIJ; ECN 2015) over six months from March 2015 to October 2015. During this period, the data recorded were compared to those from MMIJ. The verification concluded the system met best practices acceptance criteria and key performance indicators for accuracy at all comparable measurement heights. Detailed information about this validation can be found in ECN (2015).

Current industry guidance (Carbon Trust 2018) recommends conducting independent predeployment verifications against a trusted reference as part of a wind resource assessment to ensure the lowest uncertainty. The EOLOS FLS-200 buoys underwent two-phase prevalidations, one onshore and one offshore (DNV 2019b). During the onshore validations, which took place from December 7, 2018, to December 18, 2018, and the data were compared to a reference met mast. For the offshore validations, conducted from April 12, 2019, to May 12, 2019, the FLS units were compared to the National Renewable Energy Centre (NAREC) Offshore Anemometry Hub (NOAH) reference mast. All verifications concluded that the FLS units met the minimum key performance indicators and acceptance criteria for wind speed accuracy as defined by the Carbon Trust (2018) OWA Roadmap.

The FLS units were recorded data at the heights listed in Table 2. The lidar units were positioned on the buoys with the device lenses was approximately 2 meters (m) above sea level. The height above sea level of the lidars has been incorporated into the heights listed in Table 2 All floating lidar heights are referred to in mean sea level (MSL) for the remainder of this report.

The FLS buoys recorded mean wind speed and direction, maximum wind speed, and dispersion components during each 10-minute interval.

2.4 Data Processing

Data from the FLS buoys installed at Hudson Central and Hudson South are obtained through DNV’s Resource Panorama service. DNV processes and compensates this data for motion using the manufacturer’s algorithm and conducts additional quality checks to identify records affected by equipment malfunction and other anomalies.

Wind data coverage is good at E05_N and E05_SW. Coverage decreases at E06 in 2020 and 2021 because the FLS was either out of service or awaiting maintenance. Table 2 summarizes data coverage levels for the key parameters and instruments on each remote sensing device. Appendix D provides the monthly wind speed and data coverage results for the remote sensing devices.

Table 2. Summary of Site Data Coverage

Device	Height (m)	Available Period (Years)	Valid Period (Years)	Measured Wind Speed (m/s)	Wind Speed Data Coverage (%)
E05_N	140	2.1	1.9	10.2	92
	160	2.1	1.9	10.3	91
E05_SW	140	1.0	0.9	10.1	92
	160	1.0	0.9	10.3	92
E06_S	140	2.6	1.8	10.1	69
	160	2.6	1.8	10.2	68

2.5 Site Measurement Uncertainties

Table 3 presents the site measurement uncertainties estimated for the sites.

Table 3. Site Measurement Uncertainties

Uncertainty Category	% Wind Speed		
	E05_N	E05_SW	E06_S
Measurement accuracy	3.3	3.3	3.3

Measurement uncertainty for the floating lidars is based on the International Energy Agency (IEA) Floating Lidar Recommended Practices (IEA Wind 2017) and includes these components:

- **Classification uncertainty:** At the time of the energy analysis, DNV had not received classification trial results or environmental sensitivity analysis to determine classification uncertainty for the stage 3 EOLOS FLS-200 buoy system. DNV assumed a class number based on its lidar and FLS classifications knowledge. This report should slightly reduce the uncertainty levels.
- **Verification uncertainty**: This is based on the verification uncertainty analysis in the predeployment offshore verification reports completed for the EOLOS FLS-200 buoys deployed at the site (DNV 2019b).
- **Environmental condition uncertainty:** Results of the metocean comparison performed in DNV (2019b) and additional checks by DNV indicate that the environmental conditions in the Hudson Central and Hudson South lease areas are slightly harsher than those during the trial campaigns. An additional uncertainty has been applied to account for the impact of environmental variables outside of the FLS verification envelope.

3 Lidar Validation

DNV conducted an independent assessment to determine whether the validation and commissioning followed the guidelines set out in International Electrotechnical Commission (IEC 61400-12-1 2005) and industry best practices. Specifically, DNV reviewed documentation from OTS and EOLOS related to its onshore and offshore trials to evaluate:

- The condition and sea state during the validation trial compared to the sea states in the offshore study area
- Whether the FLS proposed to NYSERDA matched the system used in previous trials
- System and data availability
- Accuracy between the FLS and the reference wind measurement

The lidar validation occurred in three phases, detailed in the following subsections.

3.1 Desktop Validation and Type Certificate Review

The desktop validation aimed to ensure the suitability of the equipment selected and the validation process for the site where this equipment would be deployed, specifically the New York Bight.

DNV compared the significant wave height, average peak period, peak wave period, and wave direction metocean conditions at the Blyth, UK, where the FLS units were validated against an offshore met tower, with conditions in the New York Bight. The National Oceanic and Atmospheric Administration (NOAA) provided metocean data for the New York Bight, 60-minute averaged time series from January 1, 2015, to April 18, 2018. This analysis indicated that the metocean conditions in the New York Bight are slightly harsher than those at Blyth but not expected to exceed significantly the envelope of metocean conditions from the validation campaign at Blyth. Therefore, using the EOLOS FLS 200-unit data from the New York Bight is unlikely to introduce significant bias.

Subsequently, DNV conducted an independent review of the equipment type certificates by comparing the key performance indicators (KPIs) outlined in the OWA Roadmap, ver. 2, with data from a six-month validation campaign in 2015. The campaign assessed the EOLOS FLS-200 floating lidar buoys performance against specified criteria. DNV's review encompassed data analysis, evaluation of buoy maturity stages, and examination of additional analysis by the Energy Research Centre of the Netherlands (ECN) to validate the EOLOS FLS-200 buoys effectiveness. DNV's accreditation and membership in measurement institutes highlight its expertise in wind turbine measurements and verification.

3.2 Onshore Independent Validation

Zephir Ltd. conducted the onshore validation of the lidar at their test site in Pershore, UK, during December 7–18, 2018. During this period, the lidars were placed near a met tower to validate the wind speed measured by the lidar against the wind speed measured by the met tower.

The met tower, equipped with classical anemometry components (e.g., cup anemometers, wind vanes), served as the reference for verifying the lidar's wind speed and wind direction measurements. Those comparisons adhere to remote sensing best practices. Additionally, performance verification and uncertainty calculation followed the IEC 61400-12-1 standard.

After the test campaigns, the performance criteria confirmed that all lidars met the required standards.

Figure 3. Typical Setup of ZX Lidars Next to the Reference Mast at Pershore, UK

Onshore independent validation reports appear in Appendix B-2.

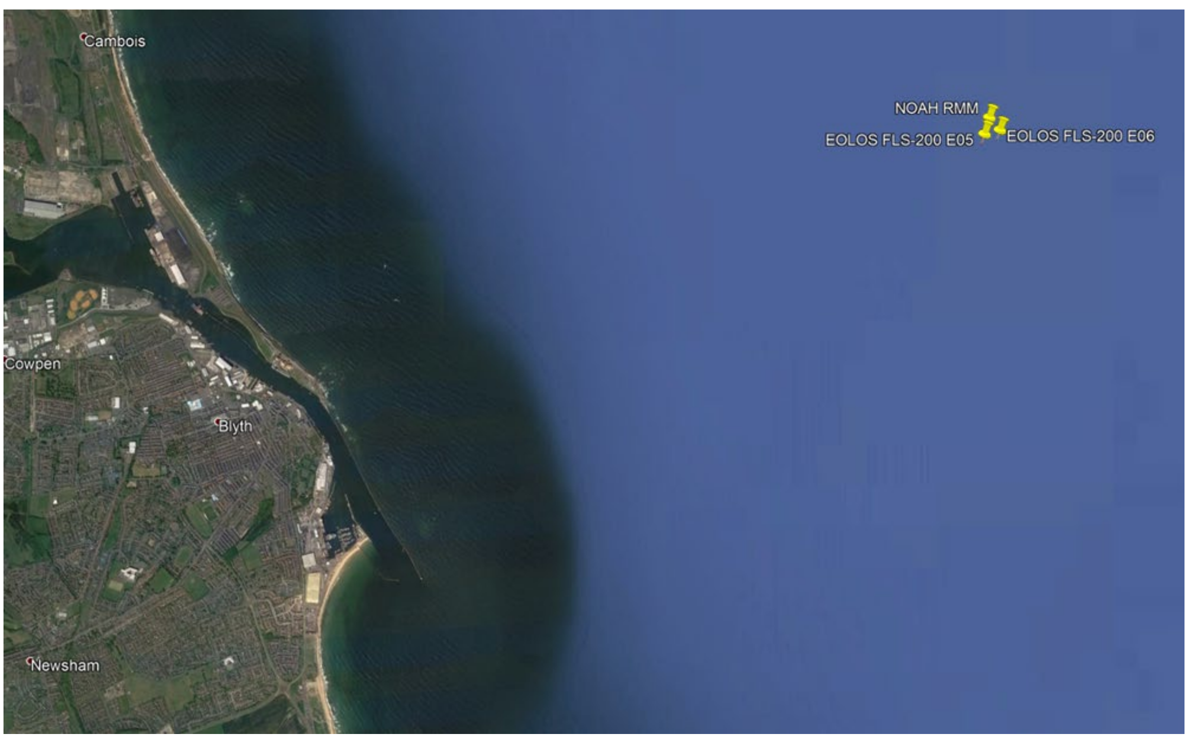
3.3 Offshore Validation

The predeployment validation of the EOLOS FLS-200 (Serial Number: E05) floating lidar device (FLD) employing a ZephIR lidar (ZX300M Serial Number: ZX842) took place over approximately 44 days from April 12, 2019, to May 26, 2019. This validation occurred against the 103 m NOAH Reference Met Mast (RMM), located in the North Sea northeast of the Port of Blyth (see Appendix A).

The RMM provided five reference levels (i.e., at 35 m, 52 m, 69 m, 86 m, and 103 m above MSL) for us to evaluate and compare data for the lidar unit on the buoy. We focused these evaluations on specific wind data quality-related KPIs and acceptance criteria (AC) as formulated in Carbon Trust (2018).

The FLS validation tests demonstrated a strong correlation in wind speeds across various heights, meeting best practice AC for mean wind speed and coefficient of determination between 35 m and 103 m. Additionally, the FLS accurately reproduced wind directions, as indicated by the successful attainment of best practice criteria for mean wind direction across all comparison heights.

Figure 4. Overview of National Renewable Energy Centre's National Offshore Anemometry Hub Reference Met Mast and EOLOS FLS-200 Floating Lidar Buoy



Offshore independent validation reports are provided in Appendix B-3.

4 Floating Lidar System Port Acceptance Tests and Commissioning

DNV observed EOLOS performing the site acceptance tests (SATs) in Blyth Harbor before deploying E05 and E06. They also completed the floating lidar predeployment validations at the NOAH Offshore Met Tower in the United Kingdom.

The FLS units underwent additional testing at the OTS shop in Avalon, NJ, prior to deployment of the two buoys in the New York Bight.

Appendix B-4 provides the commissioning reports.

4.1 Floating Lidar System Commissioning in Blyth, UK

On April 8, 2019, DNV witnessed the SAT of two 14 MW turbine buoys (E05 and E06) equipped with ZephIR ZX300M lidars (Serial Number: ZX842 and ZX844) at Blyth Harbor. DNV, along with EOLOS staff, conducted various relevant checks of technical setup and configurations during the SAT. DNV and EOLOS jointly documented the SAT progress.

The SAT verified and documented the following main topics in the checklist:

1. Actual inspection of the buoy
2. Power systems, including batteries, solar panels, wind turbines, and the fuel-powered generator
3. Meteorological and ocean state instrumentation
4. Communication systems, including telemetry, Global Positioning Systems (GPS), and on-board compass
5. ZephIR ZX300M lidar system
    - Installation position, mounting, and orientation
    - Measurement-height configuration
6. Calibration of the compass heading

4.2 Final Port Acceptance Tests in Avalon, NJ

On August 2, 2019, DNV witnessed the SAT of two 14 MW turbine buoys (E05 and E06) with ZephIR ZX300M lidars (S/N: ZX842 and ZX844) at the OTS shop in Avalon, NJ. Before the testing, DNV reviewed the Factory Acceptance Test Report (conducted by Floating Lidar System Supplier, or FLSS, in Spain) as well as the SAT procedures and checklist. DNV, together with EOLOS staff, conducted various relevant checks of technical setup and configurations during an approximately six-hour stay at the OTS location.

Figure 5 illustrates the two 14 MW turbine buoys (E05 and E06) at OTS for SAT prior to deployment in the New York Bight.

Figure 5. Theoretical 14-Megawatt Turbine Buoys

Comparison of the theoretical 14-MW turbine buoys, E05 (left) and E06 (right).

DNV and EOLOS documented SAT's progress, verifying the following topics as listed in the checklist:

1. Actual inspection of the buoy
2. Power systems, including batteries, solar panels, wind turbines, and the fuel-powered generator
3. Meteorological and ocean state instrumentation
4. Communication systems, such as telemetry, location systems (GPS), and on-board compass
5. ZephIR ZX300M lidar system:
    - Installation position, mounting, and orientation
    - Measurement-height configuration
6. Calibration of the compass heading

4.3 Observations and Recommendations

DNV began the Port Site Acceptance Test (SAT) for E05 and E06 with EOLOS on August 2, 2019, at 9:00 a.m. local time. EOLOS provided DNV with a port site assessment checklist, which DNV used as the basis for conducting the SAT at the OTS shop.

DNV made the following observations and recommendations regarding the SAT:

- The automated information system (AIS) on E05 and E06 are operational, but the buoys were awaiting permits at the time of the SAT.
- Cartridges for E05 and E06 were in transit during the SAT. DNV received photographic evidence of its installation on August 13, 2019, before deployment (see Appendix 0).
- The compasses showed a 6- to 10-degrees deviation from true north because they aligned with magnetic north. DNV recommends orienting the lidar to true north offshore for accurate wind direction measurements.
- Workers had not completely fixed the cables to the buoys, but they were near completion. The observed workmanship led DNV to conclude that no concerns existed regarding the tasks' completion.
- The camera on E05 was inaccessible via wi-fi connection. This issue is not critical, however, and does not prevent quality data collection.
- The absence of wind prevented a full validation of the turbines' and lidars' operation. However, all the functionality tests performed were reasonable.

Overall, the buoys' measurements, power, communication, and safety systems functioned well. The camera on E06 has an issue that requires further attention. This issue is not critical and does not prevent high-quality data collection, and EOLOS is actively working to resolve the issue.

5 Energy Assessments

During the measurement period, DNV conducted a full energy assessment of a generic project in the New York Bight, at three points using the collected data:

1. Initial energy assessment after one year of data
2. Final energy assessment after two years of data
3. Updated energy assessment incorporating the third year of data collection of E05 after its repositioning

5.1 Project Description

Figure 6 illustrates the Hudson Central and Hudson South lease areas, located offshore New York, approximately 70 kilometers (km) and 110 km south of Long Island, respectively.

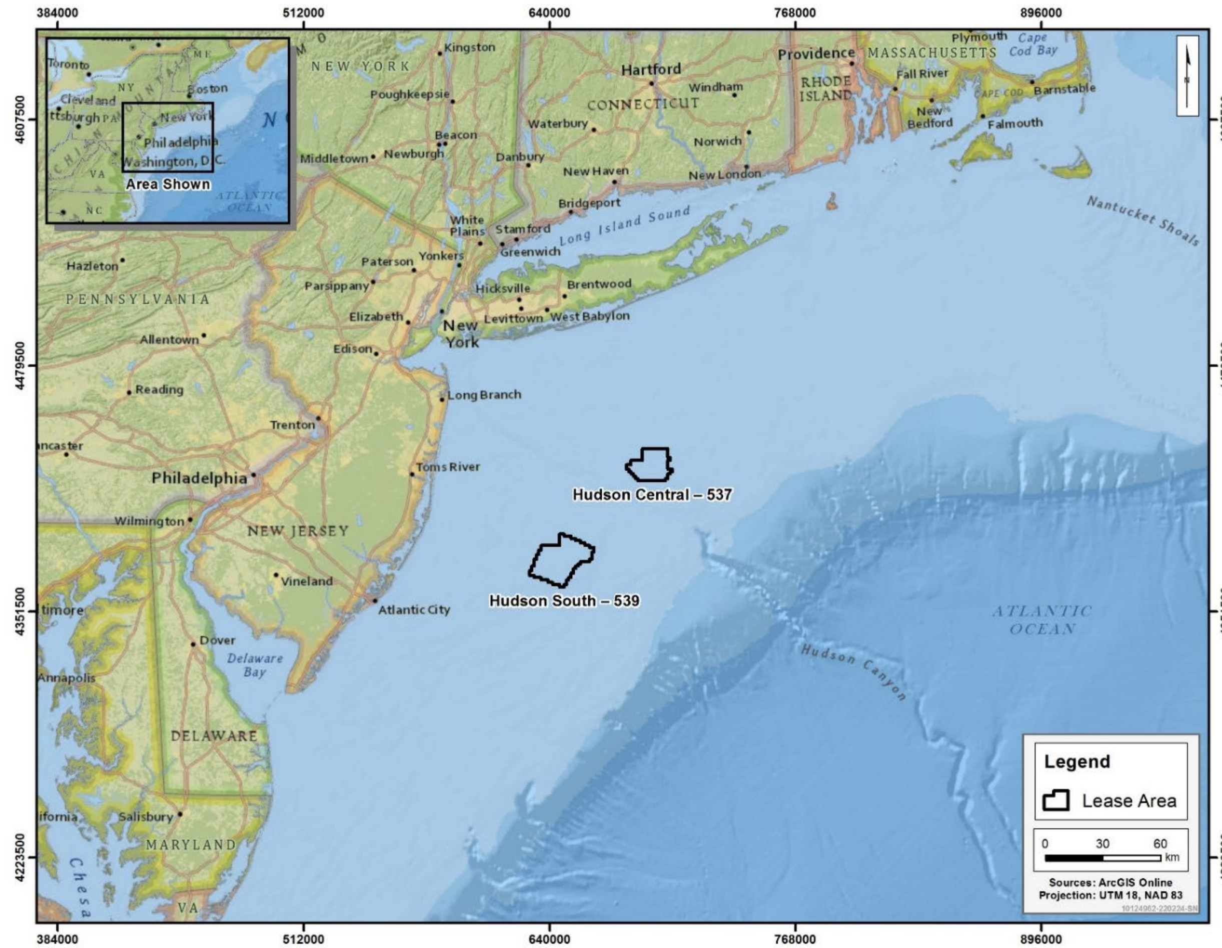
Table 4 shows the various layouts DNV analyzed for each lease area.

Table 4. Layouts Analyzed

Study Year	Number of Turbines	Turbine Model	Hub Height(m MSL)
2027	62	Theoretical 14 MW	140
2030	48	Theoretical 18 MW	155
2033	39	Theoretical 22 MW	165

Measurements of the wind regime occurred at three locations using two EOLOS FLS-200 buoys, which section 3 describes in detail.

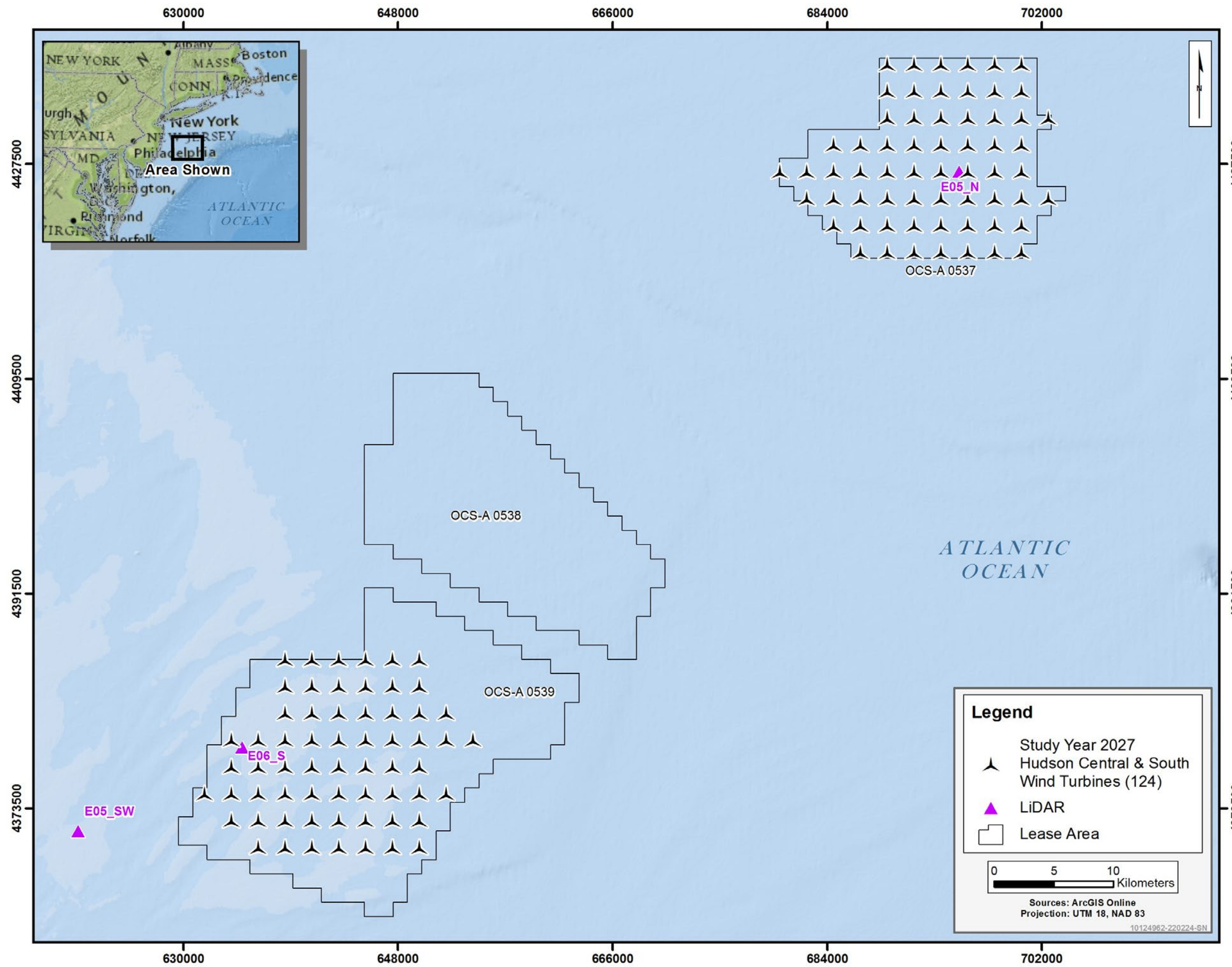
Figure 6. Map of Project Locations



5.1.1 Site Description

The Hudson Central and Hudson South lease areas are located in state waters offshore New York, approximately 70 km and 110 km south of Long Island, respectively. Figure 7 provides a map of the site, highlighting the measurement locations and modeled turbine locations. DNV notes that both lease areas use the same number of turbines, although this does not completely fill the Hudson South lease area. Section 2.3 has more information about the turbine layouts.

Figure 7. Map of the Hudson Central and Hudson South Wind Farm Study Year 2027 Scenario



Although DNV did not visit the site, DNV did visit the OTS shop in Avalon, NJ, on August 2, 2019, to witness the SAT for the EOLOS FLS-200 buoys deployed in the Hudson Central and Hudson South lease areas (DNV 2019a). Figure 8 shows photos of the EOLOS FLS-200 buoys Figure 8.

Figure 8. EOLOS FLS-200 Buoys

Photographs of the EOLOS FLS-200 buoys, E05 (left) and E06 (right). These buoys are deployed in the Hudson Central and Hudson South lease areas.

5.1.2 Turbine Technology

Table 5 summarizes the hypothetical turbine configurations under consideration for the Hudson Central and Hudson South lease areas.

Table 5. Proposed Hypothetical Turbine Model Parameters

Study Year	Turbine	Rated Power (MW)	Rotor Diameter (m)	Hub Height (m MSL)	Peak Power Coefficient (Cp)	Valid Power Curve Air Density (kg/m^3)
2027	Theoretical 14 MW	14	220	140	0.46	1.225
2030	Theoretical 18 MW	18	250	155	0.46	1.225
2033	Theoretical 22 MW	22	275	165	0.46	1.225

NYSERDA asked DNV to develop hypothetical power curves for each study year. These power curves, based on air densities of 1.225 kilograms per cubic meter (kg/m$^{3)}$, and been adjusted to the site density (IEC 2005), show peak power coefficients that, although relatively high, are considered attainable for the years 2027, 2030, and 2033.

5.1.3 Turbine Layouts

NYSERDA also asked DNV to design hypothetical wind farm layouts for each study year within he Hudson Central and Hudson South lease areas for a total of six layouts. In accordance with NYSERDA's request (Lampman 2022, Shen 2020,), the design follows these constraints:

- For simplicity, nearly identical layouts apply to each study year in both Hudson Central and Hudson South, with the only variations occurring with turbines 28 and 29, to accommodate the different shapes of the lease areas.
- The 2027 layouts serve as the base case scenarios. For subsequent study years, these base case layouts were reduced to maintain project capacities of approximately 860 MW by removing surplus turbine locations. The distances between turbines within each row and column remain consistent across study years.

Figure 7 shows the turbine layouts for the 2027 study year and the wind measurement locations. Additional layouts for the years 2030 and 2033 appear in Appendix A, while Appendix D provides the grid coordinates of the turbines.

Key aspects of the layout include:

- Typical large offshore wind developments use in-row and interrow spacings of approximately 8 rotor diameters (D). The derived turbine spacing for each hypothetical layout range from 8.2 D and 10.2 D from north to south and east to west based on a fixed distance of 2,250 m between turbine locations.
- Assuming the same total distances between turbines in each row and column across the lease areas for each study year results in decreasing relative spacing as turbine sizes increase in later years. DNV anticipates that wind farm developers will base layouts on the rotor diameter of the turbine model and not on fixed-distance spacing between turbines. Therefore, layouts assumed for the later study years, based on larger turbine technology, may not represent typical future designs. For this preliminary study, the simplistic approach is considered reasonable. New York continues to emphasize that the specific layouts for offshore wind projects will undergo strategic planning and consultation with stakeholders.
- DNV notes that alternative, nongridded layouts are possible within the lease areas. The gridded layouts assumed for this preliminary assessment aim for simplicity and do not reflect New York State policy on preferred layouts or approaches.
- This analysis does not include wind sector management strategies or any associated losses. Given the large interturbine spacings assumed, a wind sector management strategy is unlikely to be required. For future projects, DNV recommends that the turbine supplier be consulted early to approve the proposed layout, as well as have an independent engineer review the manufacturer's conclusions as part of thorough due diligence.

5.1.4 Neighboring Wind Farms

DNV reviewed publicly available data sources (American Clean Power 2023, Empire Wind 2023, Northeast Ocean Data 2023, Ocean Wind 2023) and identified nine lease areas with potential wind farms near Hudson Central and Hudson South. The locations of these lease areas are illustrated in Figure 9, and Table 6 provides the details for each potential wind farm.

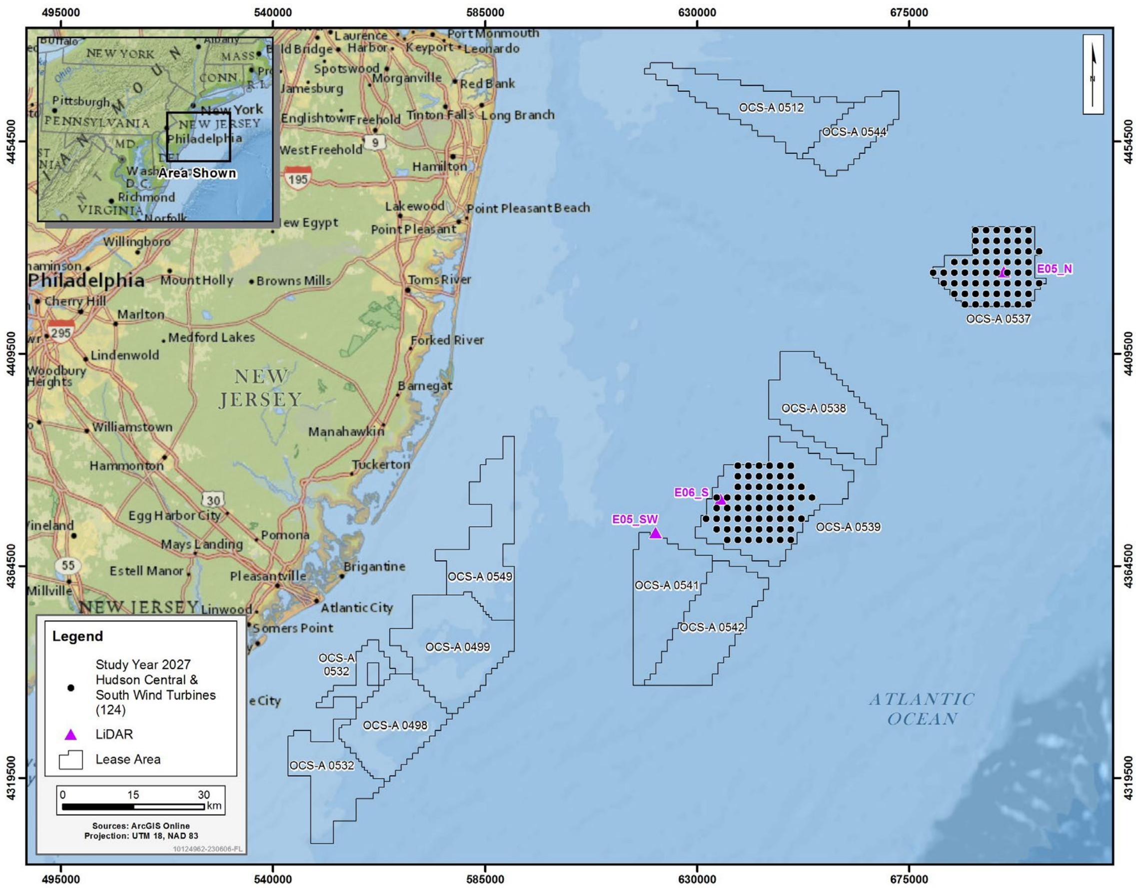
Due to the lack of publicly available details about the proposed wind farms, DNV cannot accurately model their wake effects on the Hudson Central and Hudson South lease areas. Consequently, the assessment does not include any potential impacts in the energy estimate. Given the significant distances of the proposed Ocean Wind 1 and Ocean Wind 2 offshore wind farms from the Hudson Central and Hudson South lease areas, the potential external wake effects from these projects are considered negligible and not included in this assessment.

For informational purposes, DNV estimated the future wake effects of other lease areas using a theoretical 14 MW turbine model at 140 m for these wind farms. The estimated loss appears in section 5. DNV recommends revisiting the impacts of the proposed wind farms once additional information becomes available.

Table 6. Summary of Proposed Neighboring Wind Farms

Wind Farm Name and Lease Area Number	Stage of Development	Distance to Hudson Central	Distance to Hudson South	Turbine Configuration
Attentive Energy, OCS-A 0538	Proposed	30 km southwest	Immediately northeast	Unknown
Atlantic Shores, OCS-A 0499	Proposed	115 km southwest	45 km southwest	Unknown
Atlantic Shores North, OCS-A 0549	Proposed	100 km southwest	40 km southwest	Unknown
Atlantic Shore Offshore Wind Bight, OCS-A 0541	Proposed	75 km southwest	Immediately southwest	Unknown
Empire Wind 1 and 2, OCS-A 0512	Proposed	40 km northwest	60 km north	Unknown
Leading Light Wind, OCS-A 0542	Proposed	75 km southwest	Immediately southwest	Unknown
Mid-Atlantic Offshore Wind, OCS-A 0544	Proposed	30 km northwest	55 km north	Unknown
Ocean Wind 1, OCS-A 0498	Proposed	140 km southwest	70 km southwest	98 x GE Haliade-X 12 MW (Ocean Wind 2021)
Ocean Wind 2, OCS-A 0532	Proposed	140 km southwest	75 km southwest	Unknown

Figure 9. Map of the Hudson Central and Hudson South Lease Areas with Layouts and Surrounding Lease Areas



5.2 Wind Analysis

The analysis of the site wind regime involved several steps, summarized as follows:

- Correlated data recorded at the site on a 10-minute basis to recover missing and historical data. Derived annual wind speeds at the site from August 2019 to January 2023.
- Correlated reference data sources with the measured data at FLS E05_N, E05_SW, and E06_S on a daily basis. Derived long-term mean wind speeds at the measurement locations for the periods from January 2000 to March 2023 using these correlations.
- Applied adjustments determined from correlations between the E05_N, E05_SW, and E06_S units and the reference data sources, to the annual wind speeds at the measurement locations for the full site period, aligning the data with the January 2000 to March 2023 timeframe.
- Used measured data at the measurement locations to derive boundary layer power law wind shear exponents. Used the shear estimates from the nearest lidar measurement heights to extrapolate the long-term mean wind regime at these locations to proposed hub heights of 140 m, 155 m, and 165 m.

- Extrapolated hub-height wind speed and direction frequency distributions from the measured data and subsequently adjusted these to reflect the predicted long-term mean wind speed at each measurement location.
- Performed wind flow modeling to determine the hub-height wind speed variations across the site.

The following sections provide results for each step of the process.

5.2.1 Measurement-height Wind Regime

5.2.1.1 Site Period Wind Speeds

As noted in section 3.1, the Hudson Central and Hudson South measurement sites recorded data from August 2019 to January 2023. Appendix E shows the monthly averages of upper-level measured wind speeds for each location.

To standardize the measurement periods, synthesized missing and historic wind speed and direction data for each measurement location's primary levels came from the neighboring lidar on a 10-minute directional basis. Table 7 presents the specific correlations in order of priority, as well as the site wind speeds and the synthesized data. Appendix E includes summaries of the regressions, associated statistics, and graphs.

Table 7. Site Period Wind Speeds

Device	Height (m)	Reference Device in Order of Priority	Site Period (years)	Site Period Annual Average Wind Speed (m/s)
E05_N	140	E06_S	2.4	10.1
	160	E06_S	2.4	10.2
E05_SW	140	E06_S	2.6	10.0
	160	E06_S	2.6	10.2
E06_S	140	E05_N, E05_SW	3.2	9.9
	160	E05_N, E05_SW	3.2	10.1

5.2.1.2 Extension of the Site Period to the Reference Period

Including quality reference data can reduce uncertainty in the estimating the long-term wind regime at the site. Selecting appropriate reference data requires ensuring that the reference data's wind regime is driven by factors similar to those affecting the site wind regime and that the reference data are consistent over the measurement period being considered.

Reference Data Considered

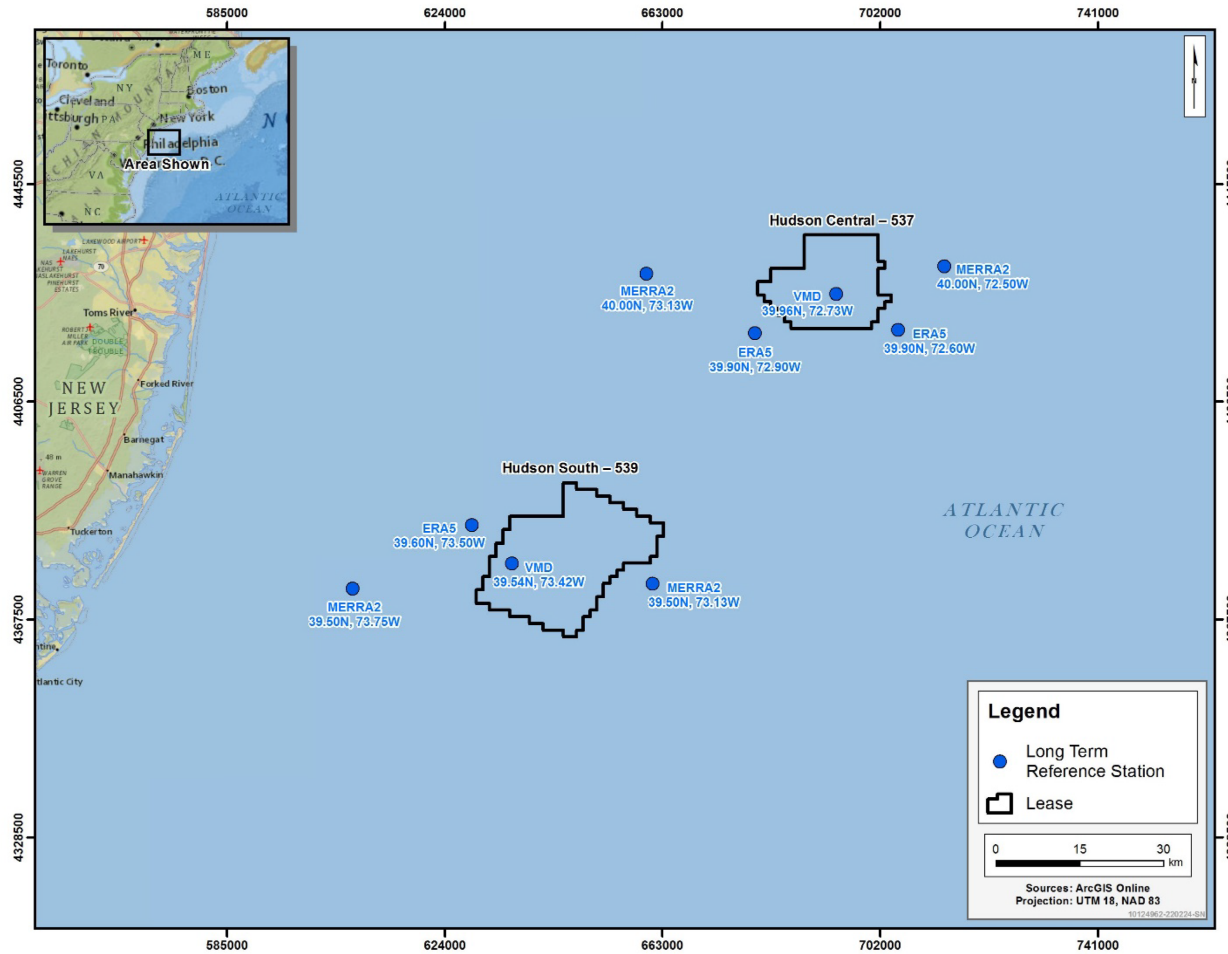
DNV conducted an extensive review of reference data sources around the Hudson Central and Hudson South lease areas to identify appropriate long-term reference stations for this analysis. Table 8 summarizes the stations considered, and Figure 10 shows their proximity to the Hudson Central and Hudson South lease areas.

Table 8. Reference Datasets Considered for Correlations to Site Data

Meteorological Data Source	Network	Start Date	End Date[a]
ERA5 39.90°N, 72.60°W	ECMWF	January 2000	March 2023
ERA5 39.90°N, 72.90°W	ECMWF	January 2000	March 2023
ERA5 39.60°N, 73.50°W	ECMWF	January 2000	March 2023
MERRA-2 40.00°N, 72.50°W	NASA	January 2000	March 2023
MERRA-2 40.00°N, 73.13°W	NASA	January 2000	March 2023
MERRA-2 39.50°N, 73.13°W	NASA	January 2000	March 2023
MERRA-2 39.50°N, 73.75°W	NASA	January 2000	March 2023
VMD 39.96°N, 72.73°W	DNV	January 2000	February 2023
VMD 39.54°N, 73.42°W	DNV	January 2000	February 2023

[a] Different end dates are the result of dataset availability at the start of the analysis.

Figure 10. Map Showing the Location of the Hudson Central and Hudson South Lease Areas and Potential Reference Data Sources



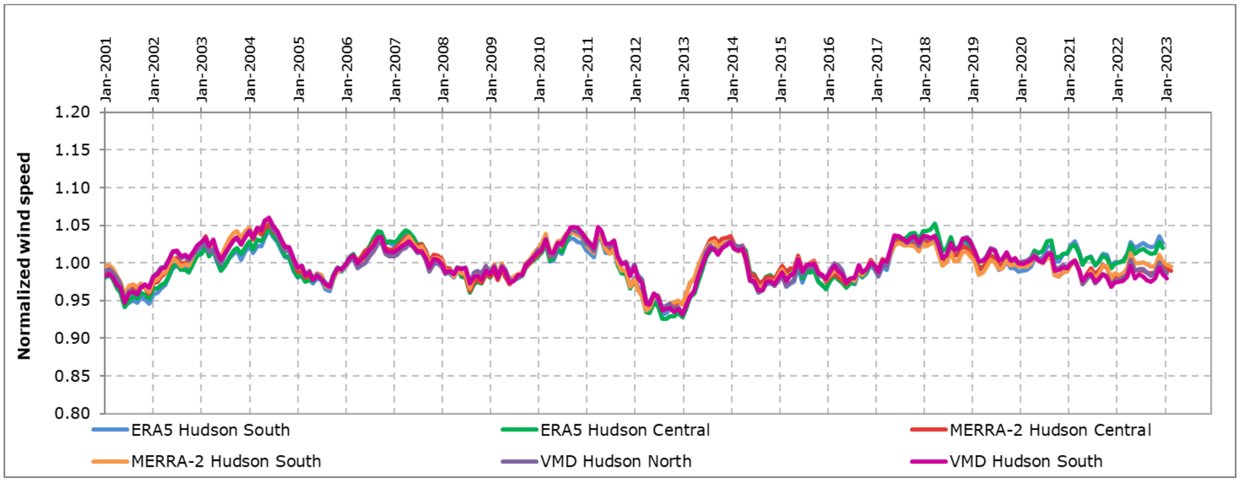
Appendix D includes additional information on long-term reference data sources DNV typically uses. A review of the suitability and use of these data reference sources in the analysis follows.

Reference Data Consistency

DNV evaluated the consistency of each reference data source by comparing it to regional trends, reviewing available station maintenance logs, and conducting a statistical change point analysis.

Figure 11 shows a plot of seasonally normalized 12-month moving average wind speeds for the reference data sources.

Figure 11. Reference Data Seasonally Normalized 12-Month Moving Average Wind Speeds



The European Reanalysis 5 (ERA5) data may have potential consistency issues in this area during the later part of its record; therefore, we have decided not to use ERA5 further. Instead, the remaining stations seem suitable as long-term reference points in the analysis. These stations have been correlated with the site data as detailed in section 5.2.2.

Quality of Correlation

To determine whether the use of reference data will reduce uncertainty, DNV completed a correlation of daily mean wind speeds between each consistent reference station and the site. Table 1 summarizes the results of this analysis.

Table 9. Summary of Correlations to 140-Meter Site Data

Device	Reference Station	Coefficient of Determination, R^2
E05_N	MERRA-2 40.00°N, 72.50°W	0.91
	MERRA-2 40.00°N, 73.13°W	0.92
	VMD 39.96°N, 72.73°W	0.93
E05_SW	MERRA-2 39.50°N, 73.75°W	0.89
	VMD 39.54°N, 73.42°W	0.93
E06_S	MERRA-2 39.54°N, 73.13°W	0.88
	MERRA-2 39.50°N, 73.75°W	0.91
	VMD 39.54°N, 73.42°W	0.92

DNV analyzed these results and assessed the uncertainties in the site period and reference period wind speeds. The analysis concludes that the method with lowest uncertainty extends the site data to the 23.2-year period available from the Modern-Era Retrospective Analysis for Research and Applications, ver. 2 (MERRA-2) and the Virtual Met Data (VMD) reference data.

For each of the selected reference data sources, independent correlations of daily data, binned by month, synthesized reference period wind speeds at the FLS units. Table 10 shows the resulting adjustments in the site period wind speeds and estimated long-term measurement height wind speeds at each of the measurement location.

Table 10. Site Period Wind Speed Adjustments and Estimated Measurement Height Long-term Wind Speeds

Device	Height (m)	Long-term Adjustment	Wind Speed (m/s)
E05_N	140	0.6%	10.2
	160	0.6%	10.3
E05_SW	140	0.1%	10.1
	160	0.2%	10.2
E06_S	140	0.4%	10.0
	160	0.2%	10.1

5.2.1.3 Measurement-height Wind Speed Uncertainties

Table 11 presents the uncertainties in determining the long-term measurement height wind speed for each of the measurement locations on the site.

Table 11. Long-term Measurement-height Wind Regime Uncertainties

Uncertainty Category	Uncertainty Subcategory	Uncertainty (% Wind Speed)					
		E05_N		E05_SW		E06_S	
		140 m	160 m	140 m	160 m	140 m	160 m
Long-term measurement-height wind regime	On-site data synthesis	0.2	0.2	1.8	1.9	0.8	0.8
	Variability of 23.2 years of data	0.9	0.9	0.9	0.9	0.9	0.9
	Correlation to reference station	1.3	1.4	1.8	1.9	1.3	1.3
	Consistency of reference data	1.3	1.3	1.3	1.3	1.3	1.3
	Wind frequency distribution—past[a]	1.3	1.3	1.2	1.2	1.1	1.1

[a] Expressed as percent energy, not wind speed

5.2.2 Hub-height Wind Regime

5.2.2.1 Hub-height Wind Speed

To extrapolate the wind speed estimates from the relevant primary measurement height to the 140 m, 155 m, and 165 m hub heights, the analysis evaluated the average power law at each measurement location across all relevant measurement heights. This power law was then applied to the primary measurement levels at each measurement location.

Table 12. Shear Exponents and Hub-height Wind Speeds

Device	Height (m)	Primary Measurement Height Long-term Wind Speed (m/s)	Measured Wind Shear Exponent	140 m Wind Speed Estimate (m/s)	155 m Wind Speed Estimate (m/s)	165 m Wind Speed Estimate (m/s)
E05_N	140	10.2	0.09	10.2	—	—
	160	10.3	0.09	—	10.2	10.3
E05_SW	140	10.1	0.10	10.1	—	—
	160	10.2	0.10	—	10.1	10.2
E06_S	140	10.0	0.09	10.0	—	—
	160	10.1	0.09	—	10.1	10.1

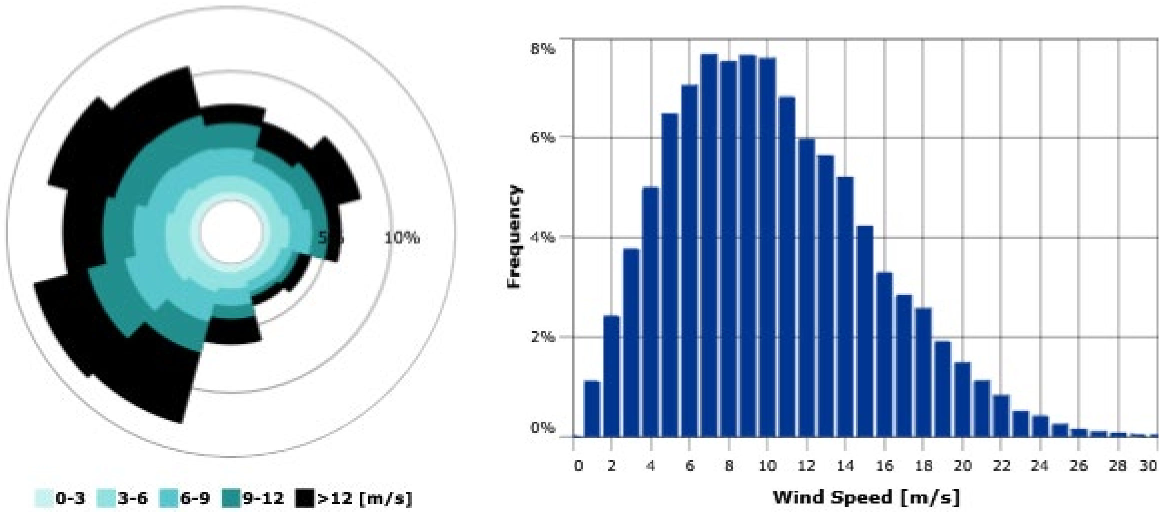
The analysis of wind shear data indicated that seasonal and diurnal variations in the shear exponent are consistent with DNV's expectations for the region.

5.2.2.2 Hub-height Wind Speed and Direction Distributions

The analysis developed hub-height wind speed and direction distributions by extrapolating the measured wind speed data on a time series basis. The frequency distributions for each FLS were scaled to match the representative, long-term hub-height mean wind speed at each FLS.

Figure 1 displays the representative, long-term hub-height wind rose and wind speed histogram for E05. Appendix E shows additional long-term hub-height wind speed and direction frequency distributions.

Figure 12. Long-term Hub-height Frequency Distribution and Wind Rose at 155 Meters for E05_N



5.2.2.3 Vertical Extrapolation Uncertainties

No material uncertainty exists at the FLS locations given the availability of measurements near hub height.

5.2.3 Wind Regime across the Site

5.2.3.1 Modeling

DNV used the VMD mesoscale model to predict wind speed variation over the Hudson Central and Hudson South lease areas. The wind flow modeling, which predicts long-term wind regimes at the Hudson Central and Hudson South turbine locations, was initiated using E05_N and E06_S, respectively. The analysis minimized uncertainty by starting with the most representative floating lidar data and using the DNV VMD mesoscale wind speed map to inform the wind speed variation across the site. Since the period of record for E05_SW is less than a year after quality control, this FLS was not used to inform wind speeds at the turbine locations.

DNV VMD predicted wind speed variation was also consistent with measurements the E05 and E06_SW FLS units recorded, showing wind speeds increasing as they move northeast away from the shore. Appendix E indicates the initiation measurement location for each turbine. Through this approach, we developed the predicted long-term mean wind speeds at each turbine's proposed hub heights as shown in Appendix E. Table 13 summarizes the average long-term wind speeds for the wind farms as a whole at each hub height.

Table 13. Wind Farm Average Wind Speeds

Lease Area	140 m Wind Speed (m/s)	155 m Wind Speed (m/s)	165 m Wind Speed (m/s)
Hudson Central	10.1	10.2	10.3
Hudson South	10.0	10.1	10.2

5.2.3.2 Spatial Variation Uncertainties

Table 14 quantifies the spatial variation uncertainty for the Hudson Central and Hudson South lease areas, based on the following considerations:

- The VMD mesoscale model indicates that wind speed variation for offshore projects is generally very low, resulting in lowered uncertainty.
- The wind speed variation the DNV VMD mesoscale model predicted is consistent with measurements, resulting in lower uncertainty.

Table 14. Spatial Extrapolation Uncertainties

Uncertainty Category	% Wind Speed	
	Hudson Central	Hudson South
Spatial extrapolation	0.7	1.0

5.2.4 Turbulence

Postprocessed turbulence intensity (TI) measurements were available from the floating lidars. However, industry standards generally accept that TI measurements from lidar devices (which are volume measurements) are not directly comparable to TI measurements from meteorological masts using cup anemometers (which are point measurements), which is currently the wind industry standard. DNV reviewed the measured TI from the FLS buoys and found it to be higher than expected.

Since no suitable measures of wind speed standard deviation were available at the sites, the analysis assumed an ambient TI based on data from the Woods Hole Oceanographic Institution (WHOI) Air-sea Interaction Tower (ASIT; MassCEC n.d.) and DNV's experience of the regional offshore wind regime. The assumption used an IEC fit profile with a TI of 4.5% at 15 meters per second (m/s; IEC 2005).

5.3 Energy Analysis

5.3.1 Gross and Net Energy Estimates

The WindFarmer software, along with the results of the wind-flow modeling and hypothetical turbine power curves DNV derived, calculated the gross energy production at each turbine location.

Table 15 and Table 16 provide the aggregated results for the sites.

To estimate the projected net energy production for each lease area, shown in Table 15 and Table 16, the analysis applied several energy loss factors to the gross energy production. These predictions represent the estimated annual production over the first 30 years of operation. Wind farms typically experience some time dependency in availability and other loss factors.

Table 15. Energy Production Summary for Hudson Central

Layout		Hudson Central			
Evaluation Period (years)		**30**			
Study Year		**2027**	**2030**	**2033**	
Wind Farm Rated Power		**868**	**864**	**858**	**MW**
Gross Energy Output		**4438.2**	**4442.9**	**4411.0**	**GWh/a**
1	**Turbine interaction effects**	**94.4**	**93.8**	**93.0**	**%**
1a	Internal wake and blockage effects	94.4	93.8	93.0	% project specific
1b	External wake effect	100.0	100.0	100.0	% not considered
1c	Future wake effect	100.0	100.0	100.0	% not considered
2	**Availability**	**94.9**	**94.9**	**94.9**	**%**
2a	Turbine availability	96.0	96.0	96.0	% project specific
2b	Balance of plant availability	99.0	99.0	99.0	% DNV standard
2c	Grid availability	99.8	99.8	99.8	% DNV standard
3	**Electrical efficiency**	**97.0**	**97.0**	**97.0**	**%**
3a	Operational electrical efficiency	97.0	97.0	97.0	% DNV standard
3b	Wind farm consumption	100.0	100.0	100.0	% DNV standard
4	**Turbine performance**	**96.7**	**96.5**	**96.4**	
4a	Generic power curve adjustment	100.0	100.0	100.0	% DNV standard
4b	High wind speed hysteresis	99.4	99.3	99.2	% project specific
4c	Site-specific power curve adjustment	99.3	99.3	99.3	% DNV standard
4d	Suboptimal performance	99.5	99.5	99.5	% DNV standard
4e	Blade and turbine degradation	98.5	98.5	98.5	% project specific
4f	Aerodynamic device degradation	100.0	100.0	100.0	% project specific

Table 15. (continued)

Layout		Hudson Central			
Evaluation Period (years)		**30**			
Study Year		**2027**	**2030**	**2033**	
Wind Farm Rated Power		**868**	**864**	**858**	**MW**
5	**Environmental**	**100.0**	**100.0**	**100.0**	**%**
5a	Performance degradation – icing	100.0	100.0	100.0	% project specific
5b	Icing shutdown	100.0	100.0	100.0	% project specific
5c	Temperature shutdown	100.0	100.0	100.0	% project specific
5d	Site access	100.0	100.0	100.0	% considered in 2a
6	**Curtailments**	**100.0**	**100.0**	**100.0**	**%**
6a	Wind sector management	100.0	100.0	100.0	% not considered
6b	Grid curtailment	100.0	100.0	100.0	% not considered
6c	Noise, visual. and environmental curtailment	100.0	100.0	100.0	% not considered
	Total Losses (%)	**83.9**	**83.2**	**82.4**	**%**
	Asymmetric production effect	99.9	99.9	99.8	%
	Net Energy Output	**3722.9**	**3697.1**	**3632.9**	**GWh/a**
	Net Capacity Factor	48.9	48.8	48.3	%
	Net Energy Output Per Turbine	**60.0**	**77.0**	**93.2**	**GWh/turbine/a**

Table 16. Energy Production Summary for Hudson South

Layout		Hudson South			
Evaluation Period (years)		**30**			
Study Year		**2027**	**2030**	**2033**	
Wind Farm Rated Power		**868**	**864**	**858**	**MW**
Gross Energy Output		**4383.9**	**4382.0**	**4350.0**	**GWh/a**
1	**Turbine interaction effects**	**94.5**	**93.8**	**93.0**	**%**
1a	Internal wake and blockage effects	94.5	93.8	93.0	% Project Specific
1b	External wake effect	100.0	100.0	100.0	% Not considered
1c	Future wake effect	100.0	100.0	100.0	% Not considered
2	**Availability**	**94.9**	**94.9**	**94.9**	**%**
2a	Turbine availability	96.0	96.0	96.0	% project specific
2b	Balance of plant availability	99.0	99.0	99.0	% DNV standard
2c	Grid availability	99.8	99.8	99.8	% DNV standard
3	**Electrical efficiency**	**97.0**	**97.0**	**97.0**	**%**
3a	Operational electrical efficiency	97.0	97.0	97.0	% DNV standard
3b	Wind farm consumption	100.0	100.0	100.0	% DNV standard

Table 16. (continued)

Layout		Hudson South			
Evaluation Period (years)		30			
Study Year		2027	2030	2033	
Wind Farm Rated Power		868	864	858	MW
4	**Turbine Performance**	**96.6**	**96.5**	**96.5**	**%**
4a	Generic power curve adjustment	100.0	100.0	100.0	% DNV standard
4b	High wind speed hysteresis	99.3	99.2	99.2	% project specific
4c	Site-specific power curve adjustment	99.3	99.3	99.3	% DNV standard
4d	Suboptimal performance	99.5	99.5	99.5	% DNV standard
4e	Blade and turbine degradation	98.5	98.5	98.5	% project specific
4f	Aerodynamic device degradation	100.0	100.0	100.0	% project specific
5	**Environmental**	**100.0**	**100.0**	**100.0**	**%**
5a	Performance degradation—icing	100.0	100.0	100.0	% project specific
5b	Icing shutdown	100.0	100.0	100.0	% project specific
5c	Temperature shutdown	100.0	100.0	100.0	% project specific
5d	Site access	100.0	100.0	100.0	% considered in 2a
6	**Curtailments**	**100.0**	**100.0**	**100.0**	**%**
6a	Wind sector management	100.0	100.0	100.0	% not considered
6b	Grid curtailment	100.0	100.0	100.0	% not considered
6c	Noise, visual, and environmental curtailment	100.0	100.0	100.0	% not considered
	Total Losses (%)	**83.8**	**83.2**	**82.4**	**%**
	Asymmetric production effect	99.8	99.9	99.8	%
	Net Energy Output	**3674.8**	**3645.8**	**3586.1**	**GWh/a**
	Net Capacity Factor	48.3	48.1	47.7	%
	Net Energy Output Per Turbine	**59.3**	**76.0**	**92.0**	**GWh/turbine/a**

Table 15 and Table 16 include potential sources of energy loss, using either the DNV standard values or estimates specific to these sites. The following text provides details on site-specific aspects of the loss estimates:

- 1a Internal wake and blockage effects: DNV recently validated its offshore wake modeling methodology using operational data from several offshore wind farms in Northern Europe (Beckford 2019, Papadopoulos 2019). As a result, DNV estimates offshore wake-only turbine interaction effects using the DNV WindFarmer: Analyst Eddy Viscosity wake model with large wind farm correction applied.

- DNV has conducted and continues to conduct extensive research into turbine interaction effects (Bleeg, Purcell, and Traiger 2018). This research suggests turbines cause lateral and upstream effects, which together create resistance, or blockage, on the wind flow, deflecting some of the flow above and around the wind farm. DNV estimated turbine interaction blockage effect losses of 0.1%, 0.8%, and 1.2% for study years 2027, 2030, and 2033, respectively, for both Hudson Central and Hudson South lease areas. These estimates use an empirical model on more than 50 computational fluid dynamics (CFD) simulations, as Bleeg, Purcell, and Traiger (2018) and Ostridge (2018) described.
- 1b External wake effect: The analysis did not consider external wake effects.
- 1c Future wake effect: Due to the unavailability of detailed information on the proposed lease area wind farms, the analysis could not accurately model wake effects for the Hudson Central and Hudson South lease areas. Therefore, the energy estimate does not include any impact from future wake effects. For informational purposes, DNV estimated the future wake effect by assuming s theoretical 14-MW turbine model at 140 m with generic turbine layouts covering the entire lease area. Table 17 shows the estimated loss factor for each scenario. DNV recommends reconsidering the wake effect when additional information about the proposed wind farms for these lease areas becomes available.

Table 17. Estimated Wake Losses

Project location	Study Year	Lease Areas Considered in Future Wake Loss	Approximate Future Wake Loss (%)
Hudson Central	2027	Hudson South, 538 Hudson South, 539 Hudson North, 544 Empire Wind, 512	0.6
	2030		0.6
	2033		0.5
Hudson South	2027	Hudson South, 538 Hudson South, 541 Hudson South, 542 Hudson Central, 537 Atlantic Shores, 499 Hudson North, 544 Empire Wind, 512	3.0
	2030		2.6
	2033		2.4

- 2a Turbine availability: For all study years for Hudson Central and Hudson South lease areas, DNV assumed a turbine availability based on the wave climate, anticipated operations and maintenance (O&M) access strategy, and the reliability and track record of the turbine technology to be installed in the future, based on DNV experience.
- 2b Balance of plant availability and 2c grid availability: DNV applied standard assumptions for the balance of plant and grid availability. DNV notes that these assumptions may vary significantly from standard values and can be mitigated to some extent, especially in early years of the project, through appropriate contractual provisions on a project-specific basis.

- 3a Operational electrical efficiency: An electrical loss of 3% has been assumed for all study years for Hudson Central and Hudson South, based on the anticipated subsea export cable lengths, assumed point-to-point high-voltage direct current (HVDC) links of 860-MW capacity, and an assumed voltage of ±320 kilovolt (kV) direct current (DC). The specific balance of plant infrastructure and grid connection point are not available at this stage given the preliminary nature of this assessment. Therefore, this estimate is not based on detailed modeling or project-specific calculations.

  DNV notes the use of shared 525 kV voltage source converter (VSC) infrastructure, expected to be viable in the years in question, would provide the most efficient electrical system configuration and reduce overall electrical losses.
- 4b High-wind speed hysteresis: The turbine cut-out wind speeds of 28.0 m/s were reduced to 25.0 m/s to estimate these losses.
- 4c Site-specific power curve adjustment: No site-specific wind flow issues are assumed to adversely affect turbine performance. The loss includes a 0.75% loss to account for the average blockage effect inherent in power performance test measurements (Papadopoulos 2019).
- 4d Suboptimal performance: A 0.5% loss is assumed for material performance deviations from the optimal power curve.
- 4e Blade and turbine degradation: This assumption accounts for the performance degradation of the turbine drivetrain and rotor assembly. The applied loss factor assumes that future projects will incorporate blade leading-edge protection systems and include a proactive plan for managing leading-edge erosion through regular blade inspections and repairs throughout the project's lifetime. For future projects, DNV recommends that an independent engineer review the plans for managing leading-edge erosion as part of thorough due diligence.
- 4f Aerodynamic device degradation: DNV assumes that aerodynamic devices will not be used at the projects.
- 5a Performance degradation-icing: DNV assumes that ice accretion on the blades is not applicable at these locations.
- 5b Icing shutdown: DNV assumes that ice accretion on the turbine casing is not applicable at these locations.
- 5c Temperature shutdown: DNV assumes an operating range of -10°C to 35°C for all turbine models.
- 5d Site access: Site access issued due to the project's offshore location is accounted for under loss 2a, turbine availability.
- 6a Wind sector management: No wind sector management has been considered.
- 6b Grid curtailment: No grid curtailment loss has been considered.
- 6c Noise, visual, and environmental curtailment: DNV did not receive or conduct studies for consideration.

5.3.1.1 Uncertainty in Loss Factors

Table 18 quantifies the uncertainties for the projects.

Table 18. Loss Factor Uncertainties

Uncertainty Category	Uncertainty Subcategory	% Energy
Loss factors	Wakes	1.6 – 1.8
	Availability	2.7
	Electrical	0.6
	Turbine performance	2.7
	Environmental	-
	Curtailment	-

5.3.2 Seasonal and Diurnal Distributions

The assessment of long-term average seasonal and diurnal variation in energy production relied on available data from the project sites. The assessment derived long-term average seasonal and diurnal variations in air density from temperature and pressure records at MERRA-2, and then scaled these variations to predict long-term annual site air densities.

Simulated time series of production data used the time series of density, wind direction, and wind speed, along with the WindFarmer energy models developed for the Hudson Central and Hudson South lease areas.

The uncertainty in predicting energy production for any given month or hour is significantly greater than the uncertainty in predicting annual energy production. The results presented include only wake and hysteresis losses.

5.4 Uncertainty

The main sources of deviation from the central estimate (P50) have been quantified and combined using a probabilistic model that assumes full independence between the sources. Additional details on this process follow.

5.4.1 Interannual Variability

Even with a perfectly defined central estimate, wind farm energy production varies from year to year due to factors such as natural variations in the wind regime, variations in system availability, and changes in environmental losses, categorized as interannual variability. Table 19 presents the estimated interannual variability for the sites.

Table 19. Interannual Variability

Uncertainty Category	Uncertainty Subcategory	%	Unit
Interannual variability	Wind frequency distribution, future	2.0	Energy
	Interannual variability of the wind	4.5	Wind speed
	Availability	3.0	Energy

5.4.2 Converting Wind Speed Uncertainties to Energy Uncertainties

The report previously described uncertainties in estimating site wind speed. Analysts controvert wind speed uncertainties into energy uncertainties using the sensitivity ratio. This ratio indicates how changes in wind speed affect net energy production and depends mainly on the wind speed distribution and the turbine's power curve. For example, a sensitivity ratio of 1.50 means a 2% reduction in wind speed at all measurement locations leads to a 3% reduction in net energy production. The sensitivity ratio is nonlinear over large ranges of wind speed, which this analysis accounts for. Table 20 reports the average calculated sensitivity ratios for the Hudson Central and Hudson South lease areas, showing variations of 10% in wind speed.

Table 20. Site Average Sensitivity Ratios

Lease Area	Study Year	Sensitivity Ratio
Hudson Central	2027	1.06
	2030	1.03
	2033	1.02
Hudson South	2027	1.05
	2030	1.03
	2033	1.01

The sensitivity of energy due to changes in wind speed (sensitivity ratio) for offshore wind projects generally decreases due to the higher wind speeds but also depends on turbine characteristics such as swept rotor size and rated power. In the Hudson Central and Hudson South lease areas, high wind speeds and the assumed turbine characteristics of the hypothetical turbines modeled for this preliminary assessment result in net energy being less sensitive to changes in wind speed, with the sensitivity ratio approaching unity. DNV notes that the sensitivity ratio and, therefore, project uncertainty may vary significantly depending on the final commercially available turbines selected for the projects.

5.4.3 Project Uncertainties

Table 21 through Table 26 summarize the project uncertainties considered in this analysis. The 1-year numbers represent any individual year in the 30-year life of the projects. The 10-year numbers represent the first 10 years of operation.

Table 21. Uncertainty in the Projected Energy Output for Hudson Central Study Year 2027

Source of Uncertainty/Variability	GWh/a			Equivalent Standard deviation (%)		
Measurement accuracy	137.8			3.7		
Long-term measurement-height wind regime	98.9			2.7		
Vertical extrapolation	0.0			0.0		
Spatial extrapolation	31.3			0.8		
Loss factors	155.0			4.2		
Interannual variability	202.3			5.4		
Future period under consideration	1 year	10 year	30 year	1 year	10 year	30 year
Overall energy uncertainty	**349.8**	**235.6**	**226.7**	**9.4**	**6.3**	**6.1**

Table 22. Uncertainty in the Projected Energy Output for Hudson Central Study Year 2030

Source of Uncertainty/Variability	GWh/a			Equivalent Standard Deviation (%)		
Measurement accuracy	133.1			3.6		
Long-term measurement-height wind regime	100.0			2.7		
Vertical extrapolation	0.0			0.0		
Spatial extrapolation	30.2			0.8		
Loss factors	154.5			4.2		
Interannual variability	196.7			5.3		
Future period under consideration	1 year	10 year	30 year	1 year	10 year	30 year
Overall energy uncertainty	**344.7**	**232.5**	**222.7**	**9.3**	**6.3**	**6.0**

Table 23. Uncertainty in the Projected Energy Output for Hudson Central Study Year 2033

Source of Uncertainty/Variability	GWh/a			Equivalent Standard Deviation (%)		
Measurement accuracy	129.4			3.6		
Long-term measurement-height wind regime	97.4			2.7		
Vertical extrapolation	0.0			0.0		
Spatial extrapolation	29.4			0.8		
Loss factors	154.2			4.2		
Interannual variability	191.7			5.3		
Future period under consideration	1 year	10 year	30 year	1 year	10 year	30 year
Overall energy uncertainty	**338.5**	**230.3**	**220.2**	**9.3**	**6.3**	**6.1**

Table 24. Uncertainty in the Projected Energy Output for Hudson South Study Year 2027

Source of Uncertainty/Variability	GWh/a			Equivalent Standard Deviation (%)		
Measurement accuracy	134.3			3.7		
Long-term measurement-height wind regime	97.7			2.7		
Vertical extrapolation	0.0			0.0		
Spatial extrapolation	40.7			1.1		
Loss factors	152.9			4.2		
Interannual variability	198.1			5.4		
Future period under consideration	1 year	10 year	30 year	1 year	10 year	30 year
Overall energy uncertainty	**345.4**	**233.1**	**224.8**	**9.4**	**6.3**	**6.1**

Table 25. Uncertainty in the Projected Energy Output for Hudson South Study Year 2030

Source of Uncertainty/Variability	GWh/a			Equivalent Standard Deviation (%)		
Measurement accuracy	131.3			3.6		
Long-term measurement-height wind regime	97.0			2.7		
Vertical extrapolation	0.0			0.0		
Spatial extrapolation	39.9			1.1		
Loss factors	152.2			4.2		
Interannual variability	193.8			5.3		
Future period under consideration	1 year	10 year	30 year	1 year	10 year	30 year
Overall energy uncertainty	**340.6**	**229.4**	**221.3**	**9.3**	**6.3**	**6.1**

Table 26. Uncertainty in the Projected Energy Output for Hudson South Study Year 2033

Source of Uncertainty/Variability	GWh/a			Equivalent Standard Deviation (%)		
Measurement accuracy	127.9			3.6		
Long-term measurement-height wind regime	94.6			2.6		
Vertical extrapolation	0.0			0.0		
Spatial extrapolation	38.8			1.1		
Loss factors	152.1			4.2		
Interannual variability	189.6			5.3		
Future period under consideration	1 year	10 year	30 year	1 year	10 year	30 year
Overall energy uncertainty	**334.8**	**227.1**	**217.5**	**9.3**	**6.3**	**6.1**

Table 27 through Table 32 summarize the results of the probabilistic simulation of net energy production.

Table 27. Summary of Project Net Average Energy Production for Hudson Central, 2027

Probability of Exceedance	1-Year (GWh/a)	10-Year Average (GWh/a)	30-Year Average (GWh/a)
50%	3735.5	3772.0	3722.9
75%	3505.6	3612.9	3571.1
90%	3287.2	3470.1	3432.4
95%	3148.0	3380.2	3351.1
99%	2854.6	3221.2	3198.7

Table 28. Summary of Project Net Average Energy Production for Hudson Central, 2030

Probability of Exceedance	1-Year (GWh/a)	10-Year Average (GWh/a)	30-Year Average (GWh/a)
50%	3709.9	3745.1	3697.1
75%	3484.4	3588.9	3548.2
90%	3268.1	3447.1	3411.7
95%	3130.8	3361.1	3331.7
99%	2841.0	3203.8	3174.1

Table 29. Summary of Project Net Average Energy Production for Hudson Central, 2033

Probability of Exceedance	1-Year (GWh/a)	10-Year Average (GWh/a)	30-Year Average (GWh/a)
50%	3646.3	3681.1	3632.9
75%	3424.4	3526.2	3486.1
90%	3212.5	3386.0	3350.8
95%	3077.4	3302.1	3271.3
99%	2792.1	3142.5	3118.8

Table 30. Summary of Project Net Average Energy Production for Hudson South, 2027

Probability of Exceedance	1-Year (GWh/a)	10-Year Average (GWh/a)	30-Year Average (GWh/a)
50%	3687.3	3723.0	3674.8
75%	3460.2	3566.4	3525.5
90%	3244.7	3424.3	3386.7
95%	3106.8	3335.3	3306.1
99%	2818.1	3177.8	3155.0

Table 31. Summary of Project Net Average Energy Production for Hudson South, 2030

Probability of Exceedance	1-Year (GWh/a)	10-Year average (GWh/a)	30-year average (GWh/a)
50%	3658.2	3692.6	3645.8
75%	3434.9	3538.6	3496.5
90%	3221.7	3398.6	3362.2
95%	3085.8	3313.3	3281.0
99%	2800.9	3152.7	3129.6

Table 32. Summary of Project Net Average Energy Production for Hudson South, 2033

Probability of Exceedance	1-Year (GWh/a)	10-Year Average (GWh/a)	30-Year Average (GWh/a)
50%	3599.4	3633.5	3586.1
75%	3380.0	3481.4	3440.3
90%	3170.4	3342.4	3307.4
95%	3037.0	3258.7	3229.7
99%	2755.1	3101.3	3078.4

6 Observations and Recommendations

DNV makes the following observations and recommendations regarding this analysis:

- DNV observes and opines the following regarding uncertainty:
  - Interannual variability, loss-factor uncertainty, and measurement uncertainty primarily drive the overall uncertainty in the analysis.
  - Obtaining commercially available turbine power curves could reduce uncertainty in the analysis.
  - Assessing electrical systems and access strategies could inform more refined estimates for electrical loss and turbine availability, thereby further reducing uncertainty.
- DNV derived hypothetical power curves for each study year based on current and expected trends in turbine technology.
- Offshore wind projects typically exhibit lower sensitivity of energy to changes in wind speed due to the higher wind speed, though sensitivity also depends on turbine characteristics such as swept rotor size and rated power. Given the high wind speeds in the Hudson Central and Hudson South lease areas and the assumed turbine characteristics of the hypothetical turbines modeled, net energy shows less sensitivity to wind speed changes, approaching unity in this preliminary assessment. DNV notes that the sensitivity ratio and the project uncertainty may vary significantly depending on the final commercially available turbines selected for the projects.
- NYSERDA requested that DNV design hypothetical wind farm layouts for each study year in each of the Hudson Central and Hudson South lease areas for a total of six layouts. DNV notes that alternative, nongridded layouts are possible within the lease areas. The gridded layouts have been assumed for this preliminary assessment for simplicity. The gridded layouts are not a reflection of New York State policy or preference for any predetermined layout or approach thereto. Project capacities for each study year remain approximately 860 MW and for hypothetical purposes and do not reflect DNV's or New York State's opinions regarding project sizing.
- By assuming the same total distances between turbines within each row and column for each study year, the relative spacing as a function of the rotor diameter decreases as turbine sizes increase in the later study years. For example, turbine spacing is 10.2 rotor diameters in 3037 and 8.2 rotor diameters in 2033, based on a fixed distance of 2,250 m between turbine locations. In practice, DNV anticipates that wind farm developers will design turbine layouts based on rotor diameter rather than fixed distances. Therefore, the layouts assumed for later study years based on larger turbines may not necessarily represent typical future layouts. However, for the preliminary and generalized study, this simplistic approach is reasonable. New York State continues to support that the specific layout of offshore wind projects will undergo strategic planning and locationally specific study consultation with stakeholders.
- DNV used the VMD mesoscale model to predict wind speed variation over the Hudson Central and Hudson South lease areas. These predictions are consistent with on-site measurements and have been included in the uncertainty analysis.

- DNV did not model wind sector management strategy or associate any losses. However, given the large interturbine spacings assumed, DNV considers a wind sector management strategy unlikely to be necessary. For future projects, DNV recommends early consultation with the turbine supplier to gain approval for the proposed layout and having an independent engineer review the manufacturer's conclusions as part of thorough due diligence.
- DNV recently validated its offshore wake modeling methodology using operational data from offshore wind farms in Northern Europe. As a result of that work, DNV estimates offshore wake-only turbine interaction effects using the DNV WindFarmer: Analyst eddy viscosity wake model with Large Wind Farm correction applied.
- DNV continues to research turbine interaction effects, finding that turbines cause both lateral as well as upstream effects, contributing to wind flow resistance or blockage, deflecting some of the flow above and around the wind farm. DNV estimated the wind flow blockage effects based on the assumed project configurations at Hudson Central and Hudson South lease areas using an empirical model based on more than 50 CFD simulations.
- Given the significant distances between the proposed Ocean Wind 1 (498) and Ocean Wind 2 (532) offshore wind farms and the Hudson Central and Hudson South lease areas, the potential external wake effects from these projects are considered negligible and excluded from this assessment.
- Due to the lack of publicly available details on other proposed wind farms, DNV cannot accurately model their wake effects on the Hudson Central and Hudson South lease areas. Therefore, the analysis does not include any impact from these projects. For informational purposes, DNV estimated future wake effects of the other lease areas using a theoretical 14-MW turbine model at 140 m for these wind farms. When additional information becomes available, DNV recommends reevaluating the impacts of the proposed wind farms.
- DNV has applied standard assumptions for the balance of plant and grid availability as a starting point. These assumptions may vary significantly from standard assumptions and could be mitigated, especially in early years of the project, through appropriate contractual provisions on a project-specific basis.
- This preliminary assessment does not include detailed modeling or project-specific calculations for operational electrical efficiency loss. DNV notes that the shared 525 kV voltage source converter (VSC) infrastructure, expected to be viable in the future, would likely provide the most efficient electrical system configuration and reduce overall electrical losses.
- Although the net energy yield (P50) and net capacity factor appear to decrease with each study year, the effect of increasing P50 per turbine over time as turbine technology improves should be considered. Despite marginal increases in wind speed with turbine height (0.1 m/s to 0.2 m/s gain over 25 m across the two sites), increased production per turbine results from the squared relationship of the swept area radius to power and the increased rated power of the turbine. As a result of the increase in turbine-rated power, fewer turbines are needed to reach the hypothetical installed capacity of approximately 860 MW, leading to a lower levelized cost of energy over time because fewer costs are associated with the number of turbines to be procured and the associated infrastructure. In addition, fewer turbines could result in lower internal wake and blockage impacts if turbine spacing is adjusted for the increased turbine size.

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Appendix A. Site Acceptance Test Pictures

A.1 Onshore Overview Pictures during Site Acceptance Test

Figure A-1. Mooring of the Buoys for New York Bight Deployment

Figure A-2. Tow Chains

A.2 Floating Lidar E05

Figure A-3. Floating Lidar E05 Control Boxes and Power Boxes

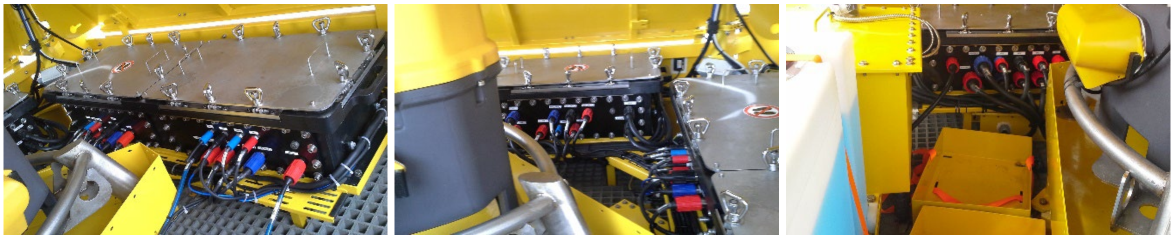


Figure A-4. Lidar Wiper Fluid Reservoir on Floating Lidar E05

Figure A-5. Lidar ZX 300-842 and Automatic Identification System on Floating Lidar E05

Figure A-6. Components of Floating Lidar E05

Shown are the lidar met station (left), weather station (middle), camera (lower right), and satellite antenna (right) on floating lidar E05.

Figure A-7. Acoustic Doppler Current Profiler on Floating Lidar E05

A.3. Floating Lidar E06

Figure A-8. Floating Lidar E06 Control Boxes and Power Boxes

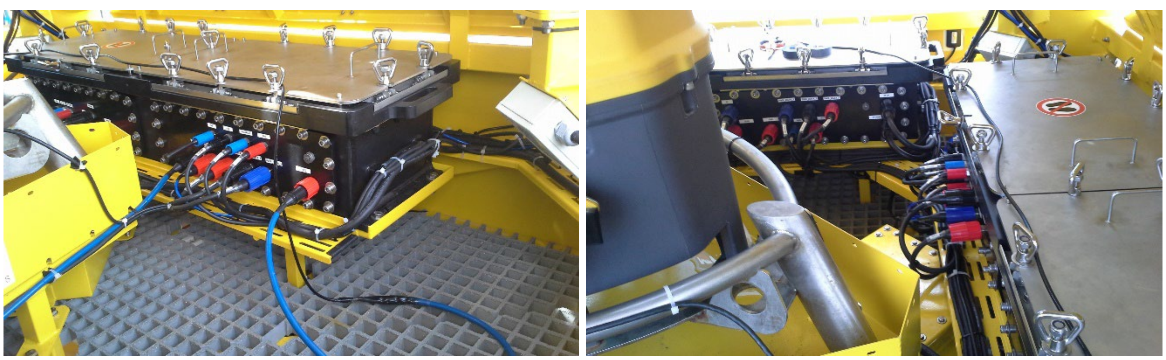


Figure A-9. Lidar Wiper Fluid Reservoir on Floating Lidar E06

Figure A-10. Lidar ZX 300-844 Automatic Identification System on Floating Lidar E06

This image was taken just before the wiper activated and cleaned the window.

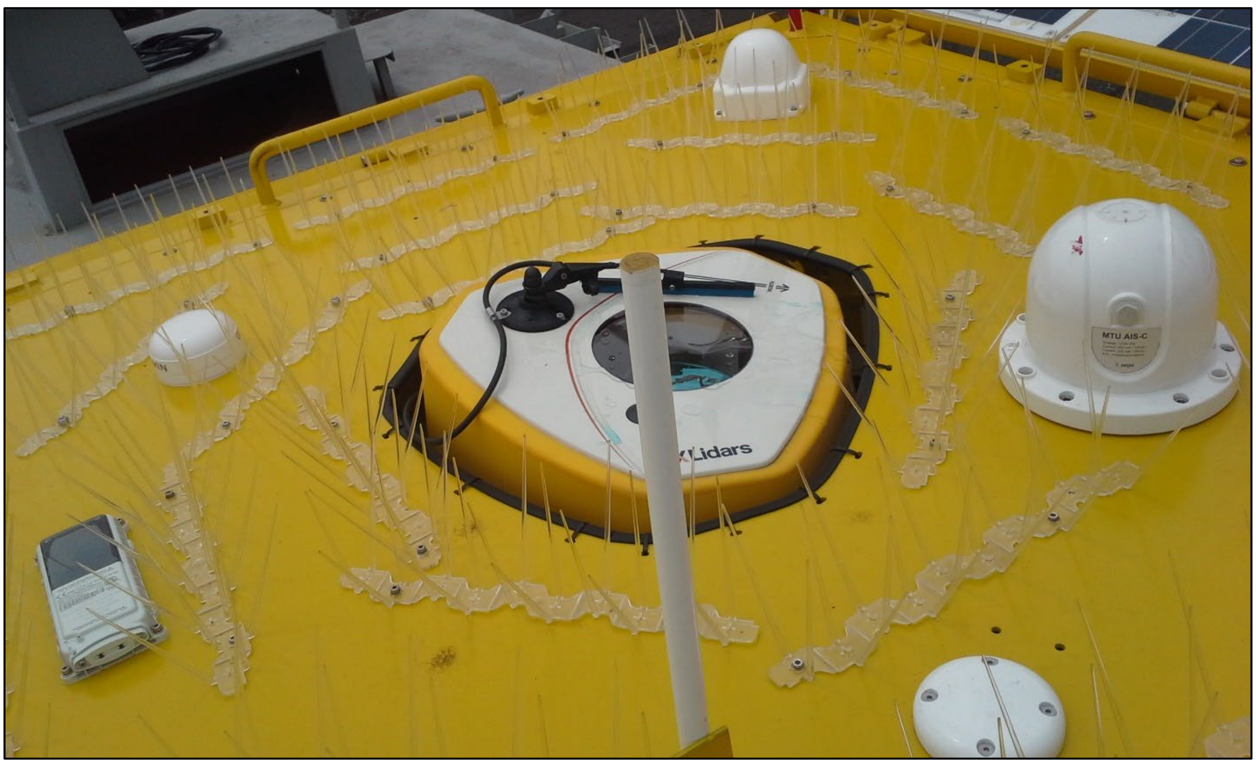


Figure A-11. Components of Floating Lidar E06

Shown are the lidar met station (left), weather station (middle), camera (lower right), and satellite antenna (right) on floating lidar E06.

Figure A-12. Acoustic Doppler Current Profiler on Floating Lidar E06

A.4 Post–Site Acceptance Test Images

Figure A-13. Fuel Cartridge Installation on Floating Lidar E05

Source: Ocean Tech Services USA; image provided on August 13, 2019.

Figure A-14. Fuel Cartridge Installation on Floating Lidar E06

Source: Ocean Tech Services USA; image provided on August 13, 2019.

Appendix B. Lidar Unit Validation Reports

B-1 Independent Review of Floating Lidar System Type Validation and Metocean Reports

- APP B.1a 10124962-R-1-A_final_draft_Blyth and New York Bight Metocean Comparison
- APP B.1b 10124962-R-4-A_draft_Type Validation Review

B-2 Onshore Lidar Independent Validation

- APP B.2a E05_ZEPHIR_300M_ZX842_GLGH-Lidar unit validation report_20190226_NYS_E05
- APP B.2a E06_ZEPHIR_300M_ZX844_GLGH-Lidar unit validation report_20190424_NYS_E06
- APP B.2c ZX-300M_ZX1071_DNV-GL-Lidar validation report_10284581-R-2-A (replacement Lidar)

B-3 Offshore Unit Validation

- APP B.3a NYSERDA_E05_ Validation Report
- APP B.3b NYSERDA_E06_ Validation Report

B-4 Floating Lidar System Port Acceptance Tests and Commissioning

- APP B.4a 10124962-HOU-T-01-A Port Site Acceptance Tests Blyth Harbor, UK
- APP B.4b 10124962-HOU-T-02-A Port Site Acceptance Test of Two EOLOS FLS-200 Lidar Buoys in Avalon, NJ

Appendix C. Wind Farm Site Information

Figure C-1. EOLOS Floating Lidar System Buoys

E05 (left) and E06 (right) EOLOS FLS-200 buoys docked at port.

Figure C-2. Map of the Hudson Central and Hudson South Study Year 2030 Scenario

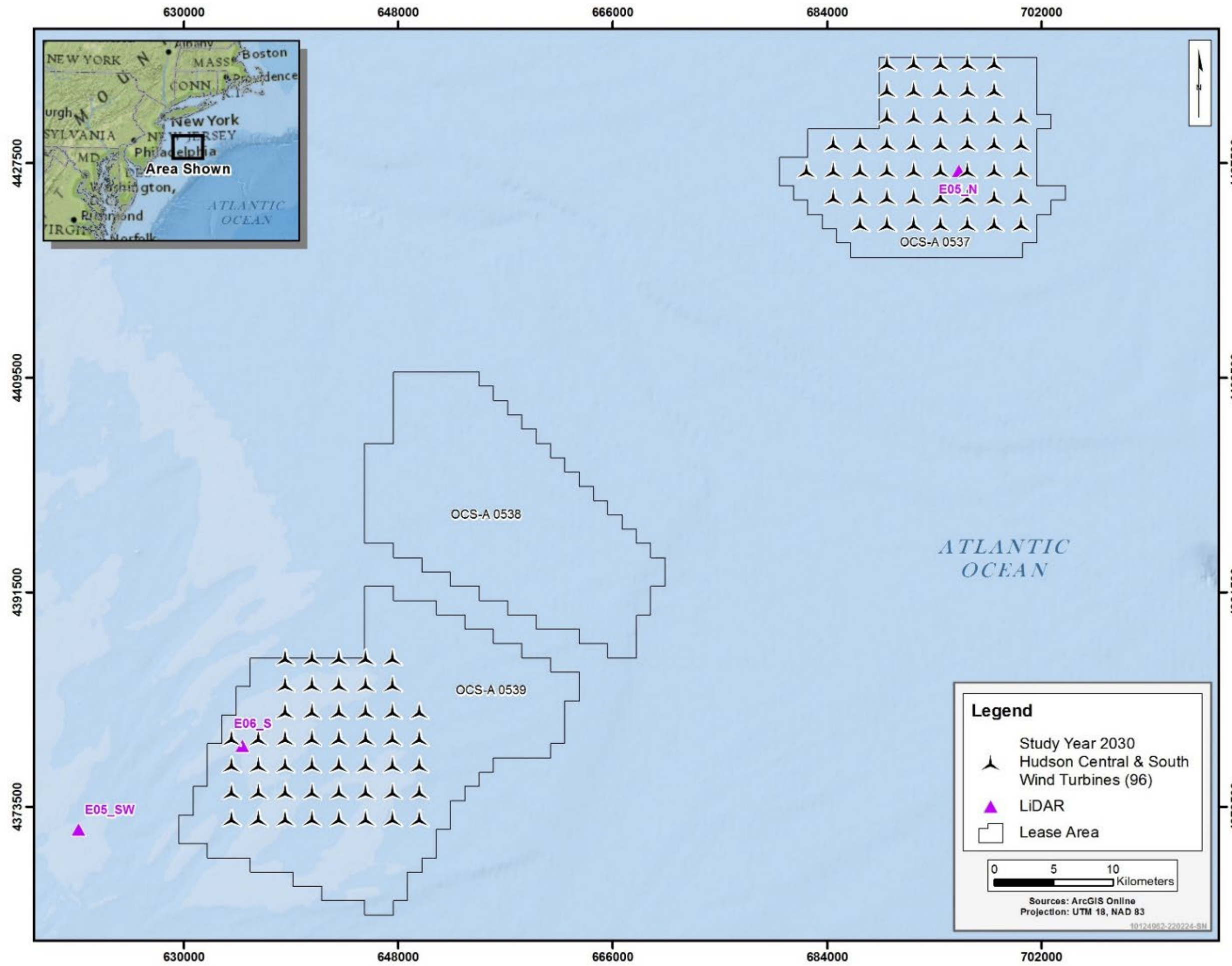
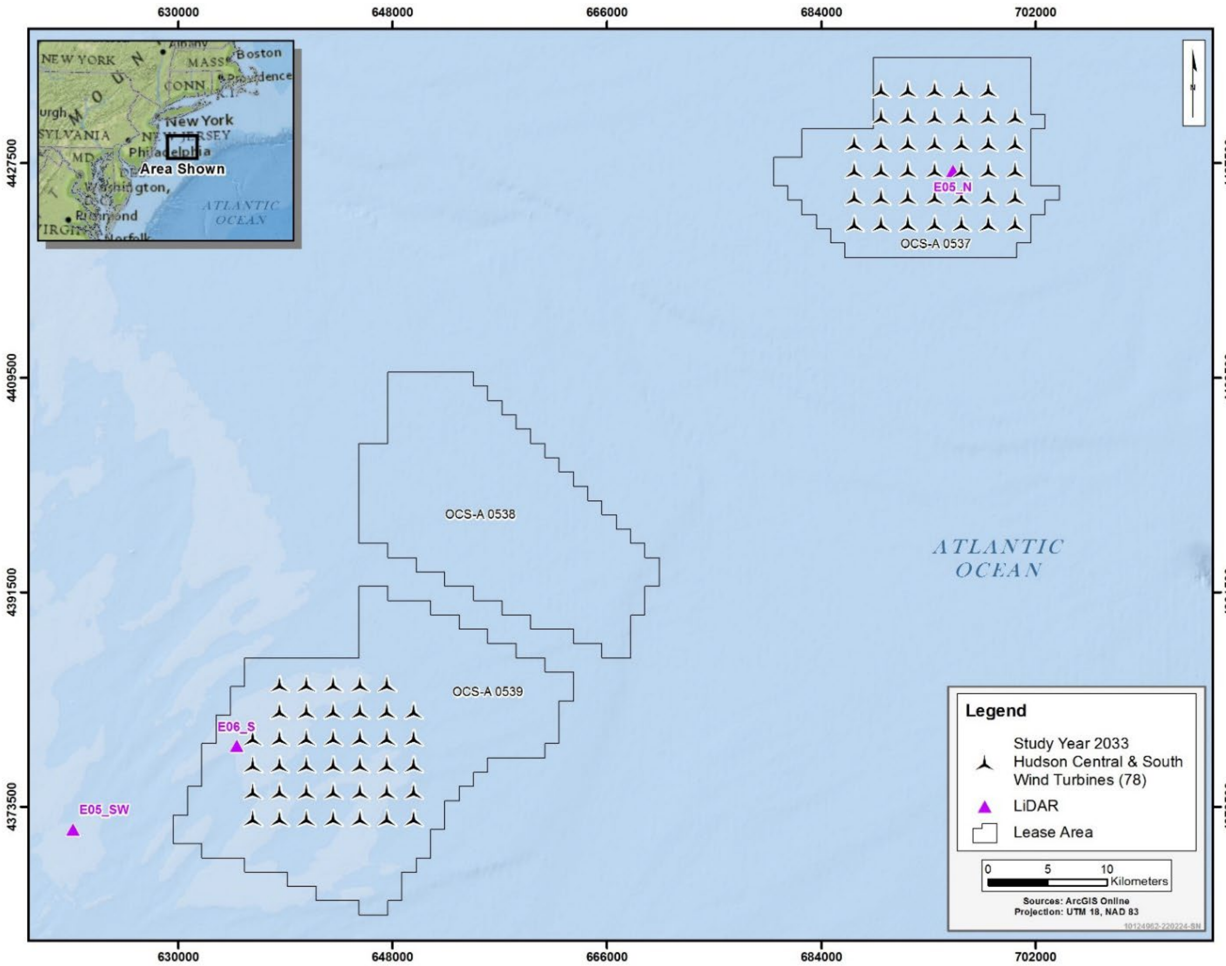


Figure C-3. Map of the Hudson Central and Hudson South Study Year 2033 Scenario



Appendix D. Wind Data Measurement and Analysis

D.1 Floating Lidar Device E05_N

Table D-1 Floating Lidar Device E05_N Configuration

Site Name	Hudson Central and Hudson South	Elevation (m)	Easting (m)	Northing (m)	Coordinate System	Datum	Zone
Device name	E05_N	0	695058	4426856	UTM	WGS84	18N
Installation date	2019-08-12	—	—	—	—	—	—

Device Description	
Device model	EOLOS FLS-200
Lidar type	ZephIR ZX300M
Unit serial no.	ZX842
Scan heights (m MSL)	20, 40, 60, 80, 100, 120, 140, 160, 180, 200
Averaging period (min)	10

The location in Table D-1 represents the initial deployment location. The device experienced occasional movement during the deployment period. However, the scale of the movements relative to the distance from the shore and the resolution of the wind maps used to model flow variation rendered these location changes negligible for the analysis. Therefore, we used the initial location in the analysis.

D.2 Floating Lidar Device E06_S

Table D-2. Floating Lidar Device E06_S Configuration

Site Name	Hudson Central and Hudson South	Elevation (m)	Easting (m)	Northing (m)	Coordinate System	Datum	Zone
Device name	E06_S	0	634944	4378580	UTM	WGS84	18N
Installation date	2019-09-04	—	—	—	—	—	—

Device Description	
Device model	EOLOS FLS-200
Lidar type	ZephIR ZX300M
Unit serial no.	ZX844
Scan heights (m MSL)	20, 40, 60, 80, 100, 120, 140, 160, 180, 200
Averaging period (min)	10

The location in Table D-2 represents the initial deployment location. The device experienced occasional movement during the deployment period. However, the scale of the movements relative to the distance from the shore and the resolution of the wind maps used to model flow variation rendered these location changes negligible for the analysis. Therefore, we used the initial location in the analysis.

D.3 Floating Lidar Device E05_SW Configuration

Table D-3. E05_SW Floating Lidar Device Configuration

Site Name	Hudson Central and Hudson South	Elevation (m)	Eastings (m)	Northings (m)	Coordinate System	Datum	Zone
Device name	E05_SW	0	621173	4371530	UTM	WGS84	18N
Installation date	2022-01-28	—	—	—	—	—	—

Device Description	
Device model	EOLOS FLS-200
Lidar type	ZephIR ZX300M
Unit serial no.	ZX842
Scan heights (m MSL)	20, 40, 60, 80, 100, 120, 140, 160, 180, 200
Averaging period (min)	10

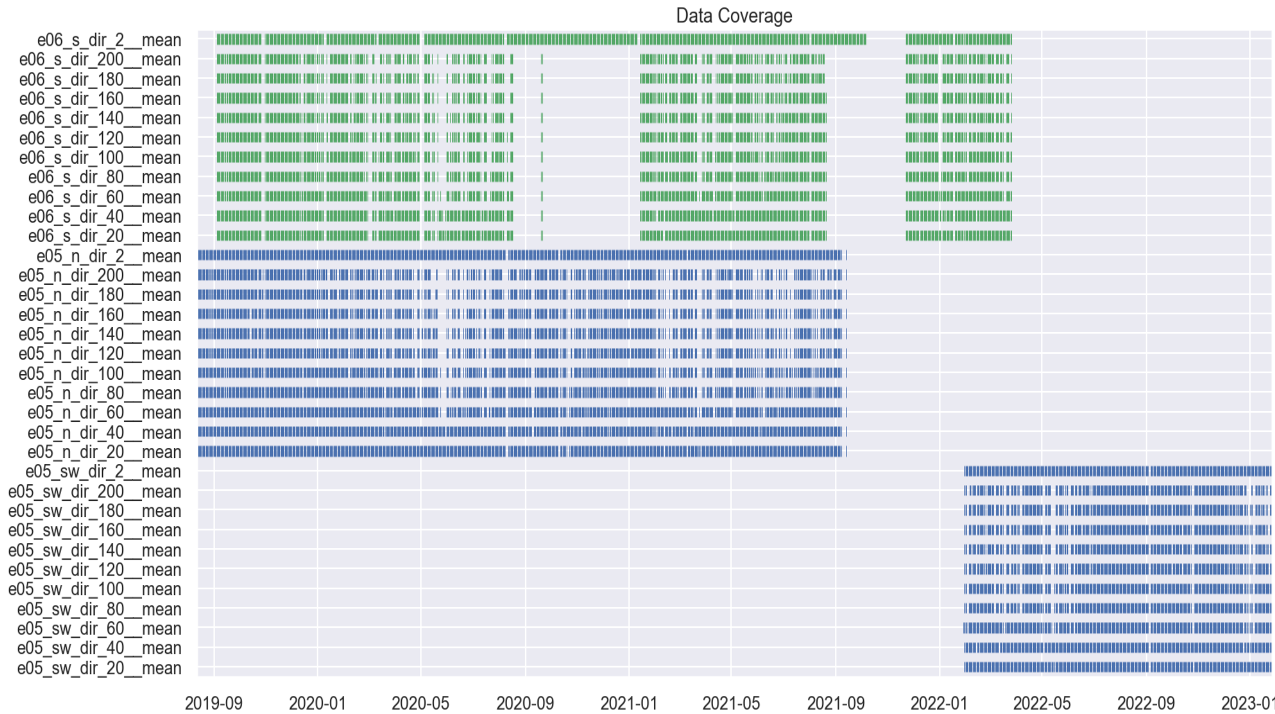
The location in Table D-3 represents the initial deployment location. The device experienced occasional movement during the deployment period. However, the scale of the movements relative to the distance from the shore and the resolution of the wind maps used to model flow variation rendered these changes negligible for the analysis. Therefore, we used the initial location in the analysis.

D.4 Measurement Location Data Coverage Summary

Figures D-1 and D-2 summarize data coverage based on wind speed and wind direction. Sensor labels identify the lidar location, type, and height.

Figure D-1. Wind Speed Data Coverage

Figure D-2. Wind Direction Data Coverage



D.5 Reference Wind Data

D.5.1 Modern-Era Retrospective Analysis for Research and Applications, Version 2, Data

The Modern-Era Retrospective Analysis for Research and Applications, ver. 2 (MERRA-2), dataset comes from the National Aeronautics and Space Administration (NASA; 2024). NASA produces this dataset by assimilating satellite observations with conventional land-based meteorology measurements using the Goddard Earth Observing System, ver. 5.12.4 (GEOS-5.12.4), atmospheric data assimilation system. The analysis occurs at a spatial resolution of 0.625° longitude by 0.5° latitude. DNV typically acquires hourly time series of two-dimensional diagnostic data at a surface height of 50 m for suitable grid cells near the project site.

D.5.2 European Reanalysis Version 5 Data

European Reanalysis 5 (ERA5) is the fifth generation of the European Centre for Medium-Range Weather Forecasts (ECMWF) atmospheric reanalysis of the global climate (2024). It provides data with significantly higher spatial and temporal resolution than its predecessor, ERA-Interim (2014). Hourly analysis fields are at a horizontal resolution of 31 km, including wind data at 100 m above ground level, as well as surface air temperature and air pressure. ERA5 incorporates vast historical measurement data from satellites, commercial aircraft, and ground-based sources (Copernicus 2024, ECMWF 2024) (D-1, D-2, and D-3).

D.5.3 Virtual Met Data

The DNV Virtual Met Data (VMD) results from a mesoscale-model–based downscaling system that generates high-resolution long-term reference time series data for any location. VMD primarily relies on the Weather Research and Forecasting (WRF) Model, a mesoscale model that a consortium of more than 150 international agencies, laboratories, and universities developed and maintains. VMD uses high-resolution inputs, including MERRA-2, global analyses of soil temperature and moisture, sea surface temperature, sea ice, and snow depth at a 25 km resolution, available every three hours and daily. A sophisticated land surface model predicts surface fluxes of heat and moisture to the atmosphere, reflected shortwave radiation, and longwave radiation emitted to the atmosphere. Data typically appear as a virtual hourly time series on a 2 km horizontal resolution grid, centered on the wind farm site where a met-mast stands.

D.5.5 Tables of Monthly Reference Data

Table D-4. Wind Speed Statistics at Modern-Era Retrospective Analysis for Research and Applications, Version 2, 40.00°N, 72.50°W

Month	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Jan	11.3	8.3	9.8	10.5	11.1	9.6	10.4	10.4	9.9	9.5	10.0	9.0	10.1	9.6	9.8	11.1	10.2	9.4	10.7	10.1	9.4	9.6	10.1	9.0
Feb	9.0	9.2	9.4	10.5	9.4	9.3	10.4	10.9	9.4	10.4	11.0	10.3	8.9	10.3	9.1	9.9	10.6	9.9	9.5	8.8	8.7	9.6	9.7	9.2
Mar	9.6	9.1	9.9	8.4	9.8	8.9	9.2	9.8	9.8	8.4	9.9	9.3	8.3	10.2	9.5	8.7	9.2	10.9	11.1	9.0	9.0	9.5	9.6	9.5
Apr	9.8	8.2	8.8	9.6	9.0	9.3	8.5	9.2	8.3	9.9	7.5	10.0	8.1	8.6	9.0	9.5	8.9	8.6	9.2	9.4	9.7	8.4	9.2	—
May	7.8	7.7	8.5	6.9	7.7	7.3	7.7	7.8	8.6	7.6	8.1	7.4	7.6	9.0	8.0	7.9	7.6	8.8	7.6	8.2	9.0	7.5	9.0	—
Jun	7.9	6.6	7.5	6.6	7.1	7.6	8.4	7.6	7.1	6.2	7.3	6.0	7.3	8.5	6.0	7.5	7.1	8.3	6.8	7.5	7.0	8.0	6.5	—
Jul	5.8	6.7	6.8	7.5	6.7	6.7	6.8	6.5	6.2	6.7	6.5	6.2	6.3	7.2	7.2	5.7	6.1	6.1	6.5	6.3	6.1	6.6	6.6	—
Aug	6.6	6.8	6.2	7.1	6.7	5.8	6.5	6.6	5.2	5.5	6.4	6.7	5.4	6.3	5.6	6.1	6.1	5.8	6.7	6.0	6.6	6.0	5.9	—
Sep	7.2	6.7	6.9	7.6	6.7	6.4	7.0	6.2	7.2	7.4	8.1	6.5	6.5	6.7	6.5	6.8	8.1	7.9	7.0	7.1	7.1	7.5	7.3	—
Oct	7.8	8.6	8.5	8.8	7.9	9.3	9.3	7.9	8.2	9.2	9.5	8.2	8.6	8.0	8.7	9.1	8.3	8.5	8.6	9.6	7.3	8.1	8.0	—
Nov	9.0	8.8	9.9	9.0	8.8	9.7	8.2	9.2	8.9	9.6	9.2	9.1	9.1	9.7	9.8	8.2	8.8	8.9	10.2	9.4	9.2	8.9	9.1	—
Dec	10.1	9.2	10.5	11.6	9.8	9.8	9.5	9.4	10.7	11.5	11.2	8.7	9.5	9.7	9.2	8.5	10.0	9.2	9.0	9.5	10.0	8.1	10.3	—
Annual	8.5	8.0	8.6	8.7	8.4	8.3	8.5	8.5	8.3	8.5	8.7	8.1	8.0	8.6	8.2	8.2	8.4	8.5	8.6	8.4	8.2	8.1	8.4	—

Table D-5. Wind Speed Statistics at Modern-Era Retrospective Analysis for Research and Applications, Version 2, 40.00°N, 73.13°W

Month	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Jan	11.0	8.0	9.4	10.2	10.7	9.3	10.1	9.9	9.6	9.0	9.7	8.6	9.8	9.2	9.4	10.6	9.9	9.1	10.3	9.8	9.2	9.3	9.9	8.7
Feb	8.8	8.8	9.2	10.0	9.0	8.9	10.1	10.6	9.1	10.1	10.5	10.0	8.6	9.8	8.7	9.5	10.3	9.6	9.1	8.5	8.3	9.5	9.4	8.9
Mar	9.4	8.9	9.7	8.3	9.3	8.6	8.9	9.6	9.6	8.2	9.5	9.1	8.2	9.7	9.4	8.4	9.0	10.4	10.7	8.8	8.6	9.3	9.4	9.1
Apr	9.4	7.9	8.7	9.3	9.0	9.0	8.4	8.8	8.0	9.5	7.5	9.7	8.0	8.5	8.8	9.2	8.7	8.3	8.9	9.1	9.5	8.2	9.1	—
May	7.6	7.4	8.2	6.9	7.7	7.1	7.4	7.6	8.4	7.5	7.9	7.2	7.3	8.7	7.7	7.8	7.4	8.5	7.4	8.0	8.6	7.3	8.7	—
Jun	7.8	6.4	7.5	6.3	7.1	7.4	8.2	7.3	7.0	6.1	7.2	5.8	7.0	8.2	5.9	7.5	6.9	7.9	6.5	7.3	6.8	7.8	6.6	—
Jul	5.8	6.5	6.6	7.3	6.7	6.4	6.7	6.3	6.1	6.5	6.5	6.1	6.2	7.1	7.1	5.8	6.1	6.1	6.4	6.1	5.9	6.4	6.6	—
Aug	6.5	6.7	6.4	6.9	6.6	5.8	6.4	6.4	5.0	5.5	6.2	6.4	5.3	6.2	5.4	6.0	6.0	5.6	6.6	5.8	6.5	5.8	5.9	—
Sep	7.1	6.6	6.8	7.6	6.5	6.3	7.0	6.3	7.1	7.2	7.9	6.4	6.4	6.4	6.4	6.6	7.7	7.4	6.8	6.8	6.9	7.3	7.1	—
Oct	7.6	8.5	8.2	8.6	7.8	9.0	9.1	7.8	7.9	9.0	9.1	8.0	8.5	7.9	8.5	8.8	7.9	8.2	8.5	9.2	7.1	7.9	8.0	—
Nov	8.8	8.6	9.6	8.8	8.5	9.5	8.2	9.0	8.7	9.2	8.8	8.8	8.7	9.4	9.5	8.0	8.5	8.7	9.8	9.1	9.1	8.6	8.8	—
Dec	9.7	8.9	10.1	11.3	9.5	9.5	9.2	9.1	10.3	11.1	10.8	8.4	9.0	9.2	9.0	8.3	9.7	8.9	8.7	9.1	9.8	7.9	9.9	—
Annual	8.3	7.8	8.3	8.4	8.2	8.1	8.3	8.2	8.0	8.2	8.5	7.9	7.7	8.3	8.0	8.0	8.2	8.2	8.3	8.1	8.0	7.9	8.3	—

Table D-6. Wind Speed Statistics at Virtual Met Data 39.96°N, 72.73°W

Month	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Jan	12.3	8.7	10.6	11.2	12.3	10.6	11.6	11.6	10.9	10.2	10.9	9.6	11.1	10.1	10.6	11.9	11.1	10.4	11.7	11.1	10.3	10.2	10.9	9.7
Feb	9.8	10.1	10.5	11.1	10.0	10.2	11.3	11.8	10.3	11.6	11.8	11.4	9.6	10.9	9.8	10.7	12.0	11.0	10.9	9.6	9.5	10.3	10.5	9.9
Mar	10.9	10.3	11.2	9.6	11.3	10.0	10.3	10.8	11.1	9.4	11.2	10.5	9.5	11.1	10.9	9.6	10.5	12.3	12.1	10.1	10.3	10.6	10.9	—
Apr	11.2	10.0	10.3	11.4	10.9	11.2	10.0	10.4	9.7	11.5	9.3	12.7	9.4	10.1	10.5	11.6	10.6	10.5	10.7	10.7	11.0	9.6	10.3	—
May	9.4	8.9	9.9	8.3	9.7	8.5	9.0	9.3	10.4	9.7	9.6	8.9	8.7	10.9	9.3	9.6	9.1	10.8	9.7	10.2	10.6	9.0	10.7	—
Jun	10.1	7.9	9.3	7.9	8.5	9.2	9.7	9.0	9.0	7.3	8.8	7.0	8.5	10.1	7.2	9.2	8.1	10.2	8.0	9.1	8.5	9.4	7.6	—
Jul	6.7	7.9	8.1	9.0	7.8	7.4	8.2	7.4	7.4	7.6	7.6	7.6	7.1	8.5	8.4	6.8	7.4	7.1	7.5	7.4	7.2	7.5	8.0	—
Aug	8.0	8.2	7.4	8.1	7.6	6.9	7.5	7.4	5.7	6.5	7.3	7.6	6.2	7.1	6.1	6.9	6.9	6.6	8.0	6.8	7.7	6.9	6.5	—
Sep	7.9	7.7	7.9	8.7	7.5	7.2	8.1	7.2	8.1	8.1	9.2	7.4	7.6	7.3	7.3	7.3	9.0	8.7	7.8	8.1	8.1	8.5	8.0	—
Oct	8.6	9.7	9.2	9.5	8.5	10.1	10.3	8.9	9.0	10.4	10.5	9.3	9.4	8.6	9.9	10.1	9.1	9.7	9.8	10.7	8.3	9.1	8.9	—
Nov	9.6	10.1	11.0	10.0	9.8	11.1	8.9	10.3	9.7	10.4	10.2	10.3	9.7	10.6	10.8	9.1	9.6	9.8	11.5	10.0	10.2	9.5	10.1	—
Dec	10.6	10.2	11.3	12.7	10.8	10.6	10.3	10.2	11.8	12.5	11.9	9.6	10.2	10.7	10.1	9.8	11.1	9.9	10.0	10.3	10.8	9.3	11.1	—
Annual	9.6	9.1	9.7	9.8	9.6	9.4	9.6	9.5	9.4	9.6	9.9	9.3	8.9	9.7	9.2	9.4	9.5	9.8	9.8	9.5	9.4	9.1	9.4	—

Table D-7. Wind Speed Statistics at Modern-Era Retrospective Analysis for Research and Applications, Version 2, 39.50°N, 73.13°W

Month	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Jan	11.1	8.0	9.5	10.3	10.8	9.5	10.1	10.2	9.8	9.2	10.0	8.8	9.9	9.2	9.4	10.7	10.1	9.1	10.4	9.8	9.3	9.4	10.1	9.0
Feb	8.8	8.9	9.3	10.3	9.1	9.1	10.1	10.7	9.2	10.2	10.9	10.1	8.6	10.0	8.9	9.7	10.5	9.7	9.2	8.5	8.6	9.6	9.5	9.0
Mar	9.6	9.2	9.9	8.3	9.6	8.6	8.9	9.7	9.8	8.3	9.7	9.1	8.1	10.1	9.6	8.5	9.0	10.5	10.9	8.8	8.7	9.4	9.6	9.2
Apr	9.7	8.4	8.7	9.4	9.2	9.5	8.6	9.2	8.3	9.9	7.3	10.2	8.1	8.7	8.9	9.2	9.0	8.6	8.9	9.3	9.8	8.3	9.1	—
May	7.9	7.3	8.2	7.0	7.8	7.2	7.4	7.9	8.6	7.7	7.9	7.2	7.6	9.0	7.7	7.8	7.3	8.8	7.4	8.0	9.0	7.2	9.2	—
Jun	7.9	6.4	7.2	6.6	7.0	7.5	8.2	7.4	7.1	6.1	7.2	5.8	7.1	8.2	5.9	7.6	7.1	8.1	6.7	7.6	7.0	7.8	6.6	—
Jul	5.8	6.7	6.4	7.5	6.6	6.4	6.7	6.2	6.1	6.4	6.5	6.1	6.1	7.0	7.0	5.5	5.8	6.0	6.4	6.1	5.8	6.4	6.4	—
Aug	6.6	6.7	6.2	7.0	6.6	5.6	6.4	6.6	5.2	5.4	6.1	6.6	5.5	6.1	5.4	6.0	5.8	5.6	6.5	5.8	6.3	5.7	5.8	—
Sep	6.9	6.6	6.9	7.6	6.6	6.4	6.8	6.0	7.3	7.5	7.7	6.2	6.3	6.4	6.5	6.7	7.9	7.8	6.8	6.9	7.0	7.4	7.2	—
Oct	7.8	8.3	8.2	8.4	7.8	8.9	9.0	7.5	7.9	9.2	9.1	8.0	8.6	7.8	8.4	8.8	8.1	8.1	8.2	9.3	7.0	8.2	7.8	—
Nov	8.9	8.4	9.7	8.7	8.4	9.4	8.0	9.0	8.8	9.3	9.0	8.9	8.9	9.4	9.6	8.0	8.7	8.6	10.0	9.2	8.9	8.9	8.9	—
Dec	9.9	9.3	10.4	11.3	9.5	9.6	9.1	9.1	10.2	11.3	11.1	8.6	9.1	9.4	9.0	8.4	9.7	8.9	8.7	9.1	9.9	8.0	9.8	—
Annual	8.4	7.9	8.4	8.5	8.2	8.1	8.3	8.3	8.2	8.4	8.5	8.0	7.8	8.4	8.0	8.1	8.2	8.3	8.3	8.2	8.1	8.0	8.3	—

Table D-8. Wind Speed Statistics at Modern-Era Retrospective Analysis for Research and Applications, Version 2, 39.50°N, 73.75°W

Month	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Jan	10.5	7.6	8.9	9.6	10.1	9.0	9.6	9.5	9.2	8.5	9.4	8.3	9.4	8.5	8.9	9.8	9.6	8.7	9.8	9.3	8.7	8.7	9.6	8.5
Feb	8.3	8.4	8.9	9.7	8.6	8.5	9.5	10.1	8.7	9.7	10.2	9.5	8.2	9.2	8.3	9.1	9.9	9.2	8.6	8.0	8.1	9.2	9.0	8.5
Mar	9.3	8.8	9.5	8.1	9.0	8.3	8.4	9.3	9.3	7.9	9.3	8.7	7.8	9.4	9.2	7.9	8.6	9.9	10.1	8.4	8.2	9.0	9.2	8.7
Apr	9.2	8.0	8.4	9.0	8.9	9.1	8.3	8.7	7.8	9.3	7.1	9.6	7.9	8.3	8.6	8.9	8.6	8.1	8.4	8.8	9.3	7.9	8.8	—
May	7.5	6.9	7.8	6.8	7.5	7.0	7.0	7.5	8.2	7.2	7.5	6.9	7.0	8.4	7.1	7.4	6.9	8.4	6.9	7.7	8.4	6.8	8.6	—
Jun	7.5	6.0	7.0	6.0	6.7	7.1	7.7	6.9	6.8	6.0	6.8	5.5	6.6	7.6	5.6	7.4	6.6	7.5	6.3	7.1	6.8	7.3	6.4	—
Jul	5.7	6.4	6.2	7.1	6.4	6.0	6.4	5.9	5.9	6.2	6.2	5.8	5.7	6.7	6.8	5.4	5.7	6.0	6.3	5.8	5.6	6.1	6.1	—
Aug	6.4	6.5	6.2	6.7	6.3	5.5	6.2	6.1	5.0	5.2	5.9	6.2	5.3	5.9	5.1	5.9	5.6	5.4	6.2	5.5	6.2	5.3	5.7	—
Sep	6.8	6.5	6.6	7.4	6.4	6.2	6.6	5.9	7.1	7.3	7.4	6.0	6.1	6.1	6.4	6.5	7.4	7.2	6.6	6.6	6.7	7.1	7.0	—
Oct	7.4	8.1	7.8	8.1	7.5	8.5	8.7	7.3	7.6	8.8	8.7	7.8	8.3	7.7	8.0	8.6	7.7	7.7	8.0	8.7	6.8	7.8	7.7	—
Nov	8.5	8.1	9.3	8.4	8.1	9.1	7.9	8.7	8.4	8.9	8.4	8.6	8.5	8.9	9.1	7.7	8.2	8.3	9.4	8.7	8.5	8.4	8.5	—
Dec	9.4	8.7	9.7	10.8	9.0	9.1	8.6	8.6	9.6	10.5	10.3	8.2	8.5	8.7	8.6	8.0	9.1	8.3	8.3	8.5	9.4	7.5	9.2	—
Annual	8.0	7.5	8.0	8.1	7.9	7.8	7.9	7.8	7.8	7.9	8.1	7.6	7.4	8.0	7.6	7.7	7.8	7.9	7.9	7.8	7.7	7.6	8.0	—

Table D-9. Wind Speed Statistics at Virtual Met Data 39.54°N, 73.42°W

Month	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Jan	12.0	8.4	10.3	10.7	11.8	10.6	11.3	11.3	10.7	9.6	10.7	9.2	10.8	9.8	10.2	11.2	11.0	10.0	11.5	10.8	10.2	9.8	10.8	9.7
Feb	9.5	9.7	10.3	10.8	9.6	10.0	10.9	11.3	10.1	11.3	11.4	11.1	9.3	10.5	9.8	10.3	11.8	10.9	10.9	9.2	9.6	10.3	10.4	9.8
Mar	10.8	10.2	11.1	9.5	11.1	9.7	9.8	10.7	11.1	9.2	11.0	10.1	9.4	10.8	10.7	9.2	10.5	12.1	11.7	10.0	10.2	10.5	11.0	—
Apr	11.1	10.2	10.4	10.9	10.9	11.4	10.0	10.2	9.7	11.6	8.9	12.7	9.2	10.2	10.4	11.1	10.5	10.5	10.6	10.8	11.1	9.5	10.1	—
May	9.4	8.4	9.5	8.2	9.6	8.2	8.7	9.1	10.3	9.7	9.4	8.8	8.5	10.5	8.8	9.2	8.5	10.6	9.4	10.0	10.5	8.5	10.7	—
Jun	9.9	7.7	8.8	7.9	8.1	8.9	9.3	8.8	8.7	7.1	8.6	7.0	8.1	10.0	6.8	9.4	7.7	9.6	7.9	9.0	8.4	9.0	7.5	—
Jul	6.7	7.7	7.7	8.9	7.6	7.1	8.0	7.2	7.3	7.2	7.7	7.2	7.0	8.7	8.2	6.7	7.1	7.3	7.4	7.2	7.0	7.6	7.8	—
Aug	7.9	8.0	7.2	8.0	7.3	6.8	7.4	7.5	5.7	6.2	6.9	7.4	6.3	7.0	5.9	6.8	6.8	6.5	7.8	6.6	7.4	6.5	6.5	—
Sep	7.7	7.4	7.6	8.5	7.4	7.0	7.8	6.8	8.1	8.3	9.0	7.2	7.4	7.1	7.3	7.3	8.8	8.4	7.8	7.9	7.9	8.3	7.9	—
Oct	8.5	9.5	8.8	9.1	8.2	9.7	10.0	8.5	8.7	10.2	10.3	9.2	9.3	8.7	9.6	9.9	9.1	9.3	9.4	10.2	8.0	9.0	8.5	—
Nov	9.4	9.7	10.7	9.6	9.4	10.8	8.9	10.0	9.6	10.2	9.9	10.3	9.6	10.3	10.6	9.1	9.3	9.5	11.1	9.9	9.8	9.5	9.9	—
Dec	10.3	10.0	11.0	12.3	10.6	10.3	9.9	9.9	11.3	12.0	11.6	9.6	9.8	10.5	9.9	9.6	10.6	9.5	9.8	10.0	10.7	9.4	10.5	—
Annual	9.4	8.9	9.4	9.5	9.3	9.2	9.3	9.3	9.3	9.4	9.6	9.1	8.7	9.5	9.0	9.1	9.3	9.5	9.6	9.3	9.2	9.0	9.3	—

D.5.4 References

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Appendix E. Wind Farm Analysis and Results

E.1 Correlations

Figure E-1. Correlation of Wind Speed between E06_S at 160 Meters (x) and E05_N at 160 Meters (y)

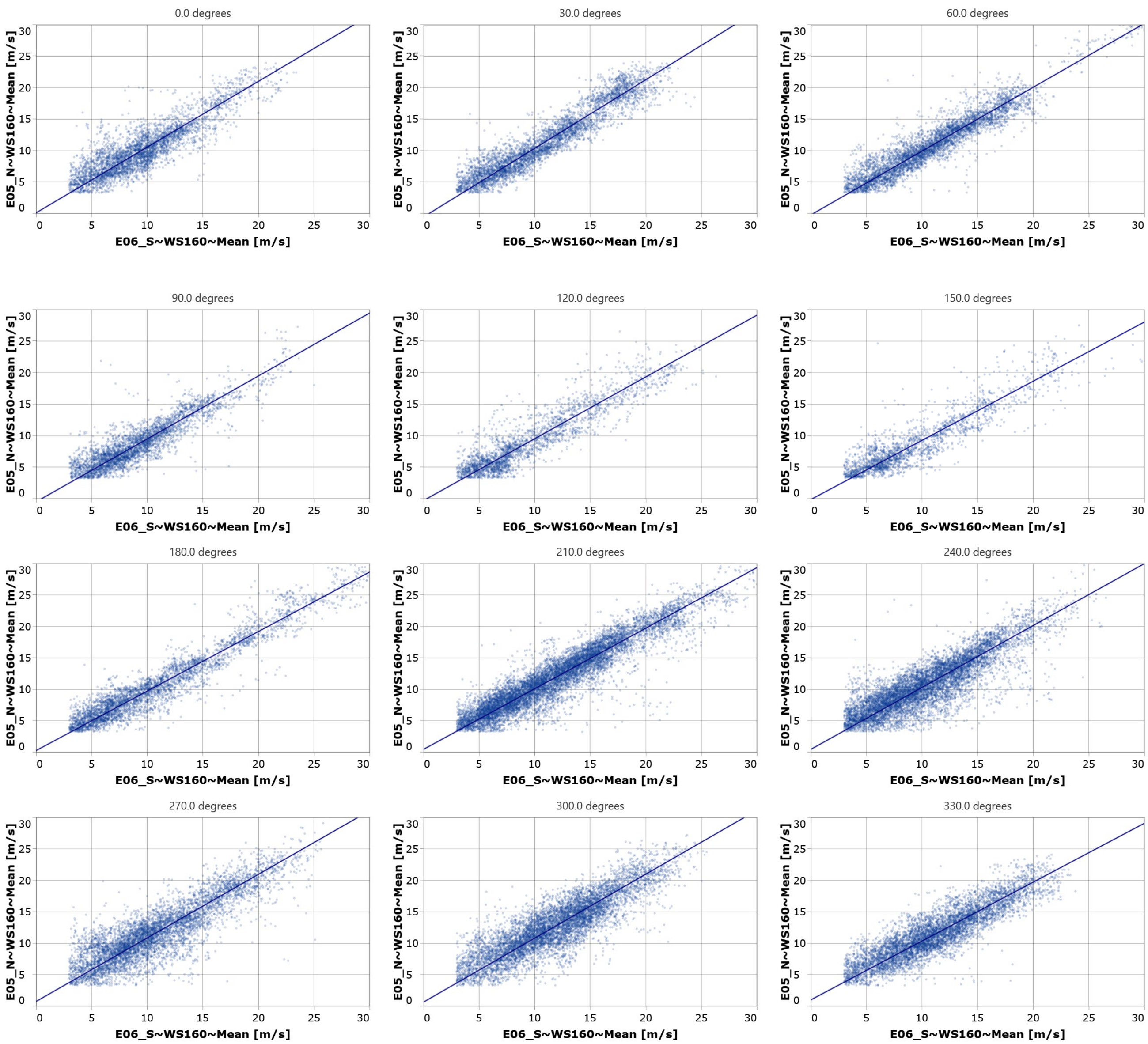


Table E-1. Directional Correlation Ratios

Bin Centers (degrees)	Wind Speed Ratio	Number of Records
0.0	1.0459	4,021
30.0	1.0917	4,529
60.0	1.0148	4,913
90.0	0.9991	3,625
120.0	0.9814	2,521
150.0	0.9391	2,093
180.0	0.9466	4,050
210.0	0.9638	10,546
240.0	0.9846	8,685
270.0	1.0112	6,260
300.0	1.0178	7,636
330.0	0.9361	6,638
All directional	1.0017	65,517

Figure E-2. Correlation of Wind Direction between E06_S (x) at 160 Meters and E05_N (y) at 160 Meters

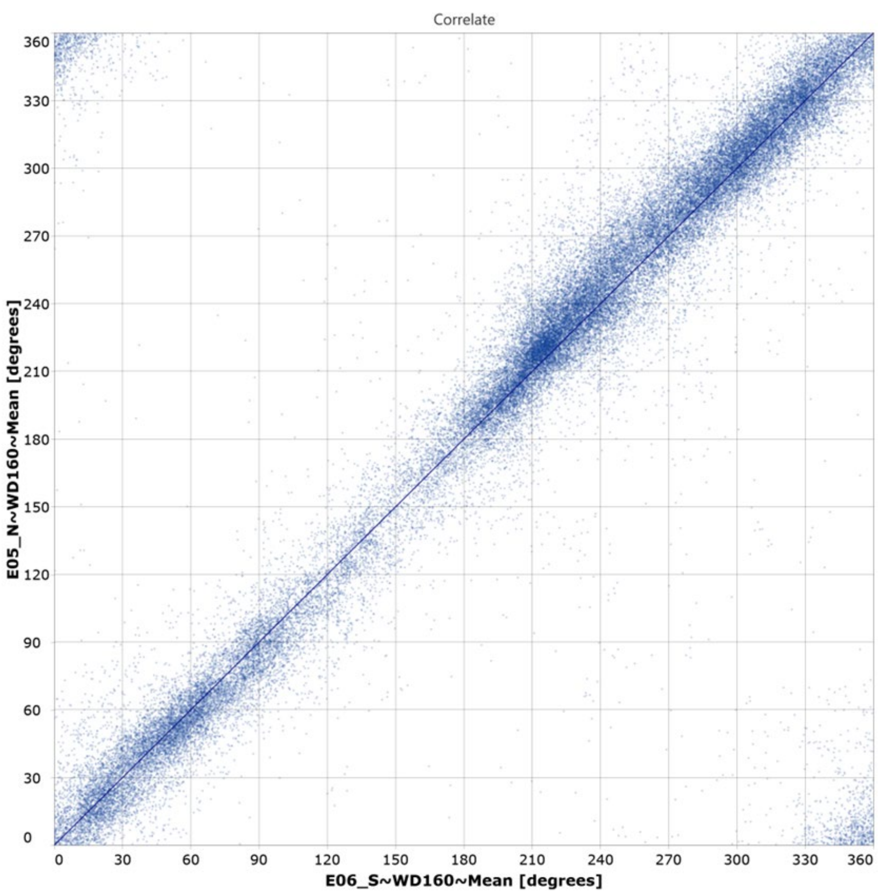


Figure E-3. Correlation of Wind Speed between E05_N at 160 Meters (x) and E06_S at 160 Meters (y)

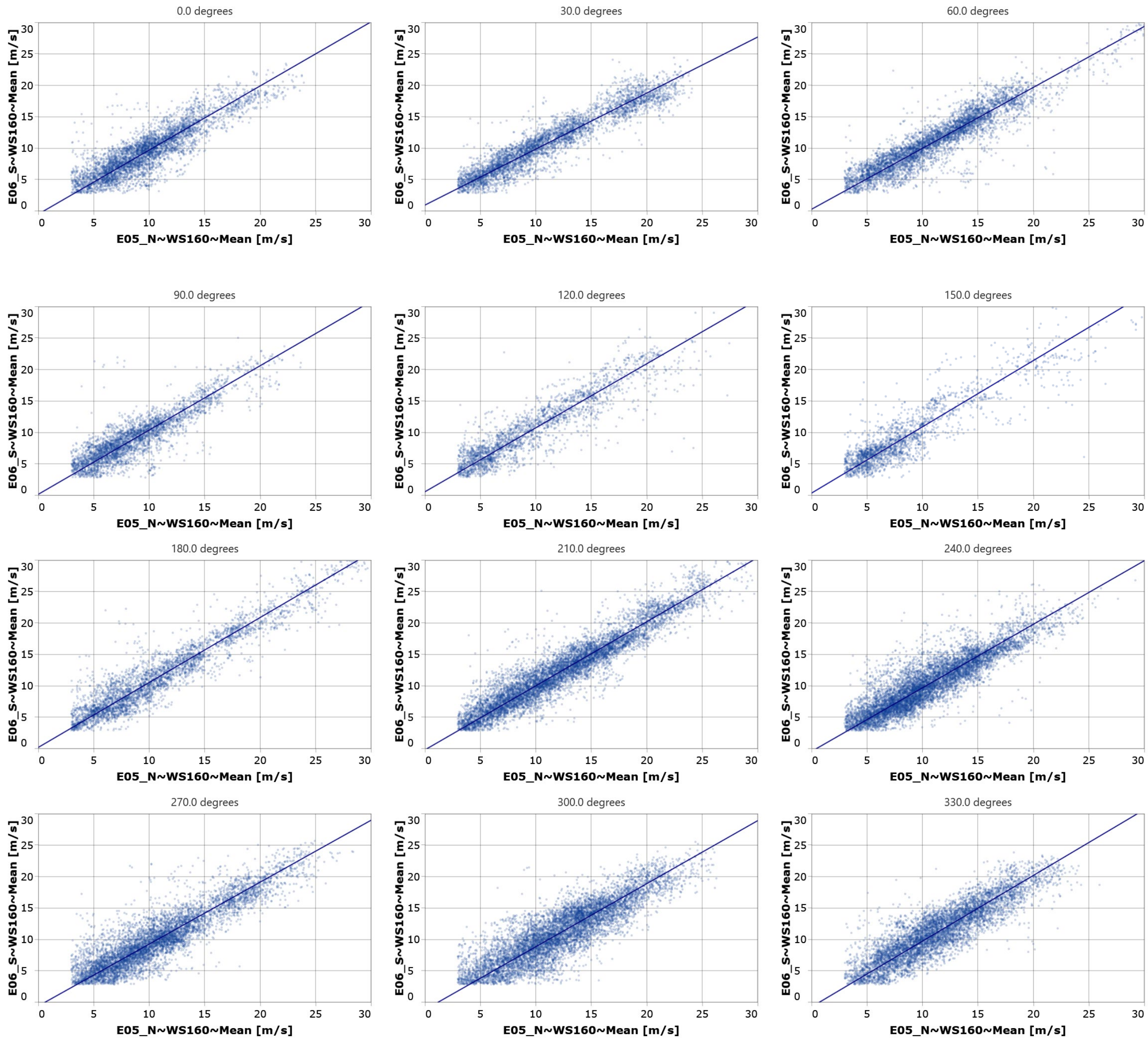


Table E-2. Directional Correlation Ratios

Bin Centers (degrees)	Wind Speed Ratio	Number of Records
0.0	1.0211	4,741
30.0	0.8925	4,546
60.0	0.9709	5,377
90.0	1.0223	3,515
120.0	1.018	2,387
150.0	1.0542	2,055
180.0	1.0347	3,802
210.0	1.0211	8,742
240.0	1.0128	8,900
270.0	0.9865	6,967
300.0	1.0041	8,338
330.0	1.0475	6,900
All directional	0.9976	66,270

Figure E-4. Correlation of Wind Speed between E06_S at 160 Meters (x) and E05_SW at 160 Meters (y)

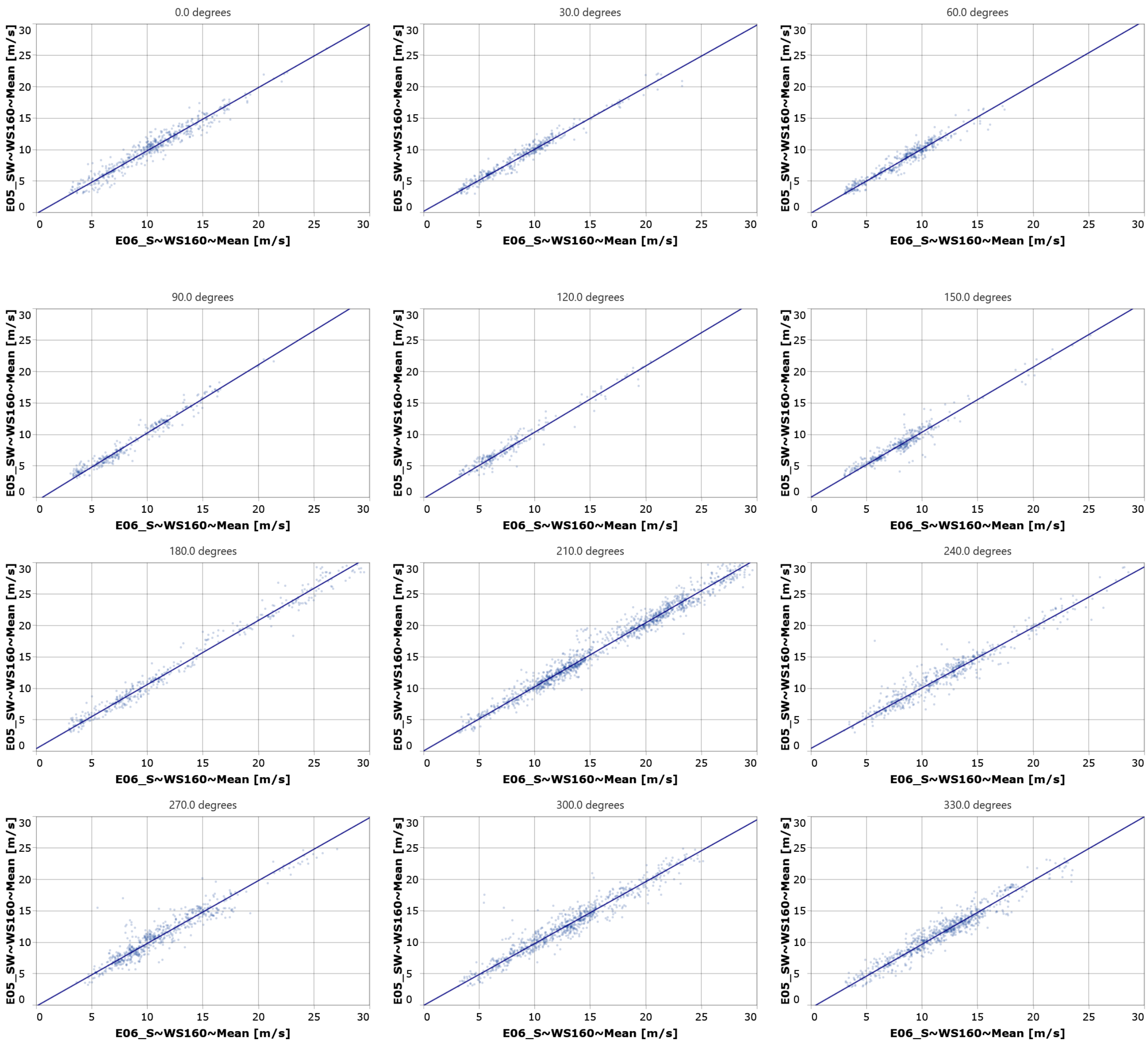


Table E-3. Directional Correlation Ratios

Bin Centers (degrees)	Wind Speed Ratio	Number of Records
0.0	1.0040	504
30.0	0.9878	403
60.0	1.0202	442
90.0	1.0851	310
120.0	1.0554	233
150.0	1.0353	387
180.0	1.0205	415
210.0	1.0196	1343
240.0	0.9625	549
270.0	0.9997	624
300.0	0.9846	845
330.0	1.0144	796
All directional	1.0173	6,851

Figure E-5. Correlation of Wind Direction between E06_S (x) at 160 Meters and E05_SW (y) at 160 Meters

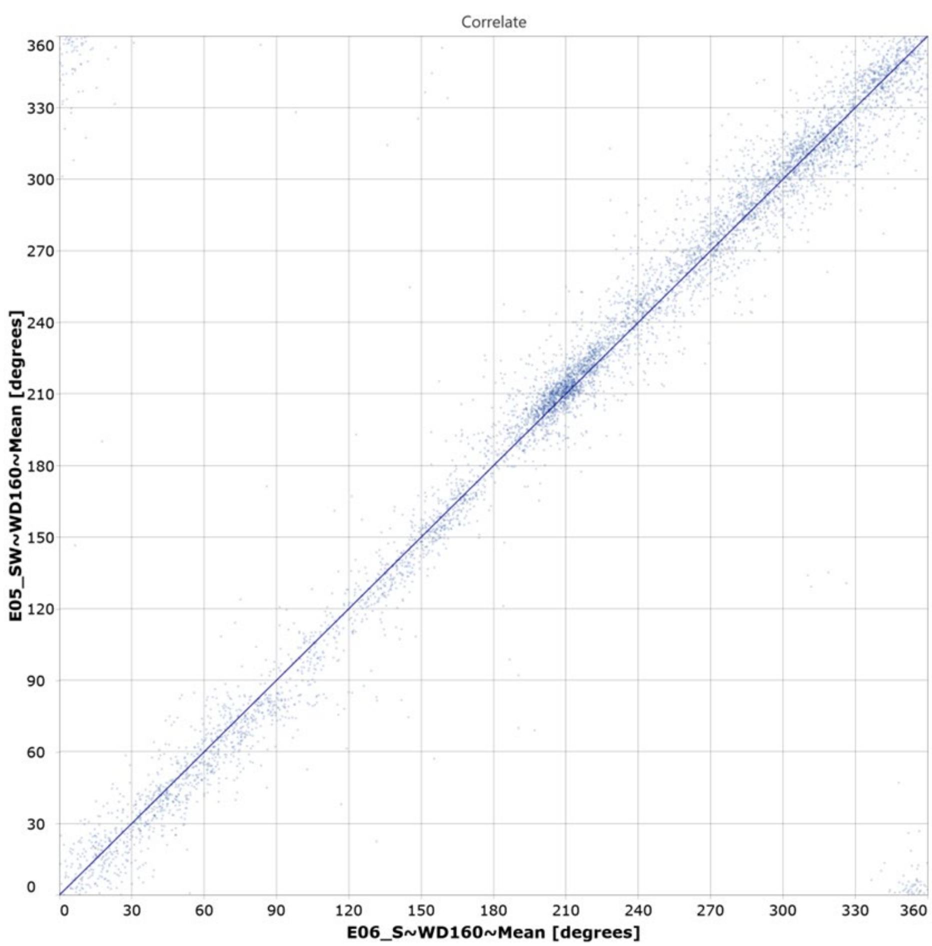


Figure E-6. Correlation of Wind Speed between E05_N at 140 Meters and Modern-Era Retrospective Analysis for Research and Applications, Version 2, 40.00°N, 72.50°W

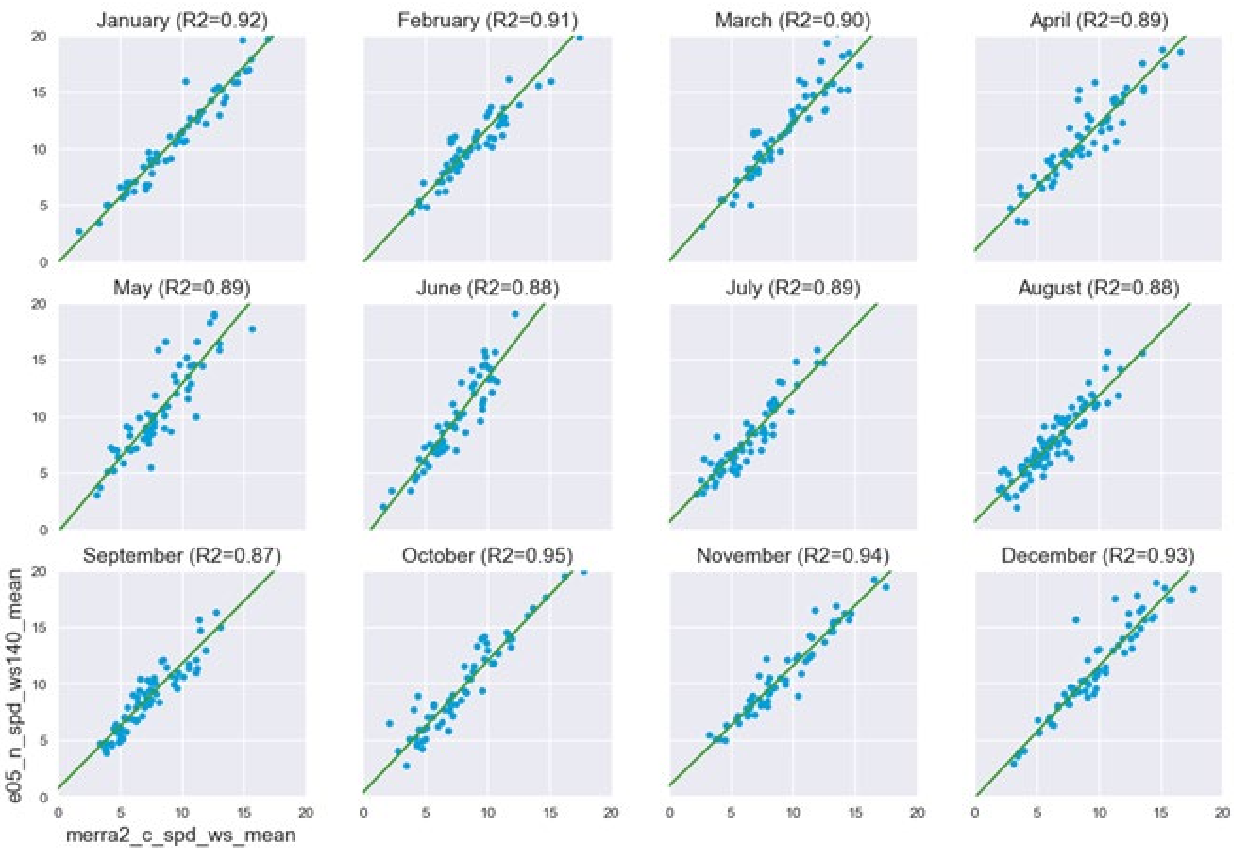


Figure E-7. Correlation of Wind Speed between E05_N at 140 Meters and Virtual Met Data 39.95°N, 72.74°W

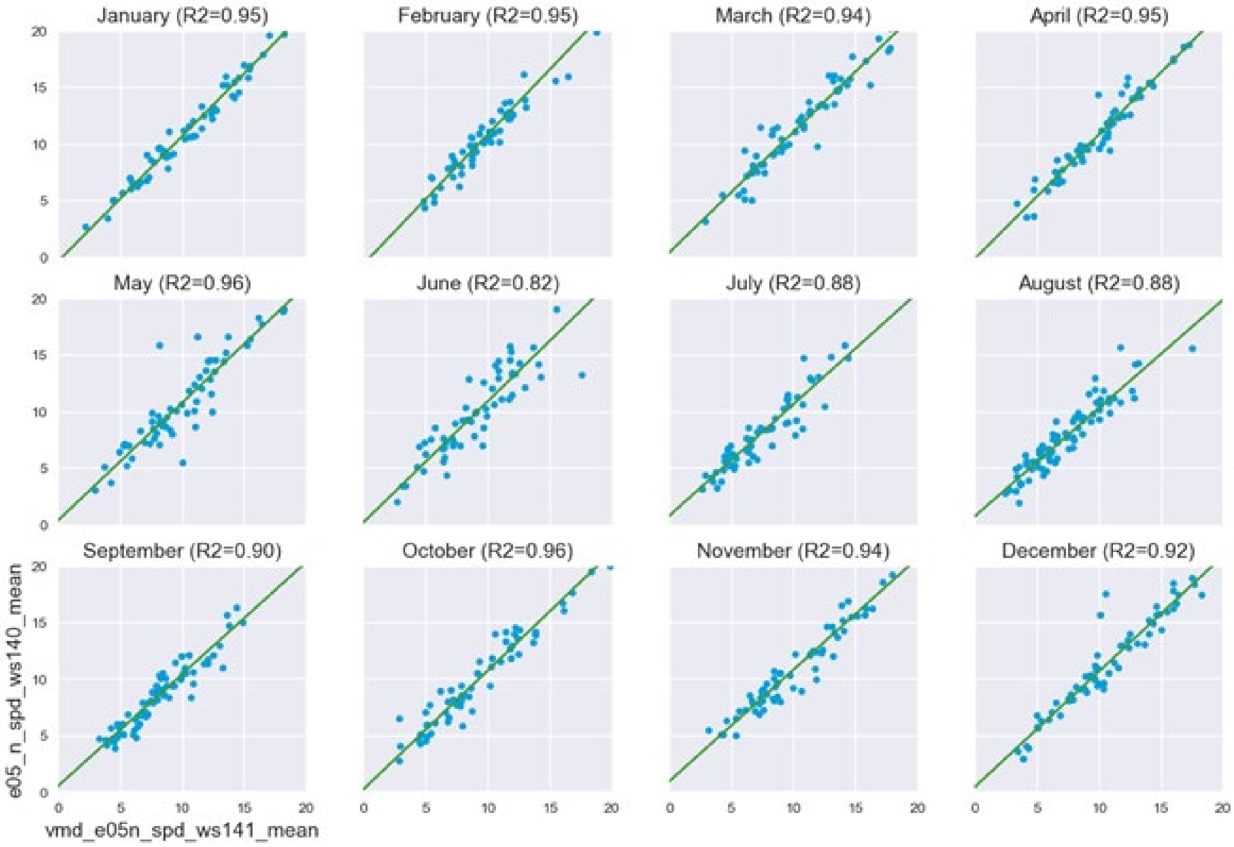


Figure E-8. Correlation of Wind Speed Between E05_SW at 140 Meters and Modern-Era Retrospective Analysis for Research and Applications, Version 2, 39.50°N, 73.75°W

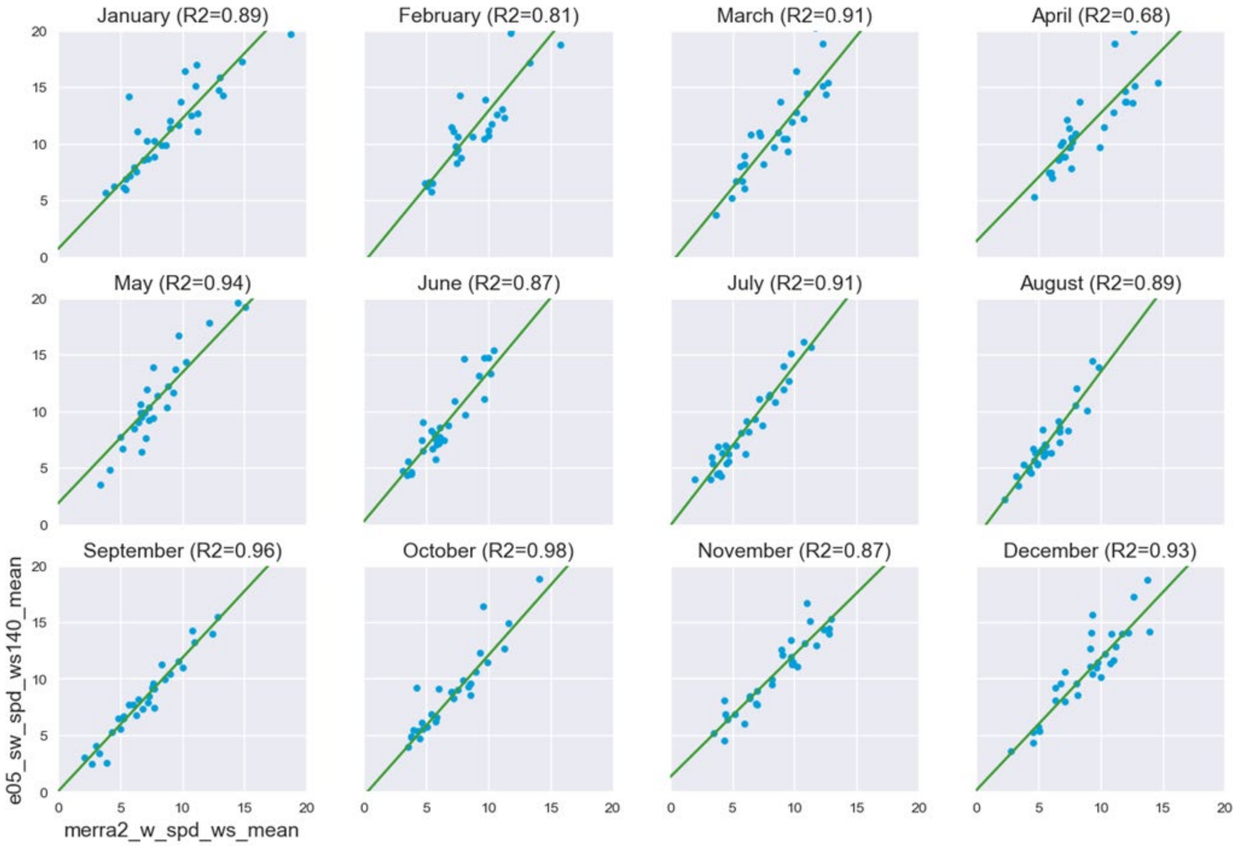


Figure E-9. Correlation of Wind Speed between E05_SW at 140 Meters and Virtual Met Data 39.53°N, 73.41°W

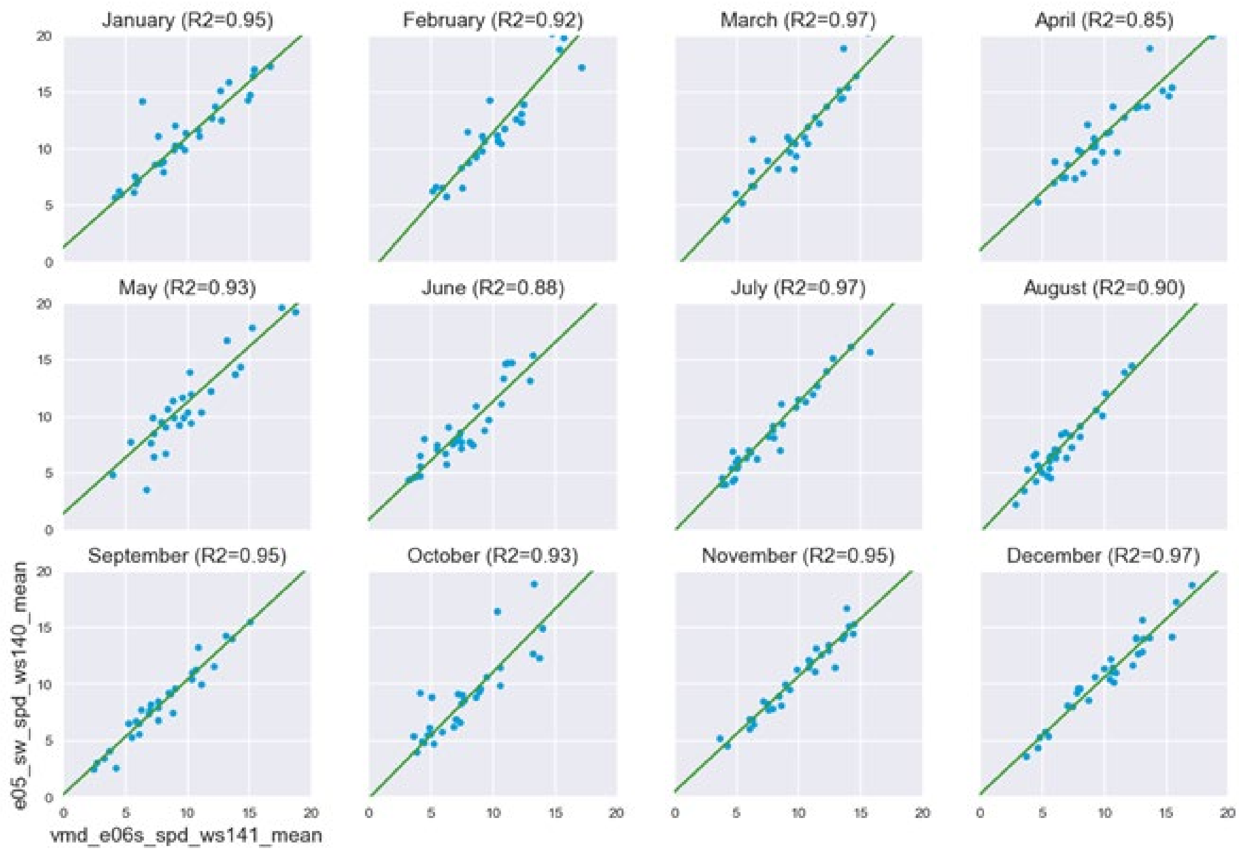


Figure E-10. Correlation of Wind Speed between E06_S at 140 Meters and Modern-Era Retrospective Analysis for Research and Applications, Version 2, 39.50°N, 73.13°W

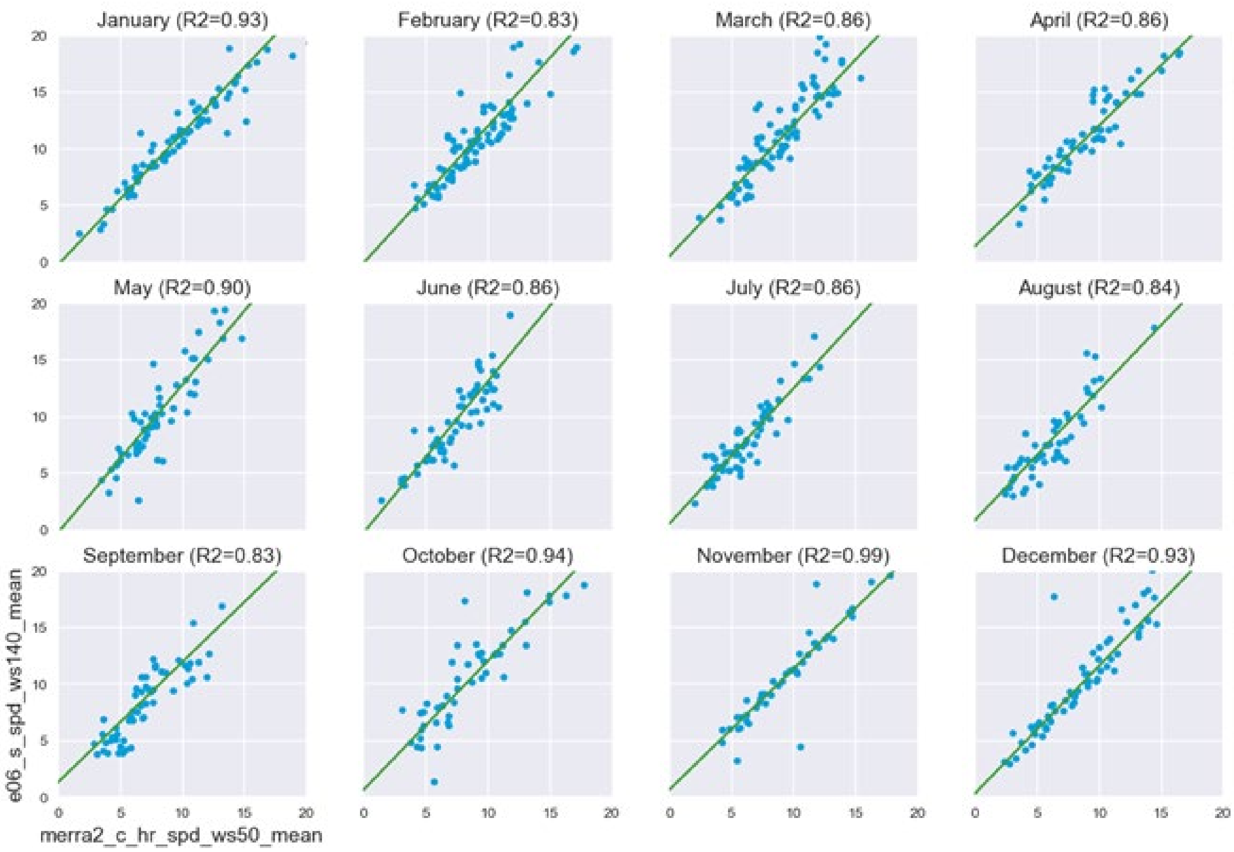
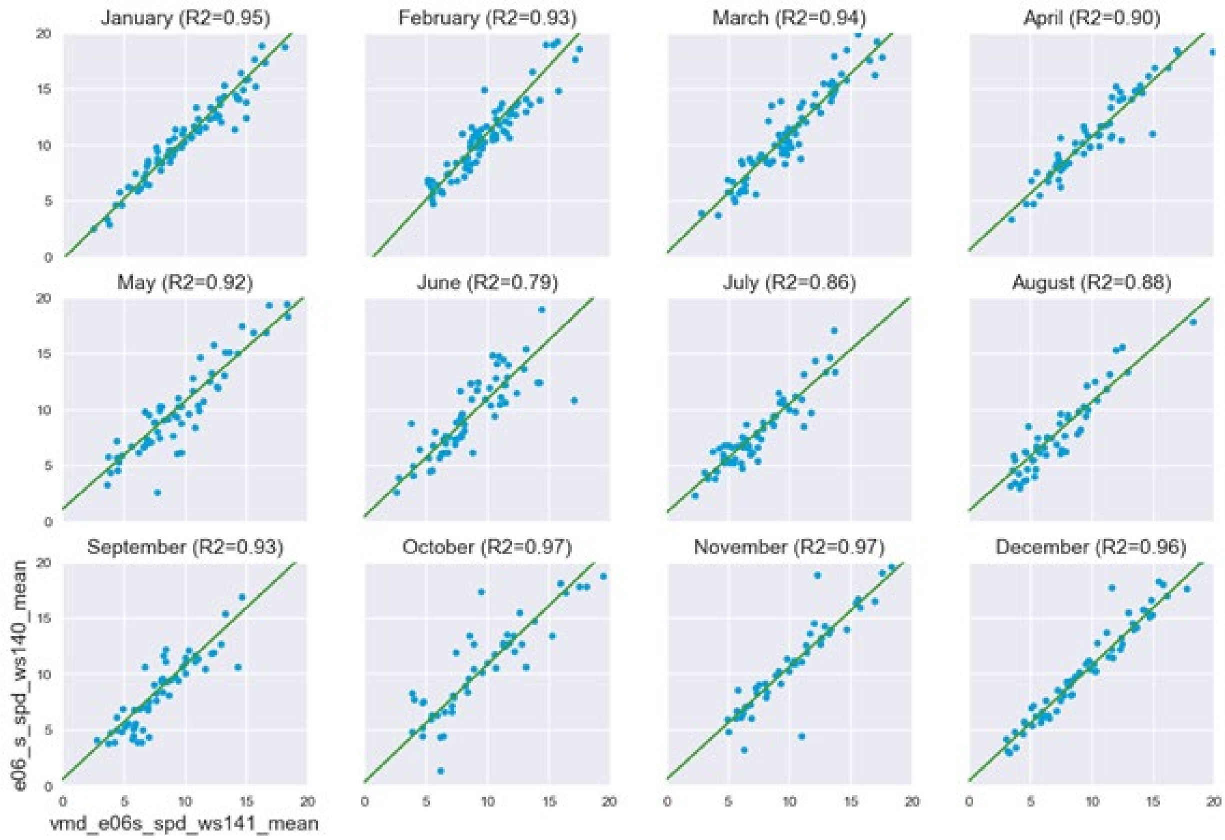


Figure E-11. Correlation of Wind Speed between E06_S and Virtual Met Data 39.53°N, 73.41°W



E.2 Site Period Wind Speeds

Table E-4. Average wind speed per month

Values include data synthesized from other site measurement locations.

Month	E05_N		E05_SW		E06_S	
	140 m	160 m	140 m	160 m	140 m	160 m
January	11.0	11.1	11.0	11.1	10.8	10.9
February	11.1	11.2	11.0	11.1	11.0	11.1
March	11.6	11.7	11.6	11.7	11.5	11.7
April	11.2	11.4	11.1	11.2	11.1	11.2
May	10.6	10.7	10.7	10.8	10.8	10.9
June	9.6	9.7	9.2	9.3	9.1	9.2
July	7.9	8.0	8.1	8.3	7.9	8.1
August	7.8	7.9	7.6	7.7	7.5	7.6
September	8.5	8.6	8.8	8.9	8.5	8.6
October	10.1	10.2	10.5	10.6	10.0	10.1
November	11.0	11.1	10.6	10.7	10.6	10.7
December	10.8	10.9	10.4	10.5	10.5	10.6
Annual	**10.1**	**10.2**	**10.0**	**10.2**	**9.9**	**10.1**

E-3 Measurement Location Long-term Wind Regime

Table E-5. Long-term Wind Speed and Frequency Distribution at 155 Meters for E05_N

Monthly Mean Wind Speeds			
Month	Wind Speed (m/s)	Valid Wind Speed Data (months)	Valid Direction Data (months)
January	11.0	1.9	1.9
February	10.8	1.8	1.8
March	11.9	1.8	1.8
April	11.5	1.9	1.9
May	10.8	1.6	1.6
June	9.7	1.7	1.7
July	8.1	1.8	1.8
August	7.9	2.5	2.5
September	8.6	2.2	2.2
October	10.5	1.8	1.8
November	11.0	2.0	2.0
December	11.3	1.9	1.9
Annual	10.2		

Figure E-12. Wind Rose for E05_N

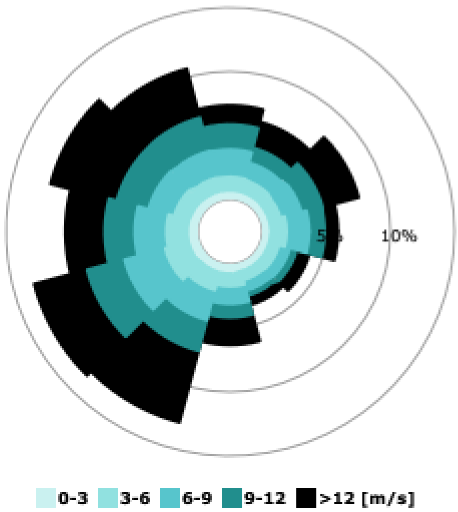


Figure E-13. Wind Speed Distribution for E05_N

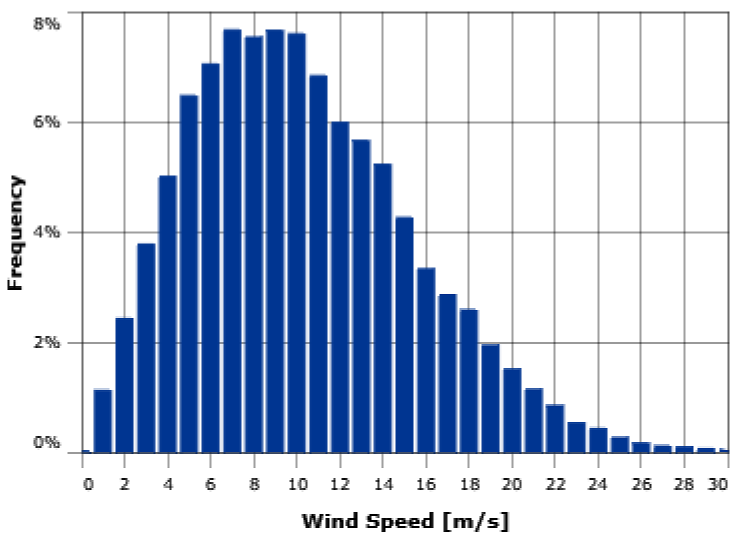


Table E-6. Wind Speed and Direction Frequency Distribution

Wind Speed (m/s)	0	30	60	90	120	150	180	210	240	270	300	330	No Dir.	Total (%)
0			+		+	+	+			+	+	+		0.01
1	0.09	0.07	0.08	0.08	0.09	0.12	0.10	0.09	0.08	0.11	0.11	0.11		1.12
2	0.21	0.19	0.15	0.18	0.15	0.16	0.23	0.22	0.27	0.25	0.22	0.21		2.43
3	0.25	0.34	0.29	0.28	0.26	0.23	0.35	0.33	0.39	0.39	0.40	0.27		3.78
4	0.36	0.39	0.29	0.47	0.35	0.27	0.34	0.51	0.60	0.59	0.47	0.38		5.01
5	0.47	0.44	0.44	0.62	0.39	0.40	0.48	0.61	0.82	0.75	0.59	0.49		6.49
6	0.68	0.45	0.52	0.55	0.37	0.35	0.48	0.74	0.88	0.82	0.56	0.67		7.06
7	0.74	0.51	0.58	0.68	0.30	0.28	0.48	0.80	1.07	0.82	0.70	0.71		7.68
8	0.72	0.40	0.56	0.55	0.31	0.30	0.44	0.84	1.16	0.81	0.72	0.74		7.54
9	0.70	0.50	0.62	0.48	0.22	0.18	0.36	0.80	1.26	0.89	0.85	0.83		7.66
10	0.80	0.40	0.58	0.52	0.17	0.16	0.40	0.80	1.09	0.77	0.94	0.98		7.60
11	0.57	0.37	0.56	0.40	0.18	0.11	0.30	0.87	0.88	0.79	0.87	0.93		6.83
12	0.48	0.37	0.43	0.21	0.15	0.08	0.30	0.82	0.80	0.76	0.77	0.81		5.97
13	0.37	0.38	0.42	0.21	0.13	0.05	0.29	0.81	0.82	0.60	0.80	0.77		5.65
14	0.29	0.22	0.51	0.19	0.13	0.06	0.29	0.76	0.78	0.41	0.89	0.66		5.21
15	0.14	0.12	0.45	0.17	0.14	0.06	0.18	0.71	0.69	0.28	0.75	0.53		4.24
16	0.09	0.09	0.35	0.11	0.11	0.06	0.19	0.52	0.52	0.23	0.59	0.44		3.30
17	0.09	0.15	0.28	0.06	0.08	0.06	0.18	0.54	0.33	0.28	0.48	0.33		2.85
18	0.10	0.24	0.25	0.05	0.06	0.04	0.15	0.40	0.27	0.24	0.46	0.33		2.58
19	0.07	0.22	0.16	0.06	0.06	0.03	0.09	0.27	0.21	0.24	0.31	0.19		1.92
20	0.03	0.16	0.06	0.05	0.08	0.06	0.09	0.32	0.13	0.16	0.23	0.12		1.49
21	0.03	0.15	0.04	0.02	0.04	0.04	0.06	0.30	0.09	0.10	0.18	0.08		1.13
22	0.02	0.10	0.02	0.01	0.02	0.04	0.05	0.24	0.05	0.08	0.14	0.06		0.83
23	0.01	0.05	0.02	+	0.03	0.04	0.06	0.15	0.03	0.05	0.06	0.01		0.51
24	+	0.01	0.02	+	0.03	0.04	0.07	0.13	0.02	0.05	0.03	0.02		0.42
25	+	+	0.02	+	0.01	0.04	0.05	0.09	0.01	0.01	0.02	0.01		0.25
26	+	+	0.01	0.01	0.01	0.03	0.03	0.03	0.01	0.01	0.01	+		0.15
27	+		0.02	+	0.01	0.03	0.02	0.02	+	+	+	+		0.11
28	+		0.02	+	+	0.01	0.03	0.02	+	+				0.08
29	+		0.01	+		0.01	0.02	0.02	+	+				0.06
30			0.02	+		+	+	0.01	+					0.04
30+														
Total (%)	7.31	6.30	7.80	5.95	3.88	3.34	6.10	12.75	13.28	10.48	12.14	10.67		100.00

Note: A plus sign (+) indicates a nonzero percentage <0.005%, while a blank space indicates zero percentage

Table E-7. Long-term Wind Speed and Frequency Distribution at 155 Meters (Monthly Mean Wind Speeds) for E05_SW

Month	Wind Speed (m/s)	Valid Wind Speed Data (months)	Valid Direction Data (months)
January	11.0	0.9	0.9
February	11.8	0.9	0.9
March	11.8	0.9	0.9
April	11.1	0.9	0.9
May	12.2	0.8	0.8
June	8.8	0.9	0.9
July	8.5	1.0	1.0
August	7.2	1.0	1.0
September	8.4	0.9	0.9
October	9.7	0.9	0.9
November	10.5	1.0	1.0
December	11.0	0.9	0.9
Annual	10.2		

Figure E-14. Wind Rose for E05_SW

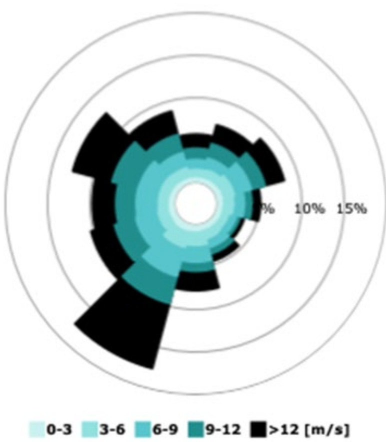


Figure E-15. Wind Speed Distribution for E05_SW

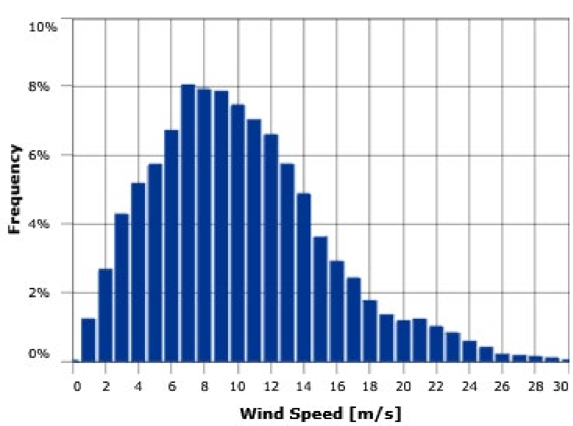


Table E-8. Wind Speed and Direction Frequency Distribution

Wind Speed (m/s)	0	30	60	90	120	150	180	210	240	270	300	330	No Dir.	Total (%)
0	+	+	+	+	+	+	+	+	+	+	+	+		0.03
1	0.08	0.07	0.09	0.11	0.13	0.10	0.11	0.14	0.13	0.11	0.09	0.09		1.25
2	0.17	0.19	0.23	0.21	0.23	0.23	0.27	0.31	0.24	0.24	0.20	0.17		2.69
3	0.32	0.41	0.44	0.31	0.28	0.31	0.38	0.43	0.37	0.35	0.36	0.33		4.30
4	0.36	0.42	0.54	0.37	0.33	0.44	0.55	0.63	0.42	0.33	0.37	0.44		5.21
5	0.32	0.30	0.45	0.59	0.34	0.40	0.66	0.71	0.52	0.46	0.50	0.51		5.75
6	0.37	0.44	0.56	0.50	0.36	0.49	0.71	0.94	0.61	0.67	0.65	0.45		6.74
7	0.41	0.43	0.84	0.45	0.33	0.31	0.71	1.19	0.96	0.94	0.85	0.65		8.07
8	0.35	0.38	0.66	0.40	0.32	0.40	0.71	1.31	0.96	0.88	0.91	0.65		7.94
9	0.46	0.61	0.67	0.39	0.25	0.34	0.45	1.15	0.98	0.97	0.96	0.66		7.89
10	0.48	0.67	0.60	0.25	0.17	0.27	0.36	1.06	0.94	0.77	1.10	0.81		7.49
11	0.40	0.56	0.54	0.26	0.11	0.24	0.36	1.15	0.84	0.78	1.09	0.73		7.05
12	0.46	0.46	0.49	0.36	0.08	0.18	0.25	1.10	0.71	0.69	1.13	0.71		6.62
13	0.34	0.20	0.30	0.19	0.09	0.12	0.32	1.11	0.65	0.59	0.96	0.87		5.76
14	0.30	0.09	0.27	0.15	0.12	0.17	0.25	0.95	0.46	0.55	0.95	0.65		4.90
15	0.22	0.05	0.20	0.10	0.05	0.09	0.19	0.69	0.39	0.51	0.80	0.34		3.63
16	0.16	0.05	0.19	0.08	0.04	0.09	0.25	0.69	0.31	0.31	0.50	0.28		2.94
17	0.14	0.14	0.17	0.06	0.03	0.10	0.16	0.65	0.24	0.17	0.43	0.16		2.44
18	0.13	0.22	0.13	0.05	0.04	0.05	0.10	0.52	0.11	0.10	0.24	0.08		1.79
19	0.10	0.27	0.10	0.04	0.04	0.01	0.12	0.40	0.09	0.04	0.11	0.06		1.37
20	0.02	0.29	0.12	0.02	0.03	0.02	0.12	0.36	0.10	0.03	0.06	0.02		1.20
21	+	0.28	0.12	0.03	0.02	0.03	0.10	0.48	0.06	0.05	0.05	0.02		1.24
22	+	0.20	0.10	0.03	0.01	0.02	0.08	0.44	0.04	0.05	0.06	0.02		1.03
23	+	0.15	0.08	0.03	+	0.02	0.11	0.33	0.05	0.02	0.05	0.01		0.85
24	+	0.09	0.11	0.02	+	0.02	0.10	0.20	0.02	0.01	0.01			0.60
25	0.01	0.03	0.14	0.02		0.01	0.10	0.10	0.01		0.01	+		0.42
26	0.01	+	0.06	0.01		0.01	0.03	0.11	+			+		0.22
27		+	0.02	0.01		+	0.03	0.12	+	+				0.18
28				0.01		+	0.06	0.08	+	+				0.16
29				+		0.01	0.05	0.06	+					0.12
30				+			0.02	0.03	+					0.05
30+														
Total (%)	5.62	7.02	8.21	5.05	3.40	4.49	7.69	17.5 2	10.2 2	9.63	12.4 5	8.70		100.00
Mean Speed	9.48	10.9 6	10.0 3	8.43	7.36	8.28	10.0 1	12.0 7	9.75	9.68	10.6 6	9.83	-	10.17

Note: A plus sign (+) indicates a nonzero percentage <0.005%, while a blank space indicates zero percentage.

Table E-9. Long-term Wind Speed and Frequency Distribution at 155 Meters (Monthly Mean Wind Speeds) for E06_S

Month	Wind Speed (m/s)	Valid Wind Speed Data (months)	Valid Direction Data (months)
January	11.0	2.4	2.4
February	11.0	2.8	2.8
March	11.3	2.5	2.5
April	11.0	1.8	1.8
May	10.2	1.6	1.6
June	9.3	1.7	1.7
July	7.9	1.9	1.9
August	7.9	1.2	1.2
September	9.0	1.1	1.1
October	11.5	0.9	0.9
November	10.7	1.3	1.3
December	10.0	1.9	1.9
Annual	10.1		

Figure E-16. Wind Rose for E06_S

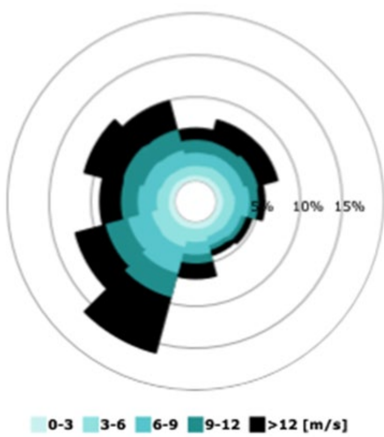


Figure E-17. Wind Speed Distribution for E06_S

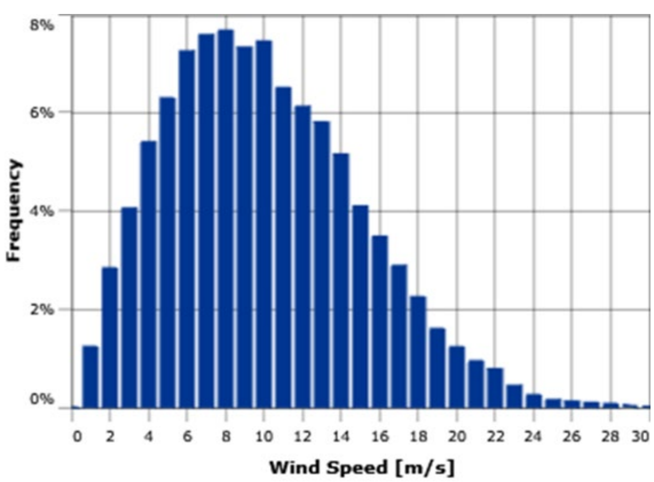


Table E-10. Wind Speed and Direction Frequency Distribution

Wind Speed (m/s)	0	30	60	90	120	150	180	210	240	270	300	330	No Dir.	Total (%)
0	+	+	+	+	+	+	+	+	+	+	+	+		0.02
1	0.08	0.11	0.08	0.16	0.11	0.11	0.10	0.12	0.11	0.10	0.09	0.09		1.26
2	0.20	0.22	0.26	0.26	0.27	0.25	0.24	0.26	0.22	0.23	0.25	0.20		2.86
3	0.26	0.32	0.34	0.30	0.26	0.39	0.40	0.40	0.45	0.35	0.32	0.28		4.08
4	0.39	0.36	0.40	0.42	0.45	0.39	0.55	0.68	0.66	0.40	0.35	0.36		5.42
5	0.39	0.46	0.49	0.52	0.52	0.34	0.54	0.87	0.80	0.54	0.44	0.40		6.32
6	0.48	0.55	0.43	0.60	0.46	0.43	0.61	1.10	0.92	0.68	0.51	0.50		7.27
7	0.52	0.52	0.47	0.65	0.48	0.41	0.51	1.10	0.96	0.68	0.66	0.65		7.60
8	0.53	0.46	0.52	0.58	0.34	0.33	0.48	1.11	1.04	0.86	0.74	0.71		7.70
9	0.56	0.49	0.61	0.45	0.23	0.25	0.39	0.94	0.98	0.77	0.84	0.84		7.35
10	0.62	0.44	0.60	0.37	0.23	0.19	0.38	1.03	0.99	0.77	0.91	0.95		7.48
11	0.45	0.46	0.49	0.33	0.17	0.18	0.34	0.98	0.85	0.60	0.87	0.81		6.53
12	0.40	0.51	0.52	0.23	0.16	0.15	0.29	1.00	0.84	0.47	0.82	0.75		6.15
13	0.29	0.47	0.48	0.20	0.13	0.10	0.30	1.02	0.81	0.42	0.85	0.77		5.83
14	0.22	0.36	0.47	0.18	0.10	0.09	0.30	0.94	0.71	0.38	0.82	0.61		5.18
15	0.19	0.26	0.32	0.14	0.09	0.10	0.18	0.87	0.50	0.30	0.66	0.52		4.12
16	0.16	0.31	0.26	0.09	0.08	0.11	0.13	0.75	0.40	0.24	0.56	0.42		3.51
17	0.14	0.37	0.32	0.05	0.06	0.05	0.10	0.56	0.29	0.23	0.43	0.32		2.91
18	0.09	0.39	0.21	0.03	0.06	0.04	0.10	0.44	0.18	0.19	0.31	0.23		2.28
19	0.06	0.22	0.11	0.02	0.06	0.04	0.10	0.30	0.18	0.15	0.23	0.16		1.63
20	0.04	0.11	0.05	0.03	0.05	0.04	0.06	0.30	0.13	0.16	0.19	0.10		1.26
21	0.04	0.05	0.01	0.02	0.03	0.04	0.06	0.31	0.08	0.12	0.12	0.08		0.97
22	0.03	0.02	+	0.01	0.04	0.03	0.10	0.30	0.06	0.08	0.08	0.05		0.81
23	+	0.01	0.01	+	0.01	0.01	0.07	0.23	0.03	0.04	0.04	0.01		0.47
24		0.01	0.01	+	0.01	0.01	0.04	0.13	0.02	0.05	0.02	+		0.28
25	+		0.01	+	+	+	0.04	0.09	0.01	0.02	0.01			0.18
26	+		+	+	+	+	0.04	0.08	0.01	+				0.15
27	+		+	+	+	+	0.05	0.06	+	+				0.12
28			0.01	+	+	+	0.04	0.04	+					0.10
29			0.01			0.01	0.03	0.03	+					0.07
30			+			+	0.01	0.03	+					0.04
30+														
Total (%)	6.15	7.46	7.52	5.66	4.42	4.11	6.60	16.07	12.23	8.83	11.13	9.82		100.00
Mean Speed	9.17	10.35	9.96	7.92	7.94	7.92	9.67	11.50	9.86	9.96	11.08	10.57	-	10.05

Note: A plus sign (+) indicates a nonzero percentage <0.005%, while a blank space indicates zero percentage.

Appendix F. Turbine Availability Assumptions

For this analysis, DNV made the following preliminary assumptions to derive a starting assumption for the turbine availability loss profile (loss category 2a):

- Projects with similar characteristics and wave and wind conditions show similar availabilities in other regions in comparison relative to those in the North Sea. Consequently, the projected turbine availability relies on North Sea experience. DNV considers this a reasonable starting assumption for projects in other regions in the absence of a more detailed review of the operations and management (O&M) access strategy and metocean conditions at the site, supported by previous experience and extensive modeling DNV conducted.
- Turbine reliability varies with wind speed conditions at site. Therefore, sites with lower wind speeds exhibit better turbine reliability compared to sites with higher wind speeds, according to. recent studies using real industry data (Carroll et al. 2015).
- The project operates or will operate with an optimal number of technicians. Therefore, values are only representative when staffing levels are well planned.
- Based on these assumptions, DNV estimates an indicative starting point for turbine availability for the specified project characteristics.
- Main component replacements use a Jack-Up vessel with an average lead time of 45 days to reach the site. This value reflects typical North Sea operational experience but may differ in the future and in different markets.
- Turbine reliability relies on the experience of turbine manufacturers and applies only to projects using models from offshore-experienced turbine suppliers. If the project considers newer turbine models, interpret this projection with caution and conduct a project-specific review.

Based on these assumptions, DNV estimates an indicative starting assumption for turbine availability for the following project characteristics:

Table F-1. Turbine Availability Loss Assumptions

Project Characteristic	Value Assumed for Modeling	Source of Assumption
Distance to O&M port (nautical miles)	Hudson South, 70 Hudson Central, 85	Customer
Mean long-term wind speed at hub height (m/s)	See main body of report	DNV
Mean long-term significant wave height (m)	1.5	DNV
Assumed drive train concept	Direct drive	DNV
Ramp up expected (in increase of %)	3%	DNV
Ramp up period (in years)	3.0	DNV
Period evaluated (in years)	See main body of report	Customer
Access strategy expected	1 Service operations vessel, 1 crew transfer vessel, and 1 daughter craft	DNV

DNV selected these values based on high-level assumptions. As projects develop and a commercially available turbine model is identified for the site, these assumptions are likely to change. At that later stage, DNV recommends updating the estimated turbine availability for the project.

F.1 Energy Results

Table F-2. Energy Results for Hudson Central Study Year 2027

Turbine	Turbine Model	Hub Height (m)	Initiation location	Easting[a] (m)	Northing[a] (m)	Elevation (m)	Long-term Wind Speed at Hub Height[b] (m/s)	Energy Output[c] (GWh/a)	Turbine Interaction Loss Factor[d] (%)
1	Theoretical 14 MW	140	E05_N	689,042	4,435,685	0	10.1	61.7	97.5
2	Theoretical 14 MW	140	E05_N	691,292	4,435,685	0	10.1	61.0	96.3
3	Theoretical 14 MW	140	E05_N	693,542	4,435,685	0	10.1	60.8	96.0
4	Theoretical 14 MW	140	E05_N	695,792	4,435,685	0	10.1	60.3	95.3
5	Theoretical 14 MW	140	E05_N	698,042	4,435,685	0	10.1	60.3	95.2
6	Theoretical 14 MW	140	E05_N	700,292	4,435,685	0	10.1	60.4	95.4
7	Theoretical 14 MW	140	E05_N	689,042	4,433,435	0	10.1	61.0	96.2
8	Theoretical 14 MW	140	E05_N	691,292	4,433,435	0	10.1	60.1	94.8
9	Theoretical 14 MW	140	E05_N	693,542	4,433,435	0	10.1	59.8	94.4
10	Theoretical 14 MW	140	E05_N	695,792	4,433,435	0	10.1	59.6	94.0
11	Theoretical 14 MW	140	E05_N	698,042	4,433,435	0	10.1	59.3	93.6
12	Theoretical 14 MW	140	E05_N	700,292	4,433,435	0	10.1	59.7	94.2
13	Theoretical 14 MW	140	E05_N	689,042	4,431,185	0	10.1	60.6	95.5
14	Theoretical 14 MW	140	E05_N	691,292	4,431,185	0	10.1	59.5	93.7
15	Theoretical 14 MW	140	E05_N	693,542	4,431,185	0	10.1	59.4	93.5
16	Theoretical 14 MW	140	E05_N	695,792	4,431,185	0	10.1	59.2	93.3
17	Theoretical 14 MW	140	E05_N	698,042	4,431,185	0	10.1	59.3	93.4
18	Theoretical 14 MW	140	E05_N	700,292	4,431,185	0	10.1	59.3	93.4
19	Theoretical 14 MW	140	E05_N	702,542	4,431,185	0	10.1	60.1	94.6
20	Theoretical 14 MW	140	E05_N	684,542	4,428,935	0	10.1	61.3	96.6
21	Theoretical 14 MW	140	E05_N	686,792	4,428,935	0	10.1	60.5	95.3
22	Theoretical 14 MW	140	E05_N	689,042	4,428,935	0	10.1	59.9	94.3
23	Theoretical 14 MW	140	E05_N	691,292	4,428,935	0	10.1	59.4	93.5
24	Theoretical 14 MW	140	E05_N	693,542	4,428,935	0	10.1	59.1	93.0
25	Theoretical 14 MW	140	E05_N	695,792	4,428,935	0	10.1	59.0	92.7
26	Theoretical 14 MW	140	E05_N	698,042	4,428,935	0	10.1	59.0	92.7
27	Theoretical 14 MW	140	E05_N	700,292	4,428,935	0	10.1	59.4	93.5
28	Theoretical 14 MW	140	E05_N	680,042	4,426,685	0	10.1	62.1	98.1
29	Theoretical 14 MW	140	E05_N	682,292	4,426,685	0	10.1	61.5	96.9
30	Theoretical 14 MW	140	E05_N	684,542	4,426,685	0	10.1	60.9	95.9
31	Theoretical 14 MW	140	E05_N	686,792	4,426,685	0	10.1	60.2	94.7
32	Theoretical 14 MW	140	E05_N	689,042	4,426,685	0	10.1	59.9	94.2
33	Theoretical 14 MW	140	E05_N	691,292	4,426,685	0	10.2	59.2	92.9

Table F-2. (continued)

Turbine	Turbine model	Hub Height (m)	Initiation Location	Easting[a] (m)	Northing[a] (m)	Elevation (m)	Long-term Wind Speed at Hub Height[b] (m/s)	Energy Output[c] (GWh/ annum)	Turbine Interaction Loss Factor[d] (%)
34	Theoretical 14 MW	140	E05_N	693,542	4,426,685	0	10.2	59.1	92.8
35	Theoretical 14 MW	140	E05_N	695,792	4,426,685	0	10.2	59.0	92.6
36	Theoretical 14 MW	140	E05_N	698,042	4,426,685	0	10.2	59.1	92.8
37	Theoretical 14 MW	140	E05_N	700,292	4,426,685	0	10.1	59.5	93.4
38	Theoretical 14 MW	140	E05_N	682,292	4,424,435	0	10.1	61.4	96.8
39	Theoretical 14 MW	140	E05_N	684,542	4,424,435	0	10.1	60.7	95.5
40	Theoretical 14 MW	140	E05_N	686,792	4,424,435	0	10.1	60.3	94.7
41	Theoretical 14 MW	140	E05_N	689,042	4,424,435	0	10.2	59.9	94.0
42	Theoretical 14 MW	140	E05_N	691,292	4,424,435	0	10.2	59.5	93.4
43	Theoretical 14 MW	140	E05_N	693,542	4,424,435	0	10.2	59.2	92.9
44	Theoretical 14 MW	140	E05_N	695,792	4,424,435	0	10.2	59.2	92.9
45	Theoretical 14 MW	140	E05_N	698,042	4,424,435	0	10.2	59.3	93.0
46	Theoretical 14 MW	140	E05_N	700,292	4,424,435	0	10.2	59.6	93.6
47	Theoretical 14 MW	140	E05_N	702,542	4,424,435	0	10.2	60.2	94.5
48	Theoretical 14 MW	140	E05_N	684,542	4,422,185	0	10.1	61.2	96.4
49	Theoretical 14 MW	140	E05_N	686,792	4,422,185	0	10.1	60.3	94.8
50	Theoretical 14 MW	140	E05_N	689,042	4,422,185	0	10.1	60.0	94.2
51	Theoretical 14 MW	140	E05_N	691,292	4,422,185	0	10.2	59.7	93.6
52	Theoretical 14 MW	140	E05_N	693,542	4,422,185	0	10.2	59.5	93.3
53	Theoretical 14 MW	140	E05_N	695,792	4,422,185	0	10.2	59.5	93.2
54	Theoretical 14 MW	140	E05_N	698,042	4,422,185	0	10.2	59.6	93.4
55	Theoretical 14 MW	140	E05_N	700,292	4,422,185	0	10.2	60.1	94.3
56	Theoretical 14 MW	140	E05_N	686,792	4,419,935	0	10.1	61.1	96.0
57	Theoretical 14 MW	140	E05_N	689,042	4,419,935	0	10.1	60.5	95.0
58	Theoretical 14 MW	140	E05_N	691,292	4,419,935	0	10.2	60.4	94.9
59	Theoretical 14 MW	140	E05_N	693,542	4,419,935	0	10.2	60.3	94.6
60	Theoretical 14 MW	140	E05_N	695,792	4,419,935	0	10.2	60.4	94.7
61	Theoretical 14 MW	140	E05_N	698,042	4,419,935	0	10.2	60.6	94.9
62	Theoretical 14 MW	140	E05_N	700,292	4,419,935	0	10.2	61.0	95.6
Average						**0**	**10.1**	**60.0**	**94.4**
Total								**3722.9**	

[a] The coordinate system is UTM18 WGS84 data.

[b] Wind speed at the turbine location, excluding wake effects.

[c] Individual turbine output figures account for all wind farm losses.

[d] Individual turbine wake loss includes all turbine interaction effects, such as wakes and blockage.

Table F-3. Energy Results for Hudson Central Study Year 2030

Turbine	Turbine Model	Hub Height (m)	Initiation Location	Easting[a] (m)	Northing[a] (m)	Elevation (m)	Long-term Wind Speed at Hub Height[b] (m/s)	Energy Output[c] (GWh/a)	Turbine Interaction Loss Factors (%)
1	Theoretical 18 MW	155	E05_N	689,042	4,435,685	0	10.2	79.3	97.1
2	Theoretical 18 MW	155	E05_N	691,292	4,435,685	0	10.2	78.3	95.7
3	Theoretical 18 MW	155	E05_N	693,542	4,435,685	0	10.2	78.1	95.4
4	Theoretical 18 MW	155	E05_N	695,792	4,435,685	0	10.2	77.7	95.0
5	Theoretical 18 MW	155	E05_N	698,042	4,435,685	0	10.2	77.8	95.1
7	Theoretical 18 MW	155	E05_N	689,042	4,433,435	0	10.2	78.2	95.6
8	Theoretical 18 MW	155	E05_N	691,292	4,433,435	0	10.2	76.8	93.8
9	Theoretical 18 MW	155	E05_N	693,542	4,433,435	0	10.2	76.5	93.4
10	Theoretical 18 MW	155	E05_N	695,792	4,433,435	0	10.2	76.2	93.0
11	Theoretical 18 MW	155	E05_N	698,042	4,433,435	0	10.2	76.5	93.5
13	Theoretical 18 MW	155	E05_N	689,042	4,431,185	0	10.2	77.6	94.6
14	Theoretical 18 MW	155	E05_N	691,292	4,431,185	0	10.2	76.2	92.9
15	Theoretical 18 MW	155	E05_N	693,542	4,431,185	0	10.2	76.0	92.6
16	Theoretical 18 MW	155	E05_N	695,792	4,431,185	0	10.2	75.8	92.5
17	Theoretical 18 MW	155	E05_N	698,042	4,431,185	0	10.2	76.0	92.7
18	Theoretical 18 MW	155	E05_N	700,292	4,431,185	0	10.2	76.8	93.7
20	Theoretical 18 MW	155	E05_N	684,542	4,428,935	0	10.2	79.0	96.4
21	Theoretical 18 MW	155	E05_N	686,792	4,428,935	0	10.2	77.7	94.7
22	Theoretical 18 MW	155	E05_N	689,042	4,428,935	0	10.2	77.0	93.8
23	Theoretical 18 MW	155	E05_N	691,292	4,428,935	0	10.2	75.9	92.4
24	Theoretical 18 MW	155	E05_N	693,542	4,428,935	0	10.2	75.7	92.2
25	Theoretical 18 MW	155	E05_N	695,792	4,428,935	0	10.2	75.5	91.9
26	Theoretical 18 MW	155	E05_N	698,042	4,428,935	0	10.2	75.6	92.1
27	Theoretical 18 MW	155	E05_N	700,292	4,428,935	0	10.2	76.1	92.7
29	Theoretical 18 MW	155	E05_N	682,292	4,426,685	0	10.2	79.6	97.1
30	Theoretical 18 MW	155	E05_N	684,542	4,426,685	0	10.2	78.2	95.3
31	Theoretical 18 MW	155	E05_N	686,792	4,426,685	0	10.2	77.5	94.3
32	Theoretical 18 MW	155	E05_N	689,042	4,426,685	0	10.2	76.8	93.4
33	Theoretical 18 MW	155	E05_N	691,292	4,426,685	0	10.2	76.1	92.5
34	Theoretical 18 MW	155	E05_N	693,542	4,426,685	0	10.2	75.7	92.0

Table F-3. (continued)

Turbine	Turbine Model	Hub Height (m)	Initiation Location	Easting[a] (m)	Northing[a] (m)	Elevation (m)	Long-term Wind Speed at Hub Height[b] (m/s)	Energy Output[c] (GWh/a)	Turbine Interaction Loss Factors (%)
35	Theoretical 18 MW	155	E05_N	695,792	4,426,685	0	10.2	75.8	92.2
36	Theoretical 18 MW	155	E05_N	698,042	4,426,685	0	10.2	75.9	92.4
37	Theoretical 18 MW	155	E05_N	700,292	4,426,685	0	10.2	76.5	93.1
39	Theoretical 18 MW	155	E05_N	684,542	4,424,435	0	10.2	78.7	95.9
40	Theoretical 18 MW	155	E05_N	686,792	4,424,435	0	10.2	77.4	94.2
41	Theoretical 18 MW	155	E05_N	689,042	4,424,435	0	10.2	77.0	93.6
42	Theoretical 18 MW	155	E05_N	691,292	4,424,435	0	10.3	76.2	92.6
43	Theoretical 18 MW	155	E05_N	693,542	4,424,435	0	10.3	75.9	92.2
44	Theoretical 18 MW	155	E05_N	695,792	4,424,435	0	10.3	76.0	92.3
45	Theoretical 18 MW	155	E05_N	698,042	4,424,435	0	10.3	76.2	92.6
46	Theoretical 18 MW	155	E05_N	700,292	4,424,435	0	10.2	76.9	93.5
49	Theoretical 18 MW	155	E05_N	686,792	4,422,185	0	10.2	78.6	95.7
50	Theoretical 18 MW	155	E05_N	689,042	4,422,185	0	10.2	77.6	94.3
51	Theoretical 18 MW	155	E05_N	691,292	4,422,185	0	10.3	77.5	94.1
52	Theoretical 18 MW	155	E05_N	693,542	4,422,185	0	10.3	77.2	93.8
53	Theoretical 18 MW	155	E05_N	695,792	4,422,185	0	10.3	77.5	94.0
54	Theoretical 18 MW	155	E05_N	698,042	4,422,185	0	10.3	77.6	94.2
55	Theoretical 18 MW	155	E05_N	700,292	4,422,185	0	10.3	78.3	95.1
Average						**0**	**10.2**	**77.0**	**93.8**
Total								**3697.1**	

[a] The coordinate system is UTM18 WGS84 data.

[b] Wind speed at the turbine location, excluding wake effects.

[c] Individual turbine output figures account for all wind farm losses.

[d] Individual turbine wake loss includes all turbine interaction effects, such as wakes and blockage.

Table F-4. Energy Results for Hudson Central Study Year 2033

Turbine	Turbine Model	Hub Height (m)	Initiation Location	Easting[a] (m)	Northing[a] (m)	Elevation (m)	Long-term Wind Speed at Hub Height[b] (m/s)	Energy Output[c] (GWh/a)	Turbine Interaction Loss Factors (%)
7	Theoretical 22 MW	165	E05_N	689,042	4,433,435	0	10.2	96.4	96.6
8	Theoretical 22 MW	165	E05_N	691,292	4,433,435	0	10.3	94.8	94.9
9	Theoretical 22 MW	165	E05_N	693,542	4,433,435	0	10.3	94.2	94.3
10	Theoretical 22 MW	165	E05_N	695,792	4,433,435	0	10.3	93.8	93.9
11	Theoretical 22 MW	165	E05_N	698,042	4,433,435	0	10.3	94.0	94.2
13	Theoretical 22 MW	165	E05_N	689,042	4,431,185	0	10.3	94.5	94.5
14	Theoretical 22 MW	165	E05_N	691,292	4,431,185	0	10.3	92.7	92.7
15	Theoretical 22 MW	165	E05_N	693,542	4,431,185	0	10.3	92.1	92.0
16	Theoretical 22 MW	165	E05_N	695,792	4,431,185	0	10.3	92.0	92.0
17	Theoretical 22 MW	165	E05_N	698,042	4,431,185	0	10.3	91.9	91.9
18	Theoretical 22 MW	165	E05_N	700,292	4,431,185	0	10.3	93.2	93.2
21	Theoretical 22 MW	165	E05_N	686,792	4,428,935	0	10.3	96.1	96.0
22	Theoretical 22 MW	165	E05_N	689,042	4,428,935	0	10.3	93.7	93.6
23	Theoretical 22 MW	165	E05_N	691,292	4,428,935	0	10.3	92.3	92.2
24	Theoretical 22 MW	165	E05_N	693,542	4,428,935	0	10.3	91.7	91.6
25	Theoretical 22 MW	165	E05_N	695,792	4,428,935	0	10.3	91.4	91.2
26	Theoretical 22 MW	165	E05_N	698,042	4,428,935	0	10.3	91.5	91.4
27	Theoretical 22 MW	165	E05_N	700,292	4,428,935	0	10.3	92.2	92.1
31	Theoretical 22 MW	165	E05_N	686,792	4,426,685	0	10.3	95.3	95.1
32	Theoretical 22 MW	165	E05_N	689,042	4,426,685	0	10.3	93.2	93.0
33	Theoretical 22 MW	165	E05_N	691,292	4,426,685	0	10.3	92.1	91.8
34	Theoretical 22 MW	165	E05_N	693,542	4,426,685	0	10.3	91.4	91.1
35	Theoretical 22 MW	165	E05_N	695,792	4,426,685	0	10.3	91.3	91.1
36	Theoretical 22 MW	165	E05_N	698,042	4,426,685	0	10.3	91.4	91.1
37	Theoretical 22 MW	165	E05_N	700,292	4,426,685	0	10.3	92.3	92.1
40	Theoretical 22 MW	165	E05_N	686,792	4,424,435	0	10.3	95.3	95.1
41	Theoretical 22 MW	165	E05_N	689,042	4,424,435	0	10.3	93.2	92.9
42	Theoretical 22 MW	165	E05_N	691,292	4,424,435	0	10.3	92.3	92.0
43	Theoretical 22 MW	165	E05_N	693,542	4,424,435	0	10.3	91.6	91.3
44	Theoretical 22 MW	165	E05_N	695,792	4,424,435	0	10.3	91.6	91.3
45	Theoretical 22 MW	165	E05_N	698,042	4,424,435	0	10.3	91.8	91.5
46	Theoretical 22 MW	165	E05_N	700,292	4,424,435	0	10.3	92.8	92.5

Table F-4. (continued)

Turbine	Turbine Model	Hub Height (m)	Initiation Location	Easting[a] (m)	Northing[a] (m)	Elevation (m)	Long-term Wind Speed at Hub Height[b] (m/s)	Energy Output[c] (GWh/a)	Turbine Interaction Loss Factor[d] (%)
49	Theoretical 22 MW	165	E05_N	686,792	4,422,185	0	10.3	96.0	95.8
50	Theoretical 22 MW	165	E05_N	689,042	4,422,185	0	10.3	94.1	93.9
51	Theoretical 22 MW	165	E05_N	691,292	4,422,185	0	10.3	93.8	93.5
52	Theoretical 22 MW	165	E05_N	693,542	4,422,185	0	10.3	93.4	93.0
53	Theoretical 22 MW	165	E05_N	695,792	4,422,185	0	10.3	93.5	93.1
54	Theoretical 22 MW	165	E05_N	698,042	4,422,185	0	10.3	93.6	93.2
55	Theoretical 22 MW	165	E05_N	700,292	4,422,185	0	10.3	94.6	94.2
Average						**0**	**10.3**	**93.2**	**93.0**
Total								**3632.9**	

[a] The coordinate system is UTM18 WGS84 data.

[b] Wind speed at the turbine location, excluding wake effects.

[c] Individual turbine output figures account for all wind farm losses.

[d] Individual turbine wake loss includes all turbine interaction effects, such as wakes and blockage.

Table F-5. Energy Results for Hudson South Study Year 2027

Turbine	Turbine Model	Hub Height (m)	Initiation Location	Easting[a] (m)	Northing[a] (m)	Elevation (m)	Long-term Wind Speed at Hub Height[b] (m/s)	Energy Output[c] (GWh/a)	Turbine Interaction Loss Factor[d] (%)
1	Theoretical 14 MW	140	E06_S	638,539	4,385,762	0	10.0	60.9	97.4
2	Theoretical 14 MW	140	E06_S	640,789	4,385,762	0	10.0	60.1	96.0
3	Theoretical 14 MW	140	E06_S	643,039	4,385,762	0	10.0	60.1	95.9
4	Theoretical 14 MW	140	E06_S	645,289	4,385,762	0	10.0	59.8	95.2
5	Theoretical 14 MW	140	E06_S	647,539	4,385,762	0	10.0	59.8	95.2
6	Theoretical 14 MW	140	E06_S	649,789	4,385,762	0	10.1	60.0	95.4
7	Theoretical 14 MW	140	E06_S	638,539	4,383,512	0	10.0	60.0	96.0
8	Theoretical 14 MW	140	E06_S	640,789	4,383,512	0	10.0	59.4	94.8
9	Theoretical 14 MW	140	E06_S	643,039	4,383,512	0	10.0	59.1	94.2

Table F-5. (continued)

Turbine	Turbine Model	Hub Height (m)	Initiation Location	Easting[a] (m)	Northing[a] (m)	Elevation (m)	Long-term Wind Speed at Hub Height[b] (m/s)	Energy Output[c] (GWh/a)	Turbine Interaction Loss Factor[d] (%)
10	Theoretical 14 MW	140	E06_S	645,289	4,383,512	0	10.0	59.0	93.9
11	Theoretical 14 MW	140	E06_S	647,539	4,383,512	0	10.0	58.8	93.6
12	Theoretical 14 MW	140	E06_S	649,789	4,383,512	0	10.0	59.2	94.2
13	Theoretical 14 MW	140	E06_S	638,539	4,381,262	0	10.0	59.7	95.4
14	Theoretical 14 MW	140	E06_S	640,789	4,381,262	0	10.0	58.7	93.7
15	Theoretical 14 MW	140	E06_S	643,039	4,381,262	0	10.0	58.6	93.5
16	Theoretical 14 MW	140	E06_S	645,289	4,381,262	0	10.0	58.6	93.2
17	Theoretical 14 MW	140	E06_S	647,539	4,381,262	0	10.0	58.7	93.4
18	Theoretical 14 MW	140	E06_S	649,789	4,381,262	0	10.1	58.7	93.4
19	Theoretical 14 MW	140	E06_S	652,039	4,381,262	0	10.1	59.3	94.3
20	Theoretical 14 MW	140	E06_S	634,039	4,379,012	0	10.0	60.7	97.2
21	Theoretical 14 MW	140	E06_S	636,289	4,379,012	0	10.0	59.8	95.6
22	Theoretical 14 MW	140	E06_S	638,539	4,379,012	0	10.0	59.2	94.5
23	Theoretical 14 MW	140	E06_S	640,789	4,379,012	0	10.0	58.6	93.6
24	Theoretical 14 MW	140	E06_S	643,039	4,379,012	0	10.0	58.4	93.0
25	Theoretical 14 MW	140	E06_S	645,289	4,379,012	0	10.0	58.3	92.8
26	Theoretical 14 MW	140	E06_S	647,539	4,379,012	0	10.0	58.4	92.9
27	Theoretical 14 MW	140	E06_S	649,789	4,379,012	0	10.1	58.7	93.4
28	Theoretical 14 MW	140	E06_S	652,039	4,379,012	0	10.1	59.0	93.7
29	Theoretical 14 MW	140	E06_S	654,289	4,379,012	0	10.1	60.3	95.6
30	Theoretical 14 MW	140	E06_S	634,039	4,376,762	0	10.0	60.1	96.3
31	Theoretical 14 MW	140	E06_S	636,289	4,376,762	0	10.0	59.1	94.5
32	Theoretical 14 MW	140	E06_S	638,539	4,376,762	0	10.0	58.9	94.0
33	Theoretical 14 MW	140	E06_S	640,789	4,376,762	0	10.0	58.2	92.9
34	Theoretical 14 MW	140	E06_S	643,039	4,376,762	0	10.0	58.2	92.7
35	Theoretical 14 MW	140	E06_S	645,289	4,376,762	0	10.0	58.1	92.5
36	Theoretical 14 MW	140	E06_S	647,539	4,376,762	0	10.1	58.3	92.7
37	Theoretical 14 MW	140	E06_S	649,789	4,376,762	0	10.1	58.7	93.3
38	Theoretical 14 MW	140	E06_S	631,789	4,374,512	0	10.0	60.8	97.6
39	Theoretical 14 MW	140	E06_S	634,039	4,374,512	0	10.0	60.0	96.1
40	Theoretical 14 MW	140	E06_S	636,289	4,374,512	0	10.0	59.4	95.1
41	Theoretical 14 MW	140	E06_S	638,539	4,374,512	0	10.0	59.0	94.2
42	Theoretical 14 MW	140	E06_S	640,789	4,374,512	0	10.0	58.7	93.6

Table F-5. (continued)

Turbine	Turbine Model	Hub Height (m)	Initiation Location	Easting[a] (m)	Northing[a] (m)	Elevation (m)	Long-term Wind Speed at Hub Height[b] (m/s)	Energy Output[c] (GWh/a)	Turbine Interaction Loss Factor[d] (%)
43	Theoretical 14 MW	140	E06_S	643,039	4,374,512	0	10.0	58.4	93.0
44	Theoretical 14 MW	140	E06_S	645,289	4,374,512	0	10.1	58.5	93.1
45	Theoretical 14 MW	140	E06_S	647,539	4,374,512	0	10.1	58.7	93.3
46	Theoretical 14 MW	140	E06_S	649,789	4,374,512	0	10.1	59.0	93.7
47	Theoretical 14 MW	140	E06_S	652,039	4,374,512	0	10.1	59.6	94.6
48	Theoretical 14 MW	140	E06_S	634,039	4,372,262	0	10.0	60.3	96.6
49	Theoretical 14 MW	140	E06_S	636,289	4,372,262	0	10.0	59.4	95.1
50	Theoretical 14 MW	140	E06_S	638,539	4,372,262	0	10.0	59.2	94.5
51	Theoretical 14 MW	140	E06_S	640,789	4,372,262	0	10.0	58.9	93.9
52	Theoretical 14 MW	140	E06_S	643,039	4,372,262	0	10.0	58.8	93.6
53	Theoretical 14 MW	140	E06_S	645,289	4,372,262	0	10.1	58.9	93.6
54	Theoretical 14 MW	140	E06_S	647,539	4,372,262	0	10.1	59.0	93.7
55	Theoretical 14 MW	140	E06_S	649,789	4,372,262	0	10.1	59.5	94.5
56	Theoretical 14 MW	140	E06_S	636,289	4,370,012	0	10.0	60.2	96.3
57	Theoretical 14 MW	140	E06_S	638,539	4,370,012	0	10.0	59.6	95.2
58	Theoretical 14 MW	140	E06_S	640,789	4,370,012	0	10.0	59.7	95.1
59	Theoretical 14 MW	140	E06_S	643,039	4,370,012	0	10.0	59.6	94.8
60	Theoretical 14 MW	140	E06_S	645,289	4,370,012	0	10.1	59.8	95.0
61	Theoretical 14 MW	140	E06_S	647,539	4,370,012	0	10.1	60.0	95.2
62	Theoretical 14 MW	140	E06_S	649,789	4,370,012	0	10.1	60.4	95.8
Average						**0**	**10.0**	**59.3**	**94.5**
Total								**3674.8**	

[a] The coordinate system is UTM18 WGS84 data.

[b] Wind speed at the turbine location, excluding wake effects.

[c] Individual turbine output figures account for all wind farm losses.

[d] Individual turbine wake loss includes all turbine interaction effects, such as wakes and blockage.

Table F-6. Energy Results for Hudson South Study Year 2030

Turbine	Turbine Model	Hub Height (m)	Initiation Location	Easting[a] (m)	Northing[a] (m)	Elevation (m)	Long-term Wind Speed at Hub Height[b] (m/s)	Energy Output[c] (GWh/a)	Turbine Interaction Loss Factor[d] (%)
1	Theoretical 18 MW	155	E06_S	638,539	4,385,762	0	10.1	78.1	96.8
2	Theoretical 18 MW	155	E06_S	640,789	4,385,762	0	10.1	77.1	95.4
3	Theoretical 18 MW	155	E06_S	643,039	4,385,762	0	10.1	77.0	95.2
4	Theoretical 18 MW	155	E06_S	645,289	4,385,762	0	10.1	76.8	94.7
5	Theoretical 18 MW	155	E06_S	647,539	4,385,762	0	10.1	77.2	95.1
7	Theoretical 18 MW	155	E06_S	638,539	4,383,512	0	10.1	76.8	95.2
8	Theoretical 18 MW	155	E06_S	640,789	4,383,512	0	10.1	75.7	93.7
9	Theoretical 18 MW	155	E06_S	643,039	4,383,512	0	10.1	75.5	93.2
10	Theoretical 18 MW	155	E06_S	645,289	4,383,512	0	10.1	75.3	92.9
11	Theoretical 18 MW	155	E06_S	647,539	4,383,512	0	10.1	75.8	93.4
13	Theoretical 18 MW	155	E06_S	638,539	4,381,262	0	10.1	76.4	94.6
14	Theoretical 18 MW	155	E06_S	640,789	4,381,262	0	10.1	75.0	92.7
15	Theoretical 18 MW	155	E06_S	643,039	4,381,262	0	10.1	75.1	92.7
16	Theoretical 18 MW	155	E06_S	645,289	4,381,262	0	10.1	74.9	92.5
17	Theoretical 18 MW	155	E06_S	647,539	4,381,262	0	10.1	75.3	92.9
18	Theoretical 18 MW	155	E06_S	649,789	4,381,262	0	10.1	76.0	93.7
20	Theoretical 18 MW	155	E06_S	634,039	4,379,012	0	10.1	77.9	96.7
21	Theoretical 18 MW	155	E06_S	636,289	4,379,012	0	10.1	76.3	94.6
22	Theoretical 18 MW	155	E06_S	638,539	4,379,012	0	10.1	75.7	93.7
23	Theoretical 18 MW	155	E06_S	640,789	4,379,012	0	10.1	74.8	92.4
24	Theoretical 18 MW	155	E06_S	643,039	4,379,012	0	10.1	74.6	92.1
25	Theoretical 18 MW	155	E06_S	645,289	4,379,012	0	10.1	74.5	91.9
26	Theoretical 18 MW	155	E06_S	647,539	4,379,012	0	10.1	74.9	92.3
27	Theoretical 18 MW	155	E06_S	649,789	4,379,012	0	10.1	75.4	92.9
30	Theoretical 18 MW	155	E06_S	634,039	4,376,762	0	10.1	77.4	96.0
31	Theoretical 18 MW	155	E06_S	636,289	4,376,762	0	10.1	75.7	93.9
32	Theoretical 18 MW	155	E06_S	638,539	4,376,762	0	10.1	75.5	93.4
33	Theoretical 18 MW	155	E06_S	640,789	4,376,762	0	10.1	74.7	92.3
34	Theoretical 18 MW	155	E06_S	643,039	4,376,762	0	10.1	74.7	92.1
35	Theoretical 18 MW	155	E06_S	645,289	4,376,762	0	10.1	74.8	92.2
36	Theoretical 18 MW	155	E06_S	647,539	4,376,762	0	10.1	75.1	92.6
37	Theoretical 18 MW	155	E06_S	649,789	4,376,762	0	10.1	75.7	93.3
39	Theoretical 18 MW	155	E06_S	634,039	4,374,512	0	10.0	77.3	96.0
40	Theoretical 18 MW	155	E06_S	636,289	4,374,512	0	10.1	75.9	94.0
41	Theoretical 18 MW	155	E06_S	638,539	4,374,512	0	10.1	75.5	93.5

Table F-6. (continued)

Turbine	Turbine Model	Hub Height (m)	Initiation Location	Easting[a] (m)	Northing[a] (m)	Elevation (m)	Long-term Wind Speed at Hub Height[b] (m/s)	Energy Output[c] (GWh/a)	Turbine Interaction Loss Factor[d] (%)
42	Theoretical 18 MW	155	E06_S	640,789	4,374,512	0	10.1	75.0	92.7
43	Theoretical 18 MW	155	E06_S	643,039	4,374,512	0	10.1	74.8	92.3
44	Theoretical 18 MW	155	E06_S	645,289	4,374,512	0	10.1	75.1	92.5
45	Theoretical 18 MW	155	E06_S	647,539	4,374,512	0	10.1	75.4	92.9
46	Theoretical 18 MW	155	E06_S	649,789	4,374,512	0	10.1	76.2	93.8
48	Theoretical 18 MW	155	E06_S	634,039	4,372,262	0	10.0	77.7	96.6
49	Theoretical 18 MW	155	E06_S	636,289	4,372,262	0	10.1	76.7	95.1
50	Theoretical 18 MW	155	E06_S	638,539	4,372,262	0	10.1	76.6	94.8
51	Theoretical 18 MW	155	E06_S	640,789	4,372,262	0	10.1	76.4	94.3
52	Theoretical 18 MW	155	E06_S	643,039	4,372,262	0	10.1	76.4	94.1
53	Theoretical 18 MW	155	E06_S	645,289	4,372,262	0	10.1	76.6	94.3
54	Theoretical 18 MW	155	E06_S	647,539	4,372,262	0	10.1	76.9	94.6
55	Theoretical 18 MW	155	E06_S	649,789	4,372,262	0	10.2	77.6	95.4
Average						**0**	**10.1**	**76.0**	**93.8**
Total								**3645.8**	

[a] The coordinate system is UTM18 WGS84 data.

[b] Wind speed at the turbine location, excluding wake effects.

[c] Individual turbine output figures account for all wind farm losses.

[d] Individual turbine wake loss includes all turbine interaction effects, such as wakes and blockage.

Table F-7. Energy Results for Hudson South Study Year 2033

Turbine	Turbine Model	Hub Height (m)	Initiation Location	Easting[a] (m)	Northing[a] (m)	Elevation (m)	Long-term Wind Speed at Hub Height[b] (m/s)	Energy Output[c] (GWh/a)	Turbine Interaction Loss Factor[d] (%)
7	Theoretical 22 MW	165	E06_S	638,539	4,383,512	0	10.1	94.8	96.3
8	Theoretical 22 MW	165	E06_S	640,789	4,383,512	0	10.1	93.3	94.5
9	Theoretical 22 MW	165	E06_S	643,039	4,383,512	0	10.2	92.9	94.0
10	Theoretical 22 MW	165	E06_S	645,289	4,383,512	0	10.2	92.7	93.7
11	Theoretical 22 MW	165	E06_S	647,539	4,383,512	0	10.2	93.0	94.0
13	Theoretical 22 MW	165	E06_S	638,539	4,381,262	0	10.1	92.9	94.3
14	Theoretical 22 MW	165	E06_S	640,789	4,381,262	0	10.1	91.3	92.6
15	Theoretical 22 MW	165	E06_S	643,039	4,381,262	0	10.2	90.8	91.9
16	Theoretical 22 MW	165	E06_S	645,289	4,381,262	0	10.2	90.9	91.9
17	Theoretical 22 MW	165	E06_S	647,539	4,381,262	0	10.2	91.0	92.0
18	Theoretical 22 MW	165	E06_S	649,789	4,381,262	0	10.2	92.3	93.3
21	Theoretical 22 MW	165	E06_S	636,289	4,379,012	0	10.1	94.4	95.8
22	Theoretical 22 MW	165	E06_S	638,539	4,379,012	0	10.1	92.1	93.4
23	Theoretical 22 MW	165	E06_S	640,789	4,379,012	0	10.2	90.9	92.1
24	Theoretical 22 MW	165	E06_S	643,039	4,379,012	0	10.2	90.4	91.5
25	Theoretical 22 MW	165	E06_S	645,289	4,379,012	0	10.2	90.2	91.2
26	Theoretical 22 MW	165	E06_S	647,539	4,379,012	0	10.2	90.5	91.5
27	Theoretical 22 MW	165	E06_S	649,789	4,379,012	0	10.2	91.4	92.3
31	Theoretical 22 MW	165	E06_S	636,289	4,376,762	0	10.1	93.6	95.1
32	Theoretical 22 MW	165	E06_S	638,539	4,376,762	0	10.1	91.6	92.9
33	Theoretical 22 MW	165	E06_S	640,789	4,376,762	0	10.2	90.7	91.8
34	Theoretical 22 MW	165	E06_S	643,039	4,376,762	0	10.2	90.1	91.1
35	Theoretical 22 MW	165	E06_S	645,289	4,376,762	0	10.2	90.3	91.2
36	Theoretical 22 MW	165	E06_S	647,539	4,376,762	0	10.2	90.5	91.3
37	Theoretical 22 MW	165	E06_S	649,789	4,376,762	0	10.2	91.5	92.4
40	Theoretical 22 MW	165	E06_S	636,289	4,374,512	0	10.1	93.6	95.1
41	Theoretical 22 MW	165	E06_S	638,539	4,374,512	0	10.1	91.7	93.0
42	Theoretical 22 MW	165	E06_S	640,789	4,374,512	0	10.2	91.0	92.1
43	Theoretical 22 MW	165	E06_S	643,039	4,374,512	0	10.2	90.5	91.4
44	Theoretical 22 MW	165	E06_S	645,289	4,374,512	0	10.2	90.6	91.5
45	Theoretical 22 MW	165	E06_S	647,539	4,374,512	0	10.2	91.0	91.8

Table F-7. (continued)

Turbine	Turbine Model	Hub Height (m)	Initiation Location	Easting[a] (m)	Northing[a] (m)	Elevation (m)	Long-term Wind Speed at Hub Height[b] (m/s)	Energy Output[c] (GWh/a)	Turbine Interaction Loss Factor[d] (%)
46	Theoretical 22 MW	165	E06_S	649,789	4,374,512	0	10.2	92.1	92.9
49	Theoretical 22 MW	165	E06_S	636,289	4,372,262	0	10.1	94.4	95.9
50	Theoretical 22 MW	165	E06_S	638,539	4,372,262	0	10.1	92.8	94.1
51	Theoretical 22 MW	165	E06_S	640,789	4,372,262	0	10.2	92.6	93.7
52	Theoretical 22 MW	165	E06_S	643,039	4,372,262	0	10.2	92.3	93.3
53	Theoretical 22 MW	165	E06_S	645,289	4,372,262	0	10.2	92.6	93.4
54	Theoretical 22 MW	165	E06_S	647,539	4,372,262	0	10.2	92.8	93.6
55	Theoretical 22 MW	165	E06_S	649,789	4,372,262	0	10.2	93.9	94.6
Average						**0**	**10.2**	**92.0**	**93.0**
Total								**3586.1**	

[a] The coordinate system is UTM18 WGS84 data.

[b] Wind speed at the turbine location, excluding wake effects.

[c] Individual turbine output figures account for all wind farm losses.

[d] Individual turbine wake loss includes all turbine interaction effects, such as wakes and blockage.

F.2 Seasonal and Diurnal Variation

Table F-8. Relative Hourly and Monthly Energy Production for Hudson Central Study Year 2027

Hour	Energy Production[a] (%)											
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
0000	0.42	0.39	0.43	0.44	0.44	0.37	0.30	0.24	0.27	0.34	0.39	0.42
0100	0.42	0.40	0.44	0.43	0.43	0.35	0.29	0.23	0.28	0.34	0.39	0.41
0200	0.41	0.41	0.44	0.42	0.43	0.34	0.27	0.22	0.27	0.35	0.38	0.40
0300	0.41	0.41	0.43	0.42	0.42	0.34	0.27	0.21	0.27	0.35	0.38	0.40
0400	0.41	0.41	0.43	0.40	0.40	0.32	0.26	0.21	0.27	0.34	0.38	0.40
0500	0.41	0.42	0.43	0.39	0.37	0.31	0.25	0.22	0.26	0.33	0.36	0.40
0600	0.39	0.42	0.44	0.39	0.36	0.30	0.25	0.22	0.26	0.33	0.35	0.39
0700	0.39	0.42	0.44	0.39	0.34	0.29	0.24	0.22	0.26	0.34	0.35	0.39
0800	0.40	0.42	0.44	0.38	0.33	0.28	0.23	0.22	0.27	0.34	0.34	0.39
0900	0.41	0.41	0.42	0.37	0.32	0.27	0.22	0.22	0.27	0.35	0.35	0.39
1000	0.41	0.39	0.40	0.36	0.30	0.26	0.21	0.21	0.27	0.34	0.35	0.39
1100	0.40	0.38	0.39	0.36	0.29	0.26	0.21	0.21	0.26	0.33	0.34	0.38
1200	0.40	0.37	0.37	0.35	0.28	0.27	0.22	0.21	0.26	0.32	0.35	0.39
1300	0.40	0.36	0.37	0.35	0.27	0.27	0.22	0.22	0.26	0.32	0.36	0.39
1400	0.40	0.35	0.37	0.36	0.28	0.28	0.23	0.23	0.26	0.34	0.37	0.40
1500	0.41	0.35	0.37	0.37	0.30	0.30	0.25	0.24	0.26	0.34	0.38	0.41
1600	0.41	0.36	0.37	0.38	0.32	0.32	0.27	0.24	0.27	0.33	0.38	0.42
1700	0.41	0.37	0.38	0.39	0.34	0.34	0.29	0.26	0.28	0.33	0.39	0.43
1800	0.41	0.37	0.38	0.38	0.36	0.35	0.30	0.27	0.29	0.34	0.40	0.44
1900	0.41	0.37	0.39	0.39	0.38	0.36	0.30	0.27	0.30	0.35	0.40	0.44
2000	0.43	0.38	0.41	0.42	0.42	0.37	0.31	0.27	0.29	0.34	0.39	0.44
2100	0.43	0.39	0.42	0.42	0.43	0.37	0.32	0.27	0.29	0.34	0.39	0.43
2200	0.43	0.39	0.42	0.43	0.43	0.36	0.31	0.26	0.29	0.34	0.39	0.42
2300	0.42	0.39	0.42	0.43	0.43	0.36	0.31	0.25	0.28	0.34	0.39	0.42
All	**9.87**	**9.33**	**9.79**	**9.42**	**8.66**	**7.63**	**6.31**	**5.62**	**6.55**	**8.11**	**8.94**	**9.77**

[a] Only wake and hysteresis are included in the calculation.

Table F-9. Relative Hourly and Monthly Energy Production for Hudson Central Study Year 2030

Hour	Energy Production[a] (%)											
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
0000	0.42	0.40	0.43	0.44	0.44	0.37	0.30	0.24	0.27	0.34	0.39	0.42
0100	0.42	0.40	0.44	0.43	0.43	0.35	0.29	0.23	0.28	0.34	0.39	0.41
0200	0.41	0.41	0.44	0.42	0.43	0.35	0.28	0.22	0.28	0.35	0.38	0.40
0300	0.41	0.41	0.43	0.41	0.42	0.34	0.27	0.22	0.28	0.35	0.38	0.40
0400	0.40	0.41	0.43	0.40	0.40	0.32	0.26	0.22	0.27	0.34	0.38	0.40
0500	0.40	0.41	0.42	0.39	0.37	0.31	0.26	0.22	0.26	0.34	0.37	0.40
0600	0.39	0.41	0.44	0.39	0.36	0.30	0.25	0.22	0.27	0.33	0.35	0.39
0700	0.39	0.41	0.44	0.38	0.34	0.29	0.24	0.22	0.27	0.33	0.35	0.39
0800	0.40	0.42	0.43	0.38	0.33	0.28	0.23	0.22	0.27	0.34	0.34	0.39
0900	0.41	0.41	0.42	0.37	0.31	0.27	0.22	0.22	0.27	0.35	0.35	0.39
1000	0.41	0.39	0.39	0.36	0.30	0.26	0.21	0.21	0.27	0.34	0.35	0.39
1100	0.40	0.38	0.38	0.36	0.29	0.26	0.21	0.22	0.26	0.33	0.34	0.38
1200	0.40	0.37	0.37	0.35	0.28	0.27	0.22	0.21	0.26	0.32	0.35	0.39
1300	0.40	0.36	0.37	0.35	0.28	0.27	0.22	0.22	0.26	0.33	0.36	0.39
1400	0.40	0.36	0.37	0.35	0.28	0.28	0.23	0.23	0.26	0.34	0.37	0.40
1500	0.40	0.36	0.37	0.36	0.30	0.30	0.25	0.24	0.26	0.33	0.38	0.41
1600	0.41	0.36	0.37	0.38	0.32	0.32	0.27	0.25	0.27	0.33	0.38	0.41
1700	0.41	0.37	0.38	0.39	0.34	0.34	0.30	0.26	0.28	0.33	0.39	0.43
1800	0.41	0.36	0.37	0.37	0.36	0.35	0.30	0.27	0.29	0.34	0.40	0.44
1900	0.41	0.37	0.38	0.38	0.38	0.36	0.30	0.27	0.30	0.35	0.40	0.44
2000	0.42	0.38	0.41	0.41	0.41	0.37	0.31	0.27	0.30	0.34	0.39	0.44
2100	0.43	0.39	0.42	0.42	0.42	0.37	0.32	0.27	0.30	0.34	0.39	0.43
2200	0.43	0.40	0.43	0.42	0.43	0.36	0.31	0.27	0.29	0.34	0.38	0.42
2300	0.42	0.40	0.42	0.43	0.43	0.36	0.31	0.26	0.28	0.35	0.39	0.42
All	9.81	9.32	9.75	9.35	8.65	7.66	6.36	5.69	6.60	8.12	8.93	9.76

[a] Only wake and hysteresis are included in the calculation.

Table F-10. Relative Hourly and Monthly Energy Production for Hudson Central Study Year 2033

Hour	Energy Production[a] (%)											
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
0000	0.42	0.40	0.43	0.44	0.44	0.37	0.31	0.24	0.27	0.34	0.39	0.42
0100	0.42	0.40	0.44	0.43	0.43	0.35	0.29	0.24	0.28	0.35	0.39	0.41
0200	0.41	0.41	0.44	0.42	0.43	0.35	0.28	0.22	0.28	0.35	0.38	0.40
0300	0.41	0.41	0.43	0.41	0.42	0.34	0.27	0.22	0.28	0.35	0.38	0.40
0400	0.40	0.42	0.43	0.40	0.40	0.32	0.26	0.22	0.27	0.34	0.38	0.40
0500	0.40	0.41	0.42	0.39	0.37	0.31	0.26	0.22	0.27	0.34	0.37	0.40
0600	0.39	0.41	0.43	0.39	0.36	0.30	0.25	0.22	0.27	0.33	0.35	0.39
0700	0.39	0.41	0.44	0.39	0.34	0.29	0.24	0.22	0.27	0.34	0.35	0.39
0800	0.40	0.42	0.43	0.38	0.33	0.27	0.23	0.22	0.27	0.34	0.34	0.39
0900	0.41	0.41	0.42	0.37	0.31	0.27	0.22	0.22	0.27	0.35	0.35	0.39
1000	0.40	0.38	0.39	0.36	0.30	0.26	0.21	0.21	0.27	0.35	0.35	0.39
1100	0.40	0.37	0.38	0.36	0.29	0.26	0.21	0.22	0.26	0.33	0.34	0.38
1200	0.40	0.37	0.37	0.35	0.28	0.27	0.22	0.21	0.26	0.32	0.35	0.39
1300	0.40	0.36	0.36	0.35	0.28	0.27	0.22	0.22	0.26	0.33	0.36	0.39
1400	0.40	0.36	0.37	0.35	0.28	0.28	0.23	0.23	0.26	0.33	0.37	0.40
1500	0.40	0.36	0.37	0.36	0.30	0.30	0.25	0.24	0.26	0.33	0.38	0.41
1600	0.41	0.36	0.37	0.38	0.32	0.32	0.27	0.25	0.27	0.33	0.38	0.42
1700	0.41	0.37	0.37	0.38	0.34	0.34	0.30	0.26	0.28	0.33	0.39	0.43
1800	0.40	0.36	0.37	0.37	0.36	0.35	0.30	0.27	0.29	0.34	0.40	0.44
1900	0.41	0.37	0.38	0.38	0.38	0.36	0.30	0.27	0.30	0.35	0.40	0.44
2000	0.42	0.38	0.41	0.41	0.41	0.37	0.31	0.27	0.30	0.34	0.39	0.44
2100	0.43	0.39	0.42	0.42	0.42	0.37	0.32	0.27	0.30	0.34	0.39	0.43
2200	0.43	0.40	0.43	0.42	0.42	0.36	0.31	0.27	0.30	0.34	0.38	0.42
2300	0.42	0.40	0.42	0.43	0.43	0.36	0.31	0.26	0.29	0.35	0.39	0.41
All	**9.79**	**9.32**	**9.74**	**9.33**	**8.65**	**7.66**	**6.36**	**5.70**	**6.61**	**8.14**	**8.94**	**9.76**

[a] Only wake and hysteresis are included in the calculation.

Table F-11. Relative Hourly and Monthly Energy Production for Hudson South Study Year 2027

Hour	Energy Production[a] (%)											
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
0000	0.40	0.40	0.44	0.44	0.45	0.36	0.31	0.27	0.29	0.37	0.38	0.41
0100	0.41	0.39	0.43	0.43	0.44	0.36	0.29	0.26	0.29	0.36	0.38	0.42
0200	0.41	0.40	0.42	0.42	0.43	0.35	0.27	0.25	0.29	0.36	0.38	0.42
0300	0.41	0.40	0.42	0.41	0.42	0.33	0.25	0.24	0.29	0.36	0.38	0.42
0400	0.42	0.40	0.42	0.41	0.40	0.32	0.25	0.23	0.28	0.35	0.37	0.41
0500	0.42	0.41	0.42	0.40	0.38	0.30	0.25	0.22	0.28	0.35	0.37	0.41
0600	0.42	0.42	0.42	0.40	0.38	0.30	0.24	0.22	0.28	0.34	0.36	0.40
0700	0.42	0.41	0.42	0.40	0.37	0.29	0.24	0.22	0.28	0.35	0.36	0.41
0800	0.42	0.41	0.41	0.41	0.35	0.29	0.23	0.22	0.28	0.34	0.36	0.41
0900	0.41	0.39	0.39	0.38	0.32	0.28	0.22	0.21	0.27	0.34	0.36	0.41
1000	0.41	0.38	0.37	0.37	0.29	0.26	0.21	0.20	0.26	0.33	0.36	0.40
1100	0.40	0.36	0.36	0.36	0.27	0.25	0.20	0.20	0.25	0.32	0.35	0.39
1200	0.39	0.35	0.35	0.36	0.26	0.25	0.20	0.21	0.25	0.32	0.35	0.38
1300	0.39	0.36	0.35	0.35	0.25	0.26	0.21	0.22	0.25	0.32	0.35	0.37
1400	0.38	0.36	0.35	0.35	0.26	0.28	0.24	0.23	0.26	0.32	0.34	0.37
1500	0.38	0.36	0.36	0.35	0.28	0.31	0.27	0.24	0.27	0.32	0.34	0.36
1600	0.38	0.37	0.38	0.36	0.31	0.32	0.29	0.26	0.28	0.32	0.35	0.37
1700	0.39	0.37	0.38	0.37	0.32	0.34	0.31	0.27	0.29	0.33	0.36	0.39
1800	0.40	0.37	0.39	0.38	0.35	0.35	0.32	0.28	0.30	0.34	0.37	0.41
1900	0.41	0.38	0.40	0.40	0.38	0.36	0.32	0.29	0.31	0.35	0.38	0.42
2000	0.41	0.39	0.41	0.41	0.41	0.37	0.31	0.29	0.32	0.36	0.37	0.41
2100	0.41	0.39	0.41	0.42	0.43	0.37	0.31	0.29	0.32	0.37	0.38	0.41
2200	0.41	0.40	0.43	0.43	0.44	0.37	0.31	0.28	0.31	0.37	0.38	0.41
2300	0.41	0.40	0.44	0.44	0.45	0.37	0.31	0.28	0.30	0.37	0.38	0.41
All	**9.72**	**9.26**	**9.58**	**9.42**	**8.67**	**7.63**	**6.36**	**5.87**	**6.82**	**8.28**	**8.77**	**9.64**

[a] Only wake and hysteresis are included in the calculation.

Table F-12. Relative Hourly and Monthly Energy Production for Hudson South Study Year 2030

Hour	Energy Production[a] (%)											
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
0000	0.40	0.40	0.44	0.44	0.45	0.37	0.31	0.27	0.29	0.37	0.39	0.41
0100	0.41	0.40	0.43	0.43	0.44	0.36	0.30	0.27	0.29	0.36	0.39	0.42
0200	0.41	0.40	0.42	0.42	0.43	0.35	0.27	0.25	0.29	0.36	0.39	0.42
0300	0.41	0.40	0.42	0.41	0.42	0.34	0.26	0.24	0.29	0.36	0.38	0.42
0400	0.42	0.40	0.42	0.41	0.41	0.32	0.25	0.23	0.29	0.35	0.37	0.41
0500	0.42	0.41	0.42	0.40	0.39	0.31	0.25	0.22	0.28	0.35	0.37	0.41
0600	0.42	0.41	0.42	0.39	0.38	0.30	0.24	0.22	0.28	0.34	0.36	0.41
0700	0.42	0.41	0.42	0.40	0.37	0.29	0.24	0.22	0.28	0.35	0.36	0.41
0800	0.42	0.41	0.41	0.40	0.35	0.29	0.23	0.22	0.28	0.35	0.36	0.41
0900	0.41	0.39	0.39	0.38	0.32	0.27	0.22	0.21	0.27	0.34	0.36	0.41
1000	0.41	0.37	0.37	0.37	0.29	0.26	0.21	0.20	0.26	0.33	0.36	0.40
1100	0.40	0.36	0.35	0.36	0.27	0.25	0.20	0.21	0.26	0.32	0.35	0.39
1200	0.39	0.35	0.35	0.36	0.26	0.25	0.20	0.21	0.25	0.32	0.35	0.38
1300	0.38	0.36	0.34	0.35	0.25	0.26	0.21	0.22	0.26	0.32	0.35	0.37
1400	0.38	0.35	0.35	0.35	0.27	0.28	0.24	0.23	0.26	0.32	0.34	0.37
1500	0.38	0.36	0.36	0.35	0.28	0.31	0.27	0.25	0.27	0.32	0.34	0.36
1600	0.38	0.37	0.37	0.36	0.31	0.32	0.29	0.26	0.28	0.33	0.35	0.37
1700	0.39	0.36	0.38	0.37	0.32	0.33	0.31	0.27	0.30	0.33	0.36	0.39
1800	0.39	0.37	0.39	0.38	0.35	0.35	0.32	0.29	0.31	0.35	0.37	0.41
1900	0.41	0.38	0.40	0.40	0.38	0.36	0.32	0.29	0.32	0.36	0.38	0.42
2000	0.41	0.39	0.41	0.41	0.41	0.37	0.31	0.29	0.32	0.36	0.37	0.41
2100	0.41	0.39	0.41	0.42	0.43	0.37	0.31	0.29	0.33	0.37	0.38	0.41
2200	0.41	0.40	0.43	0.43	0.43	0.37	0.31	0.28	0.32	0.37	0.38	0.41
2300	0.40	0.40	0.44	0.43	0.44	0.37	0.31	0.28	0.30	0.37	0.38	0.41
All	**9.68**	**9.22**	**9.52**	**9.39**	**8.65**	**7.65**	**6.39**	**5.91**	**6.87**	**8.31**	**8.79**	**9.62**

[a] Only wake and hysteresis are included in the calculation.

Table F-13. Relative Hourly and Monthly Energy Production for Hudson South Study Year 2033

Hour	Energy Production[a] (%)											
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
0000	0.40	0.40	0.43	0.43	0.45	0.37	0.31	0.27	0.30	0.37	0.39	0.41
0100	0.41	0.39	0.43	0.42	0.44	0.36	0.30	0.27	0.29	0.37	0.39	0.42
0200	0.41	0.40	0.43	0.42	0.43	0.35	0.27	0.25	0.30	0.37	0.39	0.42
0300	0.41	0.39	0.42	0.41	0.43	0.34	0.26	0.24	0.29	0.36	0.38	0.42
0400	0.42	0.40	0.42	0.41	0.41	0.32	0.25	0.23	0.29	0.35	0.38	0.42
0500	0.43	0.41	0.42	0.40	0.39	0.31	0.25	0.22	0.28	0.35	0.37	0.41
0600	0.42	0.41	0.42	0.39	0.38	0.30	0.24	0.22	0.28	0.34	0.36	0.41
0700	0.42	0.41	0.42	0.40	0.37	0.29	0.23	0.22	0.28	0.35	0.36	0.41
0800	0.42	0.40	0.41	0.40	0.35	0.28	0.23	0.22	0.28	0.35	0.36	0.41
0900	0.41	0.39	0.38	0.38	0.32	0.27	0.22	0.21	0.27	0.34	0.36	0.41
1000	0.41	0.37	0.37	0.37	0.29	0.26	0.20	0.20	0.26	0.33	0.36	0.40
1100	0.40	0.36	0.35	0.36	0.27	0.25	0.20	0.21	0.26	0.33	0.36	0.39
1200	0.39	0.35	0.34	0.36	0.26	0.25	0.20	0.21	0.26	0.32	0.35	0.38
1300	0.38	0.35	0.34	0.35	0.25	0.26	0.21	0.22	0.25	0.32	0.35	0.37
1400	0.38	0.35	0.35	0.35	0.27	0.28	0.24	0.23	0.26	0.32	0.34	0.37
1500	0.38	0.35	0.35	0.35	0.29	0.31	0.27	0.24	0.27	0.32	0.34	0.36
1600	0.38	0.36	0.37	0.36	0.31	0.32	0.30	0.26	0.28	0.33	0.35	0.37
1700	0.39	0.36	0.38	0.37	0.33	0.34	0.31	0.28	0.30	0.34	0.36	0.39
1800	0.39	0.36	0.39	0.38	0.35	0.35	0.32	0.29	0.31	0.35	0.37	0.41
1900	0.40	0.37	0.39	0.40	0.38	0.36	0.32	0.29	0.32	0.36	0.38	0.41
2000	0.41	0.39	0.41	0.41	0.41	0.37	0.31	0.29	0.32	0.36	0.37	0.41
2100	0.41	0.39	0.41	0.41	0.43	0.37	0.31	0.29	0.33	0.37	0.38	0.41
2200	0.41	0.40	0.43	0.42	0.43	0.37	0.31	0.28	0.32	0.37	0.38	0.41
2300	0.40	0.40	0.44	0.43	0.44	0.37	0.32	0.28	0.31	0.37	0.38	0.40
All	**9.67**	**9.19**	**9.50**	**9.37**	**8.65**	**7.66**	**6.40**	**5.92**	**6.89**	**8.33**	**8.81**	**9.62**

[a] Only wake and hysteresis are included in the calculation.

F.3 Uncertainty

Table F-14. Uncertainty of the Wind Speeds at the Site for Hudson Central

Uncertainty Category	E05_N					
	2027		2030		2033	
	%	m/s	%	m/s	%	m/s
Measurement accuracy	3.3	0.3	3.3	0.3	3.3	0.3
Long-term measurement-height wind regime	2.1	0.2	2.2	0.2	2.2	0.2
Vertical extrapolation	—	—	—	—	—	—
Spatial extrapolation	0.8	0.1	0.8	0.1	0.8	0.1
Sensitivity ratio	1.06		1.03		1.02	

Table F-15. Uncertainty of the Wind Speeds at the Site for Hudson South

Uncertainty Category	E06_S					
	2027		2030		2033	
	%	m/s	%	m/s	%	m/s
Measurement accuracy	3.3	0.3	3.3	0.3	3.3	0.3
Long-term measurement-height wind regime	2.2	0.2	2.2	0.2	2.2	0.2
Vertical extrapolation	—	—	—	—	—	—
Spatial extrapolation	1.0	0.1	1.0	0.1	1.0	0.1
Sensitivity ratio	1.05		1.03		1.01	

F.4 References

Carroll, J., et al. 2015. Failure Rate, Repair Time and Unscheduled O&M Cost Analysis of Offshore Wind Turbines, University of Strathclyde. https://pure.strath.ac.uk/portal/files/44298789/Carroll_etal_WE_2015_Failure_rate_repair_time_and_unscheduled_O_and_M_cost_analysis_of_offshore.pdf, first published August 6, 2015.

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