Appendix C

(to Initial Report on New York Power Grid Study)

Utility Transmission & Distribution Investment Working Group Study

Utility Transmission and Distribution Investment Working Group Report

November 2, 2020

Respectfully Submitted,

Central Hudson Gas & Electric Corp.
Consolidated Edison Company of New York, Inc.
Long Island Power Authority
Niagara Mohawk Power Corporation d/b/a National Grid
New York State Electric & Gas Corporation
Orange & Rockland Utilities, Inc.
Rochester Gas and Electric Corporation

Contents

STATE OF NEW YORK

PUBLIC SERVICE COMMISSION

Proceeding on Motion of the Commission to	)	
Implement Transmission Planning Pursuant	)	Case 20-E-0197
to the Accelerated Renewable Energy	)	
Growth and Community Benefit Act	)	

Executive Summary

On May 14, 2020, the New York Public Service Commission (Commission) issued the initiating order (May Order) in this proceeding[1] in response to environmental policy objectives and related requirements set forth in the Climate Leadership and Community Protection Act (CLCPA)[2] and the Accelerated Renewable Energy Growth and Community Benefit Act (AREGCB Act).[3] The CLCPA establishes aggressive targets for the reduction in greenhouse gas (GHG) emissions, renewable and emissions-free electric generation, and development of off-shore wind. The AREGCB Act directs the Commission to take specific actions to ensure that New York's electric grid will support the State's climate mandates. These actions include, among other things, initiating a proceeding to establish a planning process to guide future investments in local transmission and distribution (sometimes referred to here as LT&D) and establishing a LT&D capital plan for each utility. This Report contains the Utilities'[4] proposals and recommendations on these matters, in fulfilment of the requirements of the May Order.[5]

The AREGCB Act and the May Order distinguish between distribution, local transmission, and bulk transmission assets. For the purposes discussed in this Report, local transmission refers to "transmission line(s) and substation(s) that generally serve local load, and transmission lines

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1 Case 20-E-0197, *Proceeding on Motion of the Commission to Implement Transmission Planning Pursuant to the Accelerated Renewable Energy Growth and Community Benefit Act* (Transmission Planning Proceeding), Order on Transmission Planning Pursuant to the Accelerated Renewable Energy Growth and Community Benefit Act (issued May 14, 2020) (May Order).

2 New York Public Service Law, § 66-p.

3 New York Public Service Law §§ 162, 123 and 126.

4 The Utilities include: Central Hudson Gas & Electric Corp. (Central Hudson); Consolidated Edison Company of New York, Inc. (CECONY); Long Island Power Authority (LIPA); Niagara Mohawk Power Corporation d/b/a National Grid (National Grid); New York State Electric & Gas Corporation (NYSEG); Orange & Rockland Utilities, Inc. (O&R); and Rochester Gas and Electric Corporation (RG&E) (collectively, Utilities). Throughout this document, when referring to a single or generic company the term "utility" will not be capitalized.

5 Transmission Planning Proceeding, May Order.

The Commission noted in the May Order that "prior to the enactment of the [AREGCB Act], the Department of Public Service had already established working groups in collaboration with the utilities to address the policy, planning, and technological challenges to meeting the CLCPA targets. These proactive efforts are productive and useful, and this order intends to build on those efforts, as well as provide direction for future initiatives." This Report was prepared by the Utilities in collaboration with other members of the working groups, which include the Department of Public Service(DPS) Staff, the New York Independent System Operator, Inc. (NYISO), the New York Power Authority (NYPA), and the New York State Energy Research and Development Authority (NYSERDA).

The utility working groups were originally ordered to file the proposals on process and ratemaking matters discussed in this Report on October 5, 2020. On September 1, 2020 the Commission Secretary granted an extension of the filing date to November 1, 2020 to align these recommendations with the filing of analyses related to potential distribution and local transmission upgrades to facilitate CLCPA compliance, which can be found in Part 2 of this Report.

which transfer power to other service territories and operate at less than 200 kV," as defined by the Commission in the May Order.[6] Bulk power transmission facilities (BPTF) are planned and operated by the NYISO.

The recommendations made in this Report contemplate two categories of LT&D projects based on project readiness and the complexity of regulatory issues that remain to be resolved:

- *Phase 1* projects are immediately actionable projects that satisfy Reliability, Safety, and Compliance purposes but that can also address bottlenecks or constraints that limit renewable energy delivery within a utility's system. These projects may be in addition to projects that have been approved as part of the utility's most recent rate plan or are in the utility's current capital pipeline. Phase 1 projects will be financially supported by the customers of the utility proposing the project.
- *Phase 2* projects may increase capacity on the local transmission and distribution system to allow for interconnection and delivery of new renewable generation resources within the utility's system. These projects are not currently in the utility's capital plans. Phase 2 projects tend to have needs cases that are driven primarily by achieving CLCPA targets. Broad regional public policy benefits suggest the likelihood that cost sharing across the Utilities may be appropriate. These projects require additional time to plan and prioritize using the investment criteria and benefit cost analysis (BCA) methodology described in Part 1, below.

Project investment criteria and prioritization recommendations are presented with additional regulatory considerations in ***Part 1*** of this Report. The Utilities focus on adaptation of existing LT&D planning processes and consider opportunities to accelerate select projects to facilitate achievement of CLCPA objectives. Achievement of clean energy mandates will require expansion of the Utilities' planning objectives and therefore changes to the planning processes. It will also require adaptation of decision-making tools and integration of insights gained from additional stakeholder involvement. Furthermore, achieving requirements of the CLCPA and the AREGCB Act will also require changes to existing practices concerning cost allocation and cost recovery. Certain benefits of necessary and appropriate LT&D investments will accrue not only to customers within, but also outside, the investing utility's service area. Regulatory approval outside a Utility's normal rate case may be both required to advance Phase 1 LT&D projects in the timeline required to achieve CLCPA mandates, and to recover costs of Phase 2 costs from customers throughout New York. Specific proposals and recommendations on these matters include the following.

[6] Transmission Planning Proceeding, May Order, p. 3 Note 4.

CLCPA Investment Criteria and Project Prioritization

- The Utilities recommend a set of local transmission and distribution investment criteria designed to meet CLCPA mandates, including:
  - Cost effectiveness of local transmission and distribution investments;
  - Greater renewable energy utilization (*i.e.*, to reduce curtailments and increase renewable power delivery to New York customers);
  - Streamlined renewable energy project deployments to deliver benefits more quickly;
  - System expandability to interconnect renewable generation;
  - Improved system flexibility to manage intermittent resources; and
  - Firmness of renewable generation projects that would be facilitated by the proposed local transmission and distribution investments.
- Use of these criteria would allow the Utilities to identify CLCPA-driven projects along with traditional Reliability, Safety, and Compliance projects.
- The Utilities recommend that these approaches be integrated with existing local transmission and distribution planning processes going forward.

Benefit Cost Analysis

The Utilities recommend that the Commission accept a set of local transmission-related BCA guidelines for CLCPA projects. These guidelines will comprise a simple, consistent, repeatable mechanism to allow local transmission owners to efficiently prioritize CLCPA-related investments.

Stakeholder Engagement

The Utilities recommend annual engagement with stakeholders through robust dialogue and data exchange built as a supplement to existing mechanisms that already provide transparency in transmission and distribution planning. Recommended stakeholder engagement opportunities specific to local transmission planning are informed by existing NYISO processes but would be conducted outside of NYISO structures (i.e., by each New York jurisdictional utility).

Cost Allocation and Cost Recovery

State CLCPA and AREGCB Act mandates to incorporate an increasing share of renewables into local transmission and distribution activities will require additional costs. Clear cost allocation and recovery processes are imperative to ensure timely implementation and cost-effective project deployment. The Utilities make the following recommendations:

1) Cost sharing measures should not impede project development.
2) Beneficiaries must include all customers throughout the State to ensure equitable cost allocation.
3) The incremental cost of utility projects prioritized to support CLCPA mandates should be eligible for load ratio share cost allocations.

4) The Commission should determine, as part of its overall authorization of utility local projects, those projects for which costs should be shared and which should not, recognizing that regional planning differences that benefit a region are also needed to facilitate CLCPA mandates. The Commission should track individual utility CLCPA project costs and consider whether costs are incurred equitably across the State when determining the need for cost sharing.
5) Where necessary, the Commission should leverage as much as possible the existing utility rate case process to expedite CLCPA projects.
   - The Commission should authorize project cost recovery outside of rate case processes to expedite projects.
6) Utilities must have certainty on cost allocation and recovery before projects can begin.

Public Service Law, Article VII

CLCPA benefits described herein will not be realized until the LT&D improvements identified through the planning processes are sited, designed and built. Accordingly, the Utilities conclude Part 1 with an outline of potential opportunities for improving the timeliness and predictability of the transmission siting process for major electric transmission facilities under Public Service Law Article VII.

Part 2 identifies a number of potential LT&D upgrades that the utilities recommend as necessary or appropriate to accelerate progress toward achievement of the CLCPA renewable energy mandates. These include actionable local system upgrades (*i.e.*, new facilities or enhancements to existing transmission or distribution facilities) that will facilitate greater interconnection and use of clean energy resources throughout New York State. Each of the Utilities has identified Phase 1 and Phase 2 projects that can be pursued immediately following Commission approval to proceed.

The analyses presented in Part 2 are based on projected system conditions in 2030. The Utilities have evaluated LT&D capabilities required to support the CLCPA goal of delivering 70% of the State's electric energy needs from renewable sources by 2030.[7] Pursuant to the May Order, the Utilities:

- Evaluated the local transmission and distribution system of the individual service territories, to understand where capacity "headroom" exists today;
- Identified existing constraints or bottlenecks that limit energy deliverability;
- Considered synergies with traditional capital expenditure projects (i.e., aging infrastructure, reliability, resilience, compliance market efficiency, operational flexibility, etc.);
- Identified least-cost upgrade projects to increase the capacity of the existing system;

[7] New York is simultaneously evaluating bulk transmission facilities needed to support the CLCPA's goal of 100% renewable generation by 2040. Therefore, the assumptions that serve as the foundation of the Utility Study have been coordinated with both the 2040 and Offshore Wind (OSW) Studies.

- Identified potential new or emerging solutions that can accompany or complement traditional upgrades;
- Identified potential new projects that would increase capacity on the local transmission and distribution system to allow for interconnection of new renewable generation resources; and
- Identified the possibility of fossil generation retirements and the impacts and potential availability of those interconnection points.[8]

Figure 1 and Figure 2, below, summarizes the range of projects proposed for LT&D development in Phase 1 and Phase 2.

Figure 1: Phase 1 LT&D Proposed Project Estimates

Project Name	Projects (No.)	Estimated Project Cost	Estimated Project Benefit (MW)[9]
Central Hudson			
Transmission	6	$152M	433
Distribution	12	$137M	132
CECONY			
Transmission	3	$860M	900
Distribution	8	$1,130M*	418
LIPA			
Transmission	8	$402M	615
Distribution	19	$351M	520
National Grid			
Transmission	13	$773M	1,130
Distribution	5	$633M	367.1+
NYSEG/RG&E			
Transmission	16	$1,560M	3,041
Distribution	8	$229M	165.8
O&R			
Transmission	6	$417M	500
Distribution	9	$156M	308
Total	113	$6,800M	8,162
Transmission Total	**52**	**$4,164M**	**6,619**
Distribution Total	**61**	**$2,636M**	**1,543**

* $789 million of investment (reflecting 5 of 8 projects) have already received funding approval. Incremental Phase 1 distribution costs for CECONY are $341 million.

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8 Ownership of interconnection points is largely covered by FERC-approved NYISO tariffs, outside of the control of the Utilities.

9 MW Benefit is provided as an indicator of the relative benefit of each project. Once the BCA methodology outlined in Part 1, Section III is approved, the Utilities will work to update this metric for Phase 2 projects.

Figure 2: Phase 2 LT&D Proposed Project Estimates (Conceptual)

Project Name	Projects (No.)	Estimated Project Cost*	Estimated Project Benefit (MW)
Central Hudson			
Transmission	6	$138M	766
Distribution	7	$55M	222
CECONY			
Transmission	6	$4,050M	7,686
Distribution	2	$1,300M	360
LIPA			
Transmission	6	$1,281M+	1,830
Distribution	8	$167.2M	937
National Grid			
Transmission	13	$1,371M	1,500
Distribution	7	$510M-$1,206M	1,162-2,141+
NYSEG/RG&E			
Transmission	11	$780M	943MW
Distribution	5	$125M	88.3MW
Total	71	$9,7777-$10,428M	15,494-16,473
Transmission Total	42	$7,620	12,725
Distribution Total	29	$2,157-$2,853M	2,769-3,748

* In general, the Phase 2 projects included by the Utilities are in early stage development, without completed, detailed designs and/or engineering. Therefore, costs provided in this figure should be considered conceptual estimates.

Part 3 summarizes progress that has been made in the development of plans to study, evaluate, pilot, demonstrate, and deploy new and/or underused technologies and innovations that can increase electric power throughput, increase electric grid flexibility, increase renewable energy hosting capacities, increase the electric power system efficiencies and reduce overall system costs. These plans were developed to answer the following questions:

- Are there existing technologies that can improve the efficiency of the grid that are being underutilized?
- Are there research and development opportunities for new or emerging technologies?
- How should the State's research and development efforts be organized?
- How should the Utilities coordinate with other New York research and development stakeholders (Electric Power Research Institute (EPRI), universities, national labs, Department of Energy (DOE), Advance Research Projects Agency Energy (ARPAe), etc.)?

The Utilities emphasize the need to alleviate transmission system bottlenecks to allow for better deliverability of renewable energy throughout the State. In particular, there is a need to unbottle constrained resources to allow more hydro and/or wind imports, a need to reduce system congestion, a need to optimize use of existing transmission capacity and rights of way, and a need to increase circuit load factor through dynamic ratings. The Utilities have developed a set of potential technology solutions that include: transformer, cable and transmission line monitoring systems; advanced sensor placement tools; advanced transmission and sub-transmission voltage regulation systems; dynamic line and equipment rating systems; energy storage for grid services; advanced high-temperature, low-sag conductors and new composite conductors; new compact tower designs; power flow controllers; global information system utilization; sulfur hexafluoride monitoring and alternative systems; modular solid state transformers and other advanced grid control devices; and improved ability of transmission lines to redirect flow to underused lines.

The Utilities' recommendations and proposals that appear throughout this Report represent a plan to deploy facilities that will accelerate achievement of the mandates codified in the CLCPA and the AREGCB Act. The Utilities look forward to collaboration with the Commission, DPS Staff, and stakeholders to meet these requirements and the State's policy objectives in a timely, efficient, and cost-effective manner.

Part 1: Transmission Policy Working Group Report

I. INTRODUCTION

On May 14, 2020, the New York Public Service Commission (Commission) issued the initiating order (May Order) in this proceeding[10] in response to environmental policy objectives and related requirements set forth in the Climate Leadership and Community Protection Act (CLCPA)[11] and the Accelerated Renewable Energy Growth and Community Benefit Act (AREGCB Act).[12] The CLCPA establishes aggressive targets for the reduction in greenhouse gas (GHG) emissions, renewable and emissions-free electric generation, and development of off-shore wind. The AREGCB Act directs the Commission to take specific actions to ensure that New York's electric grid will support the State's climate mandates. As noted by the Commission, the integration of clean generation in New York State will require a "restructuring and repurposing"[13] of New York's electric local transmission and distribution (referred to as LT&D) infrastructure. These actions directed by the AREGCB Act include:

1) Conduct a comprehensive study to identify distribution system upgrades, local transmission upgrades, and investments in the bulk transmission system as necessary or appropriate to achieve the CLCPA targets ("power grid study"), and issue an initial report of findings and recommendations on or before December 31, 2020;
2) Initiate a proceeding to (a) establish a distribution and local transmission capital plan for each utility (with utility proposals to be filed on or before November 1, 2020)[14] and (b) establish a distribution and local transmission planning process to guide future investments; and
3) Develop a state-wide plan to develop and implement bulk transmission-level investments that are necessary or appropriate to achieve the CLCPA targets using the NYISO's Public Policy Planning Process or, for projects the Commission determines must proceed expeditiously to meet CLCPA targets, designating NYPA to develop, alone or in collaboration with others.

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10 Case 20-E-0197, *Proceeding on Motion of the Commission to Implement Transmission Planning Pursuant to the Accelerated Renewable Energy Growth and Community Benefit Act* (Transmission Planning Proceeding), Order on Transmission Planning Pursuant to the Accelerated Renewable Energy Growth and Community Benefit Act (issued May 14, 2020) (May Order).

11 New York Public Service Law, § 66-p.

12 New York Public Service Law §§ 162, 123 and 126.

13 Transmission Planning Proceeding, May Order, p. 2.

14 Transmission Planning Proceeding, May Order. The utility working groups were originally ordered to file the proposals on process and ratemaking matters discussed in this Report on October 5, 2020. On September 1, 2020 the Commission Secretary granted an extension to the filing date to November 1, 2020 to align these recommendations with the filing of analyses related to potential distribution and local transmission upgrades to facilitate CLCPA compliance, which can be found in Part 2 of this Report.

The AREGCB Act and the May Order distinguish between distribution, local transmission, and bulk transmission assets. For the purposes discussed in this Report, "local transmission" refers to transmission line(s) and substation(s) that generally serve local load, and transmission lines which transfer power to other service territories and operate at less than 200 kV, as defined by the Commission in the May Order.[15] BPTF are planned and operated by the NYISO, pursuant to its tariff approved by the Federal Energy Regulatory Commission (FERC).

In the May Order, the Commission focused on the AREGCB Act's requirements related to D&LT systems and directed the Utilities to develop proposals for:

1. A transparent planning process, to be implemented by the utilities with as much consistency and interoperability as possible, that will identify additional projects on the distribution and local transmission systems that support achievement of CLCPA goals;
2. An approach to account for CLCPA benefits in the utilities' planning and investment criteria;
3. An approach to prioritizing any such recommended projects in the context of the utilities' other capital expenditures and the CLCPA time frames;
4. A benefit/cost analysis to apply in assessing potential investments in CLCPA upgrades to the distribution and local transmission systems, as well as any other criteria the utilities believe should be applicable to evaluating these investments; and
5. Cost-containment, cost recovery, and cost allocation methodologies applicable to these investments and appropriate to the State's climate and renewable energy, safety, reliability, and cost-effectiveness goals.[16]

The recommendations made in the sections within this Part 1 reflect the Utilities' response to the May Order's directives and their recommended approach for timely and efficient achievement of the CLCPA and AREGCB Act mandates. Consistent with the Order, the Utilities focus on adaptation of existing distribution and local transmission planning processes and consider opportunities to identify and accelerate or develop select projects to facilitate achievement of CLCPA objectives. This filing does not address the NYISO BPTF planning process.

The existing end-to-end distribution and local transmission and distribution planning process consists of the following multiple steps:

- Establishing planning objectives;
- Specifying investment criteria, including reliability and safety standards that must be maintained to provide reliable service;
- Identifying preferred solutions, including a review of estimated costs; and

[15] Transmission Planning Proceeding, May Order, p. 3 Note 4. The May Order also includes the following caveat to the definition included here: "…However, as the Utilities consider the issues outlined in this order, we recognize that an alternative definition may emerge."

[16] Transmission Planning Proceeding, May Order, pp. 7-8.

- Evaluating alternative solutions, including local transmission and distribution projects and non-wires solutions, where appropriate or possible.

Achievement of clean energy mandates will require modification of the Utilities' planning objectives, and therefore changes to the system planning and project prioritization processes, decision-making tools, and stakeholder involvement. As acknowledged in the May Order, fulfilling CLCPA and the AREGCB Act may also require changes to existing practices concerning cost allocation and cost recovery, as certain benefits of the necessary or appropriate Utility T&D investments will accrue not only to customers within, but also outside, the investing Utility's service areas. For projects that support the CLCPA, regulatory approvals outside a Utility's normal rate case may be required to recover costs from customers across the state.

The Commission indicates that it seeks input and proposals on several specific elements of the planning process, including, "[a] benefit/cost analysis to apply in assessing potential investments in CLCPA upgrades to the distribution and local transmission systems, as well as any other criteria the Utilities believe should be applicable to evaluating these proposals."[17] Benefit/Cost Analysis (BCA) is currently applied selectively by the Utilities for certain customer programs (*e.g.*, energy efficiency programs, non-wire alternatives, and large investment programs such as advanced metering infrastructure). In Section IV, below, the Utilities address adaptation of the current BCA framework and consider its merits for comparing competing projects to achieve CLCPA mandates.

Finally, the Utilities understand that the Commission will consider overall costs to customers of achieving the CLCPA. The cost of implementing local T&D upgrades is one element of the costs associated with CLCPA achievement, which will also require much more significant investments in bulk transmission, large scale renewables, and other resources to balance the system. The CLCPA and the May Order recognize that *all* of these costs and clean energy opportunities must be considered together, holistically.[18] The Utilities firmly believe that regardless of the pathway the State decides on to meet the State's clean energy and clean air mandates, local transmission and distribution investment can help create the flexible system necessary to meet the mandates cost-effectively.

A. Principal Recommendations

The Utilities stand ready to work with the Commission to identify cost effective local T&D projects that support achievement of the CLCPA. The Utilities make the following

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[17] Case 20-E_0197 - May Order at p. 7.

[18] E.g., the CLCPA statute grants the Commission the discretion to suspend or temporarily modify any element of programs to meet the law's mandates after a hearing and a finding that (1) the program "impedes the provision of safe and adequate electric service," (2) the program "is likely to impair existing obligations and agreements," and/or (3) "there is a significant increase in arrears or service disconnections" that the Commission determines is related to the program.

recommendations and proposals on process and ratemaking matters in support of this critical State objective in the sections that follow in Part 1, below:

Section II: CLCPA Investment Criteria and Project Prioritization

- The Utilities recommend a set of local transmission and distribution investment criteria designed to meet CLCPA mandates, including:
  - Cost effectiveness of local transmission and distribution investments;
  - Greater renewable energy utilization (*i.e.*, to reduce curtailments and increase renewable power delivery to New York customers);
  - Streamlined renewable energy project deployments to deliver benefits faster;
  - System expandability to interconnect renewable generation;
  - Improved system flexibility to manage intermittent resources; and
  - Firmness of renewable generation projects that would be facilitated by the proposed LT&D project(s).
- Use of these criteria would allow the utilities to identify CLCPA-driven projects along with traditional Reliability, Safety, and Compliance projects.
- The Utilities recommend that these approaches be integrated with existing local transmission and distribution planning processes going forward.

Section III: Benefit Cost Analysis

The Utilities recommend that the Commission accept a set of local transmission-related BCA guidelines for CLCPA projects. These guidelines will comprise a simple, consistent, repeatable mechanism to allow local transmission owners to efficiently prioritize CLCPA-related investments.

Section IV: Stakeholder Engagement

The Utilities recommend annual engagement with stakeholders through robust dialogue and data exchange built as a supplement to existing mechanisms, which provide transparency in distribution planning. Recommended stakeholder engagement opportunities specific to local transmission planning are informed by existing NYISO processes but would be conducted outside of NYISO structures (*i.e.*, by each New York jurisdictional utility).

Section V: Cost Allocation and Cost Recovery

State CLCPA and AREGCB Act mandates to incorporate an increasing share of renewable generation into local transmission and distribution activities will mean additional costs. Clear cost allocation and recovery processes are imperative to ensure timely implementation and cost-effective project deployment. The Utilities make the following recommendations:

1) Cost sharing measures should not impede project development.
2) Beneficiaries must include all customers throughout the state to ensure equitable cost allocation.

3) The incremental cost of utility projects prioritized to support CLCPA mandates should be eligible for load ratio share cost allocations.
4) The Commission should determine, as part of its overall authorization of utility local projects, those projects for which costs should be shared and which should not, recognizing that regional planning differences that benefit a region are also needed to facilitate CLCPA mandates. The Commission should track individual utility CLCPA project costs and consider whether costs are incurred equitably across the State when determining the need for cost sharing.
5) The Commission should leverage as much as possible the existing utility rate case process to expedite CLCPA projects.
    - The Commission should authorize project cost recovery outside of rate case processes to expedite projects.
6) Utilities must have certainty on cost allocation and recovery before projects can begin.

Section VI: Public Service Law, Article VII

Even with the transmission policy and ratemaking improvements outlined above, CLCPA benefits will not be realized until the transmission and distribution improvements identified through the planning processes are sited, designed and built. Accordingly, the Utilities conclude this Report with an outline of potential opportunities for improving the timeliness and predictability of the transmission siting process for major electric transmission facilities under Public Service Law Article VII.

II. CLCPA INVESTMENT CRITERIA AND PROJECT PRIORITIZATION PROCESS

A. Introduction

The May Order recognizes that local transmission and distribution planning processes must evolve to accommodate CLCPA mandates as an explicit planning objective. Modified planning processes to facilitate compliance with the CLCPA must be transparent and consistently applied across utilities, while recognizing that regional differences do exist. The outcome of the utility T&D planning will be a portfolio of proposed projects that reflect multiple system objectives: reliability and safety, adherence to environmental standards, and cost-effectiveness.[19] Current processes are examined and proposals to enhance these processes for CLCPA adherence are described below. Section B below provides context on the current planning processes. Section C focuses on the criteria utilities will use to identify CLCPA-driven projects (or parts of projects). Section D discusses how the planning criteria will be incorporated into utility capital plans. Section E provides clarification on prioritization and approval processes, and Section F concludes with the Utilities' recommendations regarding CLCPA investment criteria and project prioritization processes.

B. Context: Current Planning Processes

i) NYISO Transmission Planning Process

The Utilities collaborate with the NYISO in evaluating, planning, and implementing transmission projects to provide reliable operations and meet forecasted needs. In general, the NYISO is responsible for identifying and resolving reliability needs on the BPTF; the Utilities are responsible for reliable operations within their transmission system footprints. The utilities are also responsible for evaluating the potential impacts of BPTF on their local transmission system and applying transmission planning criteria to select necessary infrastructure investments on the local transmission and distribution systems, coordinating as appropriate with the NYISO and neighboring utilities.

These transmission planning processes are performed in accordance with federal rules and the NYISO's Open Access Transmission Tariff.[20]

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[19] CLCPA will accelerate the deployment and interconnection of intermittent, renewable resources, which may challenge the planning and operation of local transmission and distribution systems. While standards established by the North American Electric Reliability Corporation (NERC), the Northeast Power Coordinating Council (NPCC), and the New York State Reliability Council (NYSRC) may evolve as the State's energy resource portfolio transitions, this Report assumes that compliance with existing NERC, NPCC, and NYSRC standards will remain a paramount and guiding utility concern.

[20] On April 24, 1996, the FERC issued Order No. 888, which requires jurisdictional utilities to provide access to transmission service under terms that are comparable to those that apply to the utility itself. These terms are formalized in an Open Access Transmission Tariff (OATT).

The NYISO evaluates the BPTF through its Comprehensive System Planning Process (CSPP). The CSPP includes the quarterly Short-term Reliability Process (STRP), the biennial Reliability Needs Assessment (RNA), and Comprehensive Reliability Plan (CRP). These processes identify and solicit solutions for bulk electric reliability needs. The Congestion Assessment and Resource Integration Study (CARIS) evaluates benefits of projects designed to relieve congestion, and the Public Policy Transmission Planning Process (PPTPP) identifies and solicits projects to satisfy public policy needs.[21]

In their role, the Utilities plan for both the BPTF and the non-BPTF for their service territories based on all applicable planning criteria. The Utilities' Local Transmission Plans (LTPs) and local upgrades are an input to the NYISO's determination of BPTF system needs. Local transmission needs are assessed based on applicable utility planning criteria (discussed below) and may also consider inputs from Public Policy Requirements.[22] In addition to the reliability standards, a utility may implement specific planning and investment criteria to satisfy local needs or planning directives.

ii) Current Utility Local Transmission and Distribution Planning Process

Local transmission needs are currently driven by several factors including:

- Reliability, safety, and compliance;
- System capacity/load growth;
- Customer requests including Distributed Energy Resources (DER) access and public requirements;
- Asset condition/aging infrastructure, resiliency; and
- Environmental impacts.

The *current* planning process for utility local transmission and distribution facilities varies based on planning needs and investment drivers, and consists of two project categories:

1) Reliability, Safety, and Compliance investments include:
   - *Transmission Proactive Reliability*: The Utilities propose projects to address reliability and other needs that are identified in periodic transmission planning studies (Reliability Studies). Reliability Studies assess the current and planned transmission system for compliance with applicable industry reliability standards that apply to voltage, thermal, and stability criteria among other requirements.[23]

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[21] Proposals and recommendations related to the identification and prioritization of transmission projects discussed in this Report pertain only to those projects that may accelerate achievement of CLCPA mandates. Changes to the NYISO planning processes are out of scope.

[22] The NYISO OATT allows a transmission utility to include in its LTP a project driven by a public policy need. All costs would be allocated to the utility's customers, consistent with all LTP projects.

[23] These standards include but are not limited to NERC Standard TPL-001 reliability standards, NPCC Regional Reliability Reference Directory #1, NYSRC Reliability Rules, and TO-specific reliability guidelines.

- *Interconnection or Public Requirements*: Certain transmission projects focus on designing the most appropriate and efficient solution to address needs other than compliance. These may include customer interconnections and public requirements.[24]
- *Facility Damage or Failure*: Unplanned and unforeseeable events must be addressed if and when they occur.

2) Projects required to maintain or enhance an asset condition or maintain resiliency include:
   - *Asset Condition projects*: transmission investments, such as replacement of the elements of overhead circuits, underground cable, or substation equipment. Overhead circuit investments are performed in compliance with National Electric Safety Code (NESC) requirements.
   - *Resiliency investments*: transmission investments that increase the resiliency of the transmission network against extreme weather events (*i.e.*, storm hardening).

Throughout the remainder of this filing, the term "Reliability, Safety, and Compliance" includes the concepts of asset condition and resiliency. That is, Reliability, Safety, and Compliance projects include projects that are pursued to respond to transmission proactive reliability, interconnection and public requirements, facility damage or failure, asset conditions, and resiliency needs.

Planning processes vary by project category. The outcome of the utility T&D planning is a portfolio of proposed projects that reflect the objectives identified above. All proposed projects are identified in a utility's Capital Expenditure Plans, and all proposed projects, with estimated capital spending, are identified in each utility's rate case filings. In certain cases, an application for a certificate of environmental compatibility and public need may need to be prepared and approved by the Commission before construction of a proposed project can begin.[25] Each utility retains the flexibility to organize, prioritize and deliver projects included in a rate plan based on current system needs and conditions. Cost recovery typically occurs over many years in alignment with the depreciable lives of the various capital investments. Individual projects with long implementation time frames may be developed in phases and addressed in multiple rate cases.

[24] *E.g.*, responding to a request by a municipality.

[25] Public Service Law Article VII requires the Commission to review and make findings concerning the environmental compatibility and public need of major electric transmission facilities in New York State. Major electric transmission facilities are generally defined in Article VII to include transmission lines with a design capacity of 125 kV or more that extend one mile or more, and lines 100kV or more that extend 10 miles or more. See Public Service Law §§ 120 and 121.

The Utilities continue to perform Reliability Studies throughout the year and make adjustments for a variety of evolving factors.[26] These changes can impact the timing and cost estimates for planned projects.

C. Incorporating CLCPA into the Utility T&D Planning Process

The CLCPA mandates the transformation of the State's energy supply portfolio. Integration of such large quantities of clean energy resources to local transmission and distribution facilities will require each utility to determine how to accommodate such resources and deliver the power to loads with local transmission and distribution investments that meet technical and economic criteria.

Going forward, the Utilities propose to use new investment drivers that address the unique operational attributes of renewable and intermittent resources when conducting studies that will identify "necessary or appropriate" local transmission and distribution investments. These incremental CLCPA investment criteria[27] can be incorporated into the transmission planning process and project-specific analyses. These criteria will address:

1. *Renewable Utilization* (including renewable energy unbottling and delivery) – enabling greater utilization by enabling generation connected to the local system to move renewables into the bulk system ("on-ramps"), as well as flows from the bulk system into the local transmission and distribution system where it can be used by customers ("off-ramps");
2. *Timing* –accelerate or expand a project to accommodate CLCPA targets;
3. *Expandability* – ability to help accommodate future project expansion;
4. *Cost Effectiveness* – contribution to lowering costs of achieving CLCPA targets;
5. *Improve System Flexibility to Accommodate Greater Intermittency* – does the project improve reliability in the face of rapidly increasing intermittency; and
6. *Firmness* – does the project enable existing or new renewable generation in a region? Are the renewable generation proposals in a utility or NYISO interconnection queue sufficiently firm to justify the transmission investment?

These investment criteria are discussed in greater detail, with examples, below.

i) Renewable Utilization (unbottling and delivery)

Renewable Utilization encompasses unbottling (*i.e.*, moving power from generation to the bulk transmission system) and usability (*i.e.*, bringing renewable generation to load centers).

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[26] *E.g.*, changes to assumptions, constraints, project delays/accelerations, weather impacts, outage coordination, permitting/licensing/agency approvals, changes to system operations, performance, safety, any customer-driven needs that may arise.

[27] The term CLCPA investment Criteria is used throughout this Report to mean criteria that are not driven by traditional planning concepts (*i.e.*, reliability, safety, compliance). Instead, CLCPA investment Criteria are driven by the requirement that 70 percent of energy consumed in New York come from clean resources by 2030, and 100 percent by 2040.

The concept recognizes the role of local transmission infrastructure as the between the BPTF and the distribution system.

Unbottling Renewables (Relieving Constraints Downstream of Renewables)

Explanation Improves the pathways for renewable generation to reach the bulk electric system / reduces curtailment of renewables in a given region or across New York transmission system.

Metric Annualized unbottled energy (calculated over 40 years[28])

Case Study National Grid's Multi-Value Transmission Methodology

National Grid created what it called its Multi-Value Transmission (MVT[29, 30]) project to address both National Grid system needs and New York policy and system needs. MVT projects are designed to improve system reliability while also enabling the delivery of renewable resources.

National Grid applied a production cost model to evaluate the deliverability of two separate pockets of renewable generation in National Grid's transmission system. One analysis looked at proposed solar generation in an area, located between National Grid's substations near Utica. The model included a total of 510 MW of dispatchable Large-Scale Renewable (LSR) solar generation connected to the 115kV transmission and the 69kV subtransmission networks in the study area. The model also included 156 MW of non-dispatchable Distributed Energy Resource (DER) solar connected to distribution stations throughout the study area. A second analysis looked at wind generation in Western NY. The model included a total of 207MW of existing wind and an additional 200MW of expected future wind. Initial production cost models were used to determine annual renewable curtailment for the base cases in each study. From these simulations, National Grid created a list of the most-binding elements. Subsequent models evaluated the curtailment impact of addressing the binding elements individually and in combination for each study.

The Utica area analysis found that constraints within the local network resulted in 136 gigawatt hours (GWh) of annual solar curtailment. It was found that addressing the most binding elements in the area provided 115 GWh of annual relief (addressing 85% of the renewable curtailment). The Western NY

28 The useful life of local transmission and distribution investments is generally 40 years or longer. We adopt 40 years as a reasonable proxy for a potential useful life for a given element of system equipment. See Section III, below.

29 The term MVT was created by National Grid over the years to describe a new type of project. National Grid's projects were the first in NY to be described this way. We have adapted and adopted that term in this section of this Report and others to mean transmission driven by both reliability and public policy mandates.

30 This project is described in more detail in National Grid's current, pending rate case before the New York Public Service Commission, Docket 20-E-0380.

analysis found that constraints posed by series reactors on a transmission line result in 77 GWh of annual wind curtailment. It was found that relocating the reactors provided 61 GWh of annual relief (addressing 79% of the renewable curtailment). Both transmission solutions sought to relieve the highest amount of renewable curtailment in the most cost-effective manner. Both proposed solutions also provide significant reliability and operational flexibility benefits that are difficult or infeasible to accurately quantify.

Renewable Delivery ("Off-ramps")

Explanation In addition to improving the deliverability of renewables to the bulk transmission system, utilities may need to unbottle Transmission Load Areas (TLAs, i.e. load pockets) so more renewable generation can be delivered into previously constrained load pockets. Deliverability of renewables to the bulk system and from the bulk system into constrained load pockets should be measured using the same metrics.[31] Regulatory requirements, wholesale electricity market conditions, and dynamic system topologies will likely play a role in the way these projects are prioritized.[32]

Enhancing renewable delivery may carry an ancillary benefit of emissions reduction. Renewable curtailments that persist due to transmission constraints may result in the need to dispatch fossil units to compensate for curtailed renewable generation. Relieving the transmission constraint may allow renewables to displace fossil fuel generation in load pockets.

Metric Annualized unbottled energy

Case Study Unbottling New York City Load Pockets

In New York City, generation was built in close proximity to load, requiring fewer long transmission lines to serve local customers. As a result, CECONY's service territory is made up of seventeen TLAs. In CECONY's system load pockets must be served by the combination of generation located within the pocket and imports from external generation. However, imports are limited by the transmission capability to move power into and out of the load pocket. In many of New York City's load pockets, planning and operational criteria require generation inside the pocket to generate power to meet the load in that pocket. Today, the generation in New York City and inside of CECONY's

31 See Section III, Benefit Cost Analysis for a more comprehensive discussion of the benefits of reducing curtailments.

32 A utility seeking to use this criterion would have to demonstrate the energy flowing through the solution would displace local fossil generation.

load pockets is predominantly fossil generation. This fossil generation is required to run to serve customers in the load pockets.

Most, if not all, of the existing natural gas and oil-fired generation within these load pockets will need to be retired to achieve the mandates in the CLCPA. Storage and non-wires alternatives (NWA) may reduce the need to run fossil generation in load pockets. However, such solutions by themselves are unlikely to be sufficient. New York City has several load pockets with peak loads that reach levels 200 MW to 500 MW higher than the existing transmission facilities can provide capacity to move power into the load pocket. The large magnitude of this gap as a proportion of the peak load in these load pockets creates prolonged deficiencies in the ability to meet load without running generation inside the pocket. This lack of sufficient transmission into the load pocket can require generating resources inside the pocket to provide up to 15 hours of support for several consecutive days. An energy storage solution applied to such a load pocket could be required to discharge for fifteen consecutive hours and then charge in the remaining nine hours for consecutive days. Since energy storage resources do not generate energy, their discharge capability is ultimately limited by the time and energy available to charge, storage technology.

CECONY has completed studies on the local system impacts of existing generator compliance plans with new emissions limitations for peaking units.[33] Those studies revealed that removal of the impacted generation resulted in deficiencies extending over 10 to 13 hour periods in the Astoria East/Corona load area, and over 14 hours in the Greenwood Fox Hills load area, as shown in Figure 3, below.

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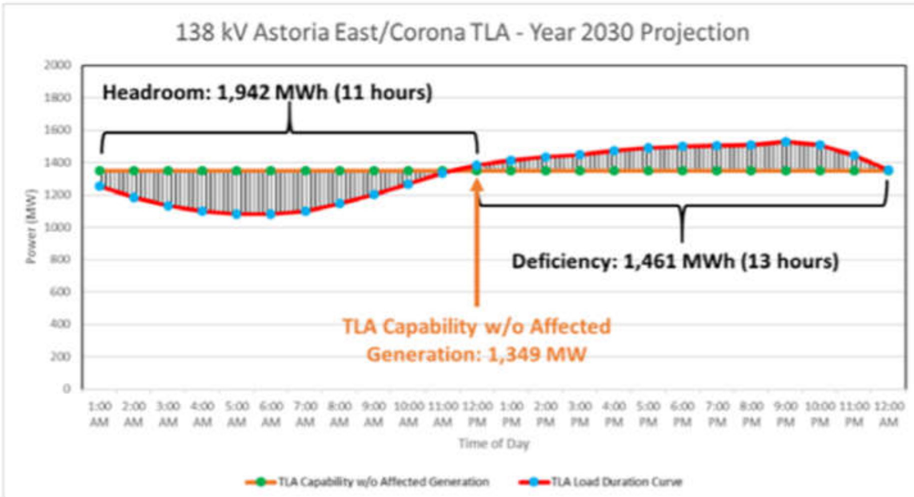
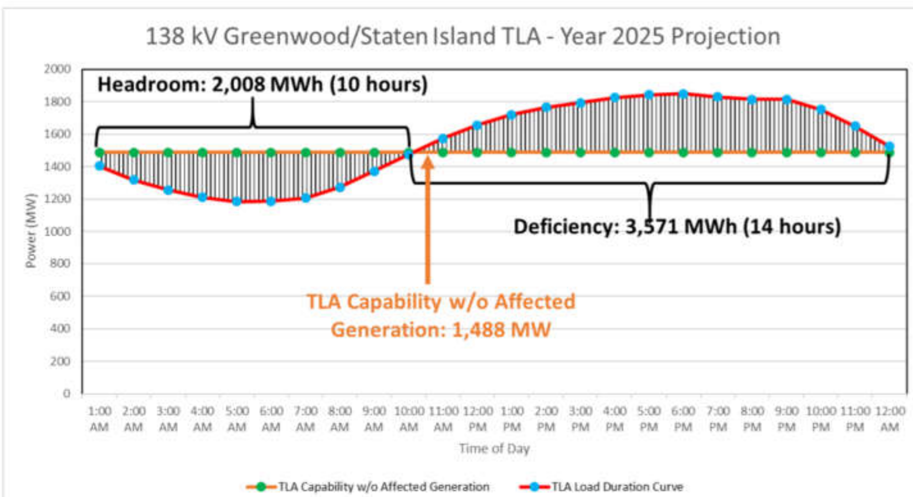
33 For more information, see https://www.nyiso.com/documents/20142/13200831/03%202020%20RNAConEd%20Local%20System%20Base%20Case%20Assessments%20Results.pdf/17424cd7-3cef-3637-2388-5a27654af266

Figure 3: Transmission Load Area Capability in Two Constrained Regions in CECONY's Service Territory





CECONY's transmission study (in Part 2 of this Report) identifies local transmission solutions to enable the generators located within these load pockets to comply with new emissions regulations. These solutions would also facilitate achievement of the CLCPA mandates.

ii) Timing

Explanation This investment criterion asks how local transmission and distribution investments should be accelerated or prioritized to deliver renewables within CLCPA mandate timelines.

Metric Construction Timeline vs. Potential Interconnection Timelines vs. CLCPA Mandates

Example *A project slated for later implementation by a Utility is moved up in its capital plan and expanded to provide renewable delivery benefits earlier, in addition to the project's baseline Reliability, Safety, and Compliance benefits.*

iii) Expandability

Explanation The ability of a project to be expanded to accommodate additional renewable development in a region of a utility service territory.

Metric Incremental headroom created for expected renewable development

Example *When conducting an asset condition assessment, a utility notices significant generator interest in the region. That utility then builds in elements that allow for future upgrade buildout that would make renewables deliverable; e.g. adding additional bays in a substation.*

Case Study New York City Clean Energy Hubs

To meet the CLCPA's mandate of 9,000 MW of offshore wind, these resources must connect to New York City and Long Island. Connecting to either area will pose challenges from both a routing and permitting perspective. However, a benefit of connecting to New York City is direct access to customers there.

The two projects selected by NYSERDA in its 2019 RFP were both larger than 800 MW, and it is expected that future projects will seek to connect at a similar scale. Such interconnections are best made directly onto the 345 kV system to make them available to reach all customers in the City and potentially to be exported for use of customers in other regions. However, the transmission system in New York City offers limited available points of interconnection for new generation to connect. Of those interconnection points that are available today, many would require substantial upgrades to make the interconnecting generation deliverable to loads. Due to the dense population in New York City and the locations of high voltage transmission lines, there are limited locations to build new transmission substations.

CECONY is exploring the opportunity to create Clean Energy Hubs in New York City that would: (1) connect and fully deliver new resources such as offshore wind; (2) solve identified bottlenecks or constraints on the local system to enable loads to be served by renewable energy; and (3) address future load growth from electrification (due to CLCPA), while also improving the resiliency of the company's local system.

iv) Cost Effectiveness

Explanation Allows renewable generation to serve loads in a cost-effective manner.

Metric Net Benefits and Benefit/Cost Ratio (over 40 years)[34]

Example *The cost of a local transmission upgrade is compared against the cost of procuring additional constrained renewable generation to allow for the achievement of CLCPA mandates. In this case, the project is a multi-value project that is an expansion of a project that is justified under existing planning criteria, but when the scope of the project is expanded will (1) reduce curtailments of existing renewable generation, and/or (2) allow new renewable generation to be delivered to load without significant curtailment of the renewable generation due to local transmission constraints. The Utilities will utilize the BCA methodology described in Section III, below, to demonstrate that the benefits of the project, when combined with other non-monetary benefits applied through the proposed planning process, justify investment in the project.*

Case Study NYSEG Geneva Area Upgrade

The scope of the CLCPA beneficial Geneva Area Upgrade project includes a modest expansion of an existing planned NYSEG substation project (the Border City 115 rebuild and capacitor additional project). In addition to the substation expansion, power flow control devices, and a storage device could together provide significant renewable generation congestion relief to this area.

In this case, the incremental substation expansion work, power flow control devices, and storage system would not be justifiable under the current planning practices. However, with the introduction of CLCPA investment planning criteria, these components can be considered based on their cost and beneficial effect in unlocking renewable resources in support of the State's CLCPA objectives. The cost effectiveness calculation would include a comparison of the amount of renewable energy that could be curtailed with and without the upgrades. The differences of the renewable energy that can be dispatched before and after the upgrades is the MWh benefit from the unbottling renewable energy, which is then utilized in the calculation of Net Benefits and Benefit/Cost Ratio. The annual revenue requirement of the incremental cost of the power flow control equipment and storage is used as the cost for BCA calculations.

[34] See Section III: Local Transmission Benefit-Cost Analysis.

v) Improve System Flexibility to Accommodate Greater Intermittency

Explanation The ability to operate local transmission and distribution system reliably and efficiently in regions with high penetration of intermittent renewables.

Metric When non-firm renewable generation[35] penetration levels in the region begin to dominate the local generation mix a Utility could trigger a LT&D project to prevent loss of load event triggered by most or all of the non-firm renewables in that region.

Example The sudden loss of 300 MW of solar generation due to unforeseen cloud formation in a specific region could trigger a local loss-of-load event. A Utility project may develop a solution[36] to improve system flexibility and eliminate this reliability risk. Such an investment will likely include resiliency, reliability, or expandability benefits as well.

vi) Firmness

Explanation Firmness represents the certainty of interconnection of renewables in a given region of a Utility's system. Firmness where sufficiently demonstrated should be a criterion that can drive the need for upgrades to a utility system.[37]

Metric Incremental, future renewable delivery. There are a number of criteria that a utility can utilize to determine how likely a generator is to reach commercial operation, or that generator's Firmness.

Example *A utility is notified that NYSERDA's Build Ready solicitation has closed and NYSERDA has identified three sites in a region of the company's service territory. Generators have signed contracts to develop their project at the site they were awarded. A Utility may then rely on a local transmission or distribution investment to permit interconnection of the clean energy resources.*

Case Study Build Ready Program

NYSERDA's Build Ready program[38] proposes to create opportunities for new renewable development at high potential sites across the New York LT&D system. NYSERDA will conduct formal and detailed assessments to identify brownfield, and other similarly underutilized parcels of land. Those parcels will

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35 Non-firm renewable generation as used here means: an intermittent generator NOT coupled with energy storage, and therefore unable to generate due to changes to weathers.

36 A transmission or distribution solution may include storage or other advanced transmission technologies.

37 Under federal rules, any new or expanded points of interconnection would need to be made available to any prospective generators consistent with open access principles. However, given the State's clean energy policies, it is not expected that there will be many future applications from fossil-fueled generators.

38 Case 15-E-0302, *Proceeding on Motion of the Commission to Implement a Large-Scale Renewable Program and a Clean Energy Standard* (CES Proceeding), Order Approving Build-Ready Program (Issued October 15, 2020).

be studied by NYSERDA from siting, interconnection, and cost of development perspectives. After identification and study NYSERDA will auction these 'Build Ready' sites to the developers prepared to make renewable energy investments in New York.

These Build Ready sites, once successfully auctioned, provide high quality and reliable data points for the Utilities to consider when conducting short and long-term capital planning processes. A handful of approved and auctioned Build Ready sites in a region will support cost-effective investment by the local and interconnection utility.

D. Classification and Prioritization of LT&D Projects

Clean energy enablement projects deliver value that should be reflected in a utility's portfolio of projects. The portfolio will continue to include Reliability, Safety, and Compliance projects that are required under existing planning criteria. This Report proposes a two-phased approach to integrating CLCPA values into the Utilities project portfolios.

- *Phase 1* projects are immediately actionable projects that satisfy Reliability, Safety, and Compliance purposes but that can also address bottlenecks or constraints that limit renewable energy delivery within a utility's system. These projects may be in addition to projects that have been approved as part of the utility's most recent rate plan or are in the utility's current capital pipeline. Phase 1 projects will be financially supported by the customers of the utility proposing the project.
- *Phase 2* projects may increase capacity on the local transmission and distribution system to allow for interconnection and delivery of new renewable generation resources within the utility's system. These projects are not currently in the utility's capital plans. Phase 2 projects tend to have needs cases that are driven primarily by achieving CLCPA targets. Broad regional public policy benefits suggest the likelihood that cost sharing across the Utilities may be appropriate. These projects require additional time to plan and prioritize using the investment criteria and benefit cost analysis (BCA) methodology described in Section III, below.

As a first step (Phase 1), the Utilities propose to apply the supplemental CLCPA Investment Criteria to identify ready opportunities to accelerate or progress Reliability, Safety, and Compliance projects to provide additional CLCPA benefits (i.e., Multi-Value projects). Part 2 of this Report provides a list of projects that are ready for immediate implementation that satisfy traditional investment criteria and that unleash CLCPA benefits. Figure 4 describes an initial classification scheme for local transmission and distribution projects. Phase 1 will consist of Multi-Value projects

Phase 2 projects will include those that are (1) purely CLCPA driven, and (2) modifications or additions to Multi-Value projects that increase CLCPA target achievement.

Figure 4: Illustrative Local Transmission and Distribution Project Types

T&D Project Type	Description
Reliability, Safety, and Compliance	Projects driven by asset condition, reliability, resiliency, cybersecurity, safety, or compliance directive from regulatory bodies including, but not limited to: Commission, NERC, NYSRC, EPA, NY DEC, FERC, NPCC. Reliability, Safety, and Compliance projects can be broken down further to include mandatory and discretionary projects.
Multi-Value	Projects that have both Reliability, Safety, and Compliance *and* CLCPA benefits.
CLCPA-Driven	Projects identified as needed to achieve CLCPA statutory requirements and CLCPA-related resiliency project.

i) Reliability, Safety, and Compliance Projects

The Utilities currently rely on Reliability, Safety, and Compliance planning criteria to inform the investments that are included in rate cases. These planning criteria are largely similar across the Utilities, but how each company applies them, and which criteria are most important to each Utility differs.

These criteria are set by myriad planning, safety, and environmental bodies as noted above and include critical infrastructure regulations and cyber security rules. Reliability, Safety, and Compliance projects relating to reliability and/or transmission system security must continue to be prioritized investments within all Utilities' capital plans.

In the process of designing and evaluating these projects, each will be assessed for any Multi-Value potential, as discussed below. The analysis of possible CLCPA benefits should have no effect on the need or value of the Reliability, Safety, and Compliance project itself.

Reliability, Safety, and Compliance projects will not change in their priority need.

ii) Multi-Value Projects

Multi-Value projects have a Reliability, Safety, and Compliance component driven by traditional planning criteria, but also serve a CLCPA planning purpose. Should a Reliability, Safety, and Compliance project present the opportunity for expansion to capture additional CLCPA-related benefits, the incremental portion of the project will be assessed using the CLCPA metrics described above in a BCA to determine whether the modification is beneficial.[39] For example, a utility may need to replace an aging transmission line, but through applying the CLCPA investment criteria, finds that it can unbottle additional renewables and move them onto

[39] This process does not apply to Phase 1 projects, which will not be assessed in a BCA.

the bulk electric system by replacing the line with a larger conductor. Now the project has at least two value streams: (1) reliability and (2) helping New York meet its renewable mandates.[40]

To the extent that a Reliability, Safety, and Compliance project presents Multi-Value potential,[41] the BCA described in the next section should apply only to the incremental benefits portion of the project can be utilized as an input to the prioritization process. Once the full metrics of incremental value have been determined, the utility will compare the project's benefits to the full range of potential within a portfolio of projects. Adjustments and prioritization will be made based on all applicable timing factors as well as the criteria discussed above.

The benefit of the incremental CLCPA component of this transmission project accrue not only to the utility's own customers, but to all customers in New York. Accordingly, the incremental cost of the CLCPA component of this Multi-Value project may be eligible for cost allocation to customers outside its service territory, as discussed further in Section V, below. The costs of the conventional Reliability, Safety, and Compliance component continues to be charged to the individual utility's customers.

iii) CLCPA-Driven Projects

This category of projects pertains to LT&D projects that a utility would only include in a rate case or capital plan based on the project's ability to meet the new CLCPA investment criteria described above. Each Utility will use a clear methodology based on the principles in this Report to determine how and why it included a CLCPA-Driven project in its rate case, accompanied by a justification as to how and why the project should be eligible for cost allocation to customers outside its service territory (where appropriate). An example of a CLCPA-Driven project would be a set of local transmission upgrades required to improve delivery of assumed renewable generation in a region of a Utility's service territory to the BPTF for a significantly higher percentage of the 8,760 hours in a given year(s).

CLCPA-driven projects will be designed specifically to achieve CLCPA mandates and will function as cost-effective investments to accelerate progress towards the CLCPA mandates and their attendant metrics. CLCPA projects will be selected using the supplemental CLCPA investment criteria described here, including relative cost-effectiveness in meeting CLCPA mandates using the Net Benefits and BCA calculations described in Section III. CLCPA projects will be organized within a total portfolio so as not to displace or compromise Reliability, Safety, and Compliance projects. Instead, that prioritization will allow for the most efficient deployment and recovery of benefits identified in the BCA and evaluation stages of this process. The benefit of CLCPA projects accrue not only to the utility's own customers, but to all customers in New

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40 See the National Grid MVT project description above.

41 This applies to Phase 2 and beyond.

York. Accordingly, costs attributable to these projects may be eligible for cost allocation to all benefiting customers.

E. Prioritization and Approval of Local Transmission and Distribution Projects

To use the CLCPA investment criteria described above, the Utilities will need to build on their existing capital planning processes. There are four basic inputs to the evaluation process:

- Existing planning criteria (e.g., reliability);
- Incremental CLCPA investment criteria:
- Expected incremental clean energy value; and
- Expected investment costs.

The Utilities plan to approach these inputs in a transparent manner and will appropriately consider stakeholder input in developing project queues.

Each Utility will stage and prioritize Multi-value and CLCPA-Driven local transmission and distribution projects based on the prioritization process described below. The BCA was developed to apply only to those projects (or portions of projects) identified based in the incremental CLCPA investment criteria, and not to projects identified based on existing planning criteria (such as reliability). Reliability, Safety, and Compliance projects are needed to maintain the integrity of the electric system. Any public policy benefits they provide should be acknowledged but performing a full BCA on such projects is not necessary for decision-making. The Utilities therefore recommend that the Commission only require application of the BCA to CLCPA-Driven projects and components of a Multi-Value project that are CLCPA-driven.

Projects identified based on CLCPA drivers and incremental portions of Multi-Value projects attributable to CLCPA drivers should be evaluated against the CLCPA Investment Criteria described above and undergo the BCA, although neither would be dispositive of whether a project proceeds.[42] For example, there may be projects that do not deliver the highest BCA evaluation score as one criterion, but can still be justified based on other factors not assessed, or impossible to accurately assess in the BCA. See the BCA section of this paper to understand how that analysis assigns monetary value to a transmission project's ability to enable New York State energy mandates and renewable delivery.

The processes for selecting and prioritizing projects under this approach are illustrated in Figure 5, below.

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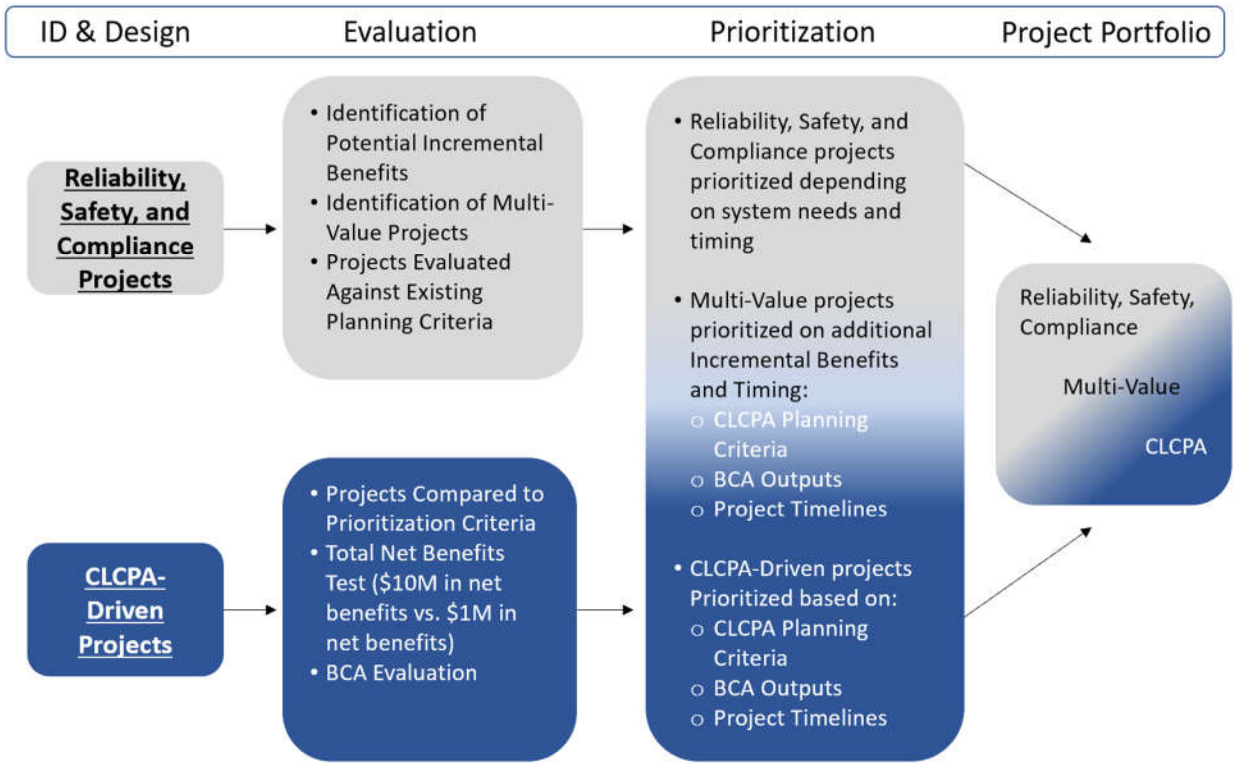
[42] The Utilities' proposals related to BCA for local transmission projects are described in Section III, below.

Figure 5: Illustration of Prioritization Process



F. Summary of Recommendations

The modifications to utility planning practices described above rightfully bring planning paradigms and practices that have been standard practice for decades into the CLCPA era. LT&D planning must evolve to develop cost-effective investment to support New York State's bold energy policies, in addition to continuing to meet all reliability, safety, and compliance criteria. These CLCPA Investment criteria and the prioritization process reflect the Utilities' recommended initial steps to drive the investment necessary to deliver renewable energy to load centers and support New York's electric customers' clean energy preferences, without sacrificing reliability.

Specifically, the Utilities recommend that the Commission approve a set of local transmission and distribution investment criteria designed to meet CLCPA mandates, including: 1) renewable energy utilization (*i.e.*, to reduce curtailments and increase renewable delivery to load pockets); 2) improved timing of renewable projects to deliver benefits faster; 3) grid access expandability to interconnect renewables; 4) cost effectiveness of local transmission and distribution investments; 5) improved intermittency management; and 6) firmness of renewable generation projects. Designation of local transmission and distribution projects by type will streamline classification, prioritization, and approval of CLCPA-driven projects and Reliability, Safety, and Compliance projects. Finally, the Utilities recommend that these approaches be integrated with, and additive to existing local transmission and distribution planning processes going forward (*i.e.*, for Phase 2 and beyond), but not replace or undermine any existing planning criteria or imperatives.

III. LOCAL TRANSMISSION BENEFIT COST ANALYSIS

A. Objectives

This section describes the Utilities' proposed approach to applying a benefit-cost analysis (BCA) to Multi-Value and CLCPA-Driven transmission projects.[43] The May Order notes the Commission's expectation that "the utilities will have to define the benefits of such a project in a way that is fair and objectively quantifiable."[44] Further, the May Order notes that the application of a BCA "presents novel issues, including how to identify who benefits from these CLCPA-targeted investments and by how much."[45]

A BCA is a key factor in project screening and prioritization, and specifically addresses benefits that are quantifiable in dollar terms. The Utilities propose a BCA approach here that can be applied to the full range of potential local transmission projects that have the potential to unlock CLCPA benefits. The approach described below focuses on CLCPA-related metrics, and uses a simple, repeatable methodology.

B. BCA Framework Approach

The Utilities' proposed BCA methodology for local transmission projects (the LT BCA) is designed to address the principles articulated in the BCA Framework Order[46] and Whitepaper.[47] It considers several principles, including:

1) Transparency: The LT BCA provides assumptions, methodologies, descriptions and quantifications of all benefits and costs considered, including those that are localized and as granular as possible.
2) Benefits and Costs Allocation: Care is taken to avoid combining or conflating CLCPA benefits and costs with those associated with Reliability, Safety, and Compliance. The benefits and costs of local transmission to achieve CLCPA objectives (through a focus on avoided renewable curtailments and alternative means of avoiding or making up the renewable energy of these curtailments) are distinctly separate from those of Reliability, Safety, and Compliance projects.

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43 The current planning process for conventional capital investment in local transmission does not require application of a benefit cost analysis (BCA) in all cases. (*E.g.*, projects pursued to address reliability requirements or constraints are not assessed using a BCA today.) A BCA is applied to assess specific customer programs and large investments.

44 Transmission Planning Proceeding, May Order, p. 9.

45 Transmission Planning Proceeding, May Order, p. 9.

46 Case 14-M-0101, *Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision* (REV Proceeding), Staff White Paper on Benefit-Cost Analysis in the Reforming Energy Vision Proceeding (BCA White Paper) (filed July 1, 2015).

47 Case 14-M-0101, *Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision* (REV Proceeding), Order Establishing the Benefit Cost Analysis Framework (BCA Framework Order) at 2 (Issued January 21, 2016).

3) Portfolio Perspective: The LT BCA provides a basis for comparing the relative cost-effectiveness of local transmission projects in meeting CLCPA mandates. This allows the Utilities to develop portfolios of investments that best satisfy the investment criteria set forth in Section II.
4) Lifecycle and Sensitivity Analysis: The Utilities' net present value approach considers a 40-year value stream for the alternative approach used for comparison.[48]
5) Comparison to Traditional Investments: The LT BCA compares the levelized cost of local transmission investments needed to reduce renewable energy curtailments to the addition of supplemental renewable energy that would otherwise be needed offset to offset curtailments to achieve the CLCPA mandates. This focuses on the societal cost of each, which is a key feature of the approach the Commission requires the Utilities to use in other contexts.[49]

There are some overlaps between this LT BCA and the approaches described in utility-specific BCA Handbooks, which apply to distribution assets. This LT BCA methodology was developed for the specific purpose of evaluating the relative cost effectiveness of local transmission projects in meeting CLCPA mandates.[50, 51] When applying this framework to local projects, it is necessary to:

1) Provide a basis for evaluating the relative cost of local transmission projects in the context of the benefits they provide in meeting CLCPA targets, both in terms of the magnitude of net benefits and the ratio of benefits to costs;
2) Allow the Utilities to perform initial benefit/cost analysis on a large number of CLCPA-related projects quickly and consistently; and
3) Distinguish incremental CLCPA investments from those that would proceed under Reliability, Safety, and Compliance drivers.

This LT BCA methodology presents a streamlined approach to assessing the benefits and costs of reducing renewable curtailments by adding local transmission.

Simplicity is essential to conduct the analysis necessary to expeditiously meet CLCPA objectives, considering the number of benefit/cost analyses that the Utilities will be required to perform in the relatively compressed time period specified by the Commission and required in the AREGCB Act. To that end, this proposed LT BCA relies on data already available and used in other Utility benefit/cost analyses. Specifically, the environmental value of each MWh of unbottled renewable energy is based on the most recent Renewable Energy Credit (REC) and

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48 This LT BCA approach is a departure from the distribution-level BCA Handbook in order to align timelines used for local transmission benefit-cost analyses with the NYISO's approach for bulk transmission.

49 Transmission Planning Proceeding, May Order, p. 7.

50 Note that the LT BCA methodology provides Utilities the option to incorporate on scenarios that consider different inputs or parameters.

51 LIPA believes that the Commission should also consider the alternative of statewide cost allocation for distribution investments with the objective of spawning distributed renewable generation investment through reducing interconnection costs new distributed renewable generators will face.

Offshore Wind Renewable Energy Credit (OREC) prices as posted or estimated by NYSERDA.[52] The energy value attributable to CLCPA projects is represented by the forecasted Location Based Marginal Price (LBMP) based on the NYISO's Congestion Assessment and Resource Integration Studies (CARIS) Study (using a renewable energy buildout consistent with CLCPA mandates), as utilized in the benefit/cost framework for NWAs. In the 2019 CARIS assessment, the NYISO studied 2029 in a 70 x 30 CARIS sensitivity case and has proposed to extend the CARIS 2 analysis through a 2060 forecast period. The BCA will use the CLCPA forecast in the most current NYISO CARIS public policy scenarios), with extrapolation for future years based on the price trends in the CARIS cases.[53] Utilities may also utilize Installed Capacity ("ICAP") prices forecasted by DPS.

This framework is best viewed as a tool to be used in conjunction with other non-monetary criteria to screen and prioritize investment opportunities for further in-depth design and study. On its own, the LT BCA will not be used to make go/no-go decisions or provide for a ranking of projects solely on benefit/cost metrics. To meet the mandates set forth above, the LT BCA will produce two primary metrics:

1) Net Benefits: Simple measure of net benefits calculated as the discounted 40-year stream of benefits minus the discounted 40-year stream of costs (both beginning at a project's in-service date), with the understanding that project cost recovery may occur over a period longer than 40 years. The net benefit metric will demonstrate the magnitude of net benefits and allow for prioritization of projects that provide the most meaningful contributions to meeting CLCPA mandates. The aggressiveness of CLCPA mandates are such that achieving scale in the selection of projects is crucial for success.
2) Benefit/Cost Ratios: The second metric is a benefit/cost ratio measured as the discounted 40-year stream of benefits divided by the discounted 40-year stream of costs. The benefit/cost ratio is a commonly used metric that shows the relative cost-effectiveness of projects irrespective of size.

Transmission projects have an economic life substantially in excess of 40 years, so this methodology provides a conservative valuation of the long-term benefits of the projects.

i) LT BCA Overview

The benefit/cost metrics were selected based on cost effectiveness in achieving CLCPA targets. The CLCPA and the AREGCB Act are focused on delivering renewable generation to load. As such, the primary metric for the LT BCA is a quantitative valuation of renewable energy that can be unbottled by a project and delivered to customers in New York.

Renewable energy is bottled (curtailed) when transmission limitations prevent renewable energy from serving load. Local transmission investments can reduce these curtailments,

52 NYSERDA. "Clean Energy Standard: 2020 Compliance Year."

53 New York ISO. "2019 CARIS Report: Congestion Assessment and Resource Integration Study. July 2020. Available here.

increase the flow of renewable energy to customers, and decrease electric sector emissions. There are two general categories of projects:

- On-ramp projects: Local transmission projects developed in areas where local customer load and current transmission export capacity is not sufficient for existing and/or new renewable generation, and where investment is needed to allow for the deliverability of excess renewable energy to the BPTF for delivery to load centers elsewhere in the State.
- Off-ramp projects: Local transmission projects developed to enable renewable energy that is injected into the BPTF to be delivered to local loads where local transmission is insufficient to absorb all renewable energy generated, and renewable energy would otherwise be curtailed.

Examples of on-ramp and off-ramp projects are shown in **Error! Reference source not found.**C. This proposed LT BCA has the flexibility necessary to evaluate both types of projects.

The benefits of unbottling renewable energy are estimated based on the assumption that, in the absence of a transmission project, the energy (MWh) curtailed would need to be replaced by construction of additional renewable energy generation to displace the curtailed energy during other hours of the year when the constraint is not binding. The replacement generation is needed in order to meet the CLCPA mandate that 70% of the State's energy needs be generated by renewable energy sources by 2030 and 100% from emissions-free energy sources by 2040. In that case, the added renewables would increase megawatt-hours of renewable energy during periods where load is sufficient, and when the transmission system has headroom, while accepting more curtailments during periods where renewables are already constrained by load and no headroom exists. For example, if renewable energy is curtailed 20% of the time due to transmission constraints, additional renewable energy can be added that produces enough renewable energy during the 80% of hours where curtailments do not occur to make up for the quantity of renewable energy that is curtailed during 20% of the time. This approach would allow for the production of sufficient renewable energy to meet CLCPA mandates, but at an additional cost. Therefore, the value of unbottled renewable energy is the levelized cost of adding a new renewable energy resource to replace the curtailed energy, accounting for the "spillage" of expected curtailment of the new resource. Because the basic value of a new megawatt-hour of renewable energy in New York, absent curtailment, is the projected market value of renewable energy per MWh (energy and capacity) plus the projected value for a REC or OREC[54], the value of new renewable energy from unbottling curtailed

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[54] There are other potential revenue streams, but they are either de-minimis compared to energy and REC prices, or not focused specifically on CLCPA-related benefits.

renewable resource is the (LBMP + ICAP[55] + REC or OREC price)/(1- curtailment percentage)[56]. The calculation above is the primary calculation of benefits for both the Net Benefits and Benefit/Cost calculations (when expressed over a 40-year period)[57]. For both calculations, the cost is calculated as the 40-year revenue requirement for the transmission project.

The LT BCA aims to address constraints and curtailments from a generation pocket to the bulk power system under two options.[58] The first option adds more renewables during unconstrained periods to compensate for curtailment periods, and the second adds transmission to eliminate constraints. Figure 6 is a graphical representation of renewable energy being curtailed when the quantity of renewable energy production in an area with transmission constraints exceeds the total load within that area plus export capability out of the area.

Figure 6: Renewables Constrained from a Generation Pocket or Into a Load Pocket

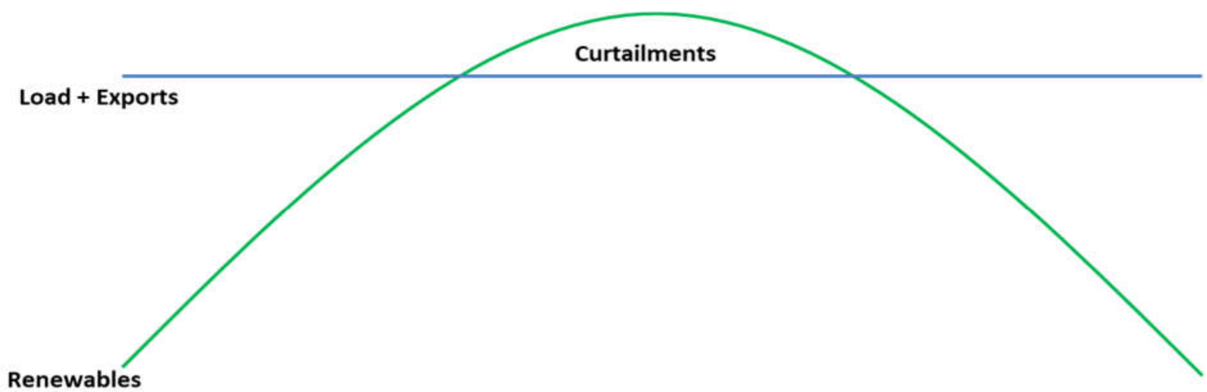

Figure 7 and Figure 8 below illustrate the two options for addressing the curtailment of renewable energy.

Under Option 1, additional renewables are added to the system during unconstrained periods to make up for renewable energy spilled during periods of curtailment. (*See* Figure 7.) As discussed above, this approach would add additional renewable energy, but also exacerbate constraints. The unit cost of the new renewables would need to increase to compensate for

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55 The inclusion of ICAP is optional and may be used at a Utility's discretion.

56 The levelized cost of a renewable facility that is unconstrained assumes that the market value is received for all production. If a resource is expected to be curtailed, the unit rate received from the market needs to be grossed up to account for lost sales during periods of constraint. In addition, , the inclusion of an ICAP component is optional.

57 The Utilities considered applying a loss factor, but because the renewable facility used in the benefits calculation is a generic renewable facility with no specific location (either generic upstate or generic offshore wind), the use of a loss factor may introduce a complexity that does not result in any meaningful differentiation between project BCA scores.

58 A similar analysis can be applied for transmission constraints from the bulk power system into a load pocket in instances where renewable curtailments are occurring on the bulk power system. For clarity, this example focuses on bottled generation.

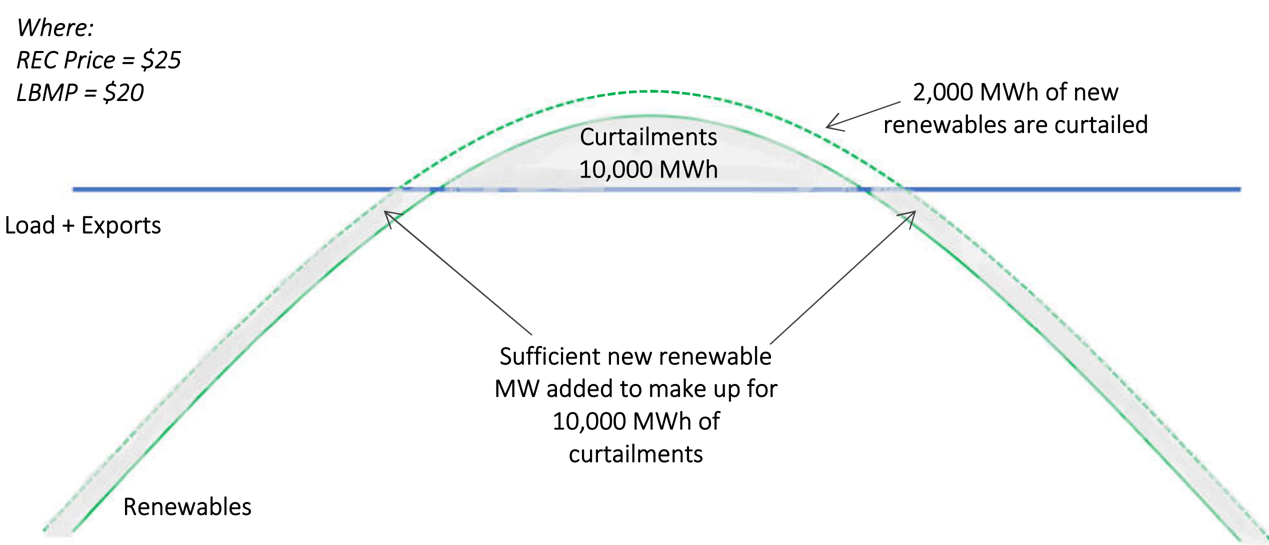
curtailment-related revenue reductions. This entails determining the levelized unit cost of the renewable additions after factoring in the financial impact of constraints. This is calculated as the (REC Price + LBMP +ICAP)/(1-curtailed MWh %). For example, if 16.67% of the new renewable MWh would be expected to be curtailed, the unit cost is:

(REC Price + LBMP + ICAP)/(1 – 16.67%).

The cost implications of each option are distinct as well. For Option 1, it takes 12,000 MWh of new renewables in the export-constrained generation pocket to make up for the curtailment of 10,000 MWh (16.67% curtailment of the renewable additions). Thus, assuming for simplicity that ICAP earnings are zero:

Net Cost = ($25 + $20)/(1-16.67%) = $54.00/MWh.

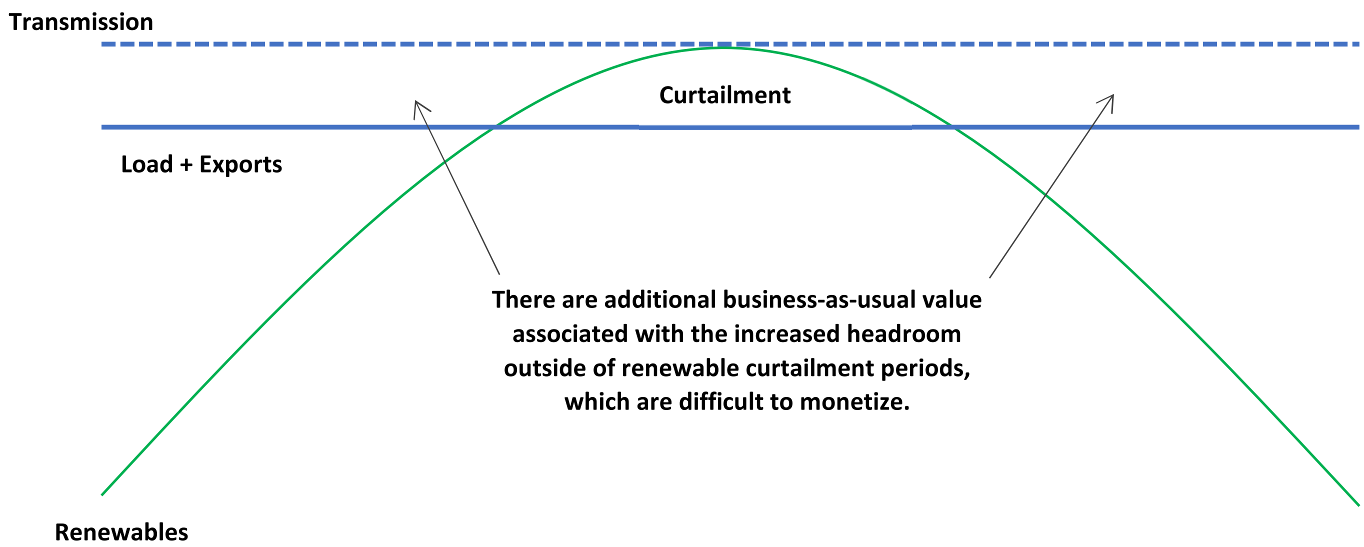
Figure 7: Option 1 (Add Renewables)



Under Option 2, transmission is added to eliminate constraints. (See Figure 8.) The avoided new renewable cost is approximated as the: (REC Price + LBMP +ICAP)/(1-curtailed MWh %) *[i.e. Option 1]*. If the cost of transmission is less than the avoided renewable cost, the B/C Ratio > 1.

Opting instead to construct transmission results in an annual benefit[59] of $54.00 x 10,000 MWh = $540,000. Assuming an annual transmission revenue requirement of $400,000, the B/C Ratio = $540,000/$400,000 = 1.35.

Figure 8: Option 2 (Add Transmission)



The value of choosing Option 2 extends beyond the Net Benefits and Benefit/Cost Ratio calculations. Transmission additions can create additional value during periods without curtailments. For example, by allowing more efficient generating sources to be dispatched and displace higher emissions from less efficient fossil generating sources. This results in additional value in the form of reduced production costs, congestion, and emissions not captured in the LT BCA. It can also provide for increased resiliency and operational flexibility. For simplicity, this BCA does not attempt to quantify these benefits.

The Net benefits and benefit/cost ratio calculations are described below.

ii) Benefit Calculations

The ***Net Benefits*** metric is calculated using the following formulae:

1. For a project that will be built specifically to meet CLCPA targets, and would not otherwise be built, this formula applies:

PV (MWh x RE) + *PV(Other Value) – PV(Project Rev Req)*

[59] This assumes the same prices as are used in the prior example.

2. For a project that is built as an expansion/improvement to a Reliability, Safety, and Compliance project (i.e., a Multi-value Project), this formula applies:

PV (Inc MWh x RE) + *PV(Other Value) – PV(Inc Project Rev Req)*

The ***Benefit/Cost Ratio*** is calculated using the following formulae:

1. For a project that will be built specifically to meet CLCPA targets, and would not otherwise be built, this formula applies:

$$\frac{\text{PV (MWh x RE)} + \textit{PV(Other Value)}}{\text{PV(Project Rev Req)}}$$

2. For a project that is built as an expansion/improvement to a Reliability, Safety, and Compliance project (i.e., a Multi-value Project), this formula applies:

$$\frac{\text{PV(Inc MWh x RE)} + \textit{PV(Other Value)}}{\text{PV(Inc Project Rev Req)}}$$

Where:

"RE" = the levelized cost (in dollars per Megawatt hour) of new constrained renewable energy resources. This is calculated as the:

(REC + LBMP + ICAP)/(1 – curtailment percentage)

Where the curtailment percentage is the expected statewide[60] percentage of MWh of renewable production that would be curtailed in a 70% renewable energy by 2030 case without expansion of the transmission system (i.e., as estimated in the CARIS 70x30 scenario).

"PV" = present value over the period using average after-tax Weighted Average Cost of Capital ("WACC") for the Utilities.[61]

"MWh" = Megawatt hours of unbottled renewable energy calculated by the transmission owner using the Unbottled Renewable Energy Calculation Methodology (described in detail in Appendix A).

60 Note that because renewable energy can be added outside of the zone where the transmission constraint is being solved, use of a statewide percentage of curtailments is more appropriate for assessing the renewable alternative than using the percentage of curtailed renewable energy within the constrained zone, which remains the relevant metric for the transmission alternative.

61 The average of all Utilities' WACC is used because CLCPA benefits are societal, and not specific to any individual Utility's customers.

"Inc MWh" = MWh of unbottled renewable energy attributable to an expansion or modification of a Reliability, Safety, and Compliance project (i.e. does not include MWh of unbottled renewables attributable to the Reliability, Safety, and Compliance project, only to the incremental investment to be made for CLCPA purposes).

"REC" = Societal value of each MWh of unbottled renewable energy, represented by the forecasted REC price or OREC price as applicable to the type of resource producing unbottled renewable energy. REC and OREC prices are the most recent REC and OREC prices posted or estimated by NYSERDA.

"LBMP" = Energy market value of each MWh of renewable energy in the load zone of the transmission project, based on a NYISO CARIS forecast that includes a buildout of renewables consistent with CLCPA mandates, with extrapolation or interpolation as needed to prices that fall outside of the years of CARIS outputs.

"ICAP" = Capacity market value (if any) of the incremental renewable investment compared against the transmission project, converted from dollars per kilowatt-month to dollars per MWh assuming a standard capacity factor for the renewable resource. The ICAP conversion formula is as follows:

Step 1: MW Nameplate x Unforced Capacity Percentage[62] = MW ICAP Value
Step 2: MW Nameplate x Annual Capacity Factor (excluding constraints) x 8,760 annual hours = MWh Energy
Step 3: MW ICAP Value x ICAP Price ($/kW-month) X 1,000 (Kw to MW conversion) x 12 months = ICAP Revenue
Step 4: ICAP Revenue/MWh Energy = ICAP Price in $/MWh

The Utilities will use ICAP price forecasts contained in the NYDPS' ICAP Spreadsheet Model[63]. For renewables with a REC price, the "NYCA" ICAP price is to be used. For renewables with an OREC price, the weighted average of the NYC, LI, and Lower Hudson Valley prices are to be used. Prices will be extrapolated beyond the forecast period based on the price trend.

"Other Value" is an optional benefit category that can be used by a utility only for the purpose of comparing projects within its own service territory (subject to COMMISSION approval of specific benefit metrics). These benefits may be specific to a particular utility in differentiating between its own projects.

"Project Rev Req" = the first 40 years of a project's revenue requirement developed using the Utility's WACC.

"Inc Project Rev Req" = the incremental revenue requirement over the initial 40-year analysis period of a project's lifecycle for a Reliability, Safety, and Compliance project that is

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62 NYISO ICAP Manual Section 4.5(b).

63 The ICAP Spreadsheet Model is identified in Attachment A of Appendix C to the Commission's January 21, 2016 Order in Case 14-M-0101.

expanded or modified to fulfill CLCPA targets (i.e. based on only the CLCPA-related incremental project cost)

iii) Benefit Inputs

As is discussed above, the LT BCA will use REC and OREC prices, as applicable, as proxies for the societal value of these reduced renewable curtailments.[64] Since the State values customer payments for the environmental attributes of the renewable energy REC or OREC price (as applicable), the environmental value of reduced renewable energy curtailments are valued at the REC or OREC price for purposes of the LT BCA.

Another proxy for the societal value of avoided renewable curtailments might be the social cost of carbon or other effluents. However, the fact that state-approved contract payments for renewables are based on REC or OREC prices provides a very clear dollar per MWh basis for valuation, whereas valuation based on a social cost of carbon would be more complex and depend, to some extent, on exogenous factors other than the reduced curtailments of renewable generation. For the purpose of developing a simple, replicable framework for analysis, the REC or OREC price fits best.

The LT BCA also accounts for the LBMP as a required revenue stream for a renewable energy project. As in the NWA analysis, the LT BCA will use the CARIS forecast of a statewide average LBMP for renewable projects using a REC price and load-weighted average J and K zonal LBMPs[65] for OREC-derived renewable projects. The forecasted LBMP is also in theory the marginal production cost of the last MWh of energy dispatched including bulk power system losses, so there is an additional rationale for the use of the LBMP. When the LBMP is positive, it is implied that the marginal production cost is associated with a generator that has a fuel source, and thus a marginal cost of energy production that can be avoided by the reduced curtailment of renewables.

iv) Valuation Specifics

The valuation criteria include a Benefit/Cost ratio and Net Benefit sum. Each component of the formula is a 40-year stream of benefits and/or costs, with present valuation performed using the average statewide Utility WACC, consistent with the NWA BCA analysis.[66] For ease of

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64 The BCA also recognizes changes in the marginal cost of energy brought about by renewable energy that is unbottled as described below.

65 Zone J refers to Kings, Queens (except the Rockaway peninsula), Richmond, New York, and Bronx counties. Zone K refers to Nassau and Suffolk counties and the Rockaway peninsula in Queens County.

66 There are a variety of metrics used in the NWA that are not utilized in the base benefit/cost analysis project comparison framework, although as noted above could be included in a utility specific project justification. Some NWA metrics were excluded because of de minimis impacts, some due to complexity given the number of analyses needed, and some because they are less relevant to meeting CLCPA targets.

this comparison between projects, all present values should be expressed in present value dollars as of the year of the analysis, not the year of the project in-service date.

The Benefit/Cost ratio provides some indication of the value proposition of an improvement but does not indicate the magnitude of savings made possible by the project, an important consideration in meeting CLCPA integration mandates quickly. The sum of Net Benefits fulfills this role, indicating the quantity of net benefits each project could deliver.

Reliability, Safety, and Compliance projects that would be built by the Utilities without modification or acceleration of development irrespective of this process may have CLCPA-related benefits. In this case, the benefit/cost ratio is effectively infinite because the CLCPA-related value is received at no incremental cost. Thus, those mandatory projects would be assumed to have been built anyway and will not be subject to an LT BCA.

For CLCPA-Driven projects (i.e. projects under development to fulfill CLCPA mandates), the value is the full benefit stream for the project, and the cost is the full project cost.

For Reliability, Safety, and Compliance projects that are expanded and/or improved to meet CLCPA mandates, the value is the incremental CLCPA-related value of the project (beyond the value of the Reliability, Safety, and Compliance project). Likewise, the cost is the incremental cost in excess of the Reliability, Safety, and Compliance project cost. Essentially, for these projects, the Net Benefit and Benefit/Cost Ratio metrics are based only on *incremental* CLCPA-related benefits and *incremental* costs.

Reliability, Safety, and Compliance projects that are justified later in the planning period in the absence of CLCPA-related benefits may be cost effective to advance and implement earlier when CLCPA benefits are considered. In this case, the incremental benefits (e.g. reduced renewable curtailments), will be considered throughout the planning period. Progressing such a project to an earlier date, in the absence of CLCPA benefits, would yield a negative incremental net present value (i.e. net cost increase). This will be considered the incremental net present value cost of the CLCPA related schedule changes.

C. Recommendations

The Utilities recommend that the Commission accept the BCA methodology for CLCPA projects proposed herein. Given the pace with which local transmission upgrades will need to be developed to satisfy 2030 and 2040 CLCPA mandates, a simple, consistent, repeatable BCA method is needed to allow the transmission owners to efficiently prioritize CLCPA-related investments. What is most relevant for this process is how cost-effectively the various projects will deliver CLCPA benefits, and this proposed LT BCA methodology is designed to do that with specificity. The Utilities also recommend that the Commission acknowledge that a) transmission projects have economic lives substantially longer than the 40 year analysis period, which results in additional benefits that are not captured by this analysis; and b) that additional non-quantifiable benefits are likely to be associated with the expansion of local transmission in the state, such as market efficiency and resiliency, and for these reasons, projects need not have a Benefit/Cost Ratio greater than 1 to be ranked for relative cost-effectiveness.

IV. STAKEHOLDER ENGAGEMENT

A. Stakeholder Engagement Overview

Gathering input and feedback from stakeholders and the development community on potential projects and their respective locations that can be fed into local transmission and distribution investment plans is crucial to ensuring the system is built out to appropriately integrate clean energy resources. Utilities communicate with stakeholders and gather input about both local transmission and distribution development plans using a variety of channels. The communication channels that apply to each category of development are designed to illustrate system needs and limitations and to focus development on local transmission and distribution projects that will provide the greatest benefit to customers. These channels are intended to facilitate collaboration with third parties.

i) Local Transmission Stakeholder Engagement

The Utilities recommend that stakeholder engagement in the local transmission planning process build on— but operate completely independent from— the utility LTP presentation process at the NYISO. The NYISO Open Access Transmission Tariff (OATT) provides that Utilities comply with federal regulatory rules governing transparency and stakeholder input for local planning, as set forth in FERC's Order No. 890,[67] and for public policy requirements, as required by FERC's Order No. 1000.[68] As required under NYISO OATT provisions, each utility posts its current Local Transmission Plan (LTP) on its website and is required to provide information on a variety of inputs to LTP plans:

- Identification of the planning horizon covered by the LTP;
- Data and modeling assumptions;
- Reliability needs, needs driven by Public Policy Requirements, and other needs addressed in the LTP;
- Potential solutions under consideration; and
- A description of the transmission facilities covered by the plan.

Under the OATT, the Utilities present their LTP to stakeholders at NYISO Electric System Planning Working Group (ESPWG) and Transmission Planning Advisory Subcommittee (TPAS) meetings. The Utilities make these presentations at a minimum every two years at the start of the ISO's biennial reliability planning cycle. NYISO stakeholders that typically attend these meetings include generators, developers, end-use consumers, environmental parties, and government agencies. Stakeholders are provided the opportunity to provide input and ask

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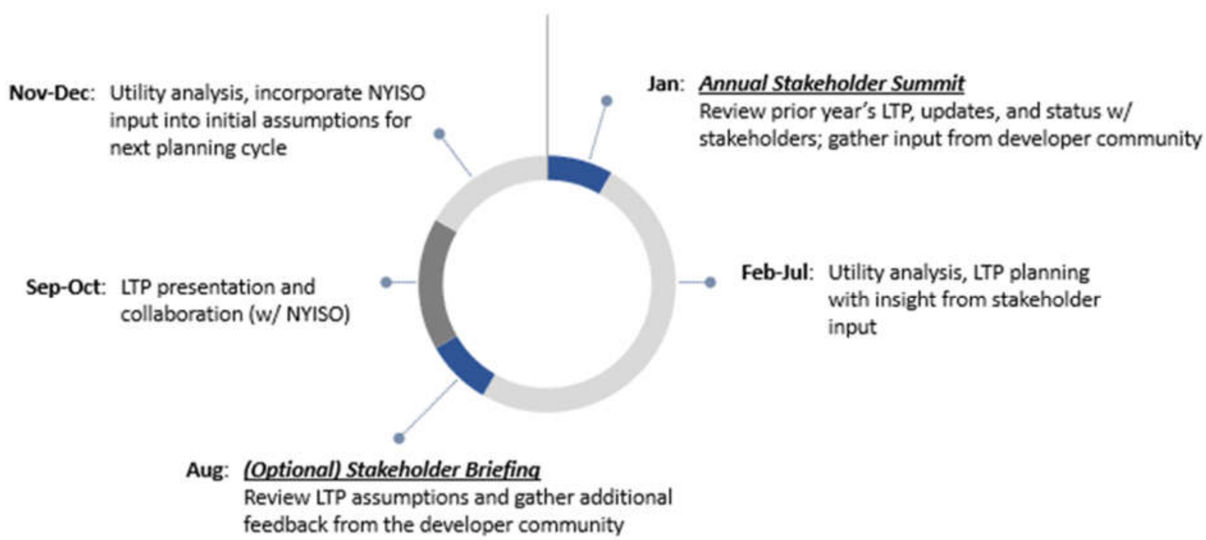
67 FERC Order No. 890.

68 FERC Order No. 1000.

questions. While the Tariff only requires the Utilities to present every two years, in practice the Utilities typically present to stakeholders more frequently as their LTP or projects change.

The utilities propose to build on the current LTP process by holding an additional annual meeting to gather feedback from the developer community on local transmission planning considerations.[69] Figure 9 illustrates the proposed stakeholder engagement opportunities throughout a generic LTP process, assuming an approximately annual update cycle.[70] The primary purpose of these meetings is for Utilities to gather information about developers' plans, so that this input can be considered in utility LTPs. These opportunities include an annual Stakeholder Summit designed to facilitate the flow of information and input from the developer community to the Utilities. Later in the year, Utilities may hold an additional Stakeholder Briefing, in which they can explain changes in assumptions and gather additional feedback from the developer community.

Figure 9: Hypothetical Annual Utility LTP Cycle (sample)



ii) Distribution-level Stakeholder Engagement

Utilities currently employ a variety of engagement strategies to apprise third parties of investment plans and to collaborate with stakeholders concerning distribution-level development. There are opportunities for stakeholders to learn about distribution-level system needs through information exchanges, procurement programs, and other regulatory processes.

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69 Information shared in these forums will need to consider limitations imposed by Critical Energy Infrastructure Information (CEII) designations and considerations for NYISO competitive processes.

70 This approximately annual update cycle does not change the reporting frequency to NYISO ESPWG. This stakeholder input opportunity is separate from that process.

Figure 10, below, illustrates many of these approaches, which apply across utilities with subtly different implementation practices from one utility to the next.

Figure 10: Venues that Provide Distribution Planning Transparency, Opportunities for Stakeholder Engagement, and Involvement

Stakeholder Engagement Opportunities	Information Gathering	Stakeholder Input Opportunity	Description
Governance, Information Sharing			
Joint Utilities Advisory Group	✓	✓	The Advisory Group (AG) is an open forum for stakeholders who are actively engaged in the REV process and the Distributed System Implementation Plan (DSIP) filings to advise the Joint Utilities of New York (JU) on a productive and collaborative stakeholder engagement process.
DSP Enablement Newsletters	✓		These newsletters are circulated quarterly and posted to the Joint Utilities of New York website.
System Data & Hosting Capacity Portals	✓		The Joint Utilities of New York website contains links to a variety of system data resources and portals for exploring hosting capacity throughout distribution systems.
Company websites, Joint Utilities website	✓		Companies share information related to a variety of distribution-infrastructure programs (e.g., EV charging locations; EV Make-Ready project implementation plans, NWA opportunities, etc.) The Joint Utilities of New York website contains a wealth of resources related to DSIP filings, stakeholder collaboration opportunities, program implementation strategies, procurement opportunities, etc.
PSEG Long Island Interconnection Working Group	✓	✓	LIPA's service provider PSEG Long Island conducts an Interconnection Working Group, including industry and utility representatives, that provides a forum for joint discussions and recommendations on matters affecting the interconnection of solar and other distributed energy resources to LIPA's electric system.
Regulatory Processes			
Rate Cases	✓	✓	Utilities initiate rate cases approximately every three years
Distributed System Implementation Plans	✓	✓	The Joint Utilities publish detailed implementation plans for distribution system-based investments. The DSIPs, which describe five-year technology and system deployment planning processes and objectives are updated every other year. *(LIPA files a similar plan, called the Utility 2.0 Long Range Plan & Energy Efficiency and Demand Response Plan.)* The Utilities each conduct stakeholder outreach sessions to present the DSIP in each two-year cycle.
Procurement Programs, Opportunities			
Non-Wires Alternatives	✓		Utilities provide information concerning Non-Wires Alternative opportunities for DER providers on company websites.

Stakeholder Engagement Opportunities	Information Gathering	Stakeholder Input Opportunity	Description
Energy Storage Solicitations	✓		Some of the Utilities plan to conduct supplemental solicitations for energy storage resources pursuant to the December 2018 Energy Storage Order in Case No. 18-E-0130.
EV Make-Ready	✓		The Utilities have published implementation plans and associated resources related to EV site Make-Ready opportunities on the Joint Utilities of New York website.
NYSERDA Build-Ready Program	✓	✓	The Commission has approved a new clean energy resources development and incentives program to encourage expedient siting and development of community and environmentally compatible renewable energy facilities to address CLCPA objectives.

B. Recommendations

Today, the Utilities provide transparency in distribution and local transmission planning through the existing mechanisms, many of which are described above. The Utilities recommend that these mechanisms be continued and strengthened to ensure that there are meaningful opportunities to gather input from the developer community that can be considered in local transmission and distribution planning processes and support integration of clean energy resources onto the local system.

V. COST ALLOCATION AND COST RECOVERY

A. Objectives

The Utilities propose methods of cost allocation and recovery for local transmission investments, and CLCPA-related distribution investments not otherwise subject to a utility's distribution cost recovery framework,[71] either entirely or partly within the rate case framework, which will form the basis of a Commission-established "distribution and local transmission capital plan" for each utility. Accordingly, cost allocation and cost recovery for "bulk transmission" (as defined in the AREGCB Act) and distribution upgrades covered under a utility's distribution cost recovery framework are not addressed here.

This section identifies:

1. Potential cost recovery pathways (including current cost recovery processes)
2. Comparison of regulatory pathways and evaluation of benefits and challenges
3. Cost recovery pathway examples
4. Utilities' recommendations to the Commission on cost allocation and cost recovery mechanisms

As stated earlier, the Utilities recommend that the Commission authorize projects in phases, with Phase 1 projects to be those that could proceed through individual utility rate cases, and Phase 2 projects consisting of CLCPA-Driven projects that may require new regulatory mechanisms to facilitate equitable cost sharing across the state.[72] In considering a staged approach, however, the Commission should avoid unnecessary delay between the successive phases, as such delay could risk compliance with the CLCPA's target of achieving 70% renewable energy by 2030.

B. Cost Allocation and Recovery Overview

The Utilities have considered four principal pathways for cost allocation and recovery:

1) **Rate Case-Based Approach:** Traditional utility rate cost recovery and consideration of potential new Commission-based regulatory mechanisms.

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[71] On October 29, 2020, the Interconnection Policy Working Group (IPWG), which consists of the Utilities, DPS Staff, and other participants, filed a proposal related to recovery of CLCPA-oriented distribution project costs in Case 20-E-0543. Proposals related to distribution cost recovery described here and in the IPWG's proposal are limited to the utility rate case approach, and do not contemplate the allocation of costs to other utilities' customers. The IPWG proposal contains cost allocation and cost recovery mechanisms for both utility driven upgrades, including multi-value synergies between a utility's capital plan and opportunities for increasing hosting capacity, and market driven upgrades triggered by DG in queue. The proposal shifts from a first mover payment concept to a pro rata concept where projects contribute to costs based on the amount of capacity they use from substation upgrades.

[72] Refer to this filing's Executive Summary for a discussion of the distinctions between Phase 1 and Phase 2 projects.

2) **Voluntary agreements:** Voluntary co-tenancy agreements or voluntary FERC-jurisdictional participant-funding agreements (recovered through rate proceedings).
3) **NYSERDA payments:** NYSERDA reimbursement to Utilities for CLCPA-driven local transmission projects through regional System Benefits Charges (SBCs) or similar charging mechanisms can be used to fund new transmission.[73]
4) **Renewable Generator Sponsorship:** Renewable generation owner/developer agreement to pay for transmission costs (based on wholesale transmission rates).

The Utilities describe four potential pathways in this section. Figure 11 provides an overview of each pathway.

Figure 11: Proposed Cost Allocation and Cost Recovery Mechanisms

	Rate Case-Based Approach	Voluntary Agreement	NYSERDA Payment	Renewable Generator Sponsorship
Jurisdiction / Legal Framework	Commission	Commission and FERC	Commission and potentially FERC	Commission and FERC
Applicability to Local Transmission Projects	All types of Multi-Value and CLCPA-driven projects, subject to rate case constraints	All types of Multi-Value and CLCPA-driven projects identified by Commission for cost-sharing	All types of Multi-Value and CLCPA-driven projects identified by Commission for cost-sharing	Only projects with benefits that can be attributed to discrete generators
Ability to Enable Alternate Cost Allocation Framework	• Local cost allocation only • Need to consider cost equity across districts	• Cost allocation methodology based on beneficiaries of CLCPA • LIPA not able to participate in a co-tenancy arrangement	• Costs allocated to load serving entities (LSEs) on volumetric basis (consistent with NYSERDA's collection of the Systems Benefit Charge from LSEs) • Need to address participation from LIPA and other non-jurisdictional entities	• Costs allocated to renewable generation project developers (on voluntary basis)
Milestones to Effectiveness	• Existing process • May need interim cost recovery for utilities in the midst of multi-year rate plans	• Time required to negotiate agreements between utilities • FERC approvals required	• Need to create new NYSERDA process to administer payments • Could require FERC approval	• Requires generator agreement • Requires certainty of REC/OREC mechanism to attract generator financing
Key Stakeholder Groups	• Utilities • Commission • DPS Staff • Rate case intervenors	• Utilities • Commission • DPS Staff • Rate case intervenors • FERC	• Utilities • Commission • DPS Staff • NYSERDA • FERC	• Utilities • Commission • DPS Staff • Renewable project developers • Existing generators • NYSERDA • FERC • NYISO

[73] CES Proceeding, Order Adopting Modifications to the Clean Energy Standard (Issued October 15, 2020), p. 91.

i) Status Quo Cost Recovery Under Commission Rate Case Proceedings

New York's investor-owned utilities recover local transmission and distribution costs through bundled rates filed with the Commission.[74] Utility costs for new facilities and upgrades to existing transmission facilities 69 kV and above (including 230 and 345 kV facilities), and in some cases lower voltage facilities down to 34.5 kV, are recovered as part of the revenue requirement approved in utility rate cases from all delivery customers within a utility's service territory. Historically, projects included in the rate case have generally been identified based on utility local system needs, and the revenue requirement of each utility's rate case has been charged only to the utility's local customers. Introduction of CLCPA drivers (and the societal benefits associated with such drivers) into utility planning processes raises a novel issue: the need to consider the revenue requirement of other utilities in the context of an imputed statewide cost allocation.

Utility rate plans may cover three years, if achieved through a negotiated joint proposal (the most typical outcome in recent years), or one year, if adjudicated. Once approved, the utility makes capital decisions through its capital planning process. The utility typically has discretion to prioritize and manage its investment plans.

1. Rate Case Limitations

As noted above, Commission jurisdictional rate cases provide for the recovery of a utility's costs from customers within its service territory, and the Commission has not implemented alternate cost arrangements for local transmission projects that may benefit other utility franchise areas or the state as a whole. FERC has exercised authority in this area and has approved formulas in the NYISO OATT for regional cost allocation of projects selected through the NYISO's planning processes. Regulatory frameworks to enable regional cost allocation other than through a NYISO planning process may require FERC approval.

Utilities have used co-ownership structures – including tenancy-in-common or co-tenancy arrangements – to partner on transmission or generation projects and charge their share of costs to their respective delivery customers in their rate cases. This was used for generation prior to deregulation and for transmission lines. For example, NYPA and National Grid own discrete assets that comprise a circuit, with National Grid owning the structures and NYPA owning the 345 kV line conductor.

Depending on the geographic distribution and magnitude of transmission investments throughout the State, allowing each utility to recover costs of its own investments through its individual utility rate case might result in customers bearing a similar proportion of statewide transmission CLCPA costs as if all transmission CLCPA investments were collectively shared statewide, pursuant to a regional cost allocation formula. In the context of this effort, achieving a

[74] National Grid is an exception; it maintains a FERC formula rate for transmission investment.

similar outcome to statewide cost-sharing may be sufficient. However, cost allocation precision should be balanced against the need to move projects forward expeditiously to achieve the requirements of the CLCPA. The rate case cost recovery path can offer an expedient and simple approach to implementing projects needed to support the CLCPA while minimizing execution risk. These are important considerations given the statute's time sensitive targets.[75]

ii) Proposed Regulatory Frameworks for Equitable Cost Recovery of CLCPA Projects

The Utilities have identified four potential regulatory frameworks that, alone or in combination, can facilitate an equitable cost allocation for Phase 2 utility projects that support the CLCPA:

1) Rate cases;
2) Voluntary utility agreements;
3) NYSERDA payments; and
4) Renewable generator sponsorship.

Each of these frameworks is described in more detail below.

1. Rate Case-Based Approach

Rate Case Benefits

- Simple, existing process
- Easy to implement
- Nimble, providing ability to tackle a specific problem
- Multi-party process, inclusive dialog between DPS, interveners, and utilities
- Maintains LIPA's ability to use tax exempt bond financing

Rate Case Challenges

- Rate pressure
- Cost allocation challenges
- Competing priorities in rate case
- Limited ability to optimize across utilities
- Lack of coordination (e.g., utilities are, generally, on 3-year rate plans on different calendars)
- Cost shift from generators to customers

Transmission investment cost recovery through individual utility rate cases may result in equitable regional cost sharing as though all transmission investments were shared according to a regional cost allocation formula, but only if the geographic distribution and magnitude of investment throughout the State reasonably reflects the load each utility serves. Under a Rate Case-Based approach, each utility would include its Multi-Value or CLCPA-driven project in its LTP. Costs would be recovered in the utility's state rate case, from customers in its service territory, as they are today. A mechanism to account for such projects across the Utilities is recommended to safeguard reasonably equitable distribution of costs paid by customers across the state.

The process for inclusion of CLCPA projects in the rate case would be as follows:

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75 Climate Leadership and Community Protection Act ("CLCPA"), A.8429 (Englebright)/S.6599 (Kaminsky) (N.Y. 2019), available at: https://legislation.nysenate.gov/pdf/bills/2019/S6599.

1. A utility identifies and prioritizes projects based on CLCPA and traditional planning criteria (as described in the Section II, above).[76]
2. The utility would work with DPS Staff and rate case intervenors to identify a final list of projects for inclusion in its rate plan.[77]
3. The utility would implement the projects agreed to in the rate case through its capital budget and planning process.

An important consideration to this proposal is an imputed load ratio share cost allocation among the Utilities for CLCPA projects. Commission authorization should also consider the timing of future projects that may impact the cost allocation outcome. The costs incurred by the Utilities could be reviewed and subject to true-up as part of the Commission's regular review of its actions taken pursuant to the AREGCB Act, which requires reevaluation every four years. Such timing would allow a holistic review of project costs across the state.

While identification of relevant projects would eventually become part of the utility rate case and capital planning processes, separate Commission approvals outside the rate case may be appropriate to expedite the development of projects in between Utility rate cases, to avoid disrupting existing three-year rate plans. For example, at the time of an expected Commission Order authorizing projects in Q1 2021, the Utilities will be in the middle of approximately three-year rate plans scheduled to expire as follows:

- Orange and Rockland – end of 2021
- CECONY - end of 2022
- NYSEG/RG&E – April 2023 (currently under Commission review)
- National Grid – July 2024 (currently under Commission review)
- Central Hudson - August 2024 (currently under Commission review)

To expedite projects in the near-term, the Commission should authorize project cost recovery outside of the normal utility rate case process, as necessary, to enable projects to proceed. Specifically, the Commission should issue an Order in the first quarter of 2021, identifying initial projects and authorizing their costs to be recovered through utility rate cases, separate from the budgets currently effective under each utility's governing three-year rate plan.

Each utility seeks Commission approval to develop its portfolio of proposed transmission and distribution projects that are immediately actionable and, in their estimation, will enable meaningful progress towards CLCPA objectives. In the event such CLCPA projects are not currently contemplated in utility rate plans, once the project is placed into service and deemed to be used and useful, the utilities would notify the Commission and begin to accrue a carrying

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76 Planning criteria for reliability, asset management, and compliance remain fundamental drivers for utility capital planning and identification of rate case projects.

77 In the case of LIPA, projects would be subject to LIPA's budget approval and ratemaking mechanisms as set forth in its Tariff and the LIPA Reform Act.

charge[78] (including return on the amount placed in service and related depreciation expense) at its current allowed weighted average cost of capital and recover such costs on a monthly basis through a surcharge until base rates are reset as described below. To the extent a carrying charge on the average electric plant in service balances would otherwise be deferred for customer benefit under the utility's rate plan,[79] such carrying charge would be applied as a credit against the surcharge recovery. To the extent a carrying charge on the average electric plant in service balances that would otherwise be deferred for customer benefit under the utility's rate plan is higher than the surcharge recovery calculation, the net difference will be deferred for the benefit of customers.

Unless an alternate rate recovery mechanism applies, the rate treatment of capital projects should generally be handled within rate proceedings whenever possible, consistent with the manner capital projects are typically handled. Given, however, that the utilities are currently in varying states of their own rate case development (with some utility rate cases currently pending, others soon to be filed and others not to be filed for several years), the Commission should permit the utilities to recover the carrying costs, including depreciation, associated with the construction of approved CLCPA projects when such projects are placed in service.

To the extent that any Phase 1 or other (as applicable) projects are not currently contemplated in utility rate plans, the Commission should permit the utilities to submit a petition for Commission approval of timely cost recovery of the carrying costs through a transmission surcharge (or other applicable pass through clauses). The surcharge would be designed to allow the utility to recover its CLCPA projects' carrying costs, including depreciation, until its next rate case, at which time the investment would be reflected in base rates.

The alternative regulatory pathways described below all take time and expense to implement, require regulatory approvals, potentially from both the Commission and FERC, and therefore involve greater risk. While these challenges can be overcome, the Utilities recommend that these pathways be reserved for cases where (a) reasonable equity between districts cannot otherwise be substantially achieved through rate case recovery, *and* (b) the cost disparity in absolute dollars is substantial enough to justify the time and expense associated with implementation. To the extent that cost recovery through the rate case provides a reasonable, but not perfect, cost allocation outcome, this approach may still be preferable to enable projects to move forward expeditiously, consistent with the aims of the AREGCB Act.

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78 The accounting profession (and the SEC) has interpreted the automatic recovery mechanism approved by the regulator in an order, is required for a regulated utility to accrue a carrying charge on an asset including the weighted average cost of capital.

79 Commonly referred to as "net plant reconciliation" in utility rate plans.

2. Voluntary Utility Agreements

Voluntary Agreements Benefits

- Enables cost allocation to beneficiaries
- Potential to optimize projects - may enable larger projects that are more cost-effective (as compared to smaller projects that would be approved in rate case)

Voluntary Agreements Challenges

- Rate pressure
- Voluntary
- Time to negotiate agreements
- Potential for challenges during PSC rate case negotiations
- LIPA unable to participate in co-tenancy agreements
- Aspects of contract require FERC approval, or entire rate for participant-funding
- Cost shift from generators to customers

Utilities could voluntarily agree to share the costs of CLCPA-driven transmission projects through either (1) voluntary co-tenancy arrangements, or (2) voluntary FERC-jurisdictional participant-funding agreements. While the two approaches differ in their legal framework and rate recovery mechanism, implementation of both would involve voluntary agreement among the Utilities to share costs.

Utilities may use co-ownership arrangements to partner on CLCPA-driven transmission projects and charge their share of costs to their respective delivery customers in their Commission rate cases. Under this approach, a utility would commit capital for an undivided interest of a local transmission project that supports CLCPA mandates (incremental to portions of the project driven by Reliability, Safety, and Compliance criteria) and that is available to other electric transmission utilities for investment. Each utility's delivery customers would fund the project in proportion with its ownership share, and each utility would recover its proportion of investment costs through its state rate case. Aspects of the agreements governing the co-tenancy arrangement that do not pertain to cost recovery (*e.g.*, handling of operations and maintenance (O&M), among other things) would likely need to be filed with FERC.

In addition, a co-tenancy arrangement would not work for NYPA, as it would be unable to pass on costs of such a voluntary agreement to its many customers with long-term contracts. However, because NYPA's customers predominately take delivery service from the Utility in whose service territory they are located, including these CLCPA costs, a co-tenancy agreement among the Utilities would ensure that NYPA customers contribute to these facilities.

Conversely, a participant-funded rate would involve the Utilities voluntarily agreeing on behalf of their customers to fund the costs of other utilities' projects. Unlike with a co-tenancy agreement, the Utilities would agree to share the costs of projects without the corresponding exchange of equity. The rate agreed to by the Utilities, if any, would be FERC-jurisdictional (as opposed to only certain elements of the agreement), and utility costs would be recovered at FERC rather than under the Commission's rates. Finally, there is no statutory limitation on any New York State LSE's ability to enter agreement to share costs.

For either approach, the process for establishing voluntary arrangements among the Utilities to facilitate cost-sharing of CLCPA projects could work as follows:

1. Utilities identify a list of projects at specified times in the future as directed by the Commission.
2. A Commission Order identifies projects to proceed and directs the Utilities to make a subsequent filing demonstrating the CLCPA benefits of those projects whose costs should be regionally allocated.
3. The Utilities propose appropriate cost allocation/recovery framework(s) for projects subject to regional cost allocation. In addition to projects that may be approved for immediate construction, consideration should also be given to the likelihood of projects that may be approved in the future.
4. Cost recovery would proceed through the relevant Commission or FERC procedure, as appropriate:
    a. Voluntary co-tenancy agreement: For projects for which the Utilities propose voluntary co-tenancy, the Commission would approve co-tenancy arrangements through an interim Order authorizing cost recovery through each utility's retail T&D rates. Aspects of the co-ownership agreements (e.g., handling of O&M) would likely be filed with FERC.
    b. Voluntary FERC participant-funded rate: For projects for which the Utilities propose to participant fund, the Utilities would file at FERC for a participant-funded rate. The rate terms (such as ROE, incentives, etc.) and cost allocation would be subject to settlement discussions at FERC.[80] A separate rate would be needed for each utility that has projects that require regional cost allocation.
5. The agreement(s) would be revisited on a regular cycle on a looking-forward basis, aligned with the Commission's schedule (established under the CLCPA) for reviewing its progress every four years, as planning progresses to include additional projects, based on an aligned schedule among the Utilities for identifying such projects. Each utility's agreement to the additional projects would continue to be voluntary.

Achieving voluntary agreement among the Utilities may require time and effort to negotiate and may not be successful. In the event the Utilities cannot successfully conclude such agreement(s), costs would be recovered through individual utility rate cases, or alternatively, if cost allocation is deemed necessary to ensure equity of cost responsibility among customers, the Commission may request the Utilities to negotiate participant funding agreements. Consideration of multiple utilities' projects together, rather on an individual project basis, could potentially address some of the challenges.

80 Although LIPA is generally FERC non-jurisdictional, this would not preclude it from participating in such an agreement. But the agreement would need limiting language to protect LIPA's non-jurisdictional status and reflect the fact that the revenue requirement and cost recovery for LIPA projects is subject to approvals under New York state law. Such an approach would be consistent with other joint agreements filed at FERC to which LIPA is a signatory, such as the NYISO Transmission Owners Agreement as well as the structure of LIPA cost recovery mechanisms which have been incorporated into the NYISO Tariff.

LIPA Limitations

Statutory limitations on LIPA's ownership of transmission and related facilities outside of its service area would preclude LIPA from participating in any co-tenancy cost sharing arrangements. In addition, LIPA's participation in any regional cost sharing arrangements beyond the traditional rate case, especially those involving multi-party agreements, would require the approval of LIPA's Board of Trustees and possibly the New York State Comptroller.

LIPA also generally finances capital projects with tax-exempt bonds, which are subject to restrictions mandated by Internal Revenue Service rules. These restrictions include a general prohibition on the use of these funds for "private business use" or for projects owned by third parties. Because LIPA uses tax-exempt bond financing, it enjoys a significantly lower cost of capital compared to many other utilities and passes these savings on to its customers. Accordingly, LIPA's participation in any regional cost sharing arrangement would need to be carefully assessed in the context of its statutory legal authority and its preference to finance investment with tax-exempt bonds. Should LIPA be required to finance these projects with non-tax-exempt bonds, or a combination of funds, there would be implications for the aggregate cost of CLCPA projects and LIPA's customers.

3. NYSERDA Payments

NYSERDA Payments Benefits

- Enables cost allocation to beneficiaries
- Potential to optimize projects - may enable larger projects that are more cost-effective (as compared to smaller projects that would be approved in rate case)
- Standardized
- Public authorities can participate

NYSERDA Payments Challenges

- Rate pressure
- New mechanism, would take time to implement
- FERC approvals for NYSERDA payment to utility could be required
- Creates administrative burden for NYSERDA
- Cost shift from generators to customers

Under this approach, NYSERDA would reimburse utilities for local transmission projects that support CLCPA mandates through revenues collected from the System Benefits Charge (SBC) (expanded, if necessary). Issues related to the applicability of the System Benefits Charge to LIPA, NYPA, and non-jurisdictional municipal power entities would need to be addressed, perhaps through the establishment of a separate charge. The Commission would identify the projects for which NYSERDA should issue payments, and the payments would be calculated based on the first 40 years of the revenue requirement of the project (or portion) that provides societal benefits over that same 40-year period by supporting the CLCPA. Under-collections (due to load used in the calculation of the SBC being lower than forecasted) would be addressed periodically via changes to the SBC rate.[81]

[81] In addition to the SBC, NYSERDA may support certain transmission development projects through alternative mechanisms. *See* CES Proceeding, Order Adopting Modifications to the Clean Energy Standard (Issued October 15, 2020), pp 91-92.

A NYSERDA payment approach could be implemented as follows:

1. The Utilities propose appropriate cost allocation/recovery framework(s) for projects subject to regional cost allocation.
2. For projects for which the Utilities propose the NYSERDA cost allocation/recovery framework, a Commission Order directs the Utilities to begin development of projects, and NYSERDA to pay utilities for the costs of the project monthly.
3. NYSERDA collects funds via the SBC or adding a new NYSERDA payment mechanism in support for local transmission that deliver significant benefits to CLCPA objectives.
4. Utilities may recover costs through state rate cases initially. However, revenues a utility receives from NYSERDA are reconciled and imputed into future rate case requests (payments by NYSERDA are an offset to base rates).
5. If pre-approved by the Commission, the Commission may direct NYSERDA to develop appropriate NYSERDA payment mechanism for the collection of new local transmission projects beyond 2021, as they are approved by the Commission. This could be scheduled to occur on a four-year cycle, consistent with the Commission's obligation to periodically review its actions taken pursuant to the CLCPA.
6. Over-collections (due to customer load exceeding NYSERDA's forecast) will be refunded to customers or retained by NYSERDA to fund future shortfalls.

This construct would need to be developed in a manner that assists NYSERDA in managing its administrative and financial impacts. For example, the volume of payments flowing in and out of NYSERDA could be reduced to reflect only the difference between the costs the Utilities actually recover through their rate cases and the amount for which their delivery customers *should* be held responsible pursuant to a load ratio share cost allocation of all CLCPA transmission investments statewide. That is, only those adjustments to a utility's rate case recovery necessary to achieve an equitable regional cost allocation (*i.e.,* overages and underages) need be processed through NYSERDA's clearinghouse. Such an approach could create efficiencies, if software systems are created and implemented to accurately track and report CLCPA projects and the costs incurred and recovered by each utility. Recovering the cost for new transmission through a NYSERDA payment model could raise several federal jurisdictional questions.[82]

[82] LIPA does not support the NYSERDA payment approach.

4. *Renewable Generator Sponsorship*

Under this model, the renewable generation owner or developer would voluntarily agree to pay for the cost of transmission to unbottle and deliver energy for its projects.[83] The Utilities have considered imposing this cost burden upon <u>all</u> generators on a mandatory basis, but several issues make this option difficult to implement.[84]

Whether voluntary or mandatory, any charge to generators for transmission would likely be a wholesale transmission rate requiring FERC approval, and could be administered under the NYISO Tariff. On a voluntary basis, the agreement with the generator could work as follows:

> Generator Sponsorship Benefits
> - Costs remain with developers
> - Achieves cost allocation to beneficiaries through RECs/ORECs
> - Maintains locational pricing signals
>
> Generator Sponsorship Challenges
> - Rate pressure
> - Voluntary, but no guaranteed delivery for generators
> - FERC approval for rate required
> - Additional parties involved – potential for disagreement between generators
> - Risk of utility customers bearing the cost of unsubscribed capacity

1. The utility works with existing generation owners or prospective generators to identify a project to unbottle their projects.
2. The utility and generators enter into an agreement and file a rate at FERC, consistent with the agreement, for recovery of the costs of the projects from the relevant generators.
3. When the renewable generator enters service, or when the transmission project comes into service (whichever last occurs), the generator is charged for costs commensurate with its usage of the new transmission facilities, as reflected in the agreement filed at FERC.
4. If the transmission commences construction prior to a renewable generation's in-service date, the utility recovers its costs from its delivery customers through its Commission rate case. The renewable generator begins payments (and utility customer payments end, to the extent the transmission is fully used) when its project enters service, and local

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83 This proposal differs from current requirements in the NYISO interconnection process because projects would consider energy deliverability, whereas the NYISO interconnection process only considers capacity deliverability (i.e., deliverability during the peak hour of the year as compared to all 8760 hours in a year). In addition, voluntary agreements may enable transmission projects to be built ahead of time, rather than waiting for the interconnection process, saving time in the overall process.

84 Precedent for such a requirement does exist. FERC approved a "Location Constrained Resource Interconnection" (LCRI) construct in the CAISO Tariff, to plan for and recover costs of transmission to "location constrained" (i.e., renewable) resources in advance of their construction. The entity proposing the transmission facility must demonstrate a minimum level of interest of 60% of the capacity of the transmission facility for a project to proceed. Once constructed, generators pay their proportionate share of the transmission facility cost (on a per-MW basis), and the costs of transmission capacity not initially subscribed is recovered in utility transmission rates until generators come online.[84] Implementing such an approach in New York would require changes to the NYISO OATT (subject to stakeholder vote), and FERC approval.

utility customers are refunded to the extent of their prior payments as generator payments are made.

5. To the extent a transmission line is not fully subscribed, the utility continues to recover the costs attributable to the unsubscribed capacity from its delivery customers through its Commission rate case.

Unlike the other three options, this approach would result in the cost burden of projects being directly assigned to unbottled generators. Cost allocation would still be regional, to the extent that generators recover the transmission investment costs they incur to utilities through the REC or OREC payments or NYISO market revenues (energy, capacity, and ancillary services, as applicable) they receive. However, this approach could raise free ridership concerns, as a generator may benefit from a project funded by another generator, and, unlike other ISOs such as PJM Interconnection Inc., the NYISO does not administer any firm transmission rights to guarantee delivery.

C. Evaluation of Regulatory Pathways

Each of the four regulatory pathways involves a tradeoff between its ease of implementation and its ability to facilitate equitable statewide cost-sharing of utility projects. In order to provide a consistent basis for comparison, the Utilities have thus far identified five key considerations against which to evaluate the cost recovery pathways: legal framework, applicability, beneficiaries pay allocation, milestones to effectiveness, and roles of stakeholder groups. In weighing these considerations, the Utilities will consider how the Commission can leverage expeditious, proven methods to enable projects to proceed swiftly to meet the CLCPA mandates, as required by the CLCPA. As noted above, the Utilities believes that, absent a gross disparity in statewide cost burdens, the greatest weight be given to the individual utility rate recovery pathway due to its ability to timely achieve CLCPA's mandates. The key considerations are described further below.

i) Legal Framework

1. Description of Consideration:

Under existing law, both the Commission and FERC have roles in transmission cost recovery. There is a need to clarify the legal framework (existing or new) for the socialization of costs within the State's jurisdiction. Without a clear legal framework, implementation of projects may be subject to risks and delays.

2. Evaluation of Pathways:

The roles of the Commission and FERC are different under each regulatory pathway:

- Rate Case: Utility costs continue to be recovered through each utility's bundled T&D rate with the Commission. Costs across utilities would need to be monitored and assessed on a regular cycle to confirm that regional equity in cost allocation is generally being achieved to the satisfaction of the Commission and stakeholders. FERC approvals are not required.

- Voluntary utility agreements: Under a co-tenancy approach, utility costs continue to be recovered through each utility's bundled T&D rate with the Commission, with aspects of the agreements requiring filing with and approval by FERC. Under a participant funded model, utility costs are recovered under a FERC participant-funded rate, subject to FERC's rate settlement procedures.
- NYSERDA payments: Likely requires FERC approval of the rates paid to the Utilities, which are subject to FERC's rate settlement procedures.
- Renewable generator sponsorship: Likely requires FERC approval of the rates paid to the Utilities.

ii) Applicability

1. Description of Consideration:

Whether the cost recovery mechanism can address cost recovery for the different types of projects likely to be identified by the Utilities.

This consideration relates to both the project's characteristics (*e.g.*, reconductoring a line) as well as the CLCPA driver that led to identification of the project (*e.g.*, enabling the interconnection/deliverability of 9,000 MW of offshore wind). In considering both aspects of a project, the Utilities recognize that regional differences should be considered in order to assess the impact on proposals meant to facilitate the CLCPA's mandates of delivering renewable power to New York's customers, reducing the reliance on fossil generation, and reducing emissions in environmental justice communities. Accordingly, this consideration acknowledges that types of transmission (*i.e.,* overhead vs underground) and the needs addressing CLCPA mandates (*i.e.,* "on-ramps" – moving renewable energy onto the 345 kV system vs "off-ramps" – moving renewable energy from the bulk power system to loads) will vary across the state. However, in the future the Utilities may need to work together to reach agreement on cost allocation schemes for projects addressing different need cases, driven by different local planning standards and approved by the Commission.

To provide further clarity on the distinction between transmission investments that are Reliability, Safety, and Compliance and those that are proposed solely to facilitate CLCPA mandates, the Utilities propose that a Reliability, Safety, and Compliance project should be any project that would have been identified and prioritized for inclusion in a utility's rate case over the near- or long-term based on traditional considerations, including good utility practice (*e.g.*, aging asset replacements). Projects that a utility would ultimately identify or have identified in a long-term system plan that can be accelerated to provide incremental CLCPA benefits can be considered for equitable cost treatment (*e.g.* load ratio or imputed load ratio share), but only to the extent of the incremental cost of acceleration (*i.e.,* the delta of costs incurred presently compared to the Reliability, Safety, and Compliance component). By contrast, a project that a utility identified based on the CLCPA Investment Criteria alone would be a CLCPA-driven project.

2. *Evaluation of Pathways:*

Under all approaches, Reliability, Safety, and Compliance projects and the Reliability, Safety, and Compliance components of Multi-Value projects would continue to be recovered from a utility's local customers under the Rate Case-Based Approach. However, compared to the other three approaches, which provide flexibility as to the types of projects that are eligible for cost recovery, the renewable generator sponsorship approach would only be applicable to those projects (i.e., CLCPA-only projects) serving generators that are unbottled by the transmission upgrades.

iii) Beneficiaries Pay Allocation

1. *Description of Consideration:*

The degree to which the costs of new or incremental CLCPA-driven transmission projects can be allocated on a "beneficiaries pay" basis.

Because the CLCPA establishes state-wide mandates, the costs of utility projects that support those mandates should be shared equally across the state (*i.e.,* based on load-ratio share). A load-ratio share cost allocation is the cost allocation formula used to implement numerous New York State mandates, including NYSERDA's Zero Emissions Credit ("ZEC"), Renewable Energy Credit ("REC"), and Offshore Wind Renewable Energy Credit ("OREC") programs.

Per the directives in the May Order, any cost allocation methodology must distinguish between projects (or portions of projects) that are identified based on traditional planning criteria (*e.g.,* reliability) and those that support renewable integration, deliverability and usability or other CLCPA mandates. The May Order directed that projects (or portions thereof) identified based on Reliability, Safety, and Compliance drivers be recovered through utility rate cases, while projects (or portions thereof) that expand or accelerate Reliability, Safety, and Compliance projects to include CLCPA benefits would be eligible for regional cost sharing.[85] Projects that are included in a utility's capital plan due to the CLCPA (i.e., "CLCPA-driven" projects) would be eligible for cost sharing.

2. *Evaluation of Pathways:*

Each of the four regulatory pathways considered could facilitate a cost allocation outcome consistent with the principles described above:

Rate Case-Based Approach: Costs would continue to be allocated to customers in the utility's service territory. Depending on locations and costs of identified projects

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[85] The May Order refers to Reliability, Safety, and Compliance projects that can be expanded to realize renewable resource benefits as "Multi-Value." The Commission stated that costs of only that incremental portion of Multi-Value projects that brings CLCPA benefit should be eligible for regional cost allocation.

throughout state, cost recovery or each utility's project(s) through its own utility rate case may provide an overall result similar to that attained if all CLCPA projects were regionally cost allocated. Computer systems or software could be installed to track and account for such projects and their payment by delivery customers to inform equitable cost sharing.

Voluntary utility agreements and NYSERDA Payments: Costs could be allocated to all CLCPA beneficiaries, consistent with state policy.

Renewable generator sponsorship: Regional cost allocation would be achieved (*i.e.,* to the extent that generators recover the costs of the transmission projects through their REC/OREC and/or the NYISO market revenue payments), but the cost of transmission investments may exceed the amount generators are willing to pay, leaving a shortfall for local delivery customers to pay.

iv) Milestones to Effectiveness

1. Description of Consideration:

Whether a cost recovery pathway can enable projects to proceed expeditiously to support achievement of the state's policies, as directed by the AREGCB Act.

Leveraging rate cases may provide for quicker near-term action compared to establishing a new cost recovery pathway. Further, using mechanisms entirely within the Commission's jurisdiction that do not require new authorizing legislation may provide the State with greater control than mechanisms that require federal approvals or the creation of new processes. Another consideration is the time and complexity to develop and implement new regulatory frameworks (or contractual agreements between or among the Utilities) to implement cost sharing, and the potential for legal challenge and corresponding delays associated therewith.

2. Evaluation of Pathways:

Compared to the rate case, each of the other regulatory pathways poses more significant implementation challenges:

- Voluntary utility agreements: Under a co-tenancy approach, time would be required to negotiate agreements between or among the Utilities. While a master agreement could potentially be negotiated in advance, specific projects would need to be identified to be subject to the agreement and challenges associated with the State authorities' participation would need to be understood and resolved. Significant issues would need to be addressed in the agreements, including NERC compliance, environmental liabilities, cost overruns, governance, etc. Cost recovery would also need to be coordinated with the Utilities' three-year rate plan cycles, which are not aligned in timing. Finally, parts of the agreement would require FERC approval, adding another step to the process before cost recovery could proceed. In contrast, negotiations between the Utilities may be less complex for a participant-funded rate but the process for establishing cost recovery at FERC may be more protracted if other affected parties protest the application before FERC.

- NYSERDA payments: Requires the creation of a new process at NYSERDA to administer the payments, and possible FERC approval of the rate paid by NYSERDA to the Utilities (e.g., a participant funding agreement that would be filed at FERC).
- Renewable generator sponsorship: Requires a willingness of generators (who may be sensitive to the magnitude and timing of their payment obligations relative to their receipt of revenues), and possible approval from FERC. Administration could be left to the individual utilities or pursuant to the NYISO OATT.

In contrast to the challenges described above, the rate case is an existing process that could be used immediately to authorize cost recovery for the identified projects. While identification of CLCPA projects would eventually become part of a utility rate case and capital planning processes, separate Commission approval outside of the rate case likely will be needed, at least in some cases, in order to expedite the development of projects without disrupting currently operating three-year rate plans.

v) Roles of Stakeholder Groups

1. Description of Consideration

How the interaction of stakeholders may affect the viability of a given pathway.

2. Evaluation of Pathways:

Each pathway would bring engagement of the various stakeholders that are typically involved in utility rate cases, transmission planning, and the NYISO markets:

- Rate case: Utilities, DPS Staff, and rate case intervenors would need to consider CLCPA-driven projects alongside the projects typically considered. Renewable generation owners and developers may also become more interested in utility rate case proceedings, to the extent projects to unbottle their existing or planned generation are included.
- Voluntary utility agreements: Under co-tenancy, the nature of rate case negotiations could change to the extent they newly address cost recovery for projects outside of the utility's service territory that are administered under a co-tenancy agreement. Utilities may also take a greater interest in other utilities' rate cases, to the extent those proceedings have implications for cost recovery of projects covered under agreements between or among the Utilities. There would also be a role required for FERC, compared to under the rate case, to approve the co-tenancy agreements between the Utilities. A voluntary participant-funded rate would involve a larger role for FERC in approving cost recovery for the Utilities. It would also require the Utilities and their intervenors to file and participate in two separate rate proceedings (at the Commission and at FERC) for cost recovery of their projects.
- NYSERDA payments: This approach would similarly involve a role for FERC, as well as create a new and potentially burdensome role for NYSERDA to administer the cost-sharing program, though constructs can be created to reduce those burdens.

- Renewable generator sponsorship: In addition to involving FERC, this approach would *directly* impact existing and new generators, as they would be paying the costs of the transmission projects. There may also be disagreement *between* generators, as projects voluntary funded by one generator may bring benefits to another (creating a free ridership problem).

D. Example Pathways

The appropriate regulatory pathway(s) to facilitate cost recovery of CLCPA-driven local transmission projects will depend on the locations and costs of projects identified throughout the state and authorized to proceed by the Commission in early 2021. Given that uncertainty, the Utilities have not presently identified a single pathway for the Commission to pursue. Rather, this paper is intended to provide an overview of available approaches that have been considered to date and outline the circumstances under which each approach may be appropriate, as well as the potential challenges associated with implementation.

To the extent that regional equity in cost allocation can be achieved through cost recovery under each utility's rate case, this would be the most immediately executable, sure approach to authorizing cost recovery for projects needed to support the CLCPA. However, doing so requires alignment in timing of utility planning studies, and tracking of CLCPA-related projects, to compare across utility districts. As noted above, this could be done as part of the Commission's obligation to review its actions under the AREGCB Act every four years. In addition, to expedite projects in the near-term, the Commission may need to authorize cost recovery for projects outside of the rate case process to enable projects to proceed in a timely manner. For example, as noted above, to the extent that any Phase 1 or other projects (as applicable) are not currently contemplated in utility rate plans, the utilities may need to submit a petition for Commission approval of timely cost recovery of the carrying costs through a transmission surcharge (or other applicable pass through clauses). The surcharge would be designed to allow the utility to recover its CLCPA projects' carrying costs, including depreciation, until its next rate case, at which time the investment would be reflected in base rates.

While the Utilities have not identified a single optimal regulatory pathway among these alternatives at this time, the following illustrative examples describe situations where each cost recovery pathway may be appropriate. Once the Commission identifies the projects that should proceed, the Commission should further direct the Utilities to file a subsequent recommendation on appropriate cost sharing for those projects. In the interim, the Utilities provided a set of conceptual recommendations for the Commission's consideration, as highlighted at the beginning of this paper.

i) Examples

These illustrative examples represent a range of potential outcomes, showing a potential appropriate cost recovery strategy under each scenario pending a final proposal. As these examples illustrate, some of the regulatory pathways may be used in combination (e.g., rate case and renewable generator developer sponsorship) to achieve the desired cost allocation.

1. *Example 1: Cost Recovery for Phase 1 Reliability, Safety, and Compliance Project with CLCPA Benefits*

A utility identifies a Reliability, Safety, and Compliance project that also provides CLCPA benefits. In this case, alternative cost-sharing arrangements are not required. Projects identified based on Reliability, Safety, and Compliance drivers would continue to be recovered through individual utility rate cases.

2. *Example 2: Cost Recovery with Roughly Equal Distribution of Costs Across State*

Utilities A, B, and C comprise roughly 20%, 30%, and 50% of statewide load, respectively, and thus equitable cost allocation in those proportions. The Commission authorizes one $19M project for Utility A, two projects of $16M each for Utility B, and a $17M and $32M project for Utility C. If each utility recovers its costs through its rate case, then Utilities A, B, and C would incur 19%, 32%, and 49% of the costs of implementing the projects in support of the state mandates. Though the outcome does not perfectly align with the intended cost allocation, it is sufficiently close that the Commission could rely on cost recovery through individual utility cases. The time and cost to implement a new, alternative pathway to facilitate "perfect" cost-sharing is unwarranted based on the distribution of projects throughout the state and well-established "beneficiaries pay" principles. It could also frustrate timely achievement of the state's environmental mandates.

3. *Example 3: Cost Recovery with Unequal Distribution of Costs Across Utilities*

For the same scenario as example 2, Utility B identifies an additional $50M project that would unbottle two existing renewable generators located in its service territory. Adding this project would result in Utility B bearing 55% of the overall costs of $150M, compared to its intended cost allocation share of 30%. In this scenario, the NYSERDA payment or renewable generator sponsorship approaches could achieve the desired cost allocation outcome.

Under the NYSERDA payment approach, NYSERDA would only be reimbursing Utility B for project costs that would not otherwise be equitably allocated through recovery in individual utility rate cases (i.e., the $50M incremental project). This would minimize the administrative and financial burden on NYSERDA, as it would only be reimbursing Utility B for its additional project (representing its customers' excess cost burden), but not all the Utilities for all of their projects, as the desired cost allocation can be achieved through each utility included those projects in its own rate case.

Alternatively, under the renewable generator sponsorship approach, Utility B could work with the two generators that would be unbottled to negotiate a rate (on a voluntary basis). The two generators would, in turn, recover their costs through incremental REC, OREC and/or NYISO market revenue payments, socializing the costs. Because this project unbottles existing renewables, the renewable generator sponsorship approach may be the more appropriate approach in this case. Since the renewable generator would be the financial beneficiary of the unbottling project (through increased REC revenues), it may be best positioned to judge the benefits and costs of a transmission project to unbottle its generation. Of course, placing the cost responsibility on the generator in this way would minimize risk to customers.

In contrast, the voluntary co-tenancy agreement approach is not likely to be expedient here, as only one utility has a project for which cost-sharing outside of the rate case is required, and because Utility B would need to relinquish 70% of the equity in its project (if it were the only project subject to agreement) to achieve the desired cost allocation outcome.

4. Example 4: Cost Recovery with Unequal Distribution of Costs Across Utilities

Building on example 3, Utility C identifies an additional $60M project to improve delivery of renewables within its service territory. Adding this project to Utility B and C's rate cases, respectively would result in Utilities A, B, and C bearing 9%, 39%, and 52% of the total project costs throughout the state, compared to their intended cost allocation shares of 20%, 30%, and 50%, respectively.

In this example, a voluntary co-tenancy agreement may be an effective regulatory pathway to share costs. Allocating the costs of Utility C's project to renewable generators is not workable because the project cannot be attributed to an identified set of generators. The NYSERDA Payment approach could also be used to reimburse both utilities, though the volume of payments administered by NYSERDA may increase.

To achieve the intended cost allocation, Utilities B and C could both offer their additional projects, costing $50M and $60M, respectively, for sharing under a co-tenancy agreement or participant funding agreements with all the Utilities. A co-tenancy agreement could be formulated such that each utility retains majority ownership over its project, but the ultimate cost allocation is consistent with the desired distribution of costs, as shown in Figure 12 below.

Figure 12: Cost Allocation Example

Project Share	Utility A Share	Utility B Share	Utility C Share
Utility B Project ($50M)	$12M	$26M	$12M
Utility C Project ($60 M)	$10M	$7M	$43M
Total Share of Costs	$22M	$33M	$55M
Total Share of Costs (%)	20%	30%	50%

E. Cost Containment

The Commission's May Order directed the Utilities to provide input and proposals for "cost-containment, cost recovery, and cost allocation methodologies applicable to these investments and appropriate to the State's climate and renewable energy, safety, reliability, and cost-effectiveness goals." The current state regulatory paradigm in New York already includes cost containment through approved capital investments and associated costs. Under the current rate case structure, utilities are awarded a defined capital budget to fund infrastructure investment over the term of the rate plan. Utilities must manage their capital needs to the agreed upon budget. In this way, the Commission's current rate recovery practices, with cost containment achieved through capital budget management and not through creation of additional risks for the Utilities, strike an appropriate balance between allowing for budget management flexibility while holding utilities to the capital budgets approved in the rate case, and compensating risks through a return on equity commensurate with such risks. The introduction of mandatory cost containment measures on top of the current process will create asymmetric risk for the Utilities and could serve to deter rather than incent the type of investment needed to expeditiously reduce transmission constraints.

Commission policies should continue to provide utilities flexibility to address changing circumstances on the system while managing to the capital budgets approved in the rate case.

F. Recommendations

As described in this Report, the Utilities provide the following recommendations related to cost allocation and cost recovery for local transmission projects that support achievement of the CLCPA for the Commission's consideration.

1. The AREGCB Act's overriding aim is to expedite construction of transmission needed to achieve the CLCPA mandates. Any alternative cost recovery pathway selected to facilitate cost sharing among the Utilities should not impede the rapid advancement of projects to meet CLCPA mandates.
2. For the purpose of defining an equitable cost allocation outcome for transmission projects that support achievement of the CLCPA, "beneficiaries" should be defined to include all customers across the state. Consistent with the state-wide policy mandates and the cost allocation method used by NYSERDA in its renewable energy program, a load-ratio share cost allocation should apply to CLCPA projects.
3. Utility projects (or the costs of incremental additions to, or acceleration of, projects) that are identified and prioritized due to their ability to support the CLCPA mandates should be eligible for load ratio share cost allocation.
4. The Commission should determine, as part of its overall authorization of utility local projects, those projects for which costs should be shared and which should not, recognizing that regional planning differences that benefit a region are also needed to facilitate CLCPA mandates.
5. The Commission should use the utility rate case process for consideration of CLCPA project costs, to the extent a reasonably equitable statewide cost allocation outcome can be achieved, even if not perfect. The rate case is the simplest, most efficient cost recovery pathway to consider project cost recovery.

6. The Commission should consider authorizing projects in phases, with the first phase of projects to be those that could proceed through individual utility rate cases, and later phases consisting of those projects that may require new regulatory mechanisms to facilitate equitable cost sharing across the state. In considering a staged approach, however, the Commission should avoid unnecessary delay between the successive phases, as such delay could risk compliance with the CLCPA's target of achieving 70% renewable energy by 2030.
7. To expedite projects in the near-term, the Commission should consider authorizing project cost recovery outside of the normal utility rate case process, through a surcharge, as appropriate, to enable projects to proceed. Specifically, in the first quarter of 2021, we recommend the Commission issue an Order identifying initial projects and authorizing their costs to be recovered through each respective utility's rate case, separate from the budgets currently governing the Utilities' rate plans. Note that Phase I projects will not require a LT BCA but require a rate case-type approach. Conversely, Phase II projects will address benefits and costs in more specificity and would be eligible for alternative regulatory mechanisms.
8. An important consideration to this proposal is that to structure an imputed load ratio share cost allocation for CLCPA projects recovered through individual utility rates, any Commission approval authorizing such action should be based on the most comprehensive estimated and actual cost information available at the time, and subject to adjustment to ensure that cost allocation remains fair to all customers.
9. If (a) reasonable cost equity among districts cannot otherwise be largely achieved through rate case recovery, *and* (b) the dollar amount of such disparity is substantial enough to warrant the potential implementation delay and expense to achieve such equity, then the Commission should direct the Utilities to follow up with a specific recommendation to effectuate cost sharing pursuant to one of the pathways identified herein (voluntary utility agreements, NYSERDA payments, or generator sponsorship), or another pathway not yet identified. It is recommended that the Commission reserve for itself the right to request the Utilities to enter into FERC-jurisdictional participant funding agreements should the Utilities be unable to agree on a cost allocation mechanism. To the extent an alternate pathway is required to achieve reasonable cost equity for projects in later phases, the Utilities will need certainty on cost allocation and recovery before projects can proceed.

VI. ARTICLE VII OF THE NEW YORK STATE PUBLIC SERVICE LAW

A. Objectives

In the May Order the Commission did not specifically direct the Utilities to provide recommendations for processes related to siting, construction, and commissioning of local transmission and distribution projects. It did, however, note that the directives of the CLCPA require a revisit of the "traditional decision-making framework that the Commission and the Utilities have relied on up to now for investing in transmission and distribution infrastructure."[86] Once projects with CLCPA benefits are identified, planned, justified through a BCA analysis, and approved by the Commission it is critical to ensure that development of these projects will occur unimpeded so that clean energy resources can be brought online without delay. With that objective in mind the Utilities provide recommendations related to the siting process for local transmission development codified in Article VII of the Public Service Law (referred to here as Article VII). These recommendations represent opportunities to expedite progress in reaching CLCPA requirements.

B. Standardization

The Commission seeks "a transparent planning process, to be implemented by the utilities with as much consistency … as possible."[87] The Utilities agree that consistency in the siting process will provide reasonable expectations for developers, investors, the Utilities, and regulators.

Standardization in siting processes offers a mechanism to formalize this consistency. The Utilities recommend that DPS Staff supplement its Article VII process guidelines to provide specific direction to applicants. Updated guidelines will help foster consistency among transmission projects, reduce data repetition within the process, and manage expectations. The guidelines should be comprehensive, incorporate specific detailed requirements, and include guidance for applications for local transmission siting approval as well as the Environmental Management and Construction Plan (EM&CP). Through these guidelines, DPS Staff can identify what must be included in an application and what should be provided in the EM&CP.

C. Local Transmission Siting Review Process

i) Siting Applications

The Utilities recommend that DPS Staff review siting application requirements to determine which remain useful and continue to provide data that are necessary to reach siting determinations on environmental compatibility and public need. The adoption of official guidance document(s) would help eliminate unnecessary steps and delays, ultimately speeding

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86 *Id.*

87 Transmission Planning Proceeding, May Order, p. 7.

up the siting review process. For example, the Utilities recommend the removal or revision of application requirements that are determined to serve no useful purpose or are routinely waived. For example, some Utilities have found that regulatory requirements that specify the scale of maps and the timeliness of aerial photos in siting applications are excessively rigid and frequently result in unnecessary effort, time and expense for the applicant to obtain waivers.

If necessary, the application content regulations should be revised to accomplish these recommendations.

ii) Application Review

Revised regulations could expedite review processes by restricting the scope of necessary project reviews. For example, archeological resource studies should be limited to areas to be newly disturbed by the proposed project, such as new substations, laydown yards, and new rights of way (ROW). Existing ROW and access roads should be assumed to have been previously disturbed and not require testing or concurrence from the New York State's Historic Preservation Office (SHPO).

Consistency within comment periods for projects should also be set forth. In some cases, requests for extensions for the comment period have been granted inconsistently, for varying periods of time, and without sufficient justification. Beyond adoption of revised regulation, official guidance documents would, ensure all participants have an understanding and proper expectation of the length of time for comments.

iii) Conditions and Deficiencies

Conditions of siting approval contained in an Article VII certificate should be standardized where possible and adopted by the Commission. The Utilities recommend removing any certificate conditions that should be covered by the EM&CP, and move any certificate conditions that identify what should be included in the EM&CP to the EM&CP specification documents that will be attached to any Joint Proposal or Order. Applicants can then be directed to identify conditions that do not apply to a specific project to expedite review.

Common deficiencies in siting applications and EM&CPs should be identified and addressed in DPS Staff guidance document(s) to improve the quality of submittals and cut down on agency review time. At the very least, new guidance document(s) should be adopted that would list information and studies that are required of applicants. This would benefit applicants preparing responsive documentation and assist DPS Staff reviewing applications to determine whether any deficiency exists.

Site visits are also recognized as a productive means to share information with parties. These should be held timely and frequently, recognizing the need to accommodate staffing constraints. To promote site visits, the use of EM&CP drawing drafts should be sufficient at this stage.

iv) EM&CP

The EM&CP contain a set of procedures for the development of Article VII transmission projects to ensure environmental protection.[88] Each EM&CP contains sub-sections designed to mitigate environmental impacts of transmission construction. An EM&CP also finalizes the design of the transmission facility (e.g., pole locations, work pad sizes, access roads, culvert replacements, *etc.*).

To promote timing and decrease repetition of data required in different documents, an official guidance document should specify what information should be added to the EM&CP, and not included in other documents in the Article VII process, like the application. For example, the guidance should allow the EM&CP to be submitted and reviewed together with a draft Storm Water Pollution Prevention Plan (SWPPP), rather than waiting for the approved local approval of the SWPPP. Concurrent submittal and review of the draft SWPPP and draft EM&CP would assist in providing information in a timely manner and would allow any necessary conforming changes to be made before the time of final siting approval. Moreover, the final EM&CP could be used for the review and approval of the SWPPP. Additionally, the required vegetation impact review should be included under the environmental impact section within the EM&CP.

DPS Staff should work to promote coordination of agency guidance documents such as DEC's Wetlands and Waterbodies Specifications. Finally, since multiple agencies have a hand in the siting process, their input should be sought and considered in the creation of DPS Staff guidance document(s).

v) Settlement Process

The Working Group has additional suggestions to make the negotiations process more efficient. For example, the Utilities recommend that the ALJ hold the parties to a settlement negotiation schedule to maintain forward momentum and progress. Additionally, parties could be held to more frequent negotiation conferences, including all-day events if necessary. Starting settlement negotiations earlier in the process would also serve to identify issues promptly, which would give the applicant time to be responsive to requests for additional information or to cure deficiencies. An initial pre-application meeting could be a productive means to identify such issues at the onset of the process. Providing early opportunities to identify issues should prevent such concerns from arising later in the process. With opportunities to identify issues earlier in the process, an ALJ could limit issue spotting after a certain period in the negotiations, and could potentially reject late objections that are raised late in the process, such as after a joint filing is proposed. The raising of issues late in the process unnecessarily creates confusion and delay in

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[88] These procedures apply to, for example: erosion and sediment controls; clearing and slash disposal; stream and wetland protections; general clean-up and restoration; access of roads and maintenance; invasive species controls; protections for rare and endangered flora and fauna, and significant natural communities; inspection and monitoring; pollution prevention; and project construction.

finalizing a settlement, particularly when parties had ample opportunity to raise such issues earlier. An actively involved ALJ would increase the likelihood of maintaining a focus and procedural schedule. Any conditions needing changes, and the reasons for those changes, should be identified at the initiation of the settlement process.

In sum, the above recommendations would promote prioritization CLCPA investments and ensure they are constructed and commissioned in a timely fashion.

Part 2: Technical Analysis Working Group

I. INTRODUCTION

This Part 2 (also referred to as the Utility Study) provides the results of analyses undertaken at the Commission's direction[89] to identify local transmission and distribution upgrades necessary or appropriate to accelerate progress toward achievement of the Climate Leadership Community Protection Act (CLCPA) renewable energy mandates. This Utility Study identifies actionable local system upgrades (i.e., new facilities or enhancements to existing transmission or distribution facilities) that will facilitate greater interconnection and use of clean energy resources throughout New York State.

The Utilities note that timely achievement of New York's clean energy and environmental requirements will require innovative electric system investment planning and execution. Significant and continued expansion of the local transmission[90] and distribution systems will be necessary to achieve CLCPA renewable energy goals in a cost-effective manner. This Report identifies the earliest opportunities to prioritize and accelerate local transmission and distribution projects that meet traditional Reliability, Safety, and Compliance requirements, but that also simultaneously contribute to CLCPA target achievement by allowing developers to deploy clean energy projects and give those projects access to the load (Phase 1 projects). This Report also identifies projects that are primarily justified by enabling achievement of the CLCPA targets, but may require additional design engineering, benefit/cost analysis, or cost recovery considerations (Phase 2 projects). A more detailed definition of Phase 1 and 2 projects are provided in Section B below.

This Utility Study and the analytical results described here form one component of the comprehensive "power grid study" required by the AREGCB Act to be completed by the end of 2020.[91] The other two components of the power grid study initiated by NYSERDA address high voltage system upgrades necessary to accommodate: (1) the State's 2035 offshore wind target

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[89] Transmission Planning Proceeding, May Order, pp. 6-7.

[90] Transmission Planning Proceeding, May Order, p 3, footnote 4: "…For purposes of this discussion, we understand "local transmission" to refer to transmission line(s) and substation(s) that generally serve local load and transmission lines which transfer power to other service territories and operate at less than 200kV. However, as the Utilities consider the issues outlined in this order, we recognize that an alternative definition may emerge."

[91] Pursuant to the AREGCB Act, the "power grid study" is to be produced by the Commission in consultation with other state agencies and authorities, the Utilities, and the NYISO to inform the identification of distribution upgrades, local transmission upgrades, and bulk transmission investments "that are necessary or appropriate" to facilitate the timely achievement of CLCPA targets.

(the "OSW Study"); and (2) the CLCPA goal that New York's electric system be emissions-free by 2040 (the "2040 Study").[92]

A. Utility Study Scope

The Utility Study is based upon projected system conditions for year 2030, as New York State moves towards achieving the CLCPA goal. It evaluates transmission and distribution capabilities in each of the Utilities' service territories that will be required to support the CLCPA goal of delivering 70% of the State's electric energy needs from renewable sources by 2030. New York is simultaneously evaluating bulk transmission facilities needed to support the CLCPA's goal of 100% renewable generation by 2040. Therefore, the assumptions that serve as the foundation of the Utility Study have been coordinated with both the 2040 and OSW Studies. However, the Utility Study is focused on local transmission and distribution development required to meet CLCPA targets, not upgrades to the bulk power system.[93] The Commission plans to initiate a separate proceeding for bulk power system investments needed to achieve CLCPA targets.

With the Utility Study's scope in mind, the May Order established a series of considerations for the Utilities to address:

1. Evaluate the local transmission and distribution system of the individual service territories, to understand where capacity "headroom" exists today;
2. Identify existing constraints or bottlenecks that limit energy deliverability;
3. Consider synergies with traditional capital expenditure projects (*i.e.*, aging infrastructure, reliability, resilience, market efficiency, operational flexibility, etc.);
4. Identify least-cost upgrade projects to increase the capacity of the existing system;
5. Identify potential new or emerging solutions that can accompany or complement traditional upgrades;
6. Identify potential new projects that would increase capacity on the local transmission and distribution system to allow for interconnection of new renewable generation resources; and
7. Identify the possibility of fossil generation retirements and the impacts and potential availability of those interconnection points.

Working within this uniform set of considerations, the Utilities have each prepared individual local system studies to describe the utility's unique system needs. These individual analyses are included in sections II-VII, below.

B. Utility Study Overview

The Utilities each provide study methodologies and initial results in separate sections below to account for significant differences among local transmission and distribution systems,

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[92] Transmission Planning Proceeding, May Order, p. 5.

[93] See Footnote 2.

local planning processes and design criteria. However, each of the Utilities has based its work on a set of common assumptions and considerations.

Each utility's report includes an introduction and discussions of the following topics:

1. Description of each utility's Service Area;
2. Any utility-specific assumptions (i.e., deviations from common assumptions shared by all of the Utilities), and description of its local design criteria;
3. Existing capacity "headroom" within the utility's local transmission and distribution facilities; and
4. Bottlenecks or constraints that limit energy deliverability within the utility's system.

These descriptions of the utility's service territory and unique features are followed by study results, which are separated into two distinct categories.

Phase 1 projects are immediately actionable projects that satisfy Reliability, Safety, and Compliance purposes but that can also address bottlenecks or constraints that limit renewable energy delivery within a utility's system. These projects may be in addition to projects that have been approved as part of the utility's most recent rate plan or are in the utility's current capital pipeline. Phase 1 projects will be financially supported by the customers of the utility proposing the project.

Phase 2 projects may increase capacity on the local transmission and distribution system to allow for interconnection and delivery of new renewable generation resources within the utility's system. These projects are not currently in the utility's capital plans. Phase 2 projects tend to have needs cases that are driven primarily by achieving CLCPA targets. Broad regional public policy benefits suggest the likelihood that cost sharing across the Utilities may be appropriate. These projects require additional time to plan and prioritize using the investment criteria and benefit cost analysis (BCA) methodology described in Part 1 of this filing.

The Study will not address all aspects of Operational and Power System Design issues with 70% by 2030 Renewable Generation Mix (with Energy Storage) including but not limited to:

a. Spinning Reserves / Ramping Requirements
b. Voltage Control
c. Stability Control
d. Protection Coordination
e. System Restoration

These issues will be required to be addressed in future studies. Subsequently, a review of existing Reliability Rules will have to be initiated based upon ongoing lessons learned in order to accommodate the goals of CLCPA.

To build on the work each utility has already completed and described in their DSIPs, each utility assessed the alignment between the 5-year forecasts and capital plans included in each utility's DSIP and the forward-looking CLCPA targets and scenarios detailed by both NYISO and NYSERDA.[94, 95] As part of this analysis, each utility specified the inputs and assumptions for its scenario development that reflected achievement of the CLCPA goals, including for electric vehicles, space heating electrification, solar PV, energy efficiency, and energy storage.

Supported by the forecast, each utility categorized two types of distribution system projects that are necessary to meet CLCPA goals. Distribution Phase 1 projects are those that each utility had previously identified in its DSIP filing, capital plans, or rate cases that will improve the company's ability to broadly support DER integration and DSP enablement and can be accelerated based on incremental CLCPA benefits. Phase 1 projects also may have already received approval as part of a rate case and can be expanded to achieve CLCPA goals. These projects also have benefits for reliability, safety, or compliance.

Distribution Phase 2 projects are specifically designed to close gaps between the DSIP forecast and achievement of CLCPA goals. For example, projects that increase hosting capacity can be proposed or accelerated following Commission approval of the CLCPCA planning criteria presented in Part 1 of this filing. A benefit cost-analysis of such projects has not yet been undertaken and may be impacted by any changes in cost sharing requirements.

If applicable, for the proposed distribution projects listed in this Report to meet the CLCPA goals, each utility's BCA handbook[96] should be applied. However it is possible that modifications may need to be made in the near future[97] to the BCA handbooks to define, capture, or modify key benefits attributed to meeting the CLCPA goals for explicit application to the proposed list of projects in this Report.

The Utilities have made significant progress on plans to modernize the electric grid's distribution system to accommodate the State's climate and clean-energy goals. Existing plans for modernization on the distribution system are described in each utility's Distributed System Implementation Plan (DSIP) filing[98] that cover a future five year period and, in the case of PSEG

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94 2019 CARIS 70x30 Scenario: Preliminary Constraint Modeling, Nuclear Sensitivity and Additional Results.

95 NYSERDA White Paper on Clean Energy Standard Procurements to Implement New York's Climate Leadership and Community Protection Act.

96 Updates to BCA Handbooks are filed every two years at the same time as the updated Distributed System Implementation Plans are filed.

97 The next BCA Handbook updates for each utility are due end of June 2022

98 *See* the Joint Utilities' recent DSIP filings in Case 16-M-0411, *In the Matter of Distribution System Implementation Plans.* http://documents.dps.ny.gov/public/MatterManagement/CaseMaster.aspx?MatterCaseNo=14-m-0101

Long Island,[99] its June 30, 2020 Utility 2.0 Long Range Plan.[100] As described in these filings, the Utilities continue to invest in modern, cost-effective solutions to support CLCPA goals through the deployment of advanced technologies to optimally manage distributed energy resources, which continue to be deployed on the distribution system across New York at a rapid rate. Those distribution projects described in the DSIP/Utility 2.0 Long Range Plan filings may be accelerated as needed

To build and expand upon each utility five-year DSIP each utility conducted a detailed study of the distribution system to identify all Phase 1 and Phase 2 projects required to meet the CLCPA 2030 goals. As part of this analysis the Joint Utilities aligned on two common 2030 forecast scenarios, that being 1) the detailed bottom up type forecasts as described in detail in the DSIPs and 2) forecasts that align with the NYISO 70X30 bases cases. As part of this analysis, each utility specified the inputs and assumptions for its scenario development that reflected achievement of the CLCPA goals, including for electric vehicles, space heating electrification, solar PV, energy efficiency, and energy storage.

The many distribution projects provided in this Report, especially the Phase 2 distribution projects are based on traditional wire-based capital projects. However, all the utilities have NWA, DLM/DR and energy storage programs[101] and associated criterion, whereby the traditional wire projects would be considered for such procurements, potentially leveraging DER as an alternative solution.

C. Summary Results

Sections II through VII, below contain more detailed assessments prepared by each of the Utilities as described above and pursuant to the May Order. Figure 13, below, summarizes the Utilities' Phase 1 projects. Figure 14 summarizes Phase 2 projects.

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[99] PSEG Long Island LLC, through its operating subsidiary Long Island Electric Utility Servco LLC, has managerial responsibility for the day-to-day operation and maintenance of, and capital investment to, the electric transmission and distribution system owned by LIPA under the Amended and Restated Operations Services Agreement between Long Island Lighting Company d/b/a LIPA and PSEG Long Island LLC dated as of December 31, 2013.

[100] PSEG Long Island Utility 2.0 Long Range Plan & Energy Efficiency and Demand Response Plan - 2020 Annual Update - Prepared for Long Island Power Authority; filed by PSEG Long Island on behalf of LIPA on June 30, 2020, dated July 1, 2020. Filed under Case 14-01299, http://documents.dps.ny.gov/public/MatterManagement/CaseMaster.aspx?MatterCaseNo=14-01299&submit=Search

[101] Case 18-E-0130, *In the Matter of Energy Storage Deployment Programs,* Order Establishing Energy Storage Goal and Deployment Policy (issued December 13, 2018).

Figure 13: Utilities' Phase 1 (Immediately Actionable) Projects

Project Name	Projects (No.)	Estimated Project Cost	Estimated Project Benefit (MW)[102]
Central Hudson			
Transmission	6	$152.1M	433
Distribution	12	$137.0M	132
CECONY			
Transmission	3	$860M	900
Distribution	8	$1,130M*	418
LIPA			
Transmission	8	$402M	615
Distribution	19	$351M	520
National Grid			
Transmission	13	$773M	1,130
Distribution	5	$633M	367.1+
NYSEG/RG&E			
Transmission	16	$1,560M	3,041
Distribution	8	$229M	165.8
O&R			
Transmission	6	$417M	500
Distribution	9	$156M	308
Total	113	$6,800M	8,162
Transmission Total	52	$4,164M	6,619
Distribution Total	61	$2,636M	1,543

* $789 million of investment (reflecting 5 of 8 projects) have already received funding approval. Incremental Phase 1 distribution costs for CECONY are $341 million.

102 MW Benefit is provided as an indicator of the relative benefit of each project. Once the BCA methodology outlined in Part 1, Section III is approved, the Utilities will work to update this metric for Phase 2 projects.

Figure 14: Utilities' Phase 2 Projects (Conceptual)

Project Name	Projects (No.)	Estimated Project Cost*	Estimated Project Benefit (MW)
Central Hudson			
Transmission	6	$138M	766
Distribution	7	$55M	222
CECONY			
Transmission	6	$4,050M	7,686
Distribution	2	$1,300M	360
LIPA			
Transmission	6	$1,281M+	1,830
Distribution	8	$167.2M	937
National Grid			
Transmission	13	$1,371M	1,500
Distribution	7	$510M-$1,206M	1,162-2,141+
NYSEG/RG&E			
Transmission	11	$780M	943MW
Distribution	5	$125M	88.3MW
Total	71	$9,7777-$10,428M	15,494-16,473
Transmission Total	**42**	**$7,620**	**12,725**
Distribution Total	**29**	**$2,157-$2,853M**	**2,769-3,748**

* In general, the Phase 2 projects included by the Utilities are in early stage development, without completed, detailed designs and/or engineering. Therefore, costs provided in this figure should be considered conceptual estimates.

II. CENTRAL HUDSON GAS & ELECTRIC

Central Hudson Gas & Electric Corporation is a regulated transmission and distribution utility serving approximately 307,000 electric customers and 82,000 natural gas customers in New York State's Mid-Hudson River Valley. Central Hudson delivers natural gas and electricity in a defined service territory that extends from the suburbs of metropolitan New York City north to the Capital District at Albany. Central Hudson supports policies that will help to cost-effectively reduce carbon emissions while continuing to provide resilient and affordable energy to the Mid-Hudson Valley.

Central Hudson owns approximately 75 substations containing power transformers with an aggregate transformer capacity of 5.5 million kilovolt amps. Central Hudson's electric system consists of approximately 9,400 pole miles of transmission and distribution lines, as well as customer service lines and meters.

The transmission system operates at nominal voltages of 69 kilovolts, 115 kilovolts and 345 kilovolts. The distribution system operates at nominal voltages of 13.8 kilovolts, 34.5 kilovolts, 4.8 kilovolts, and 4.16 kilovolts. The distribution system also encompasses sub-transmission systems that nominally operate at 13.8 kilovolts in the three urban areas of our service territory, feeding into secondary networks.

A. Local Transmission

i) Central Hudson Study Assumptions and Description of Local Transmission Design Criteria

Central Hudson analyzed its transmission system to determine Load Serving Capability (LSC), Load Headroom and Generation Headroom to identify constraints and bottlenecks to the siting of Distributed Energy Resources (DERs). The MW headroom values for each proposed project were also calculated.

Central Hudson performs system Load Serving Capability (LSC) analyses for both the existing Transmission System as well as the Transmission System with known planned upgrades/reinforcements included. For "looped" local transmission systems with two transmission inputs, the transmission line with the lowest summer Long Term Emergency (LTE) rating typically sets the LSC for the area. For looped transmission systems, however, the LSC may be set by a more limiting internal element or by a voltage limit/constraint.

Central Hudson has calculated the Load Headroom and Generation Headroom values for the fourteen transmission areas[103] within our service territory. The Load Headroom value is used to determine margin for both load growth and energy storage charging capacity prior to requiring upgrades. Load Headroom is defined as the LSC less the 2019 peak load served less the defined charging capacity of energy storage in queue. The Generation Headroom value is used to determine how much generation or injection of energy storage resources may be sited in a transmission area prior to requiring upgrades. Generation Headroom is defined as the LSC plus the 2019 minimum load served less installed generation and the defined energy storage injection in queue.

Central Hudson calculated MW headroom value increases for the proposed projects based on the local transmission area or the ratings of a single transmission line; hosting capacity may be limited by the system external to the upgraded area. The sum of these MW headroom values will be less than the benefit to the transmission system as a whole.

ii) Possible Fossil Generation Retirements; Impacts and Potential Availability of Interconnection Points

Central Hudson's service territory includes two fossil generation plants. These plants are located along the Hudson River near locations with minimal open land to site PV installations. Central Hudson cannot speculate if these locations could be used for DER installations in the future if these plants are retired.

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[103] Note that not all substations are within a transmission area.

iii) Existing Capacity "Headroom" within Central Hudson System

In Figure 15, Load Headroom and Generation Headroom[104] totals are calculated for each transmission area on the Central Hudson System. The generation and energy storage totals include DER projects in-service, projects in-queue and project pre-applications. For projects following the NY State Standardized Interconnection Requirements (SIR) process, only Community Distributed Generation (CDG) projects were included in the generation totals.

Figure 15: Transmission Area Load Headroom and Generation Headroom (note that nested areas may be limited by the larger area it is included in)

Transmission Area	Load Serving Capability (MW)	2019 Peak Load (MW)	2019 Minimum Load (MW)	Generation (MW)	Energy Storage (MW)	Load Headroom (MW)	Generation Headroom (MW)
Northwest 115/69kV	142	128	40	226	160	-146	-204
Westerlo Loop 69kV	85	62.6	11.2	173	40	-17.6	-116.8
Kingston-Rhinebeck 115kV	175	83.7	25.4	4.8	20	71.3	175.6
Ellenville 115/69kV	234	67.6	14.9	64.5	0	166.4	184.3
Ellenville 69kV	125	25.7	7.5	50.3	0	99.3	82.2
69kV WM Line	60	45.1	5.7	52.7	0	14.9	13.1
115kV RD-RJ	144	97.3	29.1	15.1	20	26.7	138
Mid-Dutchess 115kV	230	114	44	17.9	40	76	216.1
Pleasant Valley 69kV	107	70.7	14.3	12.9	10	11.3*	98.4
69kV E Line	77	30.1	7.2	5	10	21.9*	69.2
69kV Q Line	73	52.9	3.6	10.8	10	10.1	55.8
69kV G Line	99	37.9	3.5	7	10	51.1	85.5
Myers Corners Supply	44	24.9	7.3	0	0	19.1	51.3
Southern Dutchess	211	128.1	40.2	0.075	0	82.9	251.1
	* Includes effect of 15 MW flow to New England						

To date, three transmission areas in the Central Hudson service territory have experienced higher levels of DER interest. The Northwest 115/69kV transmission area will exceed its headroom capacity for siting any additional DERs as shown in Figure 15. This area serves load to the North Catskill, Saugerties, Woodstock, Lawrenceville, South Cairo, Freehold, New Baltimore, Westerlo and Coxsackie substations. The system is supplied from two 115 kV sources (Central Hudson and National Grid's '2' line and 'T-7' line) and a 69 kV source (SB Line). The 69kV SB Line is the main constraint serving this area; the rebuild of this line is currently planned within Central Hudson's five-year capital plan. The project is in the Article VII process with the Settlement Joint Proposal signed by all parties.

[104] Generation Headroom based on thermal constraints only. Potential voltage constraints, short circuit issues, and stability issues are not considered.

The Westerlo Loop 69kV transmission area is a sub-area of the Northwest 115/69kV transmission area. This area serves load to Lawrenceville, South Cairo, Freehold, Westerlo, New Baltimore and Coxsackie Substations. There has been significant interest from developers in siting DERs along this 55-mile 69kV transmission loop. The 69kV operating voltage and conductor sizes are the main constraints of this system.

The 69 kV E Line transmission area also has seen some interest from developers siting DERs. The 69 kV E Line is supplied from the Pleasant Valley Substation and feeds the Hibernia, Stanfordville, Smithfield, Pulvers Corners and Millerton substations. The other inputs to this system are the 690/FV Line to Eversource's Falls Village Substation and the normally open SA Line to NYSEG's Amenia Substation. For the N-1 loss of the Pleasant Valley 69kV source, the area transmission system could be supplied radially from the ISO-NE system. For this condition, ISO-NE would not have the ability to dispatch area generation, and participation in NYISO markets may not be allowed.

iv) Bottlenecks or Constraints that Limit Energy Deliverability within the Central Hudson System

Central Hudson performed steady state load flow analysis on the NYISO's 2020 RNA 70x30 scenario load flow cases. The Utility T&D Investment Working Group Technical Analysis Subgroup determined that it was most appropriate to perform the analysis on Case 1: Peak Load (30,000 MW), Case 3: Light Load (12,500 MW) and Case 6: Shoulder Load (21,500 MW) of the cases provided. In these cases, the NYISO placed generation at Central Hudson's Hurley Avenue 115kV, Modena 115kV and North Catskill 115kV substations as shown in Figure 16, below.

Figure 16: 2020 RNA 70x30 Central Hudson Generator Locations

Substation	Generator (MW)	Generation Dispatched		
		Case1 (MW)	Case 3 (MW)	Case 6 (MW)
Hurley Avenue 115kV	213.87	96.2103	0	85.579
Modena 115kV	213.87	96.2103	0	85.579
North Catskill 115kV	213.87	96.2103	0	85.579
North Catskill 115kV	106.94	48.1074	0	42.791
North Catskill 115kV	213.87	96.2103	0	85.579
North Catskill 115kV	213.87	96.2103	0	85.579
North Catskill 115kV	213.87	96.2103	0	85.579
North Catskill Total	962.42	432.948	0	385.107

Figure 17 and Figure 18 below show the results for Case 1 and Case 6. There were no constrained elements identified in Case 3 for N-1 analysis. The N-1 analysis flow data is listed for the worst-case contingency.

Figure 17: 2020 RNA 70x30 Case 1

Monitored Facility	kV	Ratings (MVA) Normal	LTE	Base Flow (MVA)	Base Flow (%)	N-1 Flow (MVA)	N-1 Flow (%)
#10 Line – Milan to Pleasant Valley	115	124	139	169.1	136.4	212.8	153.1
#5 Line – North Catskill to Churchtown	115	129	183	173.5	134.5	238	130.1
T-7 Line – Milan to Blue Stores	115	166	185	220.3	132.7	282.6	152.7
H Line – North Catskill to Saugerties	69	130	150	127.3	97.9	220.8	147.2
SB Line – Hurley Avenue to Saugerties	69	130	150	96.5	74.2	155.6	103.7
#2 Line – North Catskill to Feura Bush	115	116	120	59.8	51.6	160.9	134.1
North Catskill Transformer #5	115/69	112	129	89.8	80.1	257.6	199.7
North Catskill Transformer #4	115/69	112	129	93.8	83.8	172.5	133.7
I Line – Boulevard to Hurley Avenue	69	61	67	54.1	88.7	89.7	133.9
N Line – Boulevard to Sturgeon Pool	69	45	47	25.5	56.7	46.1	98.0

Figure 18: 2020 RNA 70x30 Case 6

Monitored Facility	kV	Ratings (MVA) Normal	LTE	Base Flow (MVA)	Base Flow (%)	N-1 Flow (MVA)	N-1 Flow (%)
#10 Line – Milan to Pleasant Valley	115	124	139	175.9	141.9	216.5	155.8
#5 Line – North Catskill to Churchtown	115	129	183	160.3	124.2	216.6	118.3
T-7 Line – Milan to Blue Stores	115	166	185	229.5	138.3	282.8	152.9
H Line – North Catskill to Saugerties	69	130	150	126.7	97.5	211.5	141.0
SB Line – Hurley Avenue to Saugerties	69	130	150	107.3	82.5	191.8	127.9
#2 Line – North Catskill to Feura Bush	115	116	120	52.3	45.1	143.7	119.8
North Catskill Transformer #5	115/69	112	129	79.7	71.1	230.4	178.6
North Catskill Transformer #4	115/69	112	129	85.9	76.71	154.7	119.9
I Line – Boulevard to Hurley Avenue	69	61	67	52.3	85.7	92.2	137.7
N Line – Boulevard to Sturgeon Pool	69	45	47	27.2	60.4	50.9	108.3

Due to the large amount of generation placed at the North Catskill 115kV bus, there were thermal overload issues identified on the nearby transmission lines and 115/69kV step-down transformers. The H and SB lines are constrained by their 69 kV operating voltage and conductor size. The existing #10 line (Milan to Pleasant Velley), and part of the T-7 line (North Catskill to Milan) are scheduled to be rebuilt by NY Transco with high temperature conductor which increases the summer and winter conductor ratings to 390 and 415 MVA, respectively. The conductor on the North Catskill to New Churchtown section of the T-7 Line (to be renamed the 5 line), however, will not be replaced and the existing ratings will remain. These rebuilt lines, however, will be limited by substation connections and tap transmission spans.

As described previously, loss of the Pleasant Valley source to the 69 kV E Line could result in this system being supplied from ISO-NE. For this condition, ISO-NE would not have any capability to dispatch area DER thus potentially precluding those resources from participating in the NYISO markets. To allow such NYISO market partition, an additional transmission input from the NYCA transmission system would be required.

v) Transmission Projects that would Address Bottlenecks or Constraints that limit Energy Deliverability within the Central Hudson System

From the study results presented in section iii above, Phase 2 projects that address bottlenecks and constraints that limit energy deliverability are listed in Figure 19 below. These proposed projects are in addition to the projects already approved in the Central Hudson's 5-year electric capital forecast. These projects are dependent on Commission approval of the CLCPA planning criteria proposed in the Policy Working Group.

Figure 19: Phase 2 Transmission Projects that Address Bottlenecks and Constraints

Project Name	Zone	Terminal A	Terminal B	Project Description	Proposed I/S Date	Order of Magnitude (OOM) Cost Estimate	MW Headroom
H & SB Line	G	Hurley Avenue	North Catskill	Change Operating Voltage from 69kV to 115kV	2030	$11.8M	100
NC Line	G	North Catskill	Coxsackie	Rebuild and Operate 69kV line for 115kV	2030	$29.1M	147
New Smithfield Area Line	G	Milan	Pulvers Corners	New Milan to Pulvers Corners Transmission Line	2030	$25.2M	95
Q Line	G	Rhinebeck	Pleasant Valley	Rebuild 69kV for 115kV*	2027	$15.0M**	60
					Total	$81M	402
* Line to be initially operated at 69 kV. Project would replace Q Line Phase 1 project listed in Figure 20. ** Incremental cost to build at 115 kV.							

In Figure 19, the H & SB Lines and NC Line projects proposed address constraints on the Northwest 115/69kV and Westerlo 69kV Loop transmission areas. These projects together would upgrade a significant portion of the 69kV transmission system to 115kV.

The H and SB lines are in Central Hudson's 5-year capital forecast to be rebuilt for 115kV operation to address future needs. The lines will be operated at 69kV until the upgrade to 115kV is required. The H and SB Line project proposal expedites the conversion of the operating voltage to 115kV and would provide a third 115 kV transmission line input into the transmission area. This project would require at least one new 115/69kV autotransformer to be installed at Saugerties Substation to feed the 69 kV SR Line to Woodstock.

The NC Line project addresses headroom constraints on the Westerlo Loop 69kV transmission area. The NC Line project proposal would rebuild and operate the existing 69kV line from North Catskill to Coxsackie substations for 115kV. This project would also include installing a 115/69kV autotransformer at Coxsackie.

The New Smithfield Area Line project addresses the 69 kV E Line transmission area. This project proposal includes building a new Milan to Pulvers Corners transmission line to provide a second NYCA transmission source to the area. This would allow DERs to be dispatchable by the NYISO under N-1 conditions.

The Q Line project was proposed to address future expandability of renewable energy resources. The 20.5-mile 69kV line from Rhinebeck to Pleasant Valley is in the planning stages to be rebuilt for 69kV operation. Central Hudson's 69kV operating voltage is often a significant constraint when siting large renewable generation interconnections. This project proposes to rebuild the Q Line for 115kV operation instead even though it is currently not justified by other needs. The incremental cost to build the line for 115kV operation as part of the rebuild project would be significantly less than the cost of a complete rebuild in the future if developers were to site DER projects that would require more headroom than a future 69 kV system in this area would allow.

vi) Projects that would Increase Capacity on the Local Transmission System to allow for Interconnection of New Renewable Generation Resources within the Central Hudson System

Projects in Central Hudson's 5-year electric capital forecast to address load growth, new business, compliance, day-to-day business management and infrastructure replacement will also increase capacity on the local transmission system to allow for new renewable generation resources. The capital forecast is developed each year using the most recent planning studies, customer and sales forecasts, corporate demand forecasts, and other corporate trends. Figure 20 lists Phase 1 projects that are included in the 5-year electric capital forecast that increase energy deliverability.

Figure 20: Phase 1 Transmission Projects included in 5-Year Capital Forecast

Project Name	Zone	Terminal A	Terminal B	Project Description	Proposed I/S Date	Order of Magnitude (OOM) Cost Estimate	MW Headroom
KM & TV Line	G	Knapps Corners	North Chelsea	Rebuild 69kV Line	2022	$11.6M	86
H & SB Line	G	Hurley Avenue	North Catskill	Rebuild 69kV Line for 115kV Operate at 69 kV	2024	$58.5M	75
HG Line	G	Honk Falls	Neversink	Rebuild 69kV Line	2026	$27.5M	53
Q Line	G	Rhinebeck	Pleasant Valley	Rebuild 69kV Line	2027	$37M	60
SK Line	G	Knapps Corners	Spackenkill	Rebuild 115kV Line	2025	$4.4M	57
P & MK 115kV	G	Modena	Kerhonkson	Operate P & MK at 115kV Install (2) Kerhonkson	2024	$13.1M	102
		Sturgeon Pool	Kerhonkson				

Project Name	Zone	Terminal A	Terminal B	Project Description	Proposed I/S Date	Order of Magnitude (OOM) Cost Estimate	MW Headroom
				115/69 kV Auto-XFMRs			
					Total	$152.1M	433

From the study results presented in section iv above, Phase 2 projects that increase system capacity are listed in Figure 21, below. These proposed projects are in addition to the projects already approved in the Central Hudson's 5-year electric capital forecast. These projects are dependent on Commission approval of the CLCPA planning criteria proposed in the Policy Working Group.

Figure 21: Phase 2 Projects that Increase Transmission System Capacity

Project Name	Zone	Terminal A	Terminal B	Project Description	Proposed I/S Date	Order of Magnitude (OOM) Cost Estimate	MW Headroom
10 & T-7 Line Station Connections	G	Pleasant Valley	Milan	Upgrade Station Connections to not Limit Line Conductor	2030	$0.9M	261
Northwest Reinforcement	G	New Baltimore	Westerlo	New Substation 345/115kV Auto-XFMR 115/69kV Auto-XFMR NW & CL lines at 115kV	2030	$56.0M	103
					Total	$57M	364

In Figure 21, the proposed 10 & T-7 Line Station Connections project addresses the capacity constraints on the 115kV #10 Line and the segment of the T-7 line between New Churchtown and Milan. The proposed project would replace station connections and associated limiting equipment at Pleasant Valley and Milan substations to not limit the new conductor that will be installed as part of the NY Transco Segment B project. Since the entire T-7 Line between North Catskill and New Churchtown will not be replaced as part of the NY Transco Segment B project, the existing conductor would need to be replaced to increasing area hosting capacity. This project would have to be coordinated with National Grid and NY Transco for feasibility.

The proposed Northwest Reinforcement project addresses overloads in the vicinity of North Catskill substation. This potential project proposes to build a new 345/115/69 kV substation where National Grid's 345kV '94' Line intersects the 115kV '2' Line, 115kV '8' Line and 69kV NW Line. The new substation would provide another source into the Westerlo Loop 69kV transmission area. This project does not alleviate the North Catskill overloads in the 2020 RNA

70x30 load flow case. From the DER projects in-service, projects in-queue and project pre-applications, developer interest in siting renewable generation is distributed throughout the Northwest 115/69kV and Westerlo Loop 69kV transmission areas and not located directly at North Catskill where 962 MW of renewables was placed in the 2020 RNA 70x30 load flow case. This project would provide substantial benefits to these transmission areas. The proposed Northwest Reinforcement project requires additional analysis and study work before it can be implemented; the exact configuration of the project would be highly dependent on where DER develops.

B. Distribution

i) Review and Identification Phase 1 Distribution Projects

The purpose of this section is to describe the review of the Company's current capital plans and other existing long range system plans to identify where existing Substation and Distribution projects that have load or generation headroom benefits as designed or with modifications.

Within the Company's current capital plan, the vast majority of the Company's Capital spend is for non-discretionary (new business, restoring service, safety repairs, compliance, road rebuilds/relocations) type work or to maintain system standards (equipment replacement based on condition assessment, correct existing planning/design violations and equipment replacement based on obsolescence). Over the last several years, the Company's service territory has experienced declining to stagnant electric load growth; as a result, no significant load growth-based projects are included within the Electric Capital Budgets. The Capital program is predominately infrastructure projects to ensure system integrity and customer reliability going forward.

Specifically, the Company's current capital plan for Substation and Distribution is comprised of predominately condition based infrastructure projects. As part of the Company's planning process, alternative analyses are completed to determine the appropriate replacement strategy (i.e. replace in-kind; replace with higher rated equipment; and replacement with alternative solution/ equipment/ location). Current interconnection queue data is utilized as an input in this analysis to facilitate the identification of near-term hosting capacity needs. While these projects are primarily for non-discretionary type work or to maintain system standards, a number of the projects have load or generation headroom benefits as designed or with modifications. The Figure 22 below identifies the existing projects that have load or generation headroom benefits as designed or with modifications.

Figure 22: Phase 1 Distribution Projects included in 5-Year Capital Forecast

Project Name	Zone	Substation	Project Description	Proposed I/S Date	Order of Magnitude (OOM) Cost Estimate	MW Headroom
DA/DMS	G	System Wide	Distribution Automation and Distribution Management System – Foundational Investments	Ongoing	$14.2M	**
Operating Infrastructure	G	System Wide	Infrastructure	Ongoing	$25.3M	**
Knapps Substation Replacement	G	Knapps Corners	Station Rebuild – high capacity circuit exits	2022	$1.0M	18MW
Coxsackie Transformer Replacement	G	Coxsackie	Replace with 22 MVA	2021	$2.1M	10MW
Coxsackie DEC Peaker Regulation Project	G	Coxsackie	Add a 2nd Transformer and DVAR	2024	$4M	22MW
South Cairo DEC Peaker Regulation Project	G	South Cairo	Add a 2nd Transformer and DVAR	2024	$4.1M	12MW
New Baltimore Transformer Replacement	G	New Baltimore	Add a 2nd 12 MVA Transformer	2023	$1.6M	12MW
Greenfield Road Transformer and Circuit Exits	G	Greenfield Road	Replace existing Transformers	2023	$1.5M	10MW
5 kV Aerial Cable Replacement	G	System Wide	Replace cable or convert 5 kV to 13.2 kV Operation	Ongoing	$2.5M	14MW
Copper Wire Replacement Program	G	System Wide	Replace #4 and #6 copper with higher capacity ACSR	Ongoing	$3.6M+	23MW
4800V & 4 kV Replacement Programs	G	System Wide	Upgrade 4800 V and 4kV to 13.2 kV eliminating stepdown transformers	Ongoing	$17.6M+	11MW
Storm Hardening	G	System Wide	Harden mainline zones of protection	Ongoing	$59.5M	**
				Total	$137 M	132MW

** The MW Headroom for the Distribution Improvement – Operating / Infrastructure Condition, Storm Hardening and Grid Modernization (including DMS/DA) programs is not identified within the table. These programs are larger in scale and can encompass a range of project types and geographic areas. Based on the nature of these programs, the MW headroom improvements will be distributed across our service territory and is difficult to forecast.

The Distribution Improvement – Operating / Infrastructure Condition program includes a mixture of conversions, polyphasing, reconductoring, closing circuit gaps, and rebuilding older infrastructure in poor condition. There are almost 50 projects specifically identified for 2021-2025 within this category.

Storm hardening efforts include reconductoring three-phase mainline zones of protection as well as lateral lines. Additional electronic reclosers will also be placed in strategic locations throughout the service territory as an incremental component to Central Hudson's DA/DMS initiative.

Through its Grid Modernization Program, the Company is taking significant steps to accommodate DERs and model the system impacts of DERs in order to preserve distribution system safety and reliability. Critical to these efforts are a set of foundational investments that will support DSP capabilities. Central Hudson's Grid Modernization Program is comprised of six critical projects:

1. Distribution Automation (DA) – automated devices, distribution infrastructure (poles and wires)
2. ESRI System Model Geographic Information System (GIS) – provides a single consolidated mapping and visualization system
3. Distribution Management System (DMS) – the centralized software "brains"
4. Distribution System Operations (DSO) – the organization responsible for monitoring and controlling the electric distribution system through the use of the DMS
5. Network Communications Strategy (NS) – the two-way communication system between the DA devices and DMS
6. Substation Metering Infrastructure– Substation feeder metering upgrades required for accurate ADMS power flow calculations.

Over 800 Intelligent Electronic Devices (IED; e.g. electronic reclosers, switched capacitors and voltage regulating devices) and sensors are being installed through DA and other projects. These devices provide real time data to the DMS, which enables it to make centralized decisions based on current system conditions rather than anticipated peak loads. DERs also must be monitored, and in some cases, controlled, as a critical input to the DMS. The Network Communications Strategy equipment enables communication between the DA equipment and the DMS. GIS enables new capabilities for Central Hudson, including developing accurate distribution grid models (potentially down to the customer meter) and enabling calculation and visualization of DER installations and hosting capacity.

Distribution System Operations staff will utilize DA devices to regularly feed live electrical system data into the DMS, GIS will support a number of DMS capabilities, including:

- Greater operational efficiency with improved automation management;
- Preservation of safety and reliability in real-time operations through integration of disparate data sources; and
- Improved interaction with SCADA devices, including distribution feeder breakers, substation load tap changers and DERs.

The continued implementation of these supporting technologies and systems will enable Central Hudson to produce more robust system models that incorporate the impact of DERs and ultimately allow it to utilize DERs better to provide value to the grid and customers. In the near term, Central Hudson's Grid Modernization Program aims to accommodate DERs through increased monitoring and, in some cases, control. Over the longer term, Central Hudson may seek to dispatch DERs in real time to preserve distribution system safety and reliability or provide other services of value to the grid.

ii) 70 X 30 Distribution Study Objectives

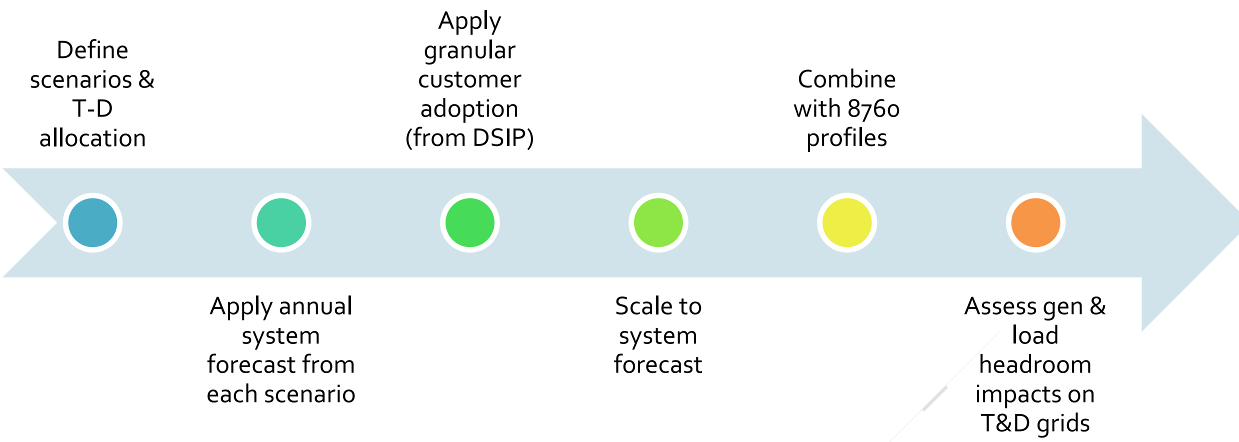
The purpose of this analysis is to identify areas within Central Hudson's territory where distribution upgrades are necessary and appropriate, and to assess the impacts of the CLCPA renewable energy and electrification goals on distribution constraints and costs. Specifically, this Report expands the forecasts and analysis of the 2020 DSIP and addresses the first evaluation scenario of the May Order, and seeks to evaluate the capacity headroom available on Central Hudson's distribution system through 2030 for the identification of Phase 2 Distribution projects. The analysis seeks to answer three main questions:

- Where is the solar capacity likely to be located within Central Hudson territory?
- What is the year-by-year capacity headroom assuming the solar capacity needed to meet the 2030 goals?
- What are the costs of the upgrades necessary to achieve the climate goals?

iii) Methodology

Figure 23 provides a high-level overview of the process for evaluating local area capacity needs and constraints under multiple scenarios.

Figure 23: 70x30 Analysis Overview



The analysis process can be summarized in six steps. These steps are:

1. **Define scenarios and T&D allocation**. Central Hudson selected three scenarios representing different levels of CLCPA goal achievement. These scenarios range from a business-as-usual scenario, where Central Hudson continues to work towards the goals outlined in their 2020 Distributed System Implementation Plan (DSIP), to a scenario where CLCPA renewable energy and electrification goals[105] are fully implemented and achieved by the target year. These scenarios incorporate T&D capacity allocation following allocations established in the NYISO CARIS 70x30 Scenario[106].
2. **Apply annual system forecast from each scenario**. Annual forecasts through the target year 2030 are defined for each scenario to align with either the DSIP or CLCPA goals, as applicable. This definition includes allocation between the ten Central Hudson transmission areas and the distribution system. CLCPA goals for renewable resources were defined at the 115 kV bus level and were spread down to substations including those connected to the 69 kV transmission system based on proximity and connection to transmission lines in the specified areas of the 115 kV system.
3. **Apply granular customer adoption (from DSIP)**. In the 2020 DSIP, loads and DER adoption (solar, storage, EE, EV, heat pumps) were estimated for each transmission area and substation. These forecasts are leveraged in this analysis to define adoption at the local level. The same proportional adoption dispersion was

[105] "White Paper on Clean Energy Standard Procurements to Implement New York's Climate Leadership and Community Protection Act"; DPS and NYSERDA; JUNE 18, 2020.

[106] "2019 CARIS 70x30 Scenario: Preliminary Constraint Modeling, Nuclear Sensitivity and Additional Results"; NYISO Electric System Planning Working Group; March 16, 2020.

used for the scenarios applying the DSIP or the CLCPA goals for behind the meter resources.

4. **Scale to system forecast**. For each year, the local adoption forecasts are then scaled up to the aggregate forecast, with the goal of accurately reflecting the expected growth or loss in headroom on a year-by-year basis.
5. **Combine with 8760 profiles**. The system year-by-year forecast is then combined with 8760 load profiles for distributed energy resources that were developed for the 2016 DSIP to understand the overall load impact DER adoption on distribution and transmission loads. Production profiles used for solar[107] and storage[108] production were different than those used for the DSIP given the focus of this analysis on identifying headroom constraints.
6. **Assess generation and load headroom impacts on T&D grids**. The aggregated load shapes and local level load and DER adoption forecasts are combined to estimate the generation and load headroom impacts of the different scenarios on the T&D grid, for each year and local area. Generation headroom is reported for the minimum net load hour. Load headroom is reported for the maximum net load hour.

iv) Headroom Calculation Definitions

This analysis explores two different types of "headroom", or the available capacity in MWs, existing in each local area of the grid – generation headroom and load headroom.

Generation headroom refers to the available capacity for additional generation or injection of energy at a transmission area prior to requiring upgrades. Resources that increase energy consumption, such as gross load or beneficial electrification, increase generation headroom, while new generation sources and consumption-reducing resources (such as energy efficiency) decrease the available capacity for generation. Figure 24 illustrates the various factors in the generation headroom equation. For the purposes of this analysis, battery storage is assumed to be unmanaged by the utility – that is, the developers and end user have full control of the battery storage. As a result, planning for storage is based on the scenario of battery storage fully discharging at the minimum load hour. Generation headroom is reported for the minimum net load hour, and battery storage is assumed to be fulling discharging at the minimum load hour.

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107 The DSIP analysis focused on typical 1-in-2 impacts for which an average monthly solar production profile was used. The key objective of the CLCPA 70x30 analysis is to identify grid constraints under minimum net load and maximum net load conditions so the peak monthly production profile was used.

108 The DSIP analysis focused on typical 1-in-2 impacts for which a market driven charge / discharge profile was used. The key objective of the CLCPA 70x30 analysis is to identify grid constraints under minimum net load and maximum net load conditions so the nameplate capacity was applied to all hours.

Figure 24: Generation Headroom Definition

LTE Rating	-New EE
+Gross load	-All New Solar
+New HP	-All New Storage
+New EV	-Existing Thermal Gen
	-Future Thermal Gen

Load headroom refers to the available capacity for load growth on the system area before requiring upgrades. Resources that reduce net load, such as behind the meter renewable energy generation and energy efficiency, effectively increase load headroom, while resources that increase energy consumption decrease load headroom. Load headroom is the inverse of generation headroom. The key difference is that it does not include front-of-the-meter solar production or any thermal generation since the focus is on load, not generation. Figure illustrates the load headroom equation. Load headroom reported for day and hour with the maximum net load, with battery storage assumed to be fully charging at the maximum net load hour.

Figure 25: Load Headroom Definition

LTE Rating	-Gross load
+New EE	-New HP
+New BTM Solar	-New EV
+New Storage	

CLCPA goals will affect both sides of the equation, for both generation and load headroom. Beneficial electrification efforts will increase loads, while energy efficiency measures will reduce them. Investments in solar generation and storage systems will increase available load capacity on the system. Central Hudson will need to balance the effects of these various changes across the transmission and distribution system in order to provide reliable electric service to its customers, while maintaining equilibrium on the electric system.

v) Scenario Definitions

This analysis explores generation and load headroom year-by-year through 2030, across three scenarios with various degrees of renewable energy and DER adoption. Figure 26 compares the three scenarios across three categories – solar and storage capacity, transmission and distribution capacity split for solar and storage, and energy efficiency, EV, and heat pump capacity.

Figure 26: Scenario Comparison

Scenario	Solar/Storage Capacity Goals	T&D Split for Solar/Storage	EE/EV/HP Capacity Goals
1	DSIP	DSIP	DSIP
2	CLCPA 70x30	NYISO 70x30	DSIP
3	CLCPA 70x30	NYISO 70x30	CLCPA 70x30

Scenario 1 is the business-as-usual baseline case, which assumes that Central Hudson continues with the goals outlined in their 2020 Distributed System Implementation Plan. Under this scenario, Central Hudson achieves the capacity goals set for solar, battery storage, energy efficiency, electric vehicle, and heat pump adoption set in the DSIP. It also includes all existing and in queue transmission connected thermal generation, solar generation, and storage capacity.

Scenario 2 explores generation and load headroom using the achievement of CLCPA goals related to generation but using the loads consistent with Central Hudson's 2020 DSIP filing. It assumes that CLCPA solar and storage capacity goals are achieved, but energy efficiency, EV, and heat pump goals from the DSIP are maintained. Since the CLCPA does not establish a specific goal transmission versus distribution connection resources, the NYISO 2019 CARIS 70x30 Scenario is used to, on a broad basis, define the allocation across the system. Capacity was subsequently allocated to substations, including those connected to the 69 kV transmission system, based on proximity and connection to transmission lines in the areas specified by the NYISO. In addition, resources were assumed to be split evenly between transmission and distribution connections. Scenario 2 is a hybrid of DSIP and CLCPA conditions and was intended to test the outcome of adding CLCPA incremental renewables without the incremental electrification goals.

Scenario 3 assumes that CLCPA renewable energy and electrification goals are achieved by the 2030 target year. It uses the same allocation methodology for connected as scenario 2 for the transmission and distribution allocation on the system and split between transmission and distribution for solar and storage capacity.

Figure 27 compares Central Hudson's DER goals under the DSIP and CLCPA. It provides a sense of the range between the business-as-usual scenario and the CLCPA scenario. While storage capacity goals are the same in both scenarios, capacity goals for all other DERs are significantly higher under the CLCPA. In particular, the solar capacity goal under CLCPA conditions is nearly four times higher than the DSIP forecast, which was based on historical adoption pattern and solar in the interconnection queue.

Figure 27: DSIP and CLCPA 2030 Goals

2030 Goals	BAU (DSIP)	CLCPA
Total Solar (MW)	479	1,872
Total Storage (MW)	620	620
EE (GWh)	446	729[109]
EV (Vehicles)	19,600	60,000[110]
Heat Pumps (GWh)	30	60[111]

vi) Other Key Assumptions

In order to calculate year-by-year minimum net load generation and load headroom at the transmission area and substation levels, the analysis incorporates granular load and DER adoption forecasts from the 2020 Central Hudson DSIP:

- Gross hourly load forecasts match the DSIP forecast through 2025 and were simply extended to 2030.
- Hourly load profiles for load modifying DERs developed for the DSIP were also used for this analysis.
- Central Hudson also assumed that the allocation of distribution connected solar, energy efficiency, and heat pumps was the same as the allocation developed for the DSIP.

A few key modifications of the DSIP framework were made to better align with the goals of this analysis:

- Loading factors reported for the DSIP were a ratio of gross loads and LTE ratings. Given the focus on understanding avoided T&D costs, load modifying DERs (energy efficiency, heat pumps, electric vehicles, solar, and storage) were not

109 Increases from the DSIP based on an increase of EE on a gross statewide basis of 34700 GWH to 56700 GWH.

110 Based on CHGE territory share of light duty vehicles and the statewide goal of 850,000 by 2025 and 2 million by 2030.

111 Based on a doubling of the HP GHW load from the DSIP to estimate the CLCPA impact.

included in load forecasts. As such load headroom calculated for this study is not comparable for to DSIP loading factors.

- Heat pumps were included as part of energy efficiency for the DSIP but were broken out for the CLCPA given the different goals and because heat pumps contribute incremental load in months where heating is needed.
- The DSIP analysis focused on typical 1-in-2 impacts for which an average monthly solar production profile was used. The key objective of the CLCPA 70x30 analysis is to identify grid constraints under minimum net load and maximum net load conditions so the peak monthly production profile was used.
- The DSIP analysis focused on typical 1-in-2 impacts for which a market driven battery storage charge / discharge profile was used. The key objective of the CLCPA 70x30 analysis is to identify grid constraints under minimum net load and maximum net load conditions so the nameplate capacity was applied to reflect a scenario where battery storage is not managed by the utility, but managed by developers and customers. It is possible that battery storage could be operated under conditions which align with local need, thereby increasing headroom. However, for planning purposes battery storage is assumed to be operated by the battery owner or developer. In effect, because battery storage is not operated by the utility it could be managed to align with other needs such as ancillary services which may be misaligned with local needs.

vii) Distribution Substation Results

1. Generation Headroom

There are 62 load serving distribution substations located in Central Hudson's territory. Figure 28 shows the generation headroom available under each planning scenario at the distribution substation level, for the 10 substations with the least available headroom in 2030. Generation headroom at the distribution level mirrors the results of the transmission area analysis, with the largest constraints in the Westerlo and Northwest 69 kV Areas. Notably, three Westerlo substations have significant generation capacity needs by 2025 in the CLCPA scenario.

Figure 28: Generation Headroom in MW by Distribution Substation, 2025 and 2030

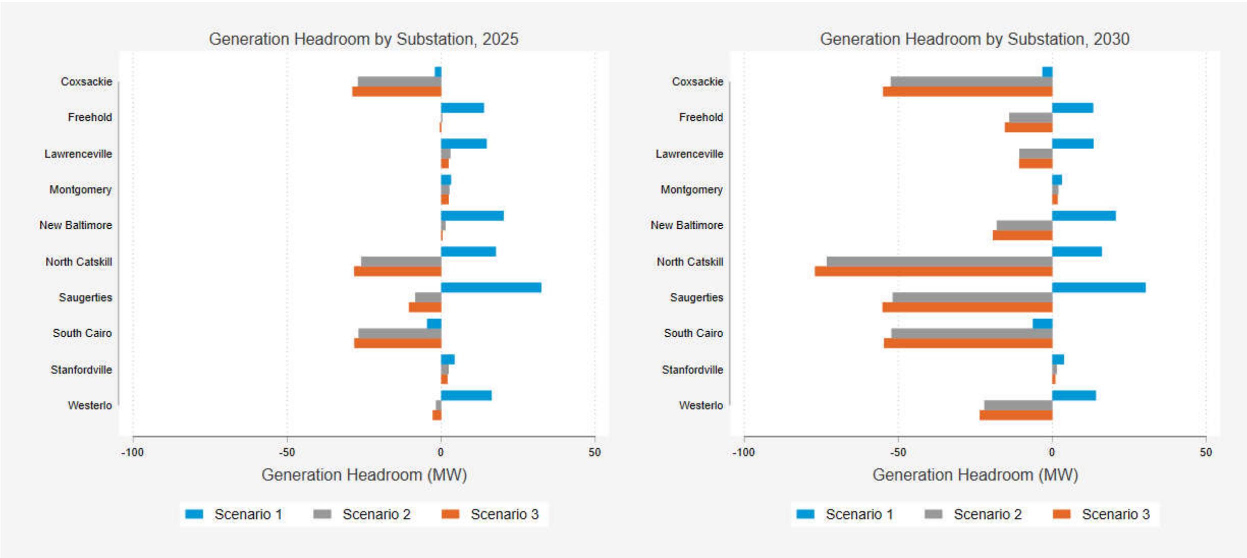


Figure 29 shows the generation headroom available as a percent of the substation's LTE rating, for the same group of 10 substations. For the substations with the lowest generation headroom, projected generation capacity needs in 2030 are approximately one to three times the current LTE ratings.

Figure 29: Generation Headroom as Percent of LTE Rating by Substation, 2025 and 2030

Figure 30 shows the generation headroom for the same set of substations, broken down by modifying factor for the business-as-usual and CLCPA scenarios in 2030. While planned bulk storage capacity additions are the largest contributor to generation needs in the business-as-usual scenario, bulk solar capacity additions are the primary driver of generation constraints under CLCPA conditions.

Figure 30: Generation Headroom Breakdown by Modifying Factor – Substation Level

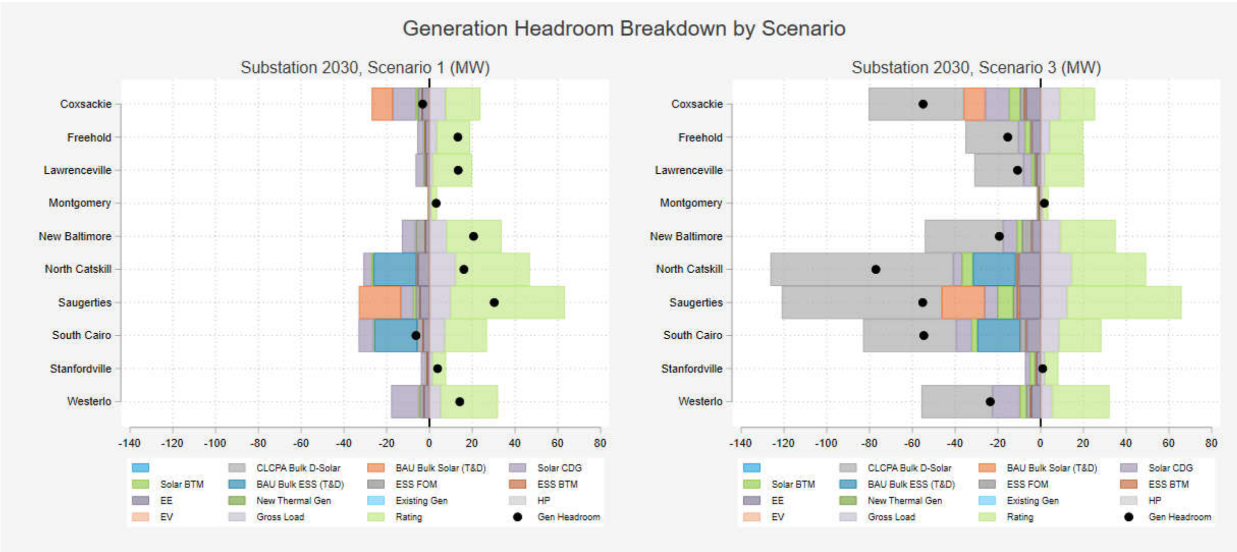
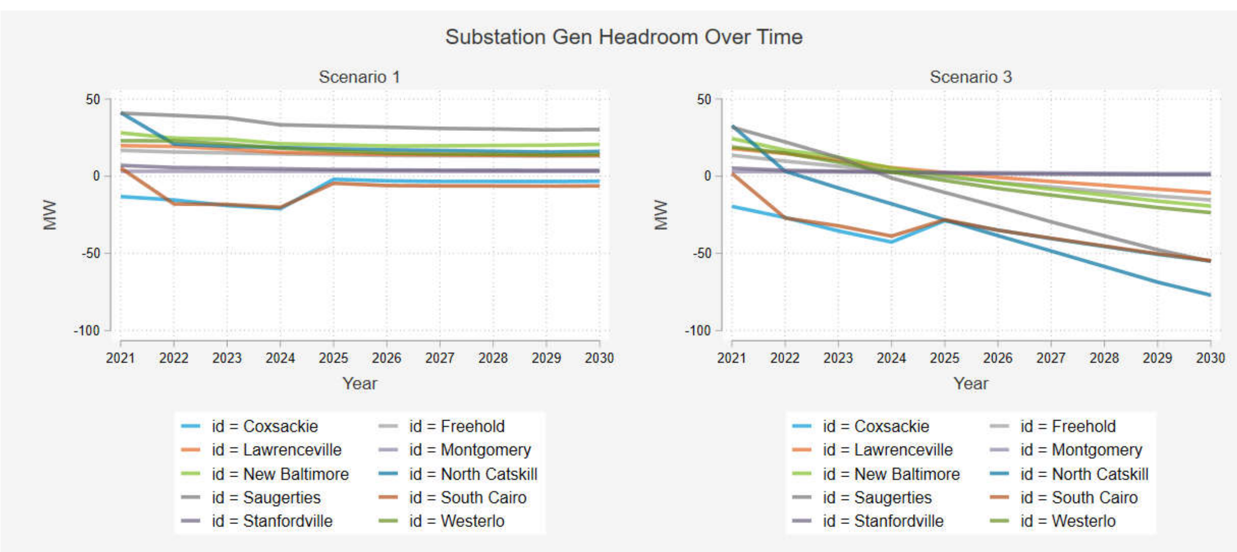


Figure 31 shows the significant impact of CLCPA goals on generation capacity needs at the distribution level. In the business-as-usual scenario, generation headroom is largely stable across the planning period, with two exceptions. The battery installation in the Northwest 115-69 kW Area decreases generation headroom available at the North Catskill and South Cairo substations, and predicts a generation constraint at the South Cairo substation from 2022-2024. In 2024, planned generation retirements increase available headroom at the South Cairo and Coxsackie substations. Under CLCPA planning conditions, most substations experience a sharp decline in generation headroom that tracks the deployment of the CLCPA. The only exceptions are the Stanfordville and Montgomery substations, which remain stable with marginal generation headroom available throughout the planning period.

Figure 31: Generation Headroom Timeline by Distribution Substation & Scenario



2. *Load Headroom*

Figure 32 shows the load headroom available for each scenario at the distribution substation level, for the 10 substations with the least available headroom in 2030. Load constraints at the distribution level are similar across scenarios and years. Note that this subset of ten substations is different from the ten lowest substations in terms of generation headroom, although three substations appear on both lists – Montgomery, North Catskill, and South Cairo.

Figure 32: Load Headroom in MW by Distribution Substation, 2025 and 2030

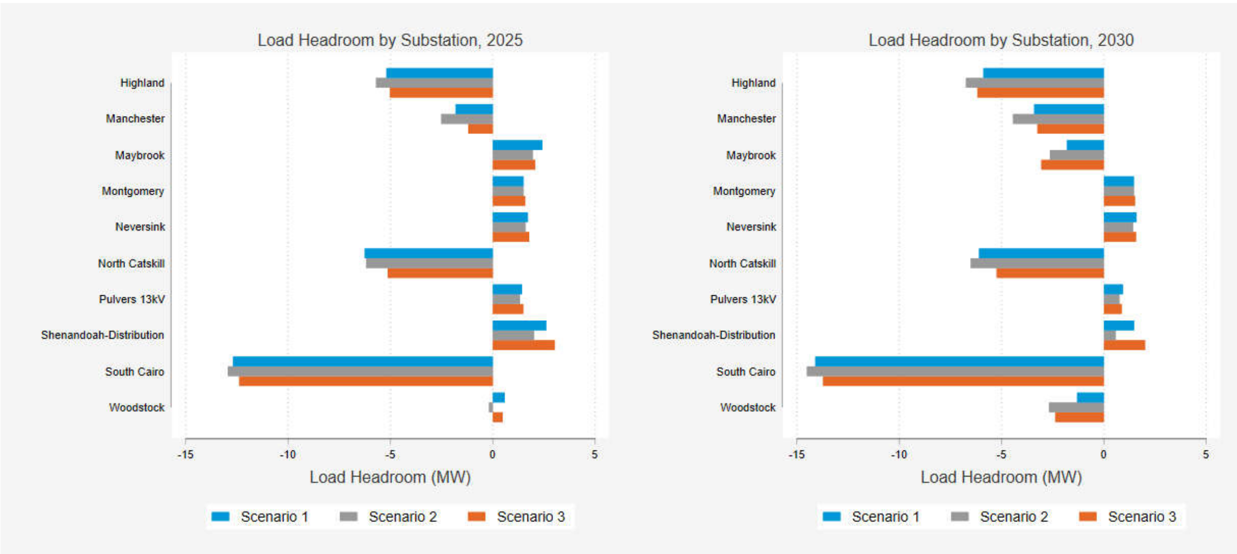


Figure 33 shows the load headroom available as a percent of each substation's LTE rating. Load constraints at the substation level are significantly smaller compared to LTE ratings than generation constraints, with deficits around 15-20% of ratings. The only exception is South Cairo, where loads are projected to exceed the substations LTE rating by 60% across scenarios and years. South Cairo has an LTE rating around 20 MW, which is low given the additional 20 MW of planned bulk storage capacity addition in the area.

Figure 33: Load Headroom as Percent of LTE Rating by Substation, 2025 and 2030

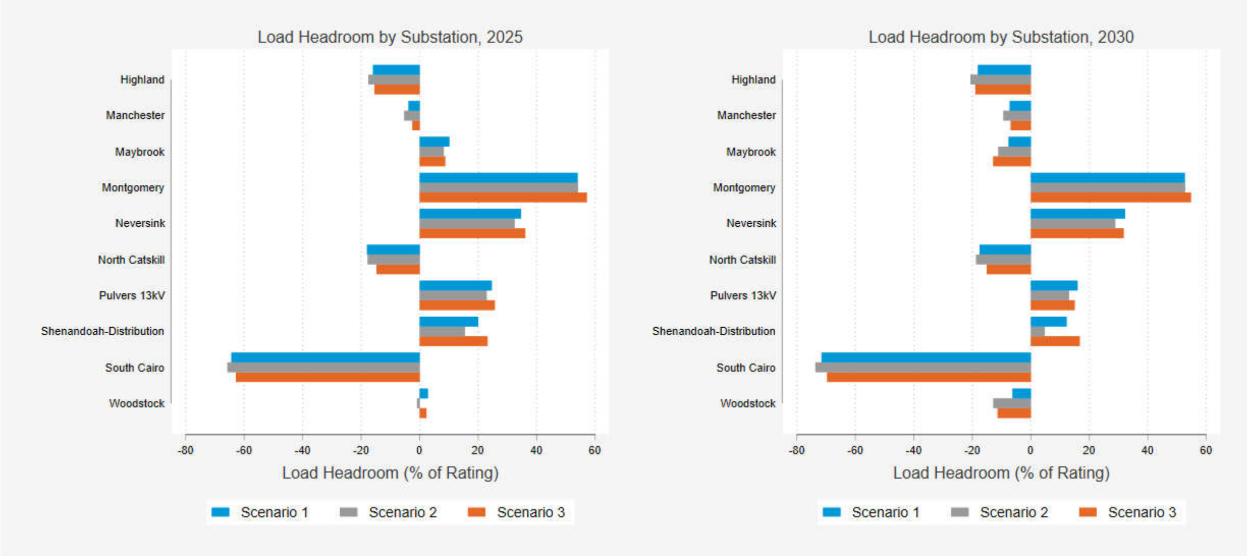


Figure 34 shows the load headroom for each substation, broken down by modifying factor for the business-as-usual and CLCPA scenarios in 2030. The black triangle indicates the overall load headroom available for each substation and year. Load deficits in both scenarios are driven by high bulk storage capacity relative to substation LTE ratings. Highland, Manchester, North Catskill, and South Cairo receive most of the impact of the 100 MW bulk storage addition that will come online in 2022.

Figure 34: Load Headroom Breakdown by Modifying Factor – Substation Level

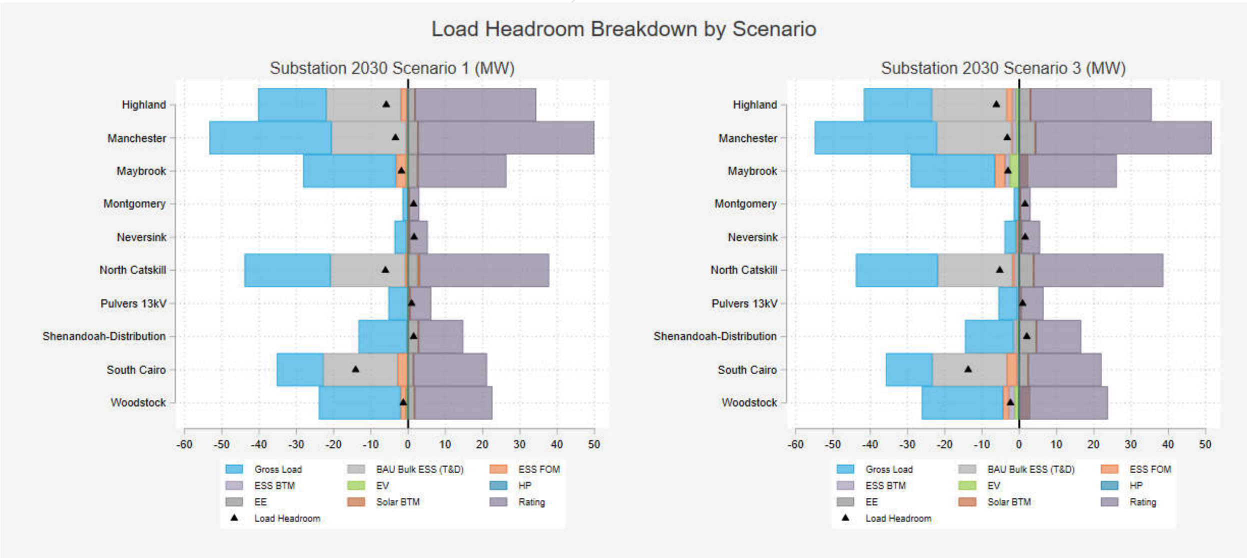
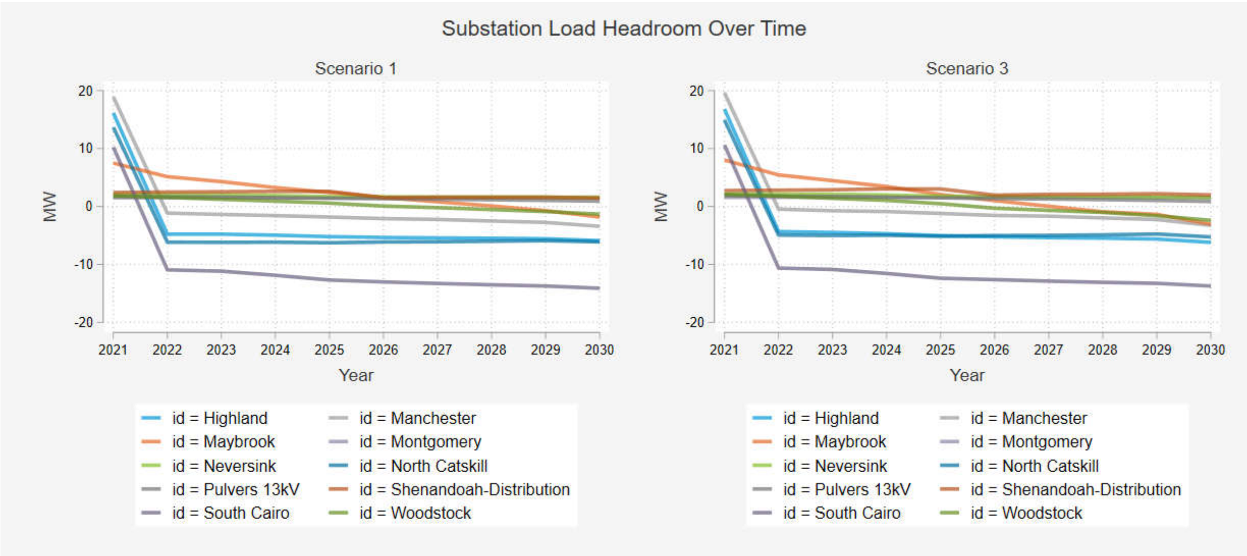


Figure 35 highlights the impact of the bulk storage capacity addition on these four substations. There is a sharp decrease in load headroom between 2021 and 2022. After the shortfall due to storage additions, load headroom remains relatively stable for these substations through 2030. For the other six substations, load headroom is generally steady across the planning period under both scenarios.

Figure 35: Load Headroom Timeline by Distribution Substation & Scenario



viii) Distribution Areas requiring Capacity Investments

Figure 36 shows projected capacity constraints in Central Hudson's territory for the business-as-usual and CLCPA scenarios in 2030, by distribution substation. Under the business-as-usual scenario, only two substations experience generation capacity constraints, due to planned thermal generation retirements. With the deployment of the CLCPA, six additional substations become constrained, concentrated in the northern part of Central Hudson's territory.

Figure 36: Capacity Constraints Across Central Hudson's Territory, by Distribution Substation

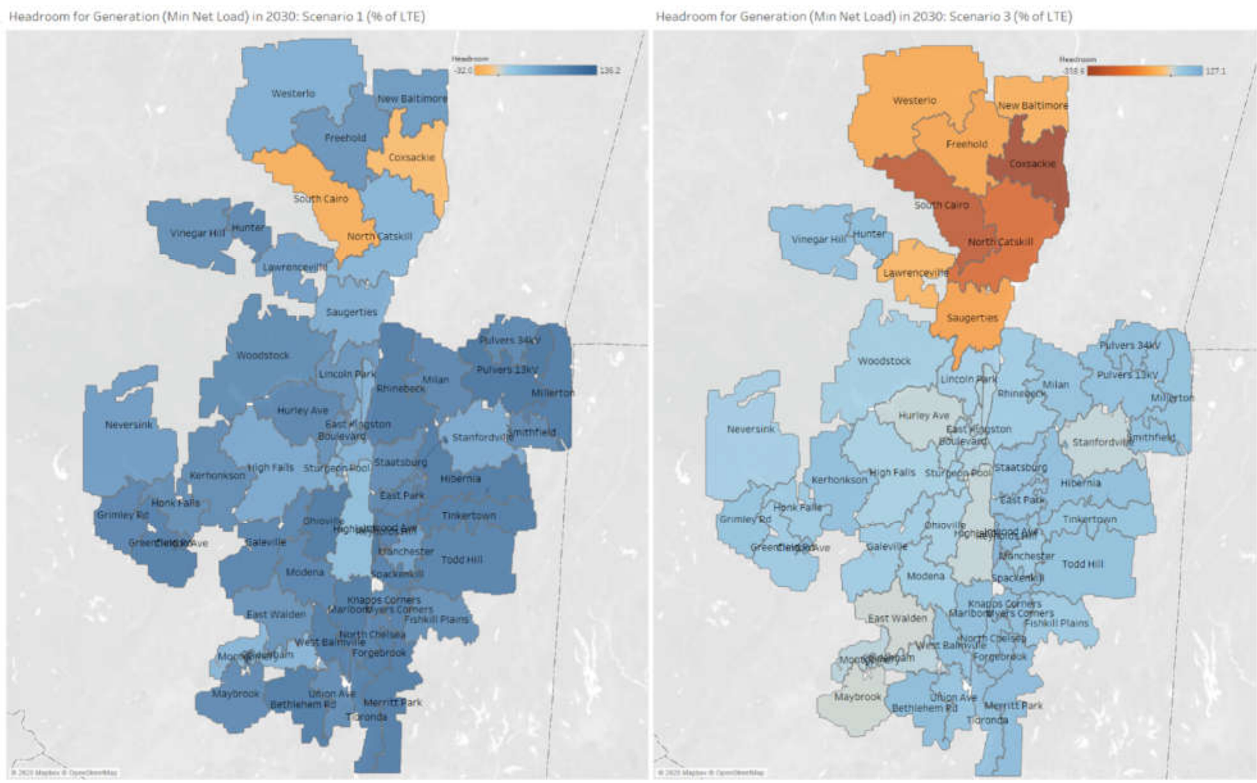


Figure 37 shows the eight substations in need of upgrades for 2020. For all eight substations, bulk solar additions that will be deployed under the CLCPA are a key driver of constraints. North Catskill and South Cairo will experience additional constraints due to bulk storage projects in queue for the Northwest 115-69 kV and Westerlo Areas. South Cairo and Coxsackie will experience a boost in generation headroom available after a planned thermal retirement in 2024. Six of the eight substations will require updates by 2025, under CLCPA planning conditions.

Figure 37: Distribution Substations with Generation Headroom Needs

Substation	Transmission Area	2030 Rating Including NWAs (MW)	2030 Incremental Generation Headroom Needed (MW)	Key Drivers of Constraints
Coxsackie	Westerlo Loop	16.2	55.0	BAU bulk solar and CLCPA bulk solar (helped by 2024 thermal retirement)
Freehold	Westerlo Loop	15.5	15.4	CLCPA bulk solar
Lawrenceville	Westerlo Loop	18.3	10.8	CLCPA bulk solar
New Baltimore	Westerlo Loop	25.8	19.3	CLCPA bulk solar
North Catskill	Northwest 115-69 Area	34.7	77.1	BAU bulk storage and CLCPA bulk solar

Substation	Transmission Area	2030 Rating Including NWAs (MW)	2030 Incremental Generation Headroom Needed (MW)	Key Drivers of Constraints
Saugerties	Northwest 69kV Area	53.6	55.2	BAU bulk solar and CLCPA bulk solar
South Cairo	Westerlo Loop	19.7	54.7	BAU bulk storage and CLCPA bulk solar (helped by 2024 thermal retirement)
Westerlo	Westerlo Loop	26.7	23.6	BAU CDG solar and CLCPA bulk solar

Figure 38 shows the four substations in need of upgrades to address load constraints. The figure includes numbers for the CLCPA scenario, although load constraints for these substations are similar under business-as-usual and CLCPA scenarios. The load capacity needs in these substations are the result of bulk storage capacity additions already in queue. The Maybrook and Woodstock substations exhibited similar, small load constraints under both the business-as-usual and CLCPA scenarios. Although these needs could potentially be addressed with renewable energy solutions, Central Hudson analyzed these substations in the 2020 DSIP and assessed that these needs can be met temporarily through lower-cost distribution load transfers that may defer the need for infrastructure investment in these areas.

Figure 38: Distribution Substations with Load Headroom Needs

Substation	Transmission Area	2030 Rating Including NWAs (MW)	2030 Incremental Load Headroom Needed (MW)	Key Drivers of Constraints
Highland	N/A	32.6	6.2	BAU bulk storage
Manchester	Mid Dutchess	47.3	3.3	BAU bulk storage
Maybrook	WM Line	23.8	3.1	Small need similar for BAU and CLCPA. Slightly worsened by CLCPA EVs and BTM ESS
North Catskill	Northwest 115-69 Area	34.7	5.2	BAU bulk storage and CLCPA bulk solar
South Cairo	Westerlo Loop	19.7	13.7	BAU bulk storage and CLCPA bulk solar (helped by 2024 thermal retirement)
Woodstock	Northwest 69kV Area	120.9	2.4	Small need similar for BAU and CLCPA. Slightly worsened by CLCPA EVs and BTM ESS

ix) Distribution substation projects that address load and generation headroom constraints

From the study results presented above, Figure 38 shows a list of substation projects that include both new substations and substation expansions that will increase load and generation headroom to meet the 70x30 CLCPA goals.

Figure 39: Phase 2 Projects that Increase Distribution System Capacity

Project Name	Zone	Substation	Project Description	Proposed I/S Date	Order of Magnitude (OOM) Cost Estimate	MW Headroom
Coxsackie	G	Coxsackie	New 2 Transformer Station	2030	$12M	44MW
Freehold	G	Freehold	2nd Transformer	2030	$4M	12MW
Lawrenceville	G	Lawrenceville	2nd Transformer	2030	$4M	12MW
North Catskill	G	North Catskill	New 3 Transformer Station	2030	$15M	66MW
Saugerties	G	Saugerties	3rd Transformer	2030	$4M	22MW
South Cairo	G	South Cairo	New 2 Transformer Station	2030	$12M	44MW
Westerlo	G	Westerlo	2nd Transformer	2030	$4M	22MW
				Total	$ 55M	222MW

C. Conclusion

Central Hudson identified local transmission and distribution projects necessary and appropriate to timely achieve the CLCPA's objectives. Central Hudson evaluated load and generation headroom metrics within the local transmission and distribution system and identified projects to address these constraints. Central Hudson also analyzed the NYISO's 2020 RNA 70x30 scenario load flow case to identify future constraints and proposed projects to address these constraints.

III. CONSOLIDATED EDISION COMPANY OF NEW YORK, INC.

A. Local Transmission

Consolidated Edison Company of New York's (CECONY) principal business operations are its regulated electric, gas and steam delivery businesses. CECONY provides electric service to approximately 3.5 million customers in all of New York City (except a part of Queens) and most of Westchester County, an approximately 660 square mile service area ("Service Area") with a population of more than nine million. In addition, CECONY delivers gas to approximately 1.1 million customers in Manhattan, the Bronx, parts of Queens and most of Westchester County. In addition, CECONY operates the largest steam distribution system in the United States, producing and delivering approximately 19,796 MMlb of steam annually to 1,589 customers in parts of Manhattan.

i) CECONY's Study Assumptions and Description of Local Transmission Design Criteria

1. Study Assumptions

The Utility Study is based upon the database established and used by the NYISO for the 2020 Reliability Needs Assessment (RNA) 70x30 CLCPA Scenario. The Utility Study is limited to a transmission security assessment only. In the case of CECONY, the Utility Study is limited to its Service Area.

The NYISO provided three base cases that allow transmission security assessment under steady state at various dispatches of renewable resources and at different load levels. These base cases are: (1) Day Peak Load of 30,000 MW (where the net load reflects Behind-the-Meter (BtM) solar reduction); (2) Shoulder Load of 21,500 MW (where the net load reflects BtM solar reduction) ; and (3) Light Load of 12,500 MW (where the net load reflects BtM solar reduction). The load is modeled based on the 2020 Gold Book forecast for 2030 with the noted adjustments for BtM solar. The renewable resource mix (using nameplate MW) included in the database consists of: (1) 6,098 MW Off-Shore Wind (OSW); (2) 8,772 MW Land Based Wind (LBW); and (3) 15,150 MW Utility based photovoltaic (UPV), for a total of 30,020 MW of renewables capacity. As it relates to CECONY's Service Area, the database includes a 1,310 MW HVDC tie from Hydro Quebec to New York City (Zone J) modeled as in-service. In addition, all Peaking Units affected by the DEC NOx Peaker Rule were removed from the database. Additional fossil fuel power plants were removed, as needed, based upon their age (oldest first).

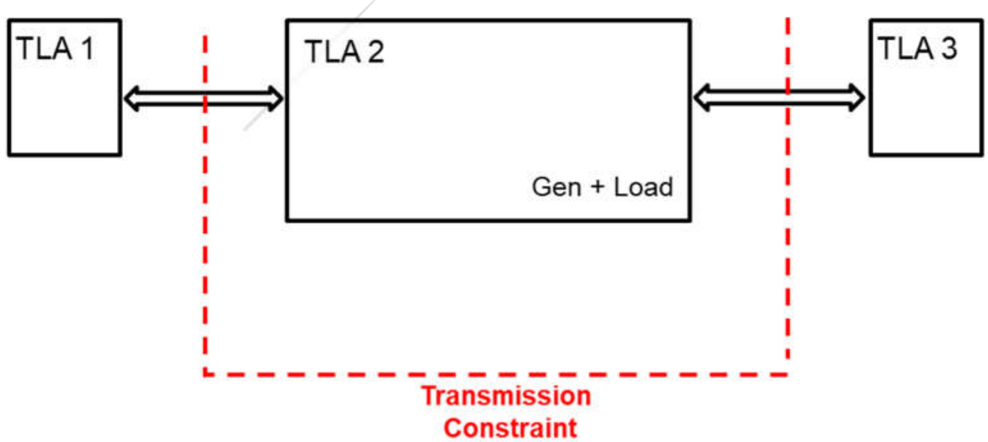
CECONY modified the provided database to (1) increase OSW from 6,098 MW to 9,000 MW, maintaining the distribution between Zones J and K based on load ratio share; and (2) modify Points of Interconnection (POI) of various assumed renewable resources based upon CECONY's knowledge of its Transmission System coupled with optimized energy delivery to load. While the CLCPA target requires 9,000 MW OSW by 2035, the Utilities determined it reasonable to model 9,000 MW interconnected by 2030 to capture the full impact of the state goal in the Utility Study.

2. *Description of Local Transmission Design Criteria*

System expansion and the incorporation of new facilities must follow published CECONY Transmission Planning Criteria (Specification TP-7100)[112] . Specification TP-7100 describes the planning criteria to assess the adequacy of CECONY's Bulk Electric System (BES) and certain non-BES 138 kV and 69 kV systems (collectively, the "Transmission System") to withstand design contingency conditions in order to provide reliable supply to all CECONY customers, throughout the planning horizon. The specification establishes Fundamental Design Principles and Performance Criteria. These two components complement each other and adherence to both is required by all new projects proposed by CECONY and by independent developers that connect to CECONY's Transmission System. In addition to Specification TP-7100, all facilities – generation and transmission – must be designed to conform with and adhere to all applicable North American Electric Reliability Corporation (NERC), Northeast Power Coordinating Council (NPCC), and New York State Reliability Council (NYSRC) Reliability Rules, including NYSRC Local Reliability Rules, as well as applicable CECONY specifications, procedures and guidelines.

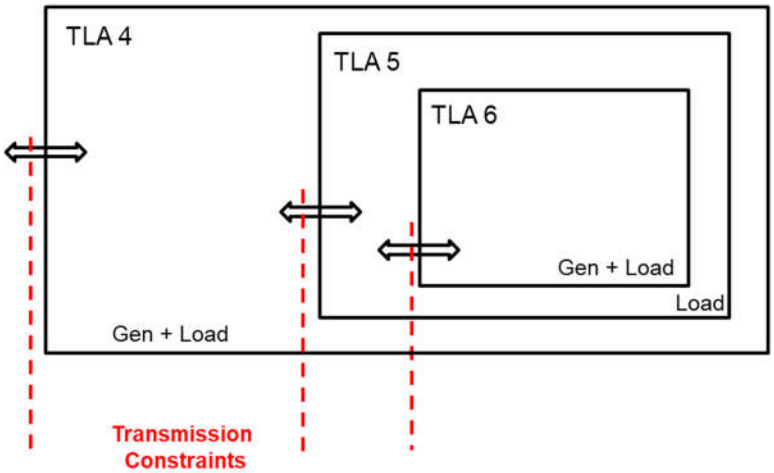
CECONY's Transmission System is comprised of seventeen (17) Transmission Load Areas (TLA). These TLAs were designated based on the identification of existing Transmission System constraints, where supply internal to the TLA is insufficient to meet the internal TLA load, hence the TLA is dependent on the transmission to balance supply and load. There are "Stand Alone" TLAs, where only one constraint exists between the area and the rest of the system (See Figure 40), and there are "Imbedded" TLAs, where one TLA is located within a larger TLA, which in turn is located in yet another TLA resulting in multiple constraints (See Figure 41).

Figure 40: "Stand Alone" TLA



[112] Publicly available at: https://www.coned.com/-/media/files/coned/documents/business-partners/transmission-planning/transmission-planning-criteria.pdf?la=en

Figure 41: "Imbedded" TLA



CECONY's TLAs are designed as follows: (1) those supplied by 345 kV are designed to Second contingency (i.e., N-1/-1/-0); (2) a list of specific 138 kV TLAs are also designed to Second contingency (i.e., N-1/-1/-0); and (3) the remaining 138 kV TLAs are designed to First contingency (i.e., worst of N-1 or N-1/-1). Specification TP-7100 identifies CECONY's TLAs with their designation as First or Second contingency design.

ii) Discussion of a Possibility of Fossil Generation retirements and the Impacts and Potential Availability of those Interconnection Points

There are currently 10,700 MW (nameplate) of fossil generation located within CECONY's service territory. Most, if not all, of the existing natural gas and oil-fired generation will need to be retired to achieve the mandates in the CLCPA. Because CECONY does not own a majority of the fossil generation on its local system (other than limited units to support its steam system), it does not have control over the fossil generation retirements. Further, availability of Points of Interconnection (POI) upon unit retirement is governed by NYISO tariffs and subject to FERC's open access rules.

Nevertheless, initial fossil generation retirements in CECONY's service territory will include those affected by the New York State Department of Environmental Conservation's (DEC) new air emissions regulations for simple cycle and regenerative combustion turbines ("Peaking Units"), which it adopted in 2019. The regulation, referred to as the "Peaker Rule," complements the CLCPA and supports its objectives by reducing nitrogen oxide (NOx) emissions from fossil generation during the summer Ozone Season, which is disproportionately located in neighborhoods already overburdened by pollution, such as the South Bronx, Sunset Park in Brooklyn, and other Environmental Justice Communities. The Peaker Rule phases in compliance obligation between years 2023 and 2025 and impacts approximately 3,300 MW of existing facilities located in downstate New York, with approximately 2,000 MW of these facilities located in New York City (Zone J). Owners of the impacted units have submitted compliance plans indicating their intention to either retire the units or operate them seasonally (outside of Ozone Season).

Many of the Peaking Units are located in already constrained areas, and so their retirement/unavailability will only exacerbate these constraints. In its analysis, CECONY assumed that all Peaking Units affected by the DEC NOx Peaker Rule were removed from the database. CECONY also assumed that none of the POI would be available for any of the assumed renewable additions. This assumption is based upon the following:

1) While existing POIs are grandfathered from current compliance obligations, any material change at the POI (*i.e.,* retirement of a fossil facility replaced by an Energy Storage System) must conform with and adhere to the latest applicable NERC, NPCC, and NYSRC Reliability Rules, including NYSRC Local Reliability Rules, as well as applicable CECONY specifications, procedures and guidelines, requiring such significant investment to utilize the existing POI that alternative POI options that are physically feasible maybe be more economical;

2) Existing POIs are located in already constrained areas and/or low voltage areas where, for example, a typical size of an OSW project would be un-deliverable due to bus equipment and/or outlet capability limitations and where local upgrades would be simply infeasible or cost prohibitive, and

3) CECONY does not own the POIs, and rules governing the use of POIs are established by the NYISO and FERC.

Finally, in addition to the Peaking Units POI, CECONY assumed in its analysis that none of the non-Peaking Units POI (e.g. Steam Electric and Combined-Cycle units) were available, since CECONY does not own these POIs and these non-Peaking Units may continue to be in-operation after 2030.

iii) Discussion of Existing Capacity “Headroom” within CECONY’s System

The existing capacity ‘headroom’ on CECONY’s Transmission System is not easily identifiable. On the Overhead (OH) portion of the Transmission System, the Right of Ways (ROWs) are fully utilized. For example, there are no double circuit towers ROW that has only one circuit strung. The Underground (UG) portion of the Transmission System is already optimized, and no simple upgrades, such as replacements of a disconnect switch, are possible to increase a feeder’s carrying capacity. Most of the bus positions within CECONY’s transmission substations are occupied; and expandability of these substations may not be feasible or cost effective. Further, due to Transmission System bottleneck or constraints, a renewable resource interconnected to an area (such as a TLA) may be deliverable only within that limited area before its flow is impeded by an upstream constraint.

For the purpose of this Report, CECONY identified Capacity “headroom” as the amount of interconnection of resources possible in a TLA before the first constraint binds and assuming no other constraints within the TLA. Thus, the listed “Headroom” values are overestimated.

CECONY's approach to identify existing Capacity "headroom" was to calculate local load – existing generation + outlet capability, under N-1 transmission conditions, both for the peak load and light load cases. These are approximate MW values. Physical feasibility and external constraints to the local TLA may preclude achieving these MW. Figure 42 identifies approximate Capacity "headroom" based on 2030 system conditions.

Figure 42: Approximate Capacity "Headroom"

Transmission Load Area	Projected Load		Existing Generation (MW)		Outlet Capability under N-1 (MW)		"Headroom" (Under N-1)	
	Peak Load	Light Load	Peak Load	Light Load	Peak Load	Light Load	Peak Load	Light Load
Staten Island 138 kV	596	232	395	401	627	738	828	569
Greenwood / Fox Hills 138 kV	1472	566	126	1244	949	1077	2295	399
Corona / Jamaica 138 kV	1242	475	414	420	1366	1536	2194	1591
Brooklyn / Queens 138 kV	3319	1273	2452	3673	1438	1660	2305	-740*
Eastern Queens 138 kV	1520	562	1169	1259	906	1044	1257	348
The Bronx 138 kV	1391	536	0	0	1671	1917	3062	2453
Dunwoodie South 138 kV	303	118	0	0	694	873	997	991
Dunwoodie North / Sherman Creek 138 kV	579	223	0	0	1270	1517	1849	1740
Eastview 138 kV	709	275	0	0	1167	1458	1876	1733
Millwood / Buchanan 138 kV	234	91	52	53	418	477	600	514
East River 138 kV	388	147	486	524	353	438	255	61
Vernon / Queensbridge 138 kV	1309	501	1106	1143	1657	1909	1860	1267
Astoria West / Queensbridge 138 kV	945	357	1220	1286	573	655	299	-274*
Astoria East / Corona 138 kV	1068	385	755	839	918	1064	1231	611
East 13th Street 138 kV	1021	385	640	723	1829	2159	2210	1821
West 49th Street 345 kV	2119	801	1210	1382	3562	4053	4471	3472
New York City 345/138 kV	11373	4316	8821	10392	3651	3974	6203	-2102*

*Negative Headroom under Light Load Conditions means that this amount of existing generation must be curtailed.

iv) Discussion of Bottlenecks or Constraints that Limit Energy Deliverability within CECONY's System

CECONY has identified the following TLAs where the current transmission capability will limit the amount of renewable generation that can be imported into the TLA and will require the continued operation of fossil fuel power plants in the TLA. If renewable resources cannot access the load located in these constrained TLAs, there will be excess renewable energy external to the local area providing zero value to these local customers and may result in curtailment. Figure 43 identifies these constrained TLAs.

Figure 43: Constrained TLAs

Transmission Load Area	Load Served (Peak)	Design Designation
Staten Island 138 kV	596	N-1/-1
Greenwood / Fox Hills 138 kV	1,472	N-1/-1
East River 138 kV	388	N-1/-1/-0
Vernon / Queensbridge 138 kV	1,309	N-1/-1/-0
Astoria West / Queensbridge 138 kV	945	N-1/-1/-0
Astoria East / Corona 138 kV	1,068	N-1/-1/-0
East 13th Street 138 kV	1,021	N-1/-1/-0

Transmission investments will be needed to address these bottlenecks or constraints and enable the State to meet the clean energy goals in the CLCPA. If renewable energy cannot serve customers within a load pocket, then fossil generation within the load pocket would continue to be required to run to serve the load, challenging the State's ability to achieve the CLCPA target of 70% renewable energy by 2030 and ultimately 100% emissions-free energy by 2040. The bottlenecks can be solved by load reductions and/or load transfers (i.e., load to be transferred out of the local constrained TLA to an unconstrained TLA), by local transmission additions, by renewable resource or energy storage additions within the TLA, or by a combination of these solutions. As large renewable intermittent resource additions connect to the 345 kV system, the constraints defining the TLAs must be addressed to enable the local loads within the constrained TLAs to be served by renewable supplies. This is especially true for New York City, where limited physical space in each of the 17 TLAs virtually forecloses the addition of utility scale PV or challenges large Energy Storage Systems within the TLAs. In addition, storage within the TLA would only partially address reliability needs, as the load pocket deficiencies extend over 10 to 14-hour periods, often over consecutive days. Energy Storage System technology to date would have difficulty responding for the duration of the reliability need period. The expansion of the Transmission System, by establishing "off-ramps" to connect the mostly free flowing 345 kV system to CECONY's 138 kV TLAs, would provide for the most effective utilization of renewable resources.

In addition to unbottling load located within TLAs, OSW will need to connect to New York City and/or Long Island to meet the CLCPA goal of 9,000 MW OSW by 2035. CECONY, in coordination with the Long Island Power Authority (LIPA), is designing an optimal plan to accommodate the injection of OSW into the two service territories, considering local transmission constraints. CECONY has identified transmission constraints for the injection of OSW into the overall New York City 345 kV / 138 kV TLA. These constraints, if not addressed, would limit OSW energy deliverability within CECONY's system, especially during off peak conditions. Given the typical size of an OSW project, connecting OSW directly to the free flowing 345 kV system is most sensible. However, because the existing Transmission System in New York City is limited in its expandability, with limited bus positions in existing substations, and limited locations to construct additional transmission substations, substantial upgrades will be required to interconnect new generation to the 345 kV system. Further, local constraints will need to be addressed to enable the OSW to both connect onto the 345 kV system and to reach bottled loads in the TLAs.

v) Discussion of Potential Projects that would Address Bottlenecks or Constraints that limit Energy Deliverability within CECONY's System

In order to meet CLCPA goals, Transmission System bottlenecks or constraints need to be eliminated to enable loads renewable resources to access and serve the load, especially when those renewable resources are connected outside the local area. Therefore, the local Transmission System should be expanded to provide both "on-ramps" (*i.e.,* moving renewable energy onto the 345 kV system highway) and "off-ramps" (*i.e.,* moving renewable energy off the 345 kV system highway down to the load areas, which would otherwise be served by fossil fuel power plants).

CECONY has identified potential projects that address the bottlenecks or constraints that limit energy deliverability. In identifying these projects, CECONY primarily seeks to meet the CLCPA targets, while simultaneously ensuring continued reliability and resilience of service to customers. For example, CECONY explored if a potential project would: (1) address reliability impacts of the DEC NOx Peaker Rule; (2) connect and fully deliver new resources such as OSW and new upstate renewables; (3) solve identified bottlenecks or constraints on the local system to enable loads to be served by renewable energy; and (4) address future load growth from electrification (due to CLCPA), while also improving resilience on CECONY's local system. Thus, these would be considered multi-benefit projects.

1. Addressing Constraint for the Astoria East / Corona 138 kV TLA

CECONY identified constraints on the Astoria East / Corona 138 kV TLA boundary feeders. These constraints are exacerbated by the retirement of local Peaking Units driven by DEC's NOx Peaker Rule. To address both the constraint and the need, CECONY is planning the installation of a 6-mile-long, 345 / 138 kV Phase Angle Regulator (PAR) controlled feeder. The new feeder will be placed in commercial operation by Summer 2023, to meet reliability needs identified in NYISO's 2020 RNA and the 2020 Quarter 3 STAR arising by that date, and coinciding with the first deadline by which Peaking Units must comply with the DEC NOx Rule's new emissions standards. The new feeder will electrically connect CECONY's 345 kV Rainey substation with CECONY's

Corona 138 kV substation creating the first of several 345 to 138 kV “off ramps” that will be necessary to support a clean energy future. The proposed feeder will have a nominal capability of approximately 300 MW. Therefore, it will enable 300 MW of renewable supply to access the load. The feeder will address the identified constraints on the Astoria East/Corona 138 kV TLA boundary feeders, and additionally allow renewable resources to access the load on CECONY’s 138 kV system, eliminating the dependency on local fossil fuel power plants to maintain local reliability.

2. *Addressing Constraint for the Greenwood / Fox Hills 138 kV TLA (Including the Staten Island 138 kV TLA)*

CECONY identified constraints on the Greenwood / Fox Hills 138 kV TLA boundary feeders. These constraints are exacerbated by the seasonal unavailability and/or retirement of local Peaking Units driven by DEC’s NOx Peaker Rule. In addition, CECONY identified constraints on the neighboring Staten Island 138 kV TLA if the local fossil fuel power plant(s) becomes unavailable or retires.

Due to the size of the constraint (370 MW) CECONY is planning to install two new feeders. The first feeder is planned to be an approximate 1-mile-long, 345 / 138 kV Phase Angle Regulator (PAR) controlled feeder. The feeder will be placed in commercial operation by Summer 2025, to meet reliability needs promulgated by the DEC NOx Peaker Rule and identified in NYISO’s 2020 RNA arising by that date and coinciding with the second deadline by which Peaking Units must comply with the DEC NOx Rule’s second set of new emissions standards. The new feeder will electrically connect CECONY’s 345 kV Gowanus substation with CECONY’s Greenwood 138 kV substation, creating another ‘off-ramp’ to support the pathway to deliver clean energy supplies.

The second feeder is planned to be an 8-mile-long, 345 / 138 kV Phase Angle Regulator (PAR) controlled feeder that will also be placed in commercial operation by Summer 2025 to meet local system reliability needs, and additionally address a portion of the bulk system reliability needs, promulgated by the DEC NOx Peaker Rule and identified in the RNA arising by that date. The new feeder will electrically connect CECONY’s 345 kV Goethals substation with CECONY’s Fox Hills 138 kV substation, installing a third such “off-ramp” on the CECONY’s Transmission System. The existing Fox Hills 138 kV substation will be re-configured as a 138 kV Ring Bus. This will not only ensure compliance with the latest applicable specifications, procedures and guidelines but will also alleviate many of the limitations imposed by the current straight bus design that limits transfer capability between substations, imposes constraints on planned outages, results in the loss of multiple facilities for a single outage and could require curtailment of renewable resources during planned or unscheduled transmission facility outages. Both feeders will have a nominal capability of approximately 300 MW each. Therefore, it will enable 600 MW of renewable supply to access the load. Not only will the feeders address the identified constraints on the Greenwood / Fox Hills 138 kV TLA boundary feeders but they will also allow approximately 600 MW of renewable resources to access the load on CECONY’s 138 kV system, decreasing the dependency on local fossil fuel power plants to maintain local system reliability. Further, the Goethals to Fox Hills feeder will un-bottle some of the existing (and future) resources connected to Staten Island's 345 kV and 138 kV system.

3. Addressing Constraint for the East River 138 kV TLA, East 13th Street 138 kV TLA, and Vernon / Queensbridge 138 kV TLA

CECONY identified constraints on the East River 138 kV TLA "Imbedded" within the East 13th Street 138 kV TLA, and on the "Stand Alone" Vernon / Queensbridge 138 kV TLA boundary feeders. Although these TLAs are mostly independent of each other, CECONY identified a potential single cost-effective project that addresses these three constrained TLAs and also creates POIs for new resource interconnections, such as OSW (for about 2x750 MW connection or approximately 1,500 MW total). The project, referred to herein as New York City Clean Energy Hub #2, is a conceptual project that will require more detailed engineering studies. The project will transfer load from the constrained 138 kV system to a 345 kV substation within New York City while simultaneously create new POIs for clean energy and/or new technology resources. Initial load un-bottling is estimates to be approximately 440 MW, with additional load unbottling estimated at an incremental 240 MW.

Renewable resources will be able to access the un-constrained load transferred out of the constrained CECONY's 138 kV system and reduce the load's dependency on local fossil fuel power plants to maintain local system reliability. CECONY is estimating that this project can be placed in commercial operation by Summer 2029.

4. Addressing Constraint for the Astoria West / Queensbridge 138 kV TLA

CECONY identified constraints on the Astoria West / Queensbridge 138 kV TLA boundary feeders. This TLA currently depends on three base load fossil power plants to be on-line (at peak and at certain levels of off-peak) for the TLA to meet its N-1/-1/-0 planning and operational requirements. CECONY identified a potential cost-effective project that will address the identified constraint through load transfers. That is some load will be transferred out of the local constrained TLA to an unconstrained TLA. Specifically, CECONY would propose transferring 406 MW out of the constrained 138 kV system to be supplied by an existing 345 kV substation. Thus, the project would enable renewable resources to access the un-constrained load that is transferred out of the constrained CECONY's 138 kV system, and also reduce the local system's dependency on local fossil fuel power plants to maintain reliability. CECONY estimate that this project can be placed in commercial operation by Summer 2030.

5. Addressing Constraints for the overall New York City 345 / 138 kV TLA

To meet the CLCPA goal of 9,000 MW OSW by 2035, OSW will need to interconnect to New York City and/or Long Island. CECONY, in coordination with LIPA, is designing an optimal plan to integrate the injection of OSW into the two service territories, considering local transmission constraints. In addition, there will be a need to construct transmission to redistribute the renewable intermittent power throughout CECONY's local Transmission System to both supply local loads and export to upstate load areas to prevent OSW's curtailment.

In the analysis, confirmed by the Utility Study, CECONY has identified transmission constraints for the injection of OSW into the overall New York City 345 kV / 138 kV TLA. These constraints, if not addressed, would limit OSW's integration onto the local 345kV system to deliver to upstate loads, as well as limit its deliverability within CECONY's system, especially during off peak conditions. CECONY identified three potential local cost-effective 345 kV feeders (NYC Feeder 1, 2 and 3) that will address the identified constraints. Each local feeder, located wholly within CECONY's service territory and rated at approximately 700 MW, will also allow upstate renewable resources access to downstate loads, thus facilitating the unbottling effect of those supplies from northern New York State. Just as importantly, these three feeders will enable the redistribution of the OSW throughout the local Transmission System so that it can be effectively utilized during peak and off peak periods, as well as exported during periods that would otherwise lead to curtailments. CECONY estimate that the first feeder can be placed in commercial operation by Summer 2027, and that the remaining two feeders can be placed in commercial operation by Summer 2030.

While the primary driver of these three local feeders is the integration of OSW (that is, they would not have been identified "but for" the CLCPA driver), as noted above they will provide a number of additional benefits to facilitate achievement of the CLCPA goals and as well as improve the resilience and operation of the local system.

vi) Discussion of Potential Projects that would Increase Capacity on the Local Transmission and Distribution System to allow for Interconnection of New Renewable Generation Resources within CECONY's System

CECONY assessed potential projects that could increase capacity on CECONY's Transmission System to allow for connection of new resources. Most of the bus positions within CECONY's Transmission Substations are occupied, and expandability of many substations may not be feasible or cost effective. CECONY explored the ability to upgrade existing or construct additional local transmission substations to connect new OSW, Energy Storage Systems, or other new, clean resources. Such projects are designed to be "multi-benefit," providing the benefits associated with achieving the goals of CLCPA, and simultaneously providing operational and resiliency benefits to CECONY's local Transmission System.

In addition to the potential project described under V.3. - New York City Clean Energy Hub #2 – CECONY has identified a another potential cost-effective project that would create POIs for new resource interconnections, such as OSW (for approximately 4x750 MW connections or 3,000 MW total). The project, referred to herein as New York City Clean Energy Hub #1, is a conceptual project that will require detailed engineering studies CECONY estimates that the project can be placed in commercial operation by Summer 2027, prior to the New York City Clean Energy Hub #2.

vii) Conclusion

Consistent with the May Order, this Report presents the results of CECONY's transmission security assessment identifying potential local system upgrades that will facilitate meeting CLCPA goals, as required by the AREGCB Act. Figure 44 identifies Phase 1 projects with Order of Magnitude (OOM) Cost Estimates. Additionally, Figure 45 identifies Phase 2 projects with Order of Magnitude (OOM) Cost Estimates.

Figure 44: Phase 1 Immediately Actionable Projects

Project Name	Zone	Terminal A	Terminal B	Project Description	Estimated Project Benefit (MW)	Proposed In-Service Date	Order of Magnitude (OOM) Cost Estimate
2nd Rainey – Corona Feeder	J	Rainey	Corona	New 345 / 138 kV PAR Controlled Feeder (~6 Miles UG)	300	2023	-
3rd Gowanus – Greenwood Feeder	J	Gowanus	Green-wood	New 345 / 138 kV PAR Controlled Feeder (~1 Miles UG)	300	2025	-
Goethals – Fox Hills	J	Goethals	Fox Hills	New 345 / 138 kV PAR Controlled Feeder and Rebuild of Fox Hills 138 kV Substation (~8 Miles UG)	300	2025	-
						Total:	$860M

Figure 45: Phase 2 Additional Potential Projects

Project Name	Zone	Terminal A	Terminal B	Project Description	Estimated Project Benefit (MW)	Proposed In-Service Date	Order of Magnitude (OOM) Cost Estimate
NYC Clean Energy Hub #1	J	TBD	TBD	Clean Energy Hub to provide additional POIs into local system	3,000	2027	-
NYC Clean Energy Hub #2	J	TBD	TBD	Clean Energy Hub to provide additional POIs into local system and enable load transfer	2,180	2029	-
NYC Feeder 1	I, J	TBD	TBD	Each is a new local Feeder to unbottle renewable supplies	700	2027	-
NYC Feeder 2	J	TBD	TBD		700	2030	-
NYC Feeder 3	J	TBD	TBD		700	2030	-
Load Transfer	J	TBD	TBD	Rebuild 2 Area Stations; Load Transfer	406	2030	-
						Total:	$4.05B

As listed in Figure 44, CECONY has identified three immediately actionable projects that are needed to give renewable resources access to the load, and unbottle load currently served by fossil generation while also enabling compliance with the DEC NOx Peaker Rule. CECONY is currently planning to file a petition with the Commission by the end of the year seeking approval to recover the costs of such projects and will provide each individual project's cost estimate for inclusion in the petition. Further, while CECONY proposes to recover costs for these projects through its rate plan capital budget due to the timing of when the projects are expected to be in service (*i.e.*, the first project will be in service in 2023), CECONY requests herein that the Commission consider the significant regional environmental benefits these three immediately actionable projects provide. Specifically, while the projects are needed to meet local system reliability needs, the Commission should recognize that such needs arise as a result of State action, taken as an initial step towards the achievement of CLCPA's climate goals, to reduce polluting emissions from the older peaking units located in New York City, many of which are in or near disadvantaged communities. Because these projects satisfy reliability needs while also facilitating the State's ultimate goal of replacing the State's combustion powered peaking units with clean energy sources, CECONY requests that:

1. The Commission approve cost recovery of the identified Phase 1 projects in this case, and approve recovery of the costs of these three projects;[113]
2. The Commission acknowledge that projects that result from the Peaker Rule qualify as CLCPA projects; and
3. The Commission credit to CECONY the costs of such projects, should the Commission develop and implement a future accounting framework to balance the CLCPA-related costs incurred by the utilities statewide, as described in the policy recommendations set forth elsewhere in this Report.

Further, in Figure 45 CECONY has identified six additional Phase 2 potential projects with broad regional CLCPA benefits that can be implemented by 2030, and which are necessary to integrate 9,000 MW of OSW feasibly and cost-effectively into New York City and Long Island. Although not proposed in Phase 1, timely approval and construction of these projects is necessary to provide offshore wind developers with needed certainty regarding viable interconnection locations, facilitate the most competitive and efficient response to any future offshore wind solicitations, and satisfy the CLCPA's renewable and offshore wind goals in a timely, and the most cost effective and efficient manner. Accordingly, for the foregoing reasons, CECONY requests that:

1. The Commission confirm in its Order adopting policies, or in its Order establishing utility capital plans implementing identified distribution and local transmission upgrades, that

[113] As noted above, CECONY may also file a separate petition for cost recovery of these projects, as contemplated by its current rate plan. See Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Consolidated Edison Company of New York, Inc. for Electric Service (Case 19-E-0065) (2019). CECONY will consult with DPS Staff regarding the need to file this separate petition.

each of the projects identified in Figure 45 is a local transmission project, within the meaning of the AREGCB Act and the May Order;

2. The Commission approve each of the six projects identified in Figure 45 for cost recovery, and direct the construction of such projects, starting first with the NYC Clean Energy Hub #1. In evaluating Phase 2 projects, NYC Clean Energy Hub #1 should be among the first projects to advance, due to the need to create POIs[114] in advance of generation to produce the most cost effective, efficient solutions for all New Yorkers; and
3. The Commission implement a cost allocation framework that allocates the costs of these Phase 2 projects statewide on a load ratio share basis, consistent with the policy recommendations elsewhere in this Report and with the statewide CLCPA benefits such projects provide.

B. Distribution

i) Introduction

Meeting the CLCPA targets, including 3,000 MW of storage by 2030 and 9,000 MW of offshore wind by 2035, will require significant investment in transmission to address existing bottlenecks and constraints and interconnect new renewable resources. While transmission represents a critical path for meeting CLCPA goals, the distribution system also plays an important role in delivering power to end users, serving as a distribution system platform (DSP) for customer products and services, and maintaining system safety and reliability by balancing supply and demand at the local level using tools such as demand response and energy storage.

In response to the Reforming the Energy Vision (REV) initiative and in line with industry trends, CECONY is investing approximately $1.1 billion over the 2020-2025 period[115] to build the DSP and modernize the electric grid. These ongoing investments are resulting in a grid that is flexible and adaptable to the changing resource mix, agile in the face of more dynamic grid operations, and capable of effective coordination between the wholesale market and distribution system operation. Through these investments, as well as innovations in system design and organizational efficiencies, CECONY is actively preparing for a clean energy future characterized by accelerated growth of distributed energy resources (DER) and electric vehicles (EVs). Additionally, increased system visibility, flexibility, and agility will help CECONY manage the shift to electric space heating and the resulting increase in winter load.

CECONY has already enabled the interconnection of approximately 300 MW of distributed solar generation and 11 MW of energy storage, and CECONY expects even higher penetration of these resources in the future. In anticipation of evolving system needs, CECONY

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114 POIs are subject to FERC Open Access rules.

115 This includes projects approved as part of CECONY's 2020-2022 rate case, approved during a prior rate case but with investment spanning into this timeframe, or included in CECONY's five-year capital plan.

has employed a programmatic approach to create distribution system flexibility by integrating non-utility-owned assets into the Company's system planning and performance evaluation. As a result of this approach, which also incorporates clean energy drivers, CECONY's planning process has effectively prepared the Company for forecasted needs until 2030. Additionally, in contrast to other New York distribution utilities that are more likely to face distribution system constraints due to significant solar, storage, and wind penetration, CECONY's future distribution system constraints are most likely to arise due to significant increases in electrification, which the Company forecasts is likely to transpire after 2030.

ii) Phase 1 Projects

The Company's distribution system Phase I initiatives represent significant progress toward the CLCPA's vision of a decarbonized grid begun under the REV initiative. The Company is committed to executing its approved investment plans, including adding at least 50MW of distribution-connected storage and investing $395 million in EV make-ready programs through 2025. The Company has also identified opportunities where existing investment programs can be expanded and accelerated to advance CLCPA goals, such as adding funding to modernize a larger percentage of network protector relays to increase hosting capacity and extending the Newtown Non-Wires Solution ("NWS") energy storage system to help prepare the Glendale/Newtown load area for EV adoption and electrification, enable greater integration of DER and energy storage, and provide additional resilience benefits.

CECONY's DSP, grid modernization, and REV initiatives promote a cleaner, more sustainable energy future, enhance the customer experience, and build the capabilities necessary for integrating DER. These efforts include working towards a transformative and scalable DSP that enables the bi-directional flow of energy and greater utilization of DER to meet system needs. Implementing these projects and programs will position the Company to meet evolving customer expectations, as well as make progress toward meeting the State's clean energy policy goals.

As shown in Figure 46, the Phase I projects total approximately $1.1 billion over the 2020-2025 period and include those already funded or represented in the Company's five-year capital plan. Many of the currently budgeted projects extend beyond the three-year timeframe of the Company's last rate case, with future phases to be described as part of the Company's next rate request. The Company continues to execute these investment programs, which are already providing customer benefits.

Figure 46: Phase 1 Project Portfolio

Project Name	Project Description	MW Impact	Proposed In-Service Date	Order of Magnitude Cost Estimate ($000s)[116]
DSP Programs	Investments to improve distribution system safety, reliability, resiliency, efficiency, and automation	-	2020+	$107,000*
DSP Incremental Programs	Incremental investment in the DSP	-	2024	-
Communications Infrastructure	Systems to manage data exchange across systems, applications, and devices	-	2020+	$50,000*
Newtown Extension	Expansion of planned NWS to install new transformer and sub-transmission line	120	2025	-
Vinegar Hill Distribution Switching Station ("DSS")	Distribution switching station to add capacity and provide operational flexibility	240	2022	$215,000*
Energy Storage Program	Five projects to provide a range of operational and CLCPA-related benefits	50	2025	-
Fox Hills Energy Storage Project	Energy Storage at Area Substation to facilitate DER interconnection and provide system support	7.5	2022	22,000*
EV Make-Ready Investments	Investments as approved by the Commission	-	2025	$395,000*
		Phase 1 Total		$1,130,000

* Denotes projects already funded (totaling $789 million).

1. Grid Modernization and DSP Investment Programs

As authorized in CECONY's last rate case, CECONY is investing an average of approximately $36 million per year over the 2020-2022 rate period to develop or enhance capabilities that improve the safety, reliability, resiliency, efficiency, and automation of the electric distribution system. Together, these expanded capabilities are creating a next-generation grid that can support CLCPA and REV goals.

As described in CECONY's 2020 Distributed System Implementation Plan ("DSIP"), many of these investments provide multiple customer benefits, simultaneously supporting decarbonization, increasing resilience to extreme weather events and climate change, enabling DER growth, and improving the customer experience. As authorized in the Company's last rate case, CECONY is investing approximately $107 million over the 2020-2022 rate period to build a DSP and develop or enhance capabilities that improve the safety, reliability, resiliency, efficiency, and automation of the electric distribution system. CECONY plans to continue funding the DSP in

116 The budget for Phase I projects represents amounts already approved by the New York Public Service Commission through CECONY's 2020-2022 rate case period or included in CECONY's five-year capital plan. The budget for Phase 2 projects represents total expected future costs associated with each project.

future rate filings Together, these expanded capabilities are creating a next-generation grid that can support CLCPA and REV goals.

For example, CECONY is on track in its installation of modernized protective relays ("MNPRs") and supervisory control and data acquisition ("SCADA"), with 600 microprocessor relay upgrades and 200 SCADA-enabled locations scheduled per year for 2020-2022. This is part of a program to upgrade the Company's underground network protectors to have bi-directional capabilities, which minimizes trips from backfeed due to DG or energy storage discharge, increases available hosting capacity, and enables lower-cost interconnection, while also providing greater grid edge visibility and shorter response time to system operators.

These programmatic investments are part of a broader grid modernization initiative that includes a Geographic Information System ("GIS," which is not included in the Phase 1 Projects), smart sensors and other tools to facilitate situational awareness, and associated communications and applications. Smart sensors, Distributed Energy Resource Management System ("DERMS"), MNPRs and other technologies depend on communications infrastructure to manage data exchange across systems, applications, and devices and maximize the value of these other investments. CECONY is approved to spend $50 million on communications infrastructure over the three-year period, with work extending into future years.

In addition to these investment programs, CECONY plans to continue investing in NWS, such as DG, energy storage, and energy efficiency ("EE") projects, to address capacity constraints as they arise on the system. Previously used to avoid transmission and distribution buildout, CECONY will use NWS in complementary portfolios that include traditional upgrades and meet the expected increased loading from electrification.

Consistent with this evolution in philosophy driven by CLCPA, CECONY will evaluate an extension to the existing Newtown NWS scope—which aims to address projected overloads in the Vernon to Glendale/Newtown/Amtrak load pocket—to defer traditional infrastructure upgrades. Following the NWS, CECONY plans to install a fourth 138/27 kV area station transformer at the Newtown substation (93.3 MVA) and new sub-transmission line to feed the fourth bank from the Vernon 138 kV substation. The project could be implemented as early as 2025.

The Newtown Extension will help prepare CECONY for achievement of multiple CLCPA objectives. First, it will prepare the Glendale/Newtown load area for greater levels of EV adoption, building electrification, and intrinsic load growth in the future. Second, it will allow for additional system capacity to integrate increasing levels of DG and energy storage. Finally, the project will add more resilient substation capacity in the Long Island City network area and provide additional contingency capability for supply of the Amtrak power facility at Sunnyside Yards.

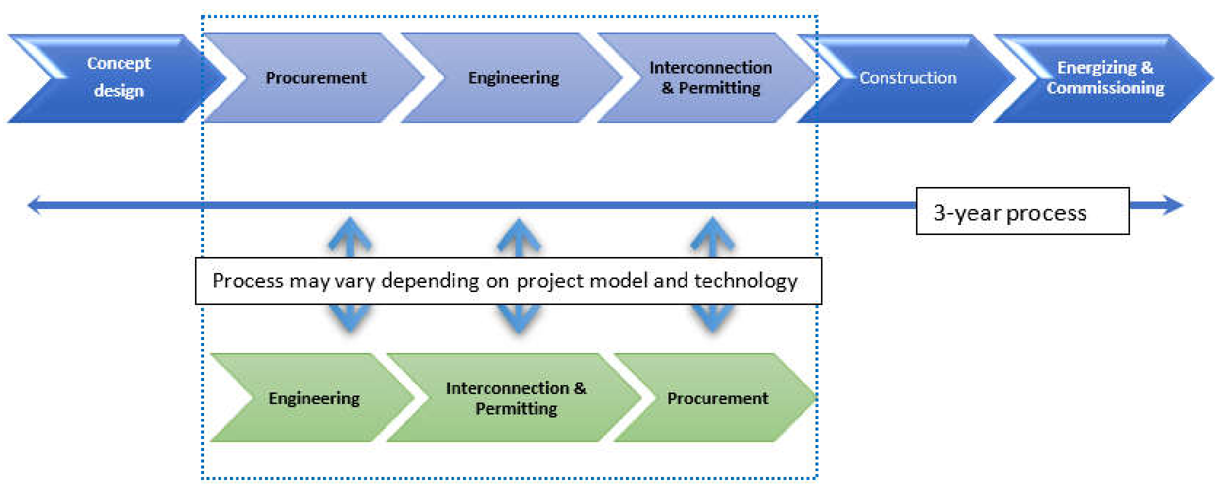
To develop an effective solution for a separate Water Street/Plymouth Street NWS, the Company is leveraging a combination of EE programs, DG, and storage to address near-term load relief needs through 2021 and enable a longer-term traditional solution—a less expensive DSS—at Vinegar Hill that will add capacity and provide operational flexibility. The DSS project, totaling approximately $215 million over the current three-year rate period, includes two new 138/27 kV transformers (supplied from 138 kV Hudson Ave East Transmission station), which will increase Plymouth Street's capability from 382 MW to 502 MW and Water Street's capability from 377 MW to 497 MW. The project is expected operational in 2022.

CECONY expects NWS to continue to benefit customers by reducing demand and spurring third-party investment. The experience the Company has gained through implementing its NWS portfolio will be valuable as the Company explores optimizing NWS with traditional solutions to serve expected load growth from electrification. For example, because of CECONY's unique network topology, CECONY can leverage NWS with advanced switching plans and bi-directional network protector relays to expand available system capacity. The Company can target these innovative solutions to areas most likely to see load growth from electrification, such as EV adoption and heating oil conversions in outer boroughs, as well as to diversify resources and increase resilience in critical areas. The ability to use technology to relieve feeder loading and add capacity takes on added significance considering CECONY's dense urban environment with limited physical space for larger-scale solar and storage installations.

2. *Energy Storage Program*

The Company, through a combination of its last rate case and current five-year capital plan, will be investing in five energy storage projects aimed at providing a range of benefits aligned with the CLCPA, including accommodating greater penetration of intermittent renewables and electrification while also providing greater resilience in high-need areas. These projects, which will be in Staten Island, Brooklyn, Queens, Bronx, and Westchester, will introduce at least 50 MW of new storage capacity onto the distribution system and be in service by 2025.

Figure 47: Prototypical Energy Storage Development Timeline



3. *EV Make Ready Investments*

The New York Public Service Commission's ("Commission") July 16, 2020 Order authorized CECONY to incent customers up to $287 million through 2025 as part of "a multi-year approach to develop and deploy the minimum critical infrastructure necessary to support the EV charging market and EV adoption."[117] In addition, CECONY estimates $93 million dollars in corollary new business developments, which results in $380 million towards EV make-ready programs. When coupled with the Nevins Street Energy Storage and EV Make-Ready project, the total EV make-ready investment is $395 million. As described in the Company's EV Make-Ready Program Implementation Plan,[118] the Company will incent make-ready infrastructure for new Level 2 and Direct Current Fast Charging ("DCFC") EV charging stations for light-duty vehicles in the Company's service territory. This includes utility electric infrastructure needed to connect and serve the load associated with new EV chargers that would have otherwise been paid by the installing customer, such as step-down transformers, overhead or underground service lines, and utility meters.

iii) Phase 2 Projects

To more closely align the distribution system's capabilities with CLCPA goals and timelines, CECONY scoped potential new projects, referred to as Phase 2 projects, that will be necessary to meet CLCPA goals and prepare for a future characterized by significant DER and renewables penetration. As described below, CECONY's distribution evaluation identified two projects that will help it prepare for prospective system changes due to achievement of CLCPA objectives.

Figure 48: Phase 2 Projects

Project Name	Project Description	MW Impact	Proposed In-Service Date	Order of Magnitude Cost Estimate ($000s)
New Area Substation	New substation and sub-transmission feeders to pick up load from nearby network	235	2030+	-
Energy Storage Projects	Six individual projects to provide a range of benefits	125	2030	-
			Total	$1,300,000

117 Case 18-E-0138, *Proceeding on Motion of the Commission Regarding Electric Vehicle Supply Equipment and Infrastructure* ("EVSE&I Proceeding"), Order Establishing Electric Vehicle Infrastructure Make-Ready Program and Other Programs (issued July 16, 2020) ("EV MRP Order"), p. 18.

118 EVSE&I Proceeding, Con Edison Electric Vehicle Infrastructure Make-Ready Program Implementation Plan (September 14, 2020).

iv) Distribution Needs Evaluation

As part of the Transmission Planning Working Group, CECONY aligned its annual system forecasting activities with the broader effort to incorporate CLCPA assumptions into the Company's system performance analysis. The Company aligned NYISO 70x30 projections with the "bottoms up" network forecasts and area substation load relief plans, comparing existing area station capability against CLCPA-related drivers on a 10- and 20-year basis. The technical analysis afforded the Company an opportunity to evaluate its system planning activities against 2030 and 2040 CLCPA goals, which underscore the likely impacts and resulting need for system expansion in CECONY's service territory due to load growth from increased electrification and EV adoption.

Through the REV initiative, the Company has taken steps to adjust business-as-usual ("BAU") planning to incorporate clean energy drivers into system forecasting and performance evaluation. CECONY accounts for BAU adoption of clean energy resources (*i.e.*, DG, demand response, and EE) as load modifications against the system peak by applying a coincidence factor. NWS have also been used as a viable means for system planners to address planning issues due to load growth within the Company's network areas.

To date, the most significant challenge to DG interconnection in the CECONY service territory has been minimum load conditions within the secondary network given the effect of reverse power flows on network protector relays. As a result, the Company has adopted a programmatic and multi-value approach to modernize protective relays and replace older, more sensitive equipment with modernized relaying capable of delineating fault current from steady DG backfeed. Through this effort, the Company also realizes additional benefits by gaining insight into the real-time performance of the distribution system as well as having the ability to remotely operate these devices. This type of system evolution has driven the Company to implement programmatic approaches that create distribution system flexibility by integrating non-utility-owned assets into system planning and performance evaluation. The Company intends to continue funding and employing programmatic approaches, where feasible, as they can easily be incorporated into traditional planning criteria and allow for system reinforcement and project design that can incrementally address changing system conditions over a longer timeframe.

Additionally, ongoing efforts related to hosting capacity analysis—including an October 2020 refresh of the Company's hosting capacity maps—continue to refine minimum load models to identify areas where DG penetration has the potential to create system constraints. CECONY evaluated the DG queues to establish areas where programmatic approaches to system design would not be sufficient to address longer-term penetration challenges. Currently, the Company's protective relay modernization program targets areas of high DG penetration within the CECONY network systems, alleviating issues stemming from DG backfeed under minimum load conditions. The Company prioritizes these relays using evaluations of current DG queues and expected growth rates of DG within the network system.

Separately, the Company continues to utilize the Network Reliability Index ("NRI") to prioritize investments. This simulation ranks network areas by the probability of a cascading event occurrence. CECONY prioritizes networks with a lower NRI for capital investment used to improve resiliency and reliability. This process exists as a parallel effort to traditional primary and secondary system reinforcement analysis that is an output of the Company's annual planning cycle.

The Company also evaluated the transmission projects identified through the technical analysis to align on a multi-value approach where applicable. The Company identified areas where proposed transmission investment may complement distribution system design through resiliency, future prepping, and enablement of electrification. CECONY evaluated scenarios where it may need projects to supplement transmission infrastructure or could incrementally add them to existing distribution project plans. Finally, the Company evaluated currently funded projects and programs as well as investments currently included in the Company's capital forecast for potential changes or incremental additions that could provide additional benefits for achieving CLCPA objectives.

1. Project Descriptions

CECONY identified two Phase 2 projects totaling $1.3 billion that will enable the Company to more effectively prepare for a future distribution system characterized by significant DER and renewables penetration and increased load levels due to meeting CLCPA objectives. Since these projects are driven by currently forecasted future conditions assuming achievement of CLCPA objectives, in the future CECONY will monitor changing market conditions and distribution capacity to possibly revise the specific scope and funding levels for each project in response to changing market conditions and transmission capacity.

The proposed Phase 2 projects reflect a long-term view based on the CLCPA timeline trajectory and consider the whole electric system, including interdependencies between transmission and distribution system investments. In its analysis, the Company sought opportunities wherever possible to both build in optionality, such that projects are designed for and anticipate future expansion, and to maximize benefits, including addressing the three primary investment drivers shown in Figure 49 below: carbon-free generation, electrification, and resilience.

Figure 49: Three Primary Investment Drivers

These identified projects make sense under a range of scenarios. However, because some of the Phase 2 projects are in response to post-2030 system needs, the Company will continue to evaluate emerging trends and may modify or propose new projects as warranted. Similarly, significant engineering design work will need to take place prior to project implementation, which will firm up project specifications and cost.

a) New Area Substation

This project will include the installation of a new area substation and four 138 kV sub-transmission feeders in one of the faster growing outer boroughs of New York City that is also primarily located in a low elevation flood prone area. This new area station will serve to create a new network by picking up load (via load transfers) from two nearby networks. The project has an estimated cost of approximately $1 billion and will be implemented sometime after 2030 depending on the speed of electrification from transportation and heating.

The New Area Substation project will also help prepare the Company for achievement of CLCPA objectives in multiple regards. First, the project improves resiliency by improving reliability in both networks from which load is transferred from and creating a new network with higher reliability than the original networks that comprise it. Second, this project prepares the area, with a relatively larger number of commuters who drive for use of EVs in support of CLCPA's clean energy goals. Third, it is anticipated that this project will increase headroom in the substations that will provide optionality to install energy storage at the new substation and add further resiliency to the area.

b) Energy Storage Projects

The Company has identified six energy storage projects that will help it prepare for meeting CLCPA objectives, totaling up to a combined 125 MW in capacity. These projects will provide a range of benefits, including increased headroom to integrate a growing penetration of offshore wind, DG, EVs and building electrification, targeted locational peak load reductions and voltage support, and enhanced resilience to future heat waves and flooding. While the Company will need to address potential challenges to deploying these projects, such as receiving New York City and Fire Department of New York ("FDNY") permits, they will directly support achievement of CLCPA objectives. All projects will be in service by 2030.

IV. LONG ISLAND POWER AUTHORITY/PSEG LONG ISLAND

Long Island Power Authority ("LIPA") respectfully submits this Report in accordance with the Order on Transmission Planning Pursuant to the Accelerated Renewable Energy Growth and Community Benefit Act (AREGCB Act) issued by the New York Public Service Commission ("Commission") on May 14, 2020 ("May 14 Order"). This Report provides results of LIPA's portion of the Utility Study to identify distribution and local transmission upgrades necessary or appropriate to timely achieve the State's climate goals as set out in the Climate Leadership and Community Protection Act ("CLCPA").

LIPA provides electric service to approximately 1.1 million customers in Nassau and Suffolk Counties and on the Rockaway Peninsula in Queens. LIPA's service territory covers about 1,230 square miles, encompassing nearly 90 percent of Long Island's total land area. The area closer to Queens County in New York City is more urbanized and the area to the eastern portion is rural. Three small independent municipal electric systems - Freeport, Rockville Centre, and Greenport - are located within the LIPA service territory. The LIPA owned transmission and sub-transmission system includes approximately 1,400 miles of overhead and underground lines with voltage levels ranging from 23 kV to 345 kV.

A. LIPA Transmission System

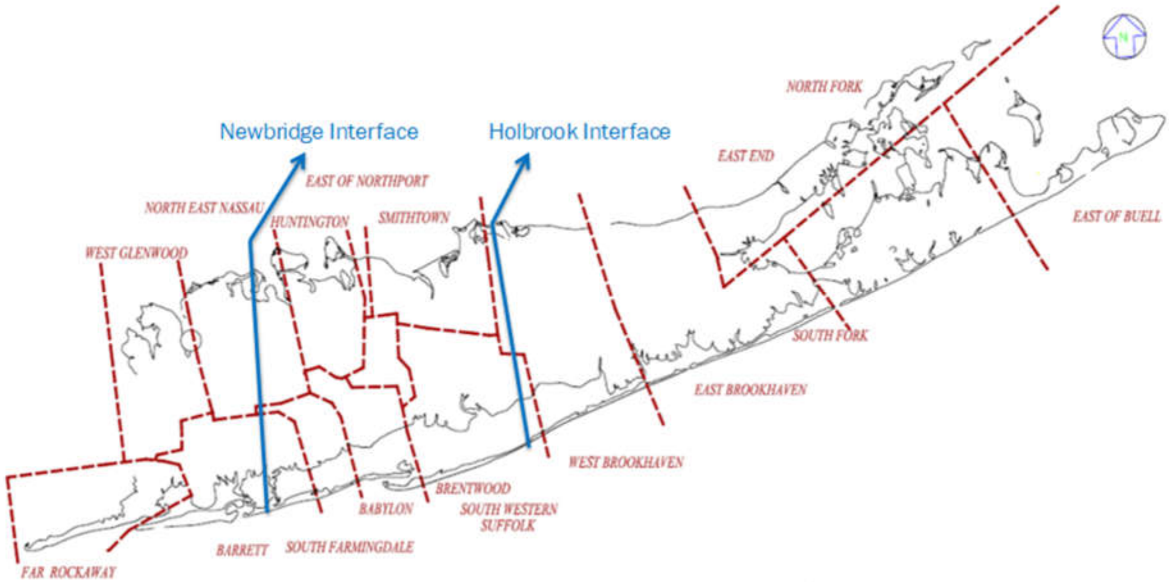
The LIPA transmission system consists of 138 kV and 345 kV voltage levels and the LIPA sub-transmission system consists of 23 kV, 34.5 kV and 69 kV voltage levels. The LIPA transmission system has limited electrical interconnections to CECONY, ISO-New England and PJM, via inter-ties.

The LIPA 138kV transmission backbone primarily runs from west to east (from the Nassau/Queens border in the west to Riverhead in the east). Transfer of power from the western part of the system to the eastern part of the system, and vice versa is primarily supported by the LIPA 138kV transmission backbone in addition to underlying 69kV sub-transmission circuits.

LIPA Internal Interfaces

The primary path for bulk power deliveries to LIPA's load center is across three internal bulk transmission interfaces defined as: Newbridge Road, Northport, and Holbrook interfaces. These interfaces divide Long Island into three separate regions: West of Newbridge, Central, and East of Holbrook regions. The largest amount of load is located in the Central region bounded by the Newbridge Road and Holbrook interfaces. Figure 50 below provides a high-level view of the LIPA internal transmission interfaces.

Figure 50: LIPA Internal Interfaces



These interfaces, which consist primarily of 138kV and underlying 69kV paths, are important for analytical purposes in determining the ability to transfer power and deliver generating capacity across the LIPA system. The interface definitions can be found in the PSEG Long Island Transmission System Planning Criteria[119] document.

i) LIPA Study Assumptions and Description of Local Design Criteria

To assist working group efforts in performing analysis for both the existing system and the high renewable injection into the system, NYISO provided two sets of base cases.

1. Steady State Study Cases

a) System As-Found cases

For the As Found base cases, the representation for the NYCA and LIPA system is based on the 2020 NYISO RNA Year 2030 peak case ("Summer As Found Case") and Year 2025 light load case ("Light Load As Found Case"). The Summer as Found Case's load level assumption was based on the 2020 Gold Book Table I-4a Zone K Non-Coincident 2030 Peak Demand with additional modifications consistent with internal study practices. The Light Load As Found Case load level was set to 1800 MW based on historical yearly load curves for the LIPA system. Historical data shows about 10% exposure to load levels less than 1800 MW.

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119 PSEG Long Island Transmission Planning Criteria; Issued July 1, 2016 https://www.psegliny.com/aboutpseglongisland/-/media/9EFC22D5FA1246F0B5E5371EA6A96AD3.ashx

b) 70x30 Scenario cases

For the 70x30 Scenario cases, the representation for the NYCA and LIPA system is based on the 2020 NYISO RNA 70x30 scenario for Year 2030 peak ("Summer Peak 70x30 Case"), shoulder ("Shoulder 70x30 Case"), and light load condition ("Light Load 70x30 Case") with additional renewable resources. The 70x30 scenario models a portfolio of renewable resources that can produce enough electricity energy to meet the State's 70/30 goal. The type, size, and location of these resources were developed from the NYISO 2019 Congestion Assessment and Resource Integration Study (CARIS). The NYISO provided cases include 1,176 MW nameplate of behind the meter solar, 77 MW nameplate of utility-scale photovoltaic (UPV), and 1,778 MW nameplate of Off-Shore wind (OSW) interconnected to the LIPA system.

A summary of the OSW resources assumed by the NYISO for the LIPA system is shown in Figure 51below.

Figure 51: NYISO 70x30 Zone K Off-Shore Wind Resource Summary

Resource	Substation	Nameplate (MW)
Off-Shore wind	East Hampton 69kV	130
	Holbrook 138kV	880
	Ruland Road 138kV	384
	Brookhaven 138kV	384
Total		1,778

c) LIPA 70x30 Scenario cases

For LIPA's analysis, adjustments were made to the NYISO 70x30 cases to have approximately 3,000 MW nameplate of OSW interconnected to the LIPA system. LIPA, in coordination with CECONY, modified the NYISO provided cases to (1) increase OSW from 6,000 MW to 9,000 MW, maintaining the distribution between Zones J and K based on approximate load ratio share, per the NYISO's assumptions; and (2) modify Points of Interconnection (POI) of OSW renewable resources based upon projects in the NYISO interconnection queue and LIPA's knowledge of the relative cost of reinforcing its transmission system at various locations. These assumed POIs were selected for study purposes to illustrate the types of reinforcements needed to accommodate OSW, though different POIs might also be accommodated with similar reinforcements. As mentioned above, this adjustment results in approximately 3,000 MW nameplate of OSW interconnected to the LIPA system. While the CLCPA requires 9,000 MW of OSW by 2035, the Filing Parties determined it was reasonable to model 9,000 MW in 2030 in order to capture the full impact of the state goal in the Utility Study. For reference, a summary of the OSW resource assumed for LIPA system is shown in Figure 52 below. In addition, NYISO's 70x30 OSW and Solar resources dispatch schedule has been adopted for these cases and has been shown in Figure 53 below:

Figure 52: LIPA 70x30 Zone K Off-Shore wind Resource Summary

Resource	Substation	Nameplate (MW)
Off-Shore Wind	East Hampton 69kV	136
	Holbrook 138kV	880
	Ruland Road 138kV	700
	Ruland Road 138kV	700
	East Garden City 345kV	700
Total		3,116

Figure 53: NYISO 70x30 Base Case Resource Dispatch Schedule

Case	Off-Shore wind (% of Pmax)	Solar (% of Pmax)
Summer Peak 70x30 Case	20	45
Light Load 70x30 Case	45	0
Shoulder 70x30 Case	45	40

d) LIPA 70x30 Scenario sensitivity cases

In addition to the LIPA 70x30 Scenario cases, a set of sensitivity cases were created with several base case modifications for the LIPA system based on the LIPA 70x30 Scenario base cases. Starting from the LIPA 70x30 Scenario base cases described above, the OSW plants injected to Zone K have been dispatched at 100% nameplate output in the cases to stress the LIPA transmission system with higher power transfers across the system. Figure 54 illustrates the OSW and Solar resource dispatch for the LIPA 70x30 Scenario sensitivity cases.

Figure 54: LIPA 70x30 Sensitivity Base Case Resource Dispatch Schedule

Case	Off-Shore wind (% of Pmax)	Solar (% of Pmax)
Summer Peak 70x30 Case	100	45
Light Load 70x30 Case	100	0

For the LIPA system, the same behind the meter (BTM) solar output percentage from NYISO 70x30 scenario cases has been utilized in this analysis.[120] The BTM solar output for each case has been directly deducted from the system load as a load modifier consistent with NYISO's base cases. In addition, LIPA adopted the same generation unavailability assumption provided by

[120] LIPA's solar output percentage at peak load may vary from NYISO's assumption.

NYISO in the 70x30 scenario including those affected by DEC NOx regulation within the LIPA system.

2. Steady State Analysis Approach

System expansion and the incorporation of new facilities must follow the PSEG Long Island Transmission Planning Criteria for the LIPA System and applicable interconnection requirements. In addition, all facilities must be designed to conform with and adhere to all applicable North American Electric Reliability Corporation (NERC), Northeast Power Coordinating Council (NPCC), and New York State Reliability Council (NYSRC) Reliability Rules.

For the purposes of evaluating the LIPA transmission system to understand where capacity “headroom” exists on the existing system as well as identifying existing constraints or bottlenecks that limit energy deliverability, a thermal transfer limits analysis was performed to maximize transfers over LIPA’s internal transmission interfaces. The Siemens PTI PSS/E and PowerGem TARA programs were used to redispatch and shift generation across Long Island to maximize the transfer over LIPA interfaces in order to identify potential transmission constraints and bottlenecks for energy delivery in the three regions bounded by LIPA’s internal interfaces: West of Newbridge, East of Holbrook, and Central. This analysis was performed to also identify any potential headroom available in these regions for resource interconnection.

To propose potential projects that would increase the capacity on the LIPA transmission system to allow for interconnection of new renewable generation resources, a detailed thermal analysis (considering N-0, N-1, N-1-1) was performed to assess the LIPA system impacts for delivering specified renewable energy injections included in the LIPA 70x30 Scenario base cases. In addition, LIPA’s system is a semi-isolated system with limited off-island interconnections. With current LIPA system build-out, energy delivery and power transfers will rely on the local transmission and sub-transmission system (138kV below) which will be limited in its ability (*i.e.,* relatively congested) to support the significant amount (*i.e.,* on the order of hundreds MW) of resource injection into the system, such as from a large OSW plant with its nameplate output. As a result, a sensitivity analysis was performed with LIPA 70x30-scenario sensitivity base cases.

The entire analysis monitored LIPA Bulk Electric System facilities (“BES”), as well as underlying sub-transmission circuits, consistent with the PSEG Long Island Transmission Planning Criteria.

N-0 and N-1 design contingencies consistent with PSEG Long Island Transmission Planning Criteria were considered in the analysis, such as:

1. No Contingency (P0)
2. Loss of Single Transmission Lines
3. Loss of Transformers
4. Loss of a single generator
5. Loss of a switched shunt device

6. Loss of a bus section
7. Failure of a circuit breaker to operate (bus tie, non-bus tie)
8. Double circuit - Two circuits lines on the same transmission pole/tower
9. For N-1-1 reliability analysis, curtailment of OSW was not considered.

ii) Discussion of Existing Capacity "Headroom" within LIPA System

For the purposes of evaluating the LIPA transmission system to understand where capacity "headroom" exists on the existing system, a thermal transfer limits analysis was performed to maximize transfers over LIPA's internal transmission interfaces. This analysis was performed considering all available existing resources within the LIPA system.

For the purposes of this study, "headroom" is defined as the additional resource that can be injected into a region beyond the existing resource capability without a thermal violation on the LIPA system driven by the transfer of power. It is calculated by taking the sum of the interface transfer capability plus the region load and subtracting the existing resource capability in the analyzed region. For some thermal transfers, a negative value was calculated which indicates the tested area has existing power transfer constraints and does not have energy deliverability "headroom". Instead of documenting a negative value, a value of zero has been presented for clarity. Intertie capacity is not included in the value for the existing resource capability for the analyzed region.

Based on this methodology, for applicable contingencies consistent with PSEG Long Island Transmission Planning Criteria, none of the regions in LIPA's existing transmission system - with the exception of East of Holbrook transfer region under peak load condition have transmission headroom for additional generation injection beyond the existing resource capability. Power transfer capability was found to be most limiting on the LIPA transmission system in the East to West direction, especially during light load conditions. Figure 55 below specifically quantifies the "headroom" for the LIPA system for East to West power transfers.

Figure 55: LIPA Headroom Limits

Transfer Regions	Direction of Transfer	N-1 Peak "Headroom" (MW)	N-1 Light Load "Headroom" (MW)
Central & East of Holbrook to West of Newbridge	East to West	0	0
East of Holbrook to Central & West of Newbridge	East to West	200	0

Consideration of other variables such as re-dispatching of existing generation resources or inter-ties and, system load level (*i.e.,* peak load versus light load) will provide some additional degree of "headroom" on the existing system with minimal transmission upgrades.

Additionally, the transmission constraints on Long Island are dependent on the location of any additional resource injection combined with deliverability constraints across interfaces consistent with NYISO Deliverability Criteria. Other internal studies that were conducted as part of the OSW analysis demonstrated that some level of additional resources can be integrated within the Central region and in the Holbrook region without triggering significant transmission investments.

iii) Bottlenecks or Constraints that Limit Energy Deliverability within LIPA System

Based on the transfer study that has been performed, resource delivery in the regions is most constrained for the LIPA system under light load conditions. Bottlenecks on the transmission backbone are observed on 138kV circuits in Western Nassau County and Western Suffolk County during delivery of power east to west. In addition, it is possible that local constraints, including but not limited to transmission, transmission ROW or substation interconnection physical feasibility, will exist at resource interconnection points across the LIPA system. While this study does not specifically capture those local bottlenecks or constraints, it will be necessary to consider system upgrades at or around those interconnection points in order to facilitate the interconnection of additional resources.

With LIPA 70x30 Scenario base case assumptions with the specific resource output schedule described in Table II-3, there are no observed thermal violations. In addition, no thermal violations have been observed for the LIPA 70x30 Scenario sensitivity peak case. However, transmission bottlenecks/constraints have been identified with LIPA 70x30 Scenario sensitivity light load case. Due to the large amount of OSW injection into the existing LIPA transmission system, multiple transmission and local sub-transmission thermal violations have been observed under the light load condition:

- Identified constraints on Central corridor for both Normal and post-contingency conditions.
- Observed overloads on the transmission and sub-transmission paths between East Garden City to Glenwood to Shore Road for both Normal and post-contingency conditions.
- Exceedances of existing LIPA export limitations with high export value to maintain the energy balance between load demand and generation output in the LIPA system

It should be noted that the violations reported above under the light load condition could be alleviated with energy curtailments. Whether energy curtailment is a desired solution from a planning perspective will depend on the relative cost of upgrades versus the value of curtailed renewable energy, which would be unavailable to meet the CLCPA goals.

Moreover, in order to meet the CLCPA goal of 9,000 MW OSW by 2035, the OSW will likely need to connect to New York City and/or Long Island. LIPA is coordinating its study in this proceeding with the CECONY to identify optimal POIs for injection of OSW into the two service territories, considering local transmission constraints. Given the expected size and scale of an OSW project connecting to the LIPA system, it is recommended consideration be given to interconnecting OSW directly to the LIPA 138kV system or converting to a new 345kV system to interconnect OSW resources.

iv) Potential Projects that would Address Bottlenecks or Constraints that limit Energy Deliverability within LIPA System

Based on its analysis as part of the May 14 Order, and on related OSW studies coordinated with CECONY, LIPA has developed a comprehensive list of projects intended to help support the State's climate policy goals and CLCPA mandates.

In coordination with the DPS Staff, the Working Group has defined two "phases" of projects based on the current state of readiness: Phase 1 projects and Phase 2 projects.

These have been generally defined as follows:

Phase 1:

- Considered priority local transmission/ distribution upgrades due to safety, reliability, and compliance requirements that also have CLCPA benefits (*e.g.,* preventing/eliminating bottlenecks).
- Reliability, Safety, and Compliance projects that potentially could be accelerated because of the CLCPA benefits without the need for a Benefit Cost Analysis ("BCA") as the projects would be completed anyway due to its safety/reliability drivers.
- Projects that may be recovered through the utility's current rate plan, but some of these projects may require supplemental approvals.

Phase 2:

- Projects not currently in the Utilities' capital plans.
- Projects / solutions that are generally more complex and conceptual in nature, and which are driven primarily by CLCPA benefits that would be unlocked.
- Projects whereby the scope of work, the needs case being driven primarily by CLCPA, and broad regional benefits suggest that it is likely that cost sharing across utilities may be required.

Multiple transmission projects have been considered and categorized according to the broad "Phase 1" and "Phase 2" project definitions for the LIPA system.

1. *"Phase 1" projects*

The "Phase 1" projects which have been included are based on following considerations:

- Projects included in the LIPA 5-year budget plan.
- Projects documented within the 2019 PSEG Long Island Local Transmission Plan.
- Projects that will address local reliability constraints.
- Projects that will potentially address transmission bottlenecks or constraints by increasing the energy deliverability along certain transmission paths or substations and/or helping to decrease dependence on fossil generation needs for the LIPA system.
- Projects that will support Distributed Energy Resource (DER) additions on the local distribution system.

Figure 56: LIPA "Phase 1" Transmission projects Summary

Project Name	Zone	Terminal A	Terminal B	Project Description	Proposed I/S Date	Order of Magnitude (OOM) Cost	Estimated Project Benefit (MW)
138 kV Riverhead to Canal New Circuit	K	Riverhead	Canal	Install a new 138 kV circuit from the Riverhead substation to the Canal substation.	6/1/2021	$83M	260
Wildwood to Riverhead 69 kV to 138 kV Conversion	K	Wildwood	Riverhead	Convert the existing Wildwood to Riverhead circuit from 69 kV to 138 kV.	6/1/2021	$10M	160
Western Nassau Transmission Project	K	East Garden City	Valley Stream	Install a new 138 kV circuit from the East Garden City substation to the Valley Stream substation.	12/31/2020	$162M	70
Rockaway Beach 34.5 kV new circuits	K	Far Rockaway	Arverne	Install a new 34.5 kV circuit from the Far Rockaway substation to the Arverne substation.	6/1/2022	$31M	10
	K	Rockaway Beach	Arverne	Install a new 34.5 kV circuit from the Rockaway Beach substation to the Arverne substation.	6/1/2022	$37M	
69 kV Ruland Road to Plainview New Circuit	K	Ruland	Plainview	Install a new 69 kV circuit from the	6/1/2022	$41M	40

Project Name	Zone	Terminal A	Terminal B	Project Description	Proposed I/S Date	Order of Magnitude (OOM) Cost	Estimated Project Benefit (MW)
				Ruland Rd. substation to the Plainview substation.			
69 kV Pilgrim Bus Reconfiguration	K	Pilgrim	-	Reconfigure connections to 69kV Buses at Pilgrim substation.	12/1/2023	$1M	20
69kV Canal to Deerfield Double Circuit Reconfiguration	K	Canal	Deerfield	Reconfigure Canal to Southampton to Deerfield overhead circuits.	6/1/2024	$2M	5
69kV Elwood to Pulaski circuit upgrade	K	Elwood	Pulaski	Reconductor Elwood to Pulaski 69kV overhead circuit	6/1/2025	$35M	50
					Total:	$402M	

All the projects included on the “Phase 1” list will facilitate the integration of renewable resources such as solar, OSW, energy storage on both transmission and distribution levels to support the CLCPA initiatives. The three BES projects all have a near term in-service date within the next two years that will increase system reliability and support CLCPA initiatives for increasing the energy deliverability across the LIPA BES.

The In-Service Dates and estimated costs for "Phase 1" projects are based on the best available information at this time and are subject to change. In addition, the “Phase 1” project list may be impacted by system changes, and subject to change due to lump load addition in a specific area, potential fossil generation retirement, and specific amount of renewable energy resource connected to a specific area in the LIPA system.

2. *“Phase 2” projects*

The “Phase 2” projects are identified for their ability to increase the transfer capability to address both On-Peak energy deliverability and Off-Peak system bottlenecks on the LIPA transmission and underlying sub-transmission systems. These projects increase the thermal transfer capability of limiting circuit paths or create additional parallel paths to bottlenecked circuits, which have been identified in the 70x30 Scenario sensitivity analysis.

Figure 57: LIPA "Phase 2" Transmission projects Summary

Project Name	Zone	Terminal A	Terminal B	Project Description	Proposed I/S Date	Order of Magnitude (OOM) Cost	Estimated Project Benefit (MW)
LIPA central corridor 138kV to 345kV Conversion	K	East Garden City	Newbridge Road	Convert the existing East Garden City to Newbridge Road circuit No.4 from 138kV to 345kV	2025-2035 TBD[121]	$221M	1,100
	K	Newbridge Road	Ruland Road	Convert the existing Newbridge Road to Ruland Road circuit No.3 from 138kV to 345kV			
	K	East Garden City; Newbridge Road; Ruland Road	-	Substation expansions and constructions associated with the 345kV conversion.			
New circuit Shore Rd-Ruland Rd 345kV	K	Shore Road	Ruland Road	Install a PAR controlled new 345 kV circuit from the Shore Road substation to the Ruland Road substation.		$647M	
	K	Shore Road; Ruland Road; Syosset	-	Substation expansions and reconfigurations associated with the new 345kV circuit.			
Series Reactors on 138kV Newbridge Rd to Ruland Rd circuits	K	Newbridge Road	Ruland Road	Install two 2-Ohm Series Reactor on Newbridge Road to Ruland Road circuit No.1 and No.2.		$7M	
345kV inter-tie from LIPA East Garden City/Shore Road	K	Zone K East Garden City or Shore Road substation	Zone I or Zone J	Install a PAR controlled new 345kV inter-tie between LIPA and Con-Ed system		TBD	500
New Synchronous Condenser Installation(s)	K	Zone K	-	Install new Synchronous	2025-2035 TBD	$200M	-

[121] The proposed OSW related project In-Service dates will be staged to precede OSW Commercial Operating dates.

Project Name	Zone	Terminal A	Terminal B	Project Description	Proposed I/S Date	Order of Magnitude (OOM) Cost	Estimated Project Benefit (MW)
				condenser(s) in LIPA system			
Upgrades on several existing sub-transmission 69kV circuits	K	Holbrook	Nesconset	Upgrades on several existing sub-transmission 69kV circuits.	2024	$68M	50
		Newbridge Rd	Bellmore		2024	$100M	40
		MacArthur	Bayport		2025	$27M	90
		Indian Head	Deposit		2025	$11M	50
					Total:	$1,281M+[122]	

LIPA central corridor 138kV to 345kV Conversion –

(1) The preliminary plan for this project is going to convert portions of the existing 138kV path from East Garden City to Newbridge Road and Newbridge Road to Ruland Road to 345kV operations. This project is part of the LIPA 345kV expansion plan that will address the constraints that have been identified above.

New circuit Shore Rd-Ruland Rd 345kV –

(2) This project is the other part of LIPA 345kV expansion plan that would install a new PAR controlled 345kV circuit between Ruland Road and Shore Road 345kV substation. As a preliminary plan, additional substation expansions and reconfiguration at Shore Road, Syosset, and Ruland would be required. With both 345kV projects in-service, the constraints/bottlenecks identified on the LIPA Newbridge Interface from East to West direction will be resolved by introducing two new 345kV transmission paths across the constrained Interface. These two paths would facilitate approximately

[122] The total cost does not include the new inter-tie between LIPA and Con Ed system. Additional coordination between LIPA and Con Ed will be required.

3,000 MW OSW injection on the LIPA system and will provide flexibility on the LIPA BES to mitigate energy delivery constraints.

Series Reactors on 138kV Newbridge Rd to Ruland Rd circuits –

(3) This project is a 138kV project to support the LIPA 345kV expansion project. The scope of this project includes installing two series reactors on the existing Ruland Road to Newbridge Road 138kV circuit No.1 and No.2 at Ruland Road 138kV substation. These two 138kV circuits will experience minor thermal limitations once LIPA 345kV expansion projects are in service. With increasing impedance on both circuits, the power flow will be redirected and will alleviate the thermal constraints on the LIPA 138kV system.

345kV inter-tie from LIPA East Garden City/Shore Road –

(4) This preliminary plan will install at least one bulk transmission PAR controlled inter-tie from LIPA's East Garden City substation and/or Shore Road substation to the CECONY system to increase the export capability of the LIPA-CECONY interface, which connects NYISO Zone K to Zones I and J. The need for a new inter-tie is driven by the LIPA export limitation under light load condition. With a large amount of renewable resource such as OSW injected to the LIPA system, the LIPA load demand under light load condition will not be sufficient to meet the renewable energy output. It also should be noted that with limited off-island interconnections to the rest of New York State, total renewable resource injection into the LIPA system will be further limited under light load conditions. In this case, bottlenecked export capability on the LIPA system will require an upgrade / transmission expansion in order to deliver the renewable energy to rest of the New York State.

New Synchronous Condenser Installation(s) –

(5) A potentially major issue on the transmission system with the significant increase of inverter-based resources (IBR) and concurrent retirement of conventional fossil power plants is the weakness of the system and the potential for adverse IBR behavior due to this weakness, as well as voltage instability. This Report does not attempt to quantify this risk. It is very likely that new synchronous resources will be required (or alternatively, existing resources not being retired and run uneconomically) to strengthen the system such that these new IBR as well as the overall power system can operate in a stable manner. Therefore, we believe that it is reasonable to include a proxy project for at least one synchronous condenser installation on the LIPA system.

Upgrades on several existing sub-transmission 69kV circuits –

(6) Several 69kV upgrades have been identified to un-bottle and relieve power transfer constraints that inhibit energy delivery through the LIPA sub-transmission system. These include:

- Upgrades on the existing sub-transmission 69kV circuit between Holbrook and Nesconset substations.
- Upgrades on the existing sub-transmission 69kV circuit between Newbridge and Bellmore substations
- Upgrades on the existing sub-transmission 69kV circuit between Bayport and MacArthur substations.
- Upgrades on the existing sub-transmission 69kV circuit between Indian Head and Deposit substations.

All four sub-transmission projects documented above would facilitate renewable resource additions within the LIPA Central and East of Holbrook areas to increase the power transfer capability and energy deliverability in the area. It should be noted these projects may potentially be identified under the NYISO Interconnection Process / NYISO Deliverability Assessment for potential developer's Capacity Resource Interconnection Service (CRIS) rights based on future renewable resource injections. In addition, there are multiple sub-transmission constraints in the Western Nassau area identified from the sensitivity study based on LIPA 70x30 Scenario sensitivity light load cases. The need for local upgrades would be dependent on the 345kV expansion introduced above that will potentially resolve both bulk and LIPA sub-transmission constraints.

The "Phase 2" projects identified above are conceptual and currently not in the LIPA's capital plans. Additional analysis will be needed to optimize the solution. The LIPA 345kV transmission upgrades and PAR controlled inter-tie from LIPA to CECONY have been identified by LIPA and PSEG Long Island as transmission needs driven by the interconnection of OSW to LIPA's system regardless of the specific locations at which future OSW projects may be connected. The sub-transmission upgrades will also provide the additional capacity on the local transmission system to facilitate the renewable injection in the LIPA system to support CLCPA initiatives.

It is important to note that expansion of the LIPA transmission backbone to 345kV operation as well as new inter-ties to CECONY will need to be implemented with underground cable. These cables will add a very large amount of charging capacitance, which can create low-order harmonic resonance issues that create issues with respect to overvoltages, transformer energization, etc. . This Report does not attempt to quantify this risk. Additional system upgrades and their associated costs, which may be required to address these complex issues, are not captured here.

The "Phase 2" projects are mainly driven by the OSW injection in the LIPA system. The In-Service Dates and estimated costs for "Phase 2" projects are subject to change and will be better defined once additional information such as NYSERDA OSW solicitation results is available. The project list will likely be revised, and subject to change based on the location and size of OSW injections along with the additional renewable resource projects (such as Solar and Battery Storage) being built in the LIPA system.

The estimated project benefits (incremental benefits, in terms of MW) highlighted in the Phase 1 and Phase 2 tables are considered best case values, approximated by using a power flow based transfer analysis approach considering PSEG Long Island Transmission Planning criteria, or by the expected incremental thermal rating increase. The LIPA Summer Peak 70x30 Scenario Case was used for this analysis. Quantifying estimated project benefits in terms of MW can be done using various approaches and is therefore representative. Collective benefits achieved by grouping select projects together may yield higher overall benefits. The approach taken considered the unique aspects of each project, considering the specific benefits provided for unbottling and/or relieving constraints.

v) Potential Projects that would Increase Capacity on the Local Transmission and Distribution System to allow for Interconnection of New Renewable Generation Resources within LIPA System

Potential projects mentioned in Subsection iv (above) will serve to increase the transfer capability within the LIPA transmission system to allow for interconnection of new renewable generation resources within LIPA system, and to increase LIPA export capability in order to facilitate the Off Shore wind resources potential up to approximately 3,000 MW. In addition to the need to increase the energy deliverability in the western part of the LIPA system and increase overall export capability in support of OSW injections, there will also be a requirement for transmission upgrades to enhance the ability to move power from eastern Long Island to western Long Island. Such a requirement might also be accompanied by the need for lower-voltage upgrades that would be dependent on the location of OSW injections.

There are slightly varying assumptions regarding LIPA's level of participation in helping the state achieve its solar and battery energy storage targets and goals under the CLCPA. The NYISO CARIS study assumed 1,176 MW nameplate of behind the meter solar and 480 MW of battery energy storage for the LIPA system. LIPA notes that these values exceed LIPA's load-ratio share of these types of resources.

LIPA has not yet identified specific Transmission "Phase 2" projects associated with CLCPA driven solar mandates based on the specific Zone K Solar distribution and output percentage at peak load and light load, from NYISO 70x30 assumptions adopted in this study. LIPA believes that transmission upgrades are likely to become apparent as those areas see further definition and development. When such upgrades become apparent, LIPA will present those projects at the appropriate time and via the appropriate forum.

In addition, energy storage will play a crucial role in meeting New York's ambitious clean energy goals. In 2018, Governor Cuomo announced a nation-leading goal of 1,500 MW of energy storage by 2025. Later that year, the Commission issued a landmark energy storage order establishing a goal of 3,000 MW of energy storage by 2030, and deployment mechanisms to achieve both the 2025 and 2030 energy storage targets. Based on the proportion of peak load in Long Island compared to the entire State, approximately 187 MW should be installed on Long Island by 2025 and 375MW by 2030.

Although LIPA has not yet identified specific transmission "Phase 2" projects associated with energy storage goals, LIPA intends to meet its share of the goal through existing energy storage contracts, energy storage projects through Utility 2.0 filing, behind the meter storage initiatives and through PSEG Long Island Energy Storage RFP process. Transmission upgrade needs may emerge as the above energy storage initiatives advanced.

With the ongoing energy storage RFP process, LIPA envisions that additional transmission reliability analyses to assess system performance with the implementation of energy storage, considering synergies with the transmission upgrades, will be required to develop an optimized plan to support CLCPA initiatives.

vi) Possibility of fossil generation retirements and the impacts and potential availability of those interconnection points

Under the Amended and Restated Power Supply Agreement ("PSA") between LIPA and National Grid, LIPA purchases capacity and energy from National Grid from a fleet of steam and combustion turbine generating units aggregating approximately 3,700 MW. Within this fleet are eight steam generating units located at three sites totaling approximately 2,350 MW. Those three sites are the Northport, Port Jefferson, and Barrett power stations. National Grid also owns and operates 41 combustion turbine generating units at ten sites totaling approximately 1,350 MW. These ten sites are inclusive of the three steam generating stations.

The need for conventional fossil generating resources is declining due to the increasing penetration of rooftop solar, distributed resources, and energy efficiency, as well as the implementation of CLCPA mandates (100% carbon-free energy by 2040). Absent any retirements, LIPA has a growing surplus of generating capacity. Earlier this year, LIPA announced that studies are underway (expected completion in Q4 2020) that will identify up to 400 MW of desired steam unit retirements as early as the end of 2022, and additional retirements after 2024. Potential transmission reinforcements that may be needed to mitigate transmission security/reliability issues due to fossil generation retirement scenarios may be represented among the Phase 2 projects described above. Others will be identified as part of future studies. Additionally, two peaking units will be retired at West Babylon and Glenwood Landing in 2020 and 2021, respectively without the need for transmission reinforcements. Additional peaking unit retirements are under study, including at Glenwood Landing.

Regarding the existing generating units located at Northport, Port Jefferson and Barrett, while retirements of any of these units may create availability of interconnection points for new renewable energy resources or battery energy storage facilities, such substations may not eliminate the need for transmission upgrades if the operating profile of the new resources is different than that of the existing plants. All three of these sites also have physical / property constraints, as well as transmission exit constraints.

As discussed previously, the NYISO as provided 70x30 Scenario cases had multiple generators, including those affected by DEC NOx regulation within the LIPA system, unavailable for dispatch. These generators included select existing fossil steam plants as well select existing combustion turbine generating units. For some of the combustion turbine generating units, the generator owner has submitted DEC NOx compliance plans.

While potential fossil generation retirement scenarios under consideration will likely create additional "headroom" on certain portions of the LIPA transmission system, these retirement scenarios are not expected to have a significant impact on the Phase 1 Transmission or Phase 2 Transmission projects summarized above. A majority of the Phase 2 projects would be considered "no-regrets" type projects which generally support CLCPA targets related to the integration of OSW. As mentioned previously in this Report, resource delivery across the LIPA interfaces and total renewable resource injection into the LIPA system are most limited/constrained under light load conditions. Under such conditions, many of the generating units on Long Island would not likely be dispatched.

In summary, LIPA and PSEG Long Island are currently evaluating potential PSA steam / combustion turbine / peaking unit retirement scenarios, and retirement studies are in progress. The list of Phase 2 projects is subject to change, and additional Phase 2 projects might be identified considering, for example, the reliability impacts of such retirement scenarios. Finally, at the present time it is difficult to make any definitive conclusion regarding whether retirements of any of these generation units will create availability of interconnection points for new renewable energy resources or battery energy storage facilities. Further, availability of transmission interconnection points upon unit retirement is governed by NYISO tariffs and subject to FERC's open access policies. Any material change at an interconnection point (*i.e.,* retirement of a fossil facility replaced by a renewable energy resource) must conform with and adhere to the latest applicable NERC, NPCC, and NYSRC Reliability Rules, as well as applicable PSEG Long Island Transmission Planning and Interconnection criteria.

vii) Conclusion/Next Steps

Consistent with the May 14 Order, this LIPA report presents the results of its transmission security assessment identifying potential local system upgrades that will facilitate meeting CLCPA goals.

The "Phase 1" projects (*i.e.*, multi-value projects) identified above are included in the LIPA 5-year budget plan. These projects address local reliability issues as well as impediments to renewable energy utilization ("bottlenecks") by increasing the energy deliverability along certain transmission paths or substations and/or helping to decrease dependence on fossil generation needs for the LIPA system, supporting DER additions and thus have synergies with achieving the CLCPA's intended benefits.

The "Phase 2" projects shown above are identified for their ability to increase the power transfer capability to address both On-Peak energy deliverability and Off-Peak system bottlenecks on the LIPA transmission and underlying sub-transmission systems. LIPA recommends the Commission consider "Phase 2" transmission projects identified above as necessary or appropriate upgrades to the Long Island electrical network in order to timely achieve the renewable energy goals established by New York State legislative policies. LIPA suggests that the Commission consider evaluating whether these projects qualify as local transmission projects that are eligible for statewide cost allocation under the Accelerated Renewable Energy Growth and Community Benefit Act.

The estimated project benefits (incremental benefits, in terms of MW) highlighted in the Phase 1 and Phase 2 tables are considered best case values. Quantifying estimated project benefits in terms of MW can be done using various approaches and is therefore representative. Collective benefits achieved by grouping select projects together may yield higher overall benefits. The approach taken considered the unique aspects of each project, considering the specific benefits provided for unbottling and/or relieving constraints.

The significant increase of inverter-based resources (IBR) and concurrent retirement of conventional fossil power plants has the potential to create various issues for the power system, above and beyond thermal and voltage issues which were the focus of this analysis. This Report does not attempt to quantify these other reliability risks; future system studies will be required. Additional system upgrades and their associated costs, which may be required to address these complex issues, are not captured here.

As part of the State's ongoing effort to incorporate 9,000MW of OSW by 2035 to meet CLCPA state goals, LIPA is coordinating its studies in this proceeding with CECONY to determine an optimal plan for injection of OSW for delivery into the New York State Transmission System. Based on these coordinated studies, LIPA's "Phase 2" projects will be refined and optimized, as necessary.

B. Distribution

LIPA provides electric service to approximately 1.1 million customers in Nassau and Suffolk Counties and on the Rockaway Peninsula in Queens. LIPA's service territory covers about 1,230 square miles, encompassing nearly 90 percent of Long Island's total land area. The area closer to Queens County in New York City is more urbanized and the area to the eastern portion is rural. Three small independent municipal electric systems - Freeport, Rockville Centre, and Greenport - are located within the LIPA service territory.

The distribution system comprises 13 kV and 4 kV facilities and a combination of overhead and underground equipment. There are 152 distribution substations throughout the Service Area that step the voltage down from transmission to distribution levels. LIPA's distribution substations have a transformation capability of approximately 8,300 MVA. The LIPA distribution system is divided into the five geographic areas as described below.

1) Queens-Nassau area: includes the Rockaway Beach area, Far Rockaway region, Hempstead Township, and the City of Long Beach

2) Central Nassau area: includes North Hempstead and Oyster Bay Townships.

3) Western Suffolk area: includes Babylon, Islip, Huntington, and Smithtown Townships that are located east of NYS Highway Route 110.

4) Central Suffolk area: Predominately the Brookhaven Township, and includes the Fire Island region of Long Island.

5) Eastern Suffolk area: includes Riverhead, Southold, Southampton, and East Hampton regions that are located east of William Floyd Parkway to the Montauk region.

i) Discussion of LIPA Study Assumptions and Description of Local Design Criteria

For the 70x30 Scenario cases, the representation for the New York Control Area ("NYCA") and LIPA system is based on the 2020 NYISO Reliability Needs Assessment ("RNA") 70x30 scenario for Year 2030 peak ("Summer Peak 70x30 Case"), shoulder ("Shoulder 70x30 Case"), and light load conditions ("Light Load 70x30 Case") with additional renewable resources. The 70x30 scenario models a portfolio of renewable resources that can produce enough electric energy to meet the State's 70/30 goal. The type, size, and location of these resources were developed from the NYISO 2019 Congestion Assessment and Resource Integration Study ("CARIS"). The NYISO provided cases include 1,176 MW nameplate of behind the meter solar, 77 MW nameplate of utility-scale solar, and 1,778 MW nameplate of Off-Shore wind ("OSW") interconnected to the LIPA system. It is relevant to note that LIPA's allocated share and/or actual penetration of these types of resources may be different than these assumptions.

ii) Discussion of Available Capacity "Headroom" and Associated Constraints

The available headroom capacities are dependent on individual substation transformer and feeder characteristics combined with the total Distributed Energy Resources (DER) penetration on that feeder/substation. It also varies depending on size and location of Distributed Energy Resource (DER) under study. Actual headroom capacity at individual substations and feeders are calculated on a case by case basis as part of studies conducted per LIPA's Small Generator Interconnection Process.

The ability of the LIPA distribution system to accommodate DER is constrained by system performance, protection, operational, and ultimately thermal, issue. Additionally, there are physical constraints where there is no room for additional interconnection at the existing substations. A certain amount of DER can be integrated without significant adverse impacts or the need for mitigation measures. After DER penetration on individual feeders or distribution systems reach situationally specific thresholds, impacts become significant and require mitigation that drives the costs of DER integration. As penetration increases further, the incremental cost of impact mitigation tends to become progressively greater until the thermal limits of the distribution are reached. Beyond this level, the incremental integration costs become quite large and impacts the integration of Distributed Energy Resources. The following describes some of the primary constraints to DER integration:

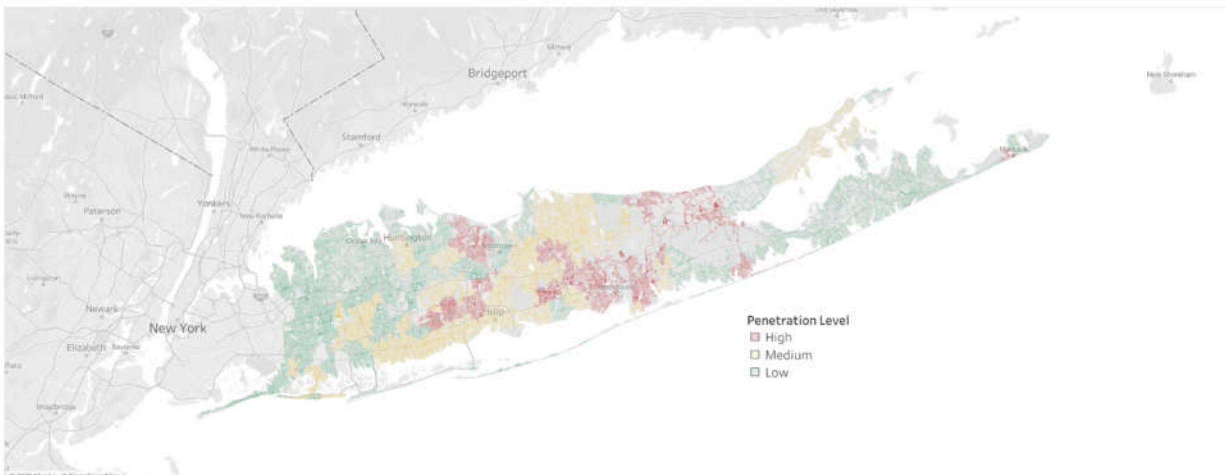
iii) Physical Constraints

The majority of distribution substations are relatively small in parcel size and are fully developed and cannot be expanded to accommodate DER injections. The substation expansion is typically needed when solar and battery DER with large injections connect to dedicated distribution feeders.

Developers are requesting to install DER injection predominately in the Eastern Suffolk part of Long Island. One reason is that Eastern Suffolk has more available land to accommodate DER installations. In this area, there is less load demand and fewer substations where DER can interconnect as compared to the rest of Long Island. This results in a limited DER injection capability in Eastern Suffolk County.

LIPA has a significant number of substations that are space constrained making the installation of new equipment that is required to accept injections of solar and battery power challenging. Figure 58 provides the penetration patterns of existing and projected DER from the queue.

Figure 58: Penetration of DG in the LIPA Service Territory



iv) System Performance Constraints

System performance constraints are primarily related to voltage levels caused by DER injection that would impact other utility customers as well as utility equipment, if not mitigated by protective equipment. DER injections tend to cause voltage rise and can result in voltages in excess of allowable limits at higher levels of local, feeder, or distribution system DER penetration. The injection can also interfere with the performance of existing utility voltage regulation controls and equipment, such as on-load tap changers and switched capacitor banks. One consequence of this interference is that some customers can be subjected to voltages less than acceptable minimum levels. Voltage variation caused by intermittent DER output (e.g., solar PV) can cause customer disturbance, excessive operation of utility voltage regulation equipment and increased potential for failure. Abrupt simultaneous loss of DER output, such as what might occur from a voltage disturbance (e.g., fault on another feeder or on the transmission system) can cause severe under voltage conditions, and abrupt return to service of DER following an outage can result in overvoltages.

v) Protection Constraints

Fault current contributions from DER can interfere with the ability of utility feeder protective relays to detect faults and can also cause undesired loss of service on a feeder due to incorrect protection operation for a fault on a different circuit. The DER fault current combined with fault current sourced by the LIPA system can also exceed the capabilities of LIPA equipment to sustain.

DER output can also cause potentially damaging transient overvoltages due to inadequate system grounding or abrupt separation of the distribution feeder from the utility substation. When DER output on a distribution system reaches approximately 80% of the load on that system, severe and damaging overvoltages can be created on the transmission system feeding that distribution system's substation when a ground fault occurs on the transmission line. DER system design, such as installing grounding transformers, provide mitigation of some of these issues but require that the DER developer add extra equipment to their projects when DER penetration levels are high.

DER can potentially maintain energization of a LIPA feeder that has become separated from the remainder of the utility system (islanding). Although DER are required to detect and eliminate islanding within two seconds, there are gaps in this performance. Because sustained DER islands requires a balance between DER output and concurrent system load in the island. At higher penetration levels, this balance occurs with greater frequency, thus exposing greater risk of islanding.

vi) Operational Constraints

The LIPA distribution systems are configured for flexible reconfiguration to restore service following outages of portions of circuits. Operational decisions made for such restoration are based on the observed load level, which can be greatly affected by DER output. The DER output masks the magnitude of the actual load and loss of the DER can result in a sudden large increase in net load that may exceed circuit capability when in the reconfigured state. This issue can be mitigated by continuous monitoring of DER output by a DER Management System (DERMS) and integration with the Distribution Management System that guides operational decisions.

vii) Thermal Limitations

The limitation to DER headroom is the thermal capacity of the system to withstand maximum reverse flow from the distribution system to the transmission system. The constraining element is typically the substation transformer, and replacement of the transformer with a larger capacity, addition of an additional transformer, or construction of a new substation require substantial capital expenditure that is almost always more than can be sustained by an individual DER project.

viii) Potential Projects that would Address Bottlenecks or Constraints within LIPA Distribution System

Based on an analysis as part of the Commission's May 14th Order on Transmission Planning Pursuant to the Accelerated Renewable Energy Growth and Community Benefit Act, LIPA has developed a comprehensive list of projects intended to help support the State's climate policy goals and CLCPA mandates. In coordination with DPS Staff, the Working Group has defined two "phases" of projects based on current state of readiness: Phase 1 projects and Phase 2 projects.

These have been generally defined as follows:

1. *Phase 1:*

- Considered priority local transmission/ distribution upgrades due to safety, reliability, compliance requirements in addition to the projects' CLCPA benefits (e.g., preventing/eliminating bottlenecks).
- Reliability, Safety, and Compliance projects would be accelerated because of the CLCPA benefits without the need for a BCA as the projects would be completed anyway due to its safety/reliability drivers.
- Projects that may be recovered through the utility's current rate plan, but some of these projects may require supplemental approvals.

2. *Phase 2:*

- Projects not currently in the utilities' capital plans.
- Projects / solutions that are generally more complex and conceptual in nature, and which are driven primarily by CLCPA benefits that would be unlocked.
- Projects whereby the scope of work, the needs case being driven primarily by CLCPA, and broad regional benefits suggest that it is likely that cost sharing across utilities may be required.

Multiple distribution projects have been considered and categorized according to the broad "Phase 1" and "Phase 2" project definitions for the LIPA system.

3. *"Phase 1" projects*

The "Phase 1" projects which have been included are based on following considerations:

- Projects that are in the LIPA 5-year Capital Budget Plan.
- Substation transformer and switchgear installations projects which add breakers where DER can connect.

- Substation upgrade projects which increase headroom capacity
- 4kV to 13 kV feeder conversion projects which increase the feeder capacity and allow DER interconnections.
- Projects that will support DER additions on the local distribution system.

Figure 59: LIPA "Phase 1" Distribution Projects Summary

Project Name	Zone	Substation	Project Description	Proposed I/S Date	OOM Cost ($M)	Estimated Project Benefit (MW)
Rockaway Beach Convert all 4kV feeders to 13kV	K	Rockaway Beach	Convert three 4kV feeders to 13kV	Dec-21	$11.3	20
Flowerfield Replace 6.25 MVA bank with 69/13kV 33 MVA banks, switchgear & C&R	K	Flowerfield	Replace 6.25 MVA bank with 69/13kV 33 MVA banks, switchgear and C&R	Dec-20	$11.4	23
Upgrade 14 MVA transformers to 33 MVA transformers	K	Far Rockaway	Upgrade 14 MVA transformers to 33 MVA transformers	Jun-21	$9.3	23
Install new 138/13 kV transformer and switchgear	K	Roslyn	Install new 138/13 kV transformer and switchgear	Jun-21	$21.9	28
Install new 138/69 kV transformer and switchgear	K	Ronkonkoma	Install new 138/69 kV transformer and switchgear	Jun-21	$19.7	28
Install new transformer and switchgear	K	Rockaway Beach	Install new transformer and switchgear	Jun-21	$11.3	24
Construct new 69/13kV substation	K	Lindbergh	Construct new 69/13kV substation	Dec-20	$54.5	56
Construct New Substation 69/13kv bank and 2 feeders	K	Round Swamp	New Substation 69/13kv bank and 2 feeders	Jun-21	$30.2	56
Install new transformer and switchgear	K	Brightwaters	Install new transformer and switchgear	Jun-22	$20.4	28
North Bellmore Install 33 MVA Bank, Swgr, Feeders & C&R	K	North Bellmore	Install 33 MVA Bank, Swgr, Feeders & C&R	Jun-23	$21.9	28
Expand 69/13kV substation & distribution circuits	K	New South Road	Expand 69/13kV substation & distribution circuits	Jun-22	$21.2	28
Upgrade existing distribution transformers	K	Peconic	Replace 1-14 & 2-6.25 MVA Banks with 2- 33 MVA Banks	Jun-23	$7.0	34
Install new 3rd bank and switchgear	K	Bridgehampton	Install new 3rd bank and switchgear	Jun-22	$11.1	28
Construct new 69/13kV substation	K	Brooklyn Ave.	Construct new 69/13kV substation	Jun-23	$32.6	56

Project Name	Zone	Substation	Project Description	Proposed I/S Date	OOM Cost ($M)	Estimated Project Benefit (MW)
Upgrade substation from 23 kV to 33 kV	K	Hero	Upgrade substation from 23 kV to 33 kV	Dec-23	$0.7	3
Upgrade substation from 23 kV to 33 kV	K	Culloden Point	Upgrade substation from 23 kV to 33 kV	Dec-22	$6.2	9
Upgrade substation from 23 kV to 33 kV	K	Amagansett	Upgrade substation from 23 kV to 33 kV	Jun-22	$15.7	12
New Navy Road substation	K	Navy Road	Replace Montauk substation with Navy Road	Oct-23	$31.7	18
Upgrade substation from 23 kV to 33 kV	K	Hither Hills	Upgrade substation from 23 kV to 33 kV	May-24	$13.0	18
				Total	$351.1	

The In-Service Dates and estimated costs for "Phase 1" projects are based on the best available information at this time and are subject to change. The "Phase 1" project list may be impacted by system changes, and subject to change due to lump load additions in a specific area, among other factors. The estimated project benefit reflects the additional MW capability added by that specific project and is not a direct correlation of additional distribution energy resources that can be added at the substation without any additional cost.

4. *Phase 2 projects*

The "Phase 2" projects are identified for their ability to increase the DER injection capability on the LIPA distribution system by addressing various constraints discussed above. Because the locations of DER injections significantly determine the specific projects, the following figure provides a representation of the types of projects that may be needed, and specific project locations may change based on the location of DER injection. The estimated MW benefit reflects the MW benefit related to the specific project and is not additive across all project categories. The actual MW benefit for the entire Phase 2 projects will be lower than the individual sum of these projects and dependent on specific substation location and the constraints associated with that substation. The project benefit for each category strictly provides the MW benefit associated with solving that specific constraint and does not reflect headroom created at those substations. The actual headroom created at a substation is the MW benefit gained by addressing all relevant constraints at a substation.

The following Phase 2 projects would increase capacity on the distribution system and allow for interconnection of new renewable generation resources. These projects align with the DPS request to support the CLCPA initiative.

a) New Substations or Transformer Upgrade Projects

Based on the land use pattern of existing DER penetration, it is anticipated that DER penetration will be concentrated in select geographic areas triggering the need to either upgrade the existing substation transformers or install new substations. Substation transformers and switchgear installations will add breakers where DER can connect.

b) Additional Breaker Cubicles for DER Feeders

Some larger commercial DER facilities will require additional equipment to interconnect the DERs directly to LIPA substations. These DER facilities will require dedicated feeders to connect to substation switchgear and their associated circuit breakers. LIPA would likely need to increase capacity by installing additional distribution breaker cubicles at certain substations (if possible) in order to permit higher DER injections at distribution substations or replacing existing switchgear with five-feeder cubicles. This would also address some of the physical constraints on the LIPA distribution system.

The "Phase 2" Breaker Cubicle projects which have been included are based on following assumptions:

- Install one additional breaker cubicle at twelve substations to allow new DER interconnections.
- Replace one ½ lineup of distribution switchgear at nine substations to allow new DER interconnections.

c) Protection Projects

In some locations, the installation of DER will require additional substation protection equipment to provide ground fault protection and voltage control. Substations with limited transmission ties may need to install transmission side ground-fault overvoltage protection (3VO) requiring the installation of relays and potential transformers to mitigate the overvoltages. In addition, the installation of the DER may require replacement of the distribution transformer load tap changer (LTC) controls in order to recognize reverse power into the transmission system. Individual feeders require the installation of capacitors and regulators to address the voltage constraints resulting from the high penetration of DERs.

The "Phase 2" Protection projects which have been included are based on following assumptions:

- Install 3V0 relays and potential transformers (PTs) on 135 transmission busses to provide grounding protection.
- Install 48 line regulators and/or capacitors on DER feeders to maintain to provide reactive compensation for DER inverters and associated voltage control.

Figure 60: LIPA "Phase 2" Distribution Projects Summary

Project Name	Zone	Project Description	Proposed I/S Date	OOM Cost ($M)	Estimated Project Benefit (MW)
Yaphank Install 33 MVA Bank, Swgr, Feeders & C&R	K	Install 33 MVA Bank, Swgr, Feeders & C&R	Jun-25	$12.0	28
Wildwood Replace 14 MVA Bank with 33 MVA Bank & Switchgear	K	Replace 14 MVA Bank with 33 MVA Bank & Switchgear	Jun-25	$6.1	16
Babylon Install 33 MVA Bank, Swgr, Feeders & C&R	K	Install 33 MVA Bank, Swgr, Feeders & C&R	Jun-26	$20.2	28
New Doctors Path Substation	K	Install 2-33 MVA Bank, Swgr & Transmission	2029	$22.7	28
Additional Breakers Cubicles for DER Feeders	K	Install 1 additional breaker cubicle at 12 substations	2021-2030	$7.3	108
Replacement of ½ lineup of distribution switchgears	K	Replacement of one ½ lineup of distribution switchgear at 9 substations	2021-2030	$40.0	81
Grounding Protection for Transmission Busses	K	Install 3V0 relays and PTs on 135 transmission busses	2021-2030	$47.2	600[123]
Voltage Regulation for DER Feeders	K	Install 48 line regulators and/or capacitors on DER feeders	2021-2030	$11.7	48
			Total	$167.2	

ix) Potential new or emerging solutions that can accompany or complement traditional upgrades

PSEG Long Island submits its Utility 2.0 Long Range Plan (Utility 2.0 Plan) annually for review by the Long Island Power Authority ("LIPA") and the New York State Department of Public Service ("DPS"). This submittal is in accordance with Public Authorities Law Section 1020-f (ee)

[123] The MW value is estimated across 135 transmission buses and can be realized only if the other constraints are addressed.

and the Amended and Restated Operations Services Agreement dated December 31, 2013. The proposed 2020 Utility 2.0 Plan recommends projects to adapt to changing needs of customers, advancing technology, and the policy direction and goals developed within the Reforming the Energy Vision (REV) process in New York, and in alignment with the CLCPA. Following is an overview of some the projects from the 2020 Utility 2.0 that would further the CLCPA goals:

x) Hosting Capacity Maps

PSEG Long Island is presently developing a Hosting Capacity Map that indicates the approximate available DER MW injection for each distribution feeder and at the substation. The hosting capacity maps will provide interconnection customer with information on the amount of DER that can be accommodated on the feeder. In 2020, PSEG Long Island will launch Stage 2 hosting capacity maps, which will provide the minimum and maximum hosting capacity that can be accommodated on the feeder. In 2021, Stage 3 hosting capacity maps will be released and will provide granular information on the amount of DER that can be accommodated at a particular node on the feeder.

xi) Distributed Energy Resource Management System (DERMS)

To support the State Goal of meeting 70x30, it is critical to implement technology, which provides operational platform for distribution to allow distribution operators to better manage DERs under different system conditions. To enable safe integration of DERs on LIPA system, PSEG Long Island is proposing to launch the DERMS (Distributed Energy Resource Management System) platform for 2021.

PSEG Long Island requested funding in 2020 Utility 2.0 filing to deploy an operational platform to allow distribution operators to effectively manage DERs under different system conditions. DERMS is an operational platform that enables the integration, measurement, monitoring, and control of DERs. This system will provide operators with the visibility of real time status and output of DERs under various system conditions. It will also provide operators enough information to ensure reliable operations of the system with higher penetration of Distributed Energy Resources. With the greater amounts of distributed generation on Long Island system, this capability is inevitable to understand the DER contributions at feeder level so that operational actions can account for load masking effects under contingency scenarios. Implementation of this platform is essential to promote higher DER penetration by providing visibility to the potential thermal constraints on the distribution system. This platform serves as the building block to utilize the monitoring and control capabilities and optimizes DER integration onto the grid.

For the future, other capabilities such as market-related functions associated with the DERs will need to be considered once the market rules associated with the DERs are established.

xii) Smart Inverter Capability

With the increase in the penetration of solar as envisioned under CLCPA, there is a need to ensure that the renewables are integrated in the most safe and reliable manner onto the distribution grid. To enhance the reliability of the system with increase in penetration of DER, PSEG Long Island will be conducting a pilot project with Smart Inverters in 2022 under its Utility 2.0 program. Under this project, PSEG Long Island will explore the capabilities, controls and functions of the smart inverters and assess the feasibility of implementing smart inverters across Long Island. The goal will be to utilize the pilot project to learn the capabilities of smart inverter technology and to develop roadmap to implement this technology in the safest and efficiency manner. In addition, smart inverter capability to address DER-caused voltage issues depends on reactive support from the grid. In order to leverage smart inverter capability, voltage support projects such as capacitor banks will be needed.

1. *Energy Storage*

Every capital project on Long Island is evaluated for non-wire alternative solutions. PSEG Long Island deployed two storage systems of total capacity of 10 MW/80 MWh in South Fork in 2018 which is the fastest growing region in Long Island with ~2% annual load growth. To increase operational flexibility on the grid and to defer the need for costly grid infrastructure investments, PSEG Long Island is evaluating on a continuous basis the need for deployment of energy storage systems on the distribution grid. With the advancement and lower cost of energy storage technology, energy storage solutions are being considered as alternatives to traditional capital projects.

xiii) Conclusion/Next Steps

A review of the LIPA electric distribution system was performed to determine the actions necessary to meet the NYS CLCPA directives and the Commission’s May 14, 2020 Order. This review outlined the major constraints that limit the integration of Distributed Energy Resources. The “Phase 1” projects identified above address local reliability issues and promote the integration of DERs, and thus have synergies with providing CLCPA benefits. LIPA recommends that the Commission consider “Phase 2” distribution projects identified above as a representation of potential upgrades to the Long Island distribution network in order to meet the renewable energy goals established by New York State legislative policies. As the penetration of distributed energy resources increases on LIPA system, it is necessary to upgrade existing technology platforms and communication infrastructure. Identification of these types of projects require additional considerations and hence not included as part of this Report.

The Phase 2 projects identified in the report support additional integration of DERs and adequate cost sharing or cost recovery mechanism needs to be considered should these projects move forward. LIPA suggests that the Commission consider evaluating whether these projects could qualify as local distribution projects that would be eligible for cost allocation or cost recovery under the AREGCB Act.[124]

[124] Transmission Planning Proceeding, May Order, pp. 8-9.

V. NATIONAL GRID

A. Transmission

National Grid's service territory covers a large geographic area of New York including portions of NYISO West, Genesee, Central, North, Mohawk Valley, and Capital zones and serves approximately 1.6 million electric customers. National Grid's transmission system is a heavily networked system and is comprised of transmission lines and substations operating at 69kV, 115kV, 230kV, and 345kV with approximately 6,500 circuit miles of 69kV, 115kV, 230kV, and 345kV lines. These facilities are extensively interconnected with facilities owned by other transmission owners in New York, surrounding states, and Canada. Further, the Company's system includes more than 200 transmission substations, over 3,200 circuit miles of sub-transmission lines, over 500 distribution substations, more than 711 large power transformers, approximately 44,000 circuit miles of primary distribution line supplying over 410,000 line transformers, with over 1.2 million distribution poles and many more assets.

Transmission facilities operating above 200kV are considered to be part of New York's bulk transmission system defined by the May Order, which is outside the scope of this study. The New York transmission facilities operating below 200kV are considered to be part of each Transmission Owner's local system and are therefore included in the scope of this study.

i) Discussion of National Grid Study Assumptions and Description of Local Design Criteria

Meeting the State's CLCPA goals requires a significant amount of renewable generation, energy storage, energy efficiency measures, demand response, and electric transportation, all of which will impact both the transmission and distribution (T&D) systems. The focus of this portion of this Report is on the transmission system.

1. National Grid Study Assumptions

This Utility Study is based upon the database established and used by the NYISO for the 2020 Reliability Needs Assessment (RNA) 70x30 CLCPA Scenario. The participants of the Technical Working Group subgroup made efforts to collaborate on high level study assumptions and methodologies; however, each utility has tailored the cases and their analysis to meet their individual needs based on system characteristics, utility planning criteria, etc.

The NYISO provided six (6) base cases that were developed as part of its 2020 RNA for use by the Technical Working Group subgroup. The cases include all transmission owner firm plans as described in the NYISO 2020 gold book. After reviewing these cases, the Technical Working Group selected three (3) cases as the starting point for the 70x30 scenario studies: (i) Day Peak Load of 30,000 MW; (ii) Shoulder Load of 21,500 MW; and (iii) Light Load of 12,500 MW. The load is modeled based on the 2020 Gold Book forecast for 2030. The renewable Resources Mix (based on nameplate MW) included in the database includes: (i) 6,098 MW of Off-

Shore Wind ("OSW"); (ii) 8,773 MW of Land Based Wind ("LBW"); and (iii) 15,150 MW of utility based photovoltaic ("UPV"). Figure 61 below provides a breakdown of the distribution of renewable resources connecting to National Grid's system; because of the networked nature of the upstate transmission system, however, the resources connecting outside of the National Grid service territory are also material to the results of this study.

Figure 61: Renewable Resource Assumptions

Zone/Type	Total LBW	Total UPV	National Grid LBW Allocation		National Grid UPV Allocation	
	MW	MW	MW	%	MW	%
A	2,286	4,432	2,088	91%	793	18%
B	314	505	314	100%	118	23%
C	2,411	2,765	455	18%	1,102	36%
D	1,762	0	103	6%	0	0%
E	2,000	1,747	1,545	77%	1,360	78%
F		3,592			2,433	68%
G		2,032			0	0%
H						
I						
J						
K		77			0	0%
Total	8,773	15,150	4,505	51%	5,706	38%

The maximum available nameplate of LBW and UPV was originally determined by the NYISO in the 2019 Congestion Assessment and Resource Integration Study (CARIS) 70x30 scenario and is also being used by the NYISO in the 2020 RNA 70x30 scenario. In CARIS, NYISO modeled the additional resources needed to meet the 70x30 goals at voltages 115 kV or higher regardless of where they may actually be located on the local system. National Grid did not adjust the interconnection point of any generation when assessing the bottlenecks that may develop and limit generation dispatch.

Starting from the 70x30 scenario peak load, shoulder load, and light load cases created by the NYISO, National Grid built 44 sensitivity cases examining different renewable dispatch conditions. These dispatch scenarios were communicated with neighboring utilities for their consideration and use in their study work. While developing the case dispatches, overloads and voltages outside of the acceptable range on the 345kV and 230kV systems were not reviewed and existing transfer limits were not respected, as these were considered out of scope for this assessment of the local system performance.

All study cases used by National Grid assumed no fossil generation was operating in areas A (West) through F (Capital) and assumed that nuclear generators at Nine Mile 1, Nine Mile 2, and Fitzpatrick were all in service at maximum output. For the ties from New York to the external areas, no import or export was allowed from New York to New England or Ontario.

Hydro generation at Gilboa was set to maximum generation in the peak and shoulder cases and set to pumping in light load cases. In all cases, the Moses generation was set to maximum output. At the Niagara/Lewiston facility, Niagara was set to 2160MW, evenly distributed across the thirteen machines and Lewiston was set to either 240MW of generation or 360MW of pumping load depending on the case. Run of river hydro generation was set to typical seasonal values. The import of Hydro generation from Hydro Quebec was set to either 1110MW or 535MW. No hydro generation was imported to Dennison from the Cedars generation.

Once the above assumptions were made in each case, LBW and UPV generation was dispatched to various levels. In the National Grid testing, LBW, primarily located in western, central and northern NY, was varied between 0 percent of nameplate up to 75 percent of nameplate and UPV, located in most areas from A to G, was dispatched between 0 percent of nameplate up to 70 percent of nameplate. No cases with wind or solar resources dispatched to 100 percent of nameplate were studied. In each scenario, all LBW or UPV was dispatched to the same percentage of nameplate, regardless of the location of the resource.

Some cases developed by National Grid include a mix of LBW and UPV. For example, one shoulder case modeled LBW at 30 percent of nameplate and UPV at 27 percent of nameplate. In addition to the cases, the NYISO also provided the zonal data of hourly load, LBW output, OSW output, and the UPV output from its CARIS study. This data from the NYISO was used to validate that the dispatches selected by National Grid were observed in the CARIS 70x30 scenario analysis. For example, LBW greater than or equal to 30 percent of nameplate concurrent with UPV output greater than or equal to 27 percent occurred in the CARIS 70x30 scenario for 802 hours. Another example of the many cases created was LBW at 15 percent of nameplate and UPV at 52 percent of nameplate, with the dispatch of these renewables at or above this level occurring in the CARIS 70x30 scenario for 457 hours. All dispatches reviewed by National Grid occurred in the NYISO CARIS 70x30 scenario for 100 hours or more.

For the National Grid assessment, no assumptions were made for the generation mix in New York City or Long Island, including no specific assumptions for offshore wind, as the generation mix downstate does not have any impact on the result of testing within National Grid's service territory. However, for simplicity of developing the scenario cases, it was assumed that the flow across the UPNY-CONED interface would not exceed 7000MW.

In addition to the cases described above. The NYISO initially provided a set of cases representing Business as Usual (BAU). These scenario cases represent the conditions where only resources that meet the NYISO inclusion rules were modeled in the study. Screening of these cases by National Grid found no notable conclusions and further analysis with these cases was abandoned to focus study efforts on the 70x30 scenario cases.

2. Local Design Criteria

For purposes of this study, National Grid performed steady state testing in accordance with its Transmission Group Procedure 28 (TGP28), *National Grid Transmission Planning Criteria*. Simulations were performed to assess the system response with all elements in service (N-0) as well as for N-1 outage conditions. These N-1 outages included loss of a circuit, transformer, generator or shunt device as well as breakers opening without a fault, bus outages, faults with a breaker failure and double circuit tower outages. As steady state testing was limited to N-0 and N-1 conditions, planned and unplanned outages (N-1-0 and N-1-1 conditions) will require generation curtailment.

The system response to these N-1 outages was generally considered acceptable when all local facilities were loaded below 100 percent of their Long-Term Emergency (LTE) rating. For pre-contingency conditions, loading was considered acceptable when all local facilities were loaded below 100 percent of their Normal (continuous) rating. The summer ratings were used in all cases. Acceptable post-contingency system voltages on the 115kV and 69kV system were between 90 percent of nominal and 105 percent of nominal and acceptable pre-contingency voltages were between 95 percent of nominal and 105 percent of nominal.

All solutions are required to meet the full set of local and regional Planning Criteria to ensure that the reliability of the planned system is not compromised. These criteria include dynamic, short circuit and expanded steady state requirements. Additional testing will be required for some proposed phase 2 solutions to ensure that they are designed to conform with and adhere to all applicable North American Electric Reliability Corporation ("NERC"), Northeast Power Coordinating Council ("NPCC"), New York State Reliability Council ("NYSRC") Reliability Rules, as well as applicable National Grid specifications, procedures, and guidelines.

ii) Possibility of Fossil Generation Retirements and the Impacts and Potential Availability of Those Interconnection Points

The National Grid study work included an evaluation of peak, shoulder and light load cases that modeled all fossil generation out of service concurrently with all existing and planned LBW and UPV out of service. In these cases, the only generation in service in zones A through F was hydro and nuclear. Analysis of these cases showed no N-1 steady state thermal overloads or voltages outside of limits. This analysis supports the conclusion that for normal system operation, the existing fossil generation fleet would not be needed for N-1 reliability or system security reasons. This test also confirms that all overloads found in this study are a direct result of the interconnection of solar and wind generation resources.

Prior to any generator retiring, additional testing would be required to confirm that the retirement does not create any steady state N-1-1 issues and would not result in a system instability. Any planned generator retirement would also need to be examined to confirm that no system upgrades or settings changes would be required to address system protection issues.

Following the retirement of a generator, the interconnection point may be available for use by a new generator. However, the new generator would have to go through the NYISO interconnection process, and the interconnection station would have to meet all National Grid interconnection requirements.

iii) Discussion of Existing Capacity "Headroom" within National Grid's System

National Grid's 115kV system operates as a continuous network from Buffalo across National Grid and Avangrid service territories to points north of Poughkeepsie and is also operated in parallel with the higher voltage and lower voltage networked systems. This makes the concept of headroom difficult to apply to individual pockets of the system. The capacity headroom analysis determined the total amount of renewable generation in MWs that can be injected into the existing system without exceeding system limits. The methodology developed is relatively complex due to the load and dispatch scenarios that were not considered, which can significantly affect the results. This is especially true of the assumed location of new renewable resource on a networked system.

To provide some indication of available capacity, National Grid performed a test where unlimited generation was added to the main 115kV switching stations in a given pocket. The cases were initialized assuming that no existing wind, solar or fossil generation was in service and that the fictitious generation at the main switching stations has zero output. An optimized dispatch was then developed that would keep all transmission elements in the pocket within acceptable loading for any N-0 or N-1 condition. This headroom calculation is the theoretical maximum generation that could be located within the pocket. For some pockets, generation may have been increased at only one switching station. In other pockets, the optimal dispatch spread the generation out across many switching stations. A real generator interconnection project located away from one of these optimal generation points would reduce the maximum area headroom at more than a one for one rate.

The maximum or optimal amount of generation within the pocket when an overload is found is listed as the headroom for that pocket. This test is only valid for the conditions in the cases used and for the assumed generator interconnections directly to the area switching stations. The test also does not account for generation in upstream pockets, which could result in lower downstream capability. Analysis does not distinguish between the type of generation, only estimates the capability for simultaneous output from generation within the local 115kV network.

Figure 62: Existing Headroom on National Grid System

Area	Peak Load	Shoulder Load	Light Load
Southwest	810	740	540
Genesee	900	780	630
East of Syracuse	1800	1850	1620

Area	Peak Load	Shoulder Load	Light Load
Watertown/Oswego/Porter	1010	1030	1080
Porter/Inghams/Rotterdam	550	460	430
Capital/Northeast	660	690	730
South of Albany	810	730	710

iv) Discussion of Bottlenecks or Constraints that Limit Energy Deliverability within National Grid's System

Using the dispatched cases and testing methodology, National Grid has completed an assessment of its local transmission system to identify system constraints, or "bottlenecks," that limit renewable energy deliverability under normal and N-1 contingency conditions. This testing has concluded that bottlenecks exist in seven major renewable generation pockets within the National Grid system. To eliminate all identified constraints in these pockets, National Grid would need to resolve 924 circuit miles of conductor overloads.

All observed overloads could be fully corrected by curtailing renewable generation. However, addressing transmission limitations through generation curtailments may require the suboptimal installation of additional renewable generation to overcome the energy curtailed and meet 70X30. An estimate of the amount of generation in each pocket that would have to be curtailed, or relocated to where it would be fully deliverable, to address transmission overloads is given in Figure 63. However, given the constraints encountered in many parts of the system, identifying an area where this generation could relocate without being curtailed is unlikely.

Figure 63: Summary of System Concerns in Generation Pockets

Constrained Area	Miles of Overloaded Conductor	Highest Area Circuit Loading (% of Rating)	Highest Base Case Generation Curtailment	Estimated Equivalent Replacement Generation Capacity
Southwest	101 miles	205%	330MW	440MW
Genesee	17 miles	156%	110MW	140MW
East of Syracuse	0 miles	157%	90MW	270MW
Watertown/Oswego/Porter	380 miles	368%	870MW	1,160MW
Porter/Inghams/Rotterdam	267 miles	448%	660MW	950MW
Capital/Northeast	13 miles	159%	2,590MW	7,190MW
Albany South	146 miles	252%	660MW	950MW
Total	924 miles			

Area descriptions:

1. Southwest - south of Buffalo to the New York-Pennsylvania border
2. Genesee - east of Buffalo to Rochester

3. Watertown/Oswego/Porter - bound by Moses and Willis stations in the north, Oswego in the southwest and Porter in the southeast
4. East of Syracuse - south and east of Syracuse from Cortland to Oneida
5. Porter/Inghams/Rotterdam - bound by Porter to the west and Rotterdam to the east
6. Capital/Northeast – bound by Rotterdam to the west and New Scotland to the south
7. Albany South - the area from New Scotland south to Pleasant Valley and from Greenbush south to Pleasant Valley

1. *Potential Projects that would Address Bottlenecks or Constraints that Limit Energy Deliverability within National Grid's System*

Potential projects that would address bottlenecks or constraints as well as the potential projects that would increase capacity on the local system to allow for interconnection of new renewables are discussed in the following section.

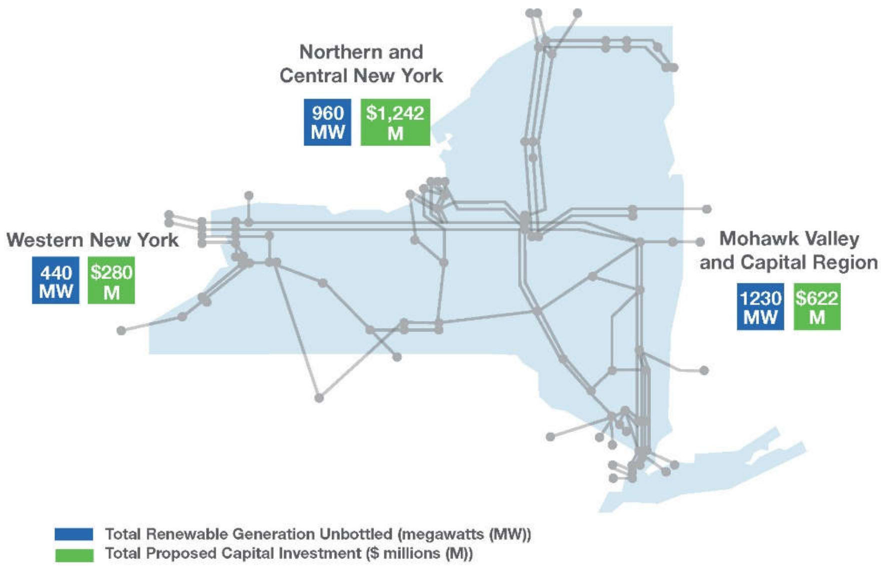
2. *Potential Projects that would Increase Capacity on the Local Transmission and Distribution System to Allow for Interconnection of New Renewable Generation Resources within National Grid's System*

Based on the study identified constraints limiting renewable energy integration in each area of the National Grid system, projects were developed. For each area, recommend transmission solutions are separated into Phase 1 and Phase 2. An estimate of the amount of generation unbottled in the most constrained case tested as part of this study is included for the Phase 1 projects as well as the combination of the Phase 1 and Phase 2 projects. The MW of additional generation capability reported represents the increase in deliverability of the area generation. In some areas the recommended projects would provide increased headroom above that required for the area generation included in the study cases. All Phase 2 Projects are consolidated and summarized in Figure 65: . The Phase 2 projects are conceptual and additional analysis will be needed to optimize those solutions.

Although a few alternatives were considered in each area, one option is recommended as the most cost effective and efficient solution to the area needs after consideration of Multi Value Transmission drivers. Most of the cost estimates in this study are considered to be Order of Magnitude level based on a limited desktop engineering analysis with an accuracy of +200/-50%. The proposed in-service dates are also estimates that will require additional refinement through detailed engineering and scope development.

National Grid requests the Commission approve all Phase 1 projects described below, and illustrated in Figure 64. National Grid believes these projects are immediately actionable and will provide significant benefits towards unbottling the renewable resources needed to meet CLCPA objectives. In addition, National Grid requests the Commission approve the cost recovery framework described in Section V of this Report for the costs associated with Phase 1 projects not currently in National Grid's existing capital investment plan or included in its most recent rate filing.

Figure 64: National Grid's Total Regional Transmission Investments, and Associated Renewable Benefits



a) Southwest Pocket: Phase 1

The Phase 1 projects in this area are estimated to reduce the need for generation curtailment by 310MW. The combination of the Phase 1 and Phase 2 projects are estimated to reduce the need for generation curtailment by 440MW.

Figure 65: List of Phase 1 Projects in the Southwest Pocket

Project Name	Zone	Terminal A	Terminal B	Project Description	Proposed I/S Date
Dunkirk – Falconer 115kV Line Upgrades	A	Dunkirk	Falconer	115kV Upgrade: sections of Dunkirk-Falconer	2027
Moons Series Reactors	A	Moons	Moons	Retire and relocate series reactors near end of life	2024 *In rate case
Homer Hill – Bennett 115kV Terminal Upgrades	A/C	Homer Hill	Bennett	Address all limiting 115kV terminal equipment at various stations between Homer Hill and Bennett	2023
Batavia – Golah 115kV Line Upgrade	B	Batavia	Golah	115kV Upgrade: sections of Batavia – Golah	2026
				Total Cost	$262M

b) East of Syracuse: Phase 1

The Phase 1 projects in this area are estimated to reduce the need for generation curtailment by 90MW.

Figure 66: Phase 1 Projects in the East of Syracuse Pocket

Project Name	Zone	Terminal A	Terminal B	Project Description	Proposed I/S Date
Clarks Corners – Oneida 115kV Terminal Upgrades	C	Clarks Corners	Oneida	Address all limiting 115kV terminal equipment at various stations between Clarks Corners and Oneida	2023
				Total Cost	$5M

c) Watertown/Oswego/Porter: Phase 1

The phase 1 projects in this area are estimated to reduce the need for generation curtailment by 300MW. The combination of the Phase 1 and Phase 2 projects are estimated to reduce the need for generation curtailment by 870MW.

Figure 67: Phase 1 Projects in the Watertown/Oswego/Porter Pocket

Project Name	Zone	Terminal A	Terminal B	Project Description	Proposed I/S Date
Colton – Boonville 115kV Terminal Upgrades	E	Colton	Boonville	Address all limiting 115kV terminal equipment at various stations between Colton and Boonville	2022 *In rate case
Lighthouse Hill – Clay 115kV Clearance Limits	C/E	Lighthouse Hill	Clay	Address all clearance limits on the Lighthouse-Clay 115kV line	2023
Coffeen – Black River 115kV Terminal Upgrades	E	Coffeen	Black River	Address all limiting 115kV terminal equipment on lines connected to Coffeen	2023
Malone 115kV PAR	D	Malone	Malone	Add a 115kV Phase Angle Regulator to the Willis – Malone circuit	2026 *In rate case
				Total Cost	$18M

d) Porter/Inghams/Rotterdam: Phase 1

The Phase 1 projects in this area are estimated to reduce the need for generation curtailment by 150MW. The combination of the Phase 1 and Phase 2 projects are estimated to reduce the need for generation curtailment by 660MW.

Figure 68: Phase 1 Projects in the Porter/Inghams/Rotterdam Pocket

Project Name	Zone	Terminal A	Terminal B	Project Description	Proposed I/S Date

Rotterdam 69kV Line and Station Upgrades	F	Rotterdam	Rotterdam	69kV Upgrade at Rotterdam and sections of 69kV circuits connected to Rotterdam	2027 *In rate case
Inghams – Rotterdam 115kV Line Upgrades	F	Inghams	Rotterdam	115kV Upgrade: Inghams-Rotterdam circuits	2026-2030
				Total Cost	$433M

e) *Capital Region: Phase 1*

The Phase 1 projects in this area are driven by much higher flows into the Rotterdam area across the local and bulk system and are not related to a specific generator or group of generators. Due to the generation being further away from the constraint, the projects are estimated to reduce the need for generation curtailment by 2590MW. No Phase 2 projects were identified as being needed in this area.

Figure 69: Phase 1 Projects in the Capital Pocket

Project Name	Zone	Terminal A	Terminal B	Project Description	Proposed I/S Date
Rotterdam – Wolf/State Campus 115kV Line Upgrades	F	Rotterdam	Wolf Rd / State Campus	115kV Upgrade: sections of Rotterdam-Wolf, Rotterdam-State Campus	2027
				Total Cost	$46M

f) *Albany South: Phase 1*

The Phase 1 projects in this area are estimated to reduce the need for generation curtailment by 280MW. The combination of the Phase 1 and Phase 2 projects are estimated to reduce the need for generation curtailment by 570MW.

Figure 70: Phase 1 Projects in the Albany South Pocket

Project Name	Zone	Terminal A	Terminal B	Project Description	Proposed I/S Date
Churchtown– Pleasant Valley 115kV Upgrades	F/G	Churchtown	Pleasant Valley	115kV Upgrade: sections of Churchtown- Pleasant Valley	2025
				Total Cost	$9M

g) *National Grid Company-Wide: Phase 2*

All proposed Phase 2 projects for National Grid are summarized below, the benefits of the projects in each region are summarized with the Phase 1 projects above.

Figure 71: National Grid Phase 2 Projects

Project Name	Zone	Terminal A	Terminal B	Project Description	Proposed I/S Date
Lockport – Mortimer 115kV Smart Valve System	B	Lockport	Mortimer	115kV Upgrade: Add Smart Valve system to Lockport-Mortimer Lines	2027
Black River – Lighthouse Hill 115kV Line Upgrade	C/E	Black River	Lighthouse Hill	115kV upgrade: sections of Black River to Lighthouse Hill	2025
Taylorville – Boonville 115kV Line Upgrade	E	Taylorville	Boonville	115kV upgrade: sections of Taylorville to Boonville	2027
Coffeen – Black River 115kV Line Upgrade	E	Coffeen	Black River	115kV upgrade: sections of Coffeen to Black River	2027
Lighthouse Hill – Clay 115kV Line Upgrade	C/E	Lighthouse Hill	Clay	115kV upgrade: sections of Lighthouse Hill to Clay	2029
Coffeen – Lyme 115kV Line Upgrade	E	Coffeen	Lyme	115kV Upgrade: sections of Coffeen to Lyme	2030
Black River – Taylorville 115kV Line Upgrade	E	Black River	Taylorville	115kV upgrade: sections of Black River to Taylorville	2031
South Oswego – Lighthouse Hill 115kV Line Upgrade	C	South Oswego	Lighthouse Hill	115kV upgrade: sections of South Oswego to Lighthouse Hill	2033
Boonville – Porter 115kV Line Upgrade	E	Boonville	Porter	115kV upgrade: sections of Boonville to Porter	2035
Meco Station Upgrade	F	Meco	Meco	Upgrade Meco	2026
Albany 115kV PAR	F	TBD	TBD	Add a 115kV Phase Angle Regulator South of Albany	2027
Marshville Station Upgrade	F	Marshville	Marshville	Upgrade Marshville	2028
Leeds Station Upgrade	F	Leeds	Leeds	Upgrade Leeds	2028
				Total Cost	$1,371M

v) Conclusion

Based on current and future renewable generation developer interest, a significant amount of renewable generation necessary to meet CLCPA objectives is expected to be interconnected to the local transmission system in National Grid's service territory. National Grid has performed extensive system analysis and has determined that the Company's transmission system creates bottlenecks or constraints in many of the areas that renewable generator developers have shown interest. All observed overloads could be fully corrected by curtailing renewable generation production. Addressing transmission limitations through energy production curtailments would require the suboptimal installation of additional renewable generation capacity to overcome the energy production curtailed and meet 70X30. However, given the large number of constraints encountered in many parts of the system, identifying an area where this generation could relocate without being curtailed is unlikely. The Phase 1 and Phase 2 projects that have been identified by National Grid are needed to address these local system limits and avoid curtailments. National Grid also selected these projects because they would not only support renewable energy deliverability but many of them provide additional benefits to customers (i.e. Multi-Value Transmission). Without these projects, the amount of resulting energy curtailments will require additional generation capacity to be built in order to meet the CLCPA's 70X30 target.

B. Distribution

i) Introduction

This portion of the report provides a high-level overview of National Grid's detailed analysis and results of the worst case scenario impacts on its 5 kV – 46 KV distribution system ("grid") in achieving the State's CLCPA goals up to, and including, the year 2030. Although several CLCPA targets exceed this time frame, such as achieving 100% clean electrical energy by 2040, analysis of such impacts on the distribution system are beyond the scope of this Report. National Grid's current Distribution Planning Criteria was applied in these studies.

The analysis primarily captured DER technologies that are expected to have the most negative impacts on National Grid's distribution system and require system upgrades to resolve. In this regard, solar PV has been, and is expected to continue to be, the most significant driver of grid upgrades.

To examine the key elements of the study identified in the May Order, including identification of bottlenecks, traditional capital projects that can alleviate bottlenecks, and new projects to alleviate all remaining bottlenecks, the Company developed detailed forecasts that capture a range of potential scenarios. In particular, National Grid identified the following four forecast scenarios[125] to frame the study:

1. 2019 gross loads with existing generation and energy storage, plus interconnection queue for generation and storage projects that have made 25% CIAC interconnection cost payment made as of June 1, 2020.
2. 2019 gross loads with existing generation and energy storage, plus 100% of total generation and storage in the interconnection queue as of June 1, 2020.
3. NYISO 70x30 peak load case[126] with 69% dispatch of behind the meter (BTM) solar PV.[127]
4. 2030 CLCPA bottom-up feeder level forecast.[128]

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[125] None of the forecast scenarios capture heat pumps as the forecasts for that technology is not currently available. Also note only limited storage (below the CLCPA targets) and zero demand response is modeled as the study aimed to identify the violations that could then potentially be solved by these technologies/programs.

[126] See Figure 61, above

[127] BTM is defined as any DER that is not seen/bidding into the markets i.e. treated as net load by the NYISO

[128] Highly granular forecast as described in detail in the Company's 2020 DSIP Update Report that was adjusted to meet achieve National Grid's expected portion of the 2030 CLCPA goals.

ii) Overview of Results

1. Existing Headroom

The May Order directed that utilities determine where capacity "headroom" exists on today's grid. To that end, National Grid conducted an analysis of all four forecast scenarios and identified the locations where the forecast scenario power flows are less than the current grid asset hosting capacity[129] available. The results show that for the worst case scenario (Scenario 2), the grid has limited existing headroom available and highlights a key challenge where most of the interconnection queue looks to connect to the grid in constrained locations, such as rural areas with available land but weak grid infrastructure. On the other hand, Scenario 4 revealed sufficient headroom exists that could potentially accommodate the Company's solar PV CLCPA 2030 goals. It is important to note, however, under Scenario 4, the allocation method of solar PV projects only locates solar PV to those geographic areas where there is enough available hosting capacity. Therefore, the Company does not believe Scenario 4 accurately reflects where solar PV is looking to interconnect over the duration of the forecast.[130] However, the Company has and continues to promote solar PV specifically, in areas where the grid has sufficient hosting capacity headroom via the Company's publicly available hosting capacity map website.[131]

2. Bottlenecks

The second question in the May Order is to identify existing constraints or bottlenecks that limit energy deliverability. To answer this question, the Company identified the assets and associated locations that show violations (i.e., power flows above the asset hosting capacity) for all four forecast scenarios. The results revealed that Scenario 2 had the greatest number of asset violations, with Scenarios 1 and 3 producing some violations that in general overlapped with violations identified in Scenario 2. Scenario 4 revealed no violations. The list of projects in the tables below highlight the locations of the grid where such bottlenecks exist.

3. Capital Expenditure Synergies

The third question in the May Order directs utilities to identify synergies with traditional capital expenditure projects driven by aging infrastructure, reliability, resilience, market efficiency, and operational flexibility that simultaneously alleviate some bottlenecks identified (*i.e.*, increase hosting capacity). This concept aligns with the Multi-Value Distribution concept as part of the on-going New York Standardized Interconnection Requirements ("NYSIR") cost sharing proposal being discussed at the Interconnection Policy Working Group ("IPWG"). To answer this question, the Company reviewed its current five year Capital Investment Plan

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129 The term hosting capacity is considered in the broadest term (i.e., ability to host both generation and load).

130 The Company is currently making revisions to its bottom up forecast methodology to address this issue

131 https://ngrid.portal.esri.com/SystemDataPortal/NY/index.html

("CIP")[132] and identified existing projects that solve reliability, capacity, and asset condition issues but also provide increased hosting capacity primarily to resolve Scenario 1 and 2 violations. The analysis identified several projects as shown in Figure 72, below[133] and are labeled as Phase 1 projects.[134] National Grid's study revealed limited overlap between planned capital projects and the CLCPA driven violations identified, as a large portion of the Company's planned capital projects are to replace or build new assets in the Company's towns and cities that suffer from asset condition challenges, such as, the City of Buffalo and contrasts with the more rural areas where solar PV is typically looking to interconnect.

4. New Incremental Projects

The fourth question identified for the study in the May Order is to identify potential new projects that would increase hosting capacity on the grid to resolve all remaining bottlenecks not resolved via projects in the capital plan. These projects are referred to as Phase 2[135] projects as shown in the Figure 73 below. The results identified a significant number of projects that would be required to meet CLCPA goals, mostly driven by Scenario 2. It is important to note that the solutions and estimates are based on traditional, wire-based solutions. Non-Wire Alternatives (e.g., controllable and dispatchable DER)[136] may be able to solve some of the violations identified. It is also important to note resources, including procurement, design, engineering, right-of-way, installation and operations staff, required to implement Phase 2 projects will be significant and are not factored into this analysis and the proposed projects listed.

5. New or Emerging Solutions

The fifth question is to determine potential new or emerging solutions that can accompany or complement traditional upgrades. This includes identifying opportunities to propose new innovative solutions to create additional hosting capacity in areas with bottlenecks. National Grid has a number of new or emerging projects already in flight (Phase 1) and recently proposed in its most recent rate filing that will support the CLCPA goals either directly or indirectly. National Grid's Distributed System Implementation Plan provides significant details of how these new or emerging solutions support CLCPA goals. Examples include energy storage projects, NWAs, Volt/VAR Optimization (VVO) and Conservation through Voltage Reduction (CVR), and Advanced Distribution Management System (ADMS), as well as the Clean Innovation

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[132] 2020 Electric Transmission and Distribution Capital Investment Plan, filed March 31, 2020 in Case 17-E-0238.

[133] Several projects are currently proposed in the Company's 2020 July 31st rate filing.

[134] Located on circuits that create impediments to renewable energy utilization (bottlenecks), provide multi-value benefit such as to asset condition or reliability in addition to the projects' CLCPA benefits and are projects already listed in the Company's latest version of the CIP,

[135] These projects are not currently in the Utilities' capital plans, solutions are generally more complex than phase 1 projects, are driven primarily by CLCPA benefits that would be unlocked, require commission approval to proceed, for example, the JU Cost Sharing proposal and are subject to changing market conditions

[136] The Company would look to apply the current NWA criteria to identify potential NWA RFP opportunities.

and Distributed Energy Resource Management System (DERMS) Investigation projects proposed in the Company's 2020 rate case. None of these new or emerging solutions were factored into the detailed analysis due to the complexity in modeling and simulating their impacts. National Grid has not identified any new or emerging Phase 2 solutions at this time, but continues to actively participate in R&D related groups and forums such as NYSERDA projects, EPRI, and CEATI programs to help inform future potential new or emerging solutions for the longer term.

6. Prioritization

In addition to the questions discussed above, the May Order also requests the list of proposed projects be ranked and prioritized. As such the Phase 1 and Phase 2 lists are provided as the answer to this question, where it is recommended Phase 1 projects are the higher priority than Phase 2 due to the multi-value nature provided by these projects as described previously.

iii) Results

1. Phase 1

Figure 72: Phase 1 Projects[137]

Project Name	Violation Type	Zone	Terminal A	Terminal B	Project Description	Est. Proposed I/S Date	OOM Estimate	Incremental Hosting Capacity [138]
Stoner Sub	Substation	F-4	Stoner	N/A	Upgrade 25MVA transformer bank with 40MVA bank to address asset condition and hosting capacity concerns	2019-2021	$2.5M	15 MW
Hoosick Sub	Substation	F-4	Hoosick	N/A	Upgrade 12.5MVA transformer bank with 25MVA bank as part of rebuild for IEC 61850 standard	2020-2024	$11M	12.5 MW
Altamont Sub	Substation	F-4	Altamont	N/A	Upgrade 22.4MVA to 40MVA bank to address asset condition and hosting capacity concerns	2025-2030	$10M	17.6 MW
Cllinton Sub	Substation	E-3	Clinton	N/A	Upgrade 10.5 MVA bank to address asset condition and hosting capacity concerns, size TBD	2025-2030	$10M	TBD
3V0 and LTC upgrades Phase 1	Substation	multiple	various	N/A	51 Pending customer and company funded 3V0/LTC upgrades	2020-2025	$32.5M	224 MW
Buffalo Station 32 Rebuild	SubT	A-1	Stat 32	N/A	Removal of all the existing equipment and the installation of four (4) new 23/4.33kV 3.75/4.687 MVA transformers	2020-2024	$7.6M	4 MW
Buffalo Station 38 Rebuild	SubT	A-1	Stat 38	N/A	Removal of all the existing equipment and the installation of four (4) new 23/4.33kV 3.75/4.687 MVA transformers	2020-2024	$9.7M	4 MW
Buffalo Station 139	SubT	A-1	Stat 139	N/A	Replace Transformers. This project will replace the existing 3.75/4.687MVA transformer with a 7.5/9.375MVA transformer.	2024-2027	$2.9M	4.7 MW
Golah Sub TB1	SubT	B-29	Golah	N/A	Upgrade 63kV to 34.5 kV transformer from 10MVA to 25 MVA	2020-2024	$4.5M	15 MW
Golah Sub TB3	SubT	B-29	Golah	N/A	Upgrade 63kV to 34.5 kV transformer from 10MVA to 25 MVA	2020-2024	$4.5M	15 MW
Perkins South West to DG	SubT	TBD	Perkins	DG	Reconductor 2.1 miles 34.5 kV conductor to 336.4	2020-2025	$1.4M	2 MW
Avon to Golah	SubT	B-29	Avon	Golah	10 MW/ 20 MWh battery project at 34.5 kV	2022	$8M	2 MW
Newark to Maplewood Refurb	SubT	F-4	Maple	NRLT	Install a new 34.5 kV cable	2020	$0.7M	3 MW
Raquette Lake	SubT	E-3	Raquette	N/A	Replace the existing (3)-333KVA 46:4.8kV substation transformer with 46/4.8 kV 2.5 MVA pad-mounted transformers	2020-2021	$0.9 M	1.5 MW
Fairdale	SubT	C-2	Fairdale	N/A	Replace 2.5 MVA transformer with new 5 MW transformer	2020-2021	$0.9 M	2.5 MW
Gilbert Mills	SubT	C-2	Gilbert Mills	N/A	Upgrade of transformer bank one (1) from 9.375MVA to a 15/20/25MVA transformer and includes the installation of EMS at the station.	2023-2026	$3M	15.625 MW
West Adams	SubT	E-3	W Adams	N/A	New second transformer bank at West Adams substation	2023-2026	$3.5M	1MW

137 Several projects are also captured in the National Grid rate case as filed on July 31st, 2020.

138 Hosting capacity increases are not typically incremental and should not be added together

Project Name	Violation Type	Zone	Terminal A	Terminal B	Project Description	Est. Proposed I/S Date	OOM Estimate	Incremental Hosting Capacity [138]
Sorrell Hill	SubT	C-2	Sorrell Hill	N/A	Install second 115/13.2kV 15/20/25MVA transformer at Sorrell Hill.	2023-2027	$5M	1MW
Feeder 1562	Distribution	TBD	TBD	TBD	Rebuild portions of Catt. F1562	2020-2025	$1.5M	17MW
Feeder 32451	Distribution	TBD	TBD	TBD	Minor Storm Hardening – 32451	2020-2025	$17M	12MW
Feeders 7765, 7656, 23251, 20653, 7656, 7656, 20653, 7656	Distribution	TBD	TBD	TBD	Middleport F7765 Tie w/Shelby 7656 F23251 Create Ties with 20653&7656 F7656 to relieve F20653 for Cust MSH Upgrade Limited Tie to F7656	2020-2025	$25M	8MW
Feeder 98352	Distribution	TBD	TBD	TBD	State HWY 58 Relocation 98352	2020-2025	$1.7M	8MW
Feeder 37061	Distribution	TBD	TBD	TBD	NR-Hammond 37061-T.I. Transformers	2020-2025	$10.6M	7MW
Feeder 93852	Distribution	TBD	TBD	TBD	Ogdensburg 93852 HWY 37 - Rebuild	2020-2025	$2M	6MW
Feeder 97654	Distribution	TBD	TBD	TBD	97654 Skinnerville Road - Rebuild	2020-2025	$2.1M	6MW
Feeders 7958, 15351, 6161	Distribution	TBD	TBD	TBD	Create Fdr Tie F7958-F15351&F6161	2020-2025	$2.6M	4MW
Feeders 7958, 15351, 6161	Distribution	TBD	TBD	TBD	Create Fdr Tie F7958-F15351&F6161	2020-2025	$4.1M	3MW
Feeders 0456, 0457	Distribution	TBD	TBD	TBD	F0456/0457 Build feeder tie	2020-2025	$12.5M	3MW
Feeder 66954	Distribution	TBD	TBD	TBD	MV-Lehigh 66954 Reconductoring	2020-2025	$1.9M	3MW
Feeder 25456	Distribution	TBD	TBD	TBD	NY14 Fairdale 64 tie with 25456	2020-2025	$3.8M	2MW
Feeder 2861	Distribution	TBD	TBD	TBD	Rebuild portion of E. Otto F2861	2020-2025	$1.2M	2MW
Feeder 26552	Distribution	TBD	TBD	TBD	Burdeck 26552 - Burnett St Conversion Burdeck 26552 - Westcott / Curry Rd	2020-2025	$1.1M	2MW
Feeders 15351, 15352, 15151, 15351, 15151, 15351, 7958, 15351, 6161	Distribution	TBD	TBD	TBD	Create Full Tie F15351 to F15352 Make Ready Fdr Tie F15151-15351 MSH Create Fdr Tie F15151-15351 Create Fdr Tie F7958-F15351&F6161	2020-2025	$9M	1MW
Feeders 89552, 89552, 89552	Distribution	TBD	TBD	TBD	89552 Crooks Road - Rebuild 89552 Dyke Road - Rebuild French Road Relocation 89552	2020-2025	$15.3M	1MW
Feeder 22651	Distribution	TBD	TBD	TBD	Knapp Rd 22651 Feeder Tie	2020-2025	$5.3M	1MW
Feeder 98455	Distribution	TBD	TBD	TBD	Dekalb 98455 Town Line rd - Rebuild	2020-2025	$1.5M	1MW
Feeder 3354, 10451	Distribution	TBD	TBD	TBD	MSH-WOlean 3354 tie 10451 Chipmunk	2020-2025	$2.6M	1MW

Project Name	Violation Type	Zone	Terminal A	Terminal B	Project Description	Est. Proposed I/S Date	OOM Estimate	Incremental Hosting Capacity [138]
New/Emerging Technologies Phase 1	Various	multiple	various	various	Grid Modernization investments filed in rate case and IT rents	2021-2024	$520M	Requires complex analysis[139]

2. *Phase 2*

Figure 73: Phase 2 Projects

Project Name	Violation Type	Zone	Terminal A	Terminal B	Project Description	Est. Proposed I/S Date	OOM Estimate	Incremental Hosting Capacity [140]
>10 MW in Queue	Substation	multiple	various	N/A	12 stations in National Grid territory currently with over 10MW of DG in queue above the nameplate rating of the bank include 44 South Park, Berry Rd, Brockport, Cattaraugus, East Pulaski, East Watertown, Hudson, Lawrence Ave, Lisbon E. S., North Carthage, Salisbury ES, and W Hamlin.	2025-2030	36M to $180 M depending on scope of upgrades	15 MW to 330 MW depending on the scope for each upgrade
>Nameplate<10MW in queue	Substation	multiple	various	N/A	47 station transformers across all 3 regions where DG in queue is greater than rating but under 10MW: 171 Burt, 51 Elk St, 76 Shawnee, 89 Ransomville, Ashley, Batavia Station, Bennett Rd, Boyntonville, Bremen, Bridgeport, Brunswick, Butts Rd, Delphi, E. Batavia Station, East Otto, Ft. Covington, Hammond, Hudson Falls, Knapp Rd, Langford, Lyme E.S., Moira, Morristown, N. Eden, New Haven, Nicholville, Niles, North Governeur, Ogdensburg, Peterboro, Phoenix, Port Henry, Port Leyden, Randall Rd, Rock City Falls, Schodack, Sharon, Shelby, Sherman WRCC, South Wellsville, St Johnsonville, Starr Rd, Stittville, Thousand Islands, W Albion, Whitehall, and York Ctr	2025-2030	$141 M to $705 M depending on scope of upgrades	59 MW to 1292 MW depending on the scope for each upgrade
3V0 and LTC upgrades Phase 2	Substation	multiple	various	N/A	Additional 3V0/LTC upgrades	2025-2030	$63.5 M	498 MW
Sub Transmission Thermal Violations Phase 2	SubT	multiple	various	various	23 bank upgrades, 29 build new ties, 3 new stations, 16 reconductor,	2025-2030	$211 M	124 MW

139 Does not include foundational investments such as feeder sensors, substation SCADA, AMI etc.

140 Hosting capacity increases are not typically incremental and should not be added together.

Project Name	Violation Type	Zone	Terminal A	Terminal B	Project Description	Est. Proposed I/S Date	OOM Estimate	Incremental Hosting Capacity [140]
Sub Transmission Voltage Violations Phase 2	SubT	multiple	various	various	Regulator and capacitor bank installations	2025-2030	$26.7 M	Requires complex analysis
Distribution Phase 2	Distribution	multiple	various	various	119 feeder violations with no solution already in CIP	2025-2030	$106 M	456 MW
New/Emerging Technologies Phase 2	Various	multiple	various	various	Additional Grid Modernization investments	2025-2030	TBD	TBD

iv) Key Assumptions

Several key assumptions were made to conduct the study as listed below:

1. *Global:*

- All costs are capex only
- No consideration of CLCPA targets beyond 2030
- In alignment with the local transmission study, did not account for NYSERDA reports
- Studies did not explicitly model Grid Modernization investments other than for Distribution Feeder analysis
- No modeling of time-of-use (TOU)/time-variable pricing (TVP) impacts on load via advanced metering infrastructure (AMI)
- No inclusion of DR or standalone energy storage i.e. does not meet associated CLCPA goals but are considered as solutions rather than problems generating technologies/programs
- No beneficial electrification is heat modeled

2. *Scenario 1*

- 1317 MW of solar plus some storage combined less than 5 MW individually

3. *Scenario 2*

- 3036 MW of solar plus some storage combined less than 5 MW individually

4. *Scenario 3*

- Only 1 scenario (peak load and high solar) studied based on worst case TPAM sensitivities
- 1925 MW of behind the meter[141] solar, other DER is netted with load

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[141] NYISO defines behind the meter solar as projects that are not bidding into the NYISO wholesale market.

5. *Scenario 4*

- 440 MW Connected solar PV
- 446 MW of incremental Rooftop solar PV
- 547 MW of incremental Non-Roof Top Solar PV
- 641 MW of incremental Solar & some storage
- 1014 MW of incremental EV
- 566 MW of incremental EE
- Solar PV is spread based on available hosting capacity

6. *Distribution Feeder Analysis:*

- Minimum load is not factored into analysis due to the conservative approach taken in this analysis
- Phase 2 solutions do not consider include feeder conductor upgrades but are based on linearized $/kW hosting capacity costs accounting for recloser settings changes, bi-directional voltage regulators, fixed to switched capacitor banks, smart inverters and energy storage
- Average Max-Min hosting capacity values with some weighting was applied and not the more recent nodal hosting capacity analysis
- Combination of four variables drive the violations identified including thermal, voltage, protection, and short circuit
- Available hosting capacity limits are based on 2020 hosting capacity result values
- Released incremental hosting capacity is based on size of violation and not actual MVA of solution
- CIP projects are assumed to completely solve the hosting capacity violation

7. *Substation Transformers & 3V0 + LTC Analysis:*

- Minimum load is not factored into analysis due to the conservative approach taken in this analysis
- Accounts for new proposed transformers that would be built with 3V0 and LTC as part of the Company’s standard design
- Does not include DTT upgrades
- Does not account for any dual banks where only one combined 3V0 scheme would be deployed

8. *Sub-Transmission Analysis:*

- Day time minimum load modeled for scenario 1 & 2
- Modeled NYISO Sub-Transmission connected generation and queue generation from the September 2020 NYISO queue
- Sub-Transmission loads scaled to match NYISO scenario 3 case
- Peak and minimum load cases applied for scenario 4

- Investments do not include solutions to several extreme low voltages identified due to complexity of the contingencies and the associated solutions that require more time to evaluate
- Released incremental hosting capacity is based on size of violation and not actual MVA of solution for Phase 2 projects only

9. New /Emerging Technologies:

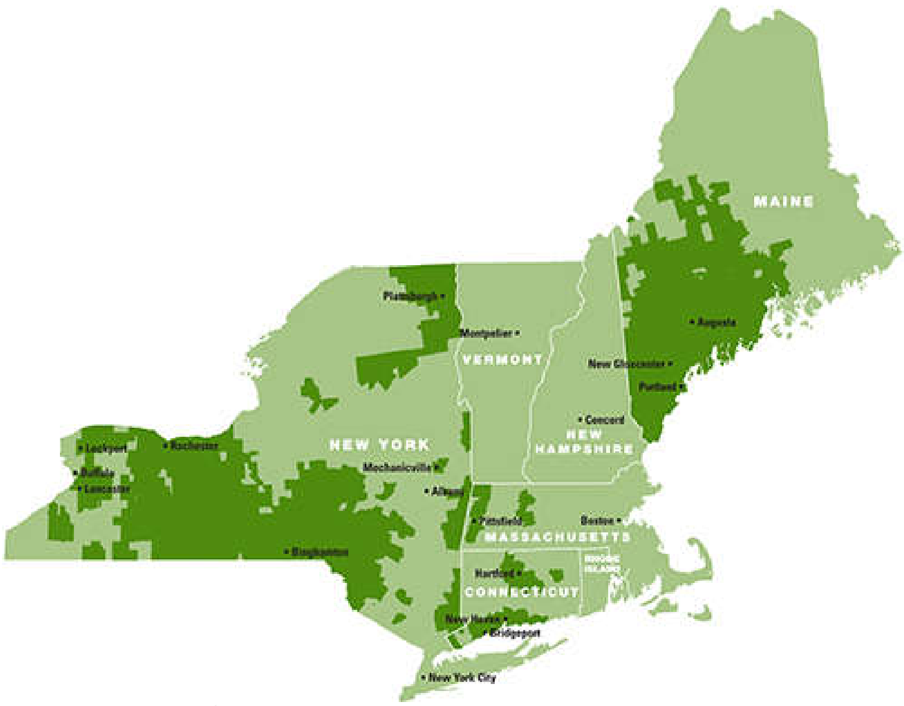
- Other than distribution feeder upgrades that capture smart inverters and energy storage in the analysis, no other new/emerging technologies were factored in the analysis and as such could offset some of the traditional wire-based upgrades proposed.
- In accordance with National Grid's planning criteria, NWAs would be considered to solve violations.

VI. NYSEG AND RG&E

A. Transmission

AVANGRID has assets and operations in several U.S. states and has two primary lines of business including its Networks and Renewables companies. The AVANGRID Networks business is shown in Figure 74 below and includes eight electric and natural gas utilities, serving 3.2 million customers in New York (i.e. NYSEG and RG&E) and New England. The AVANGRID Renewables business owns and operates 7.1 gigawatts of electricity capacity, primarily through wind power, with a presence in 22 states across the United States.

Figure 74: AVANGRID Networks (Electric + Gas) Service Territories

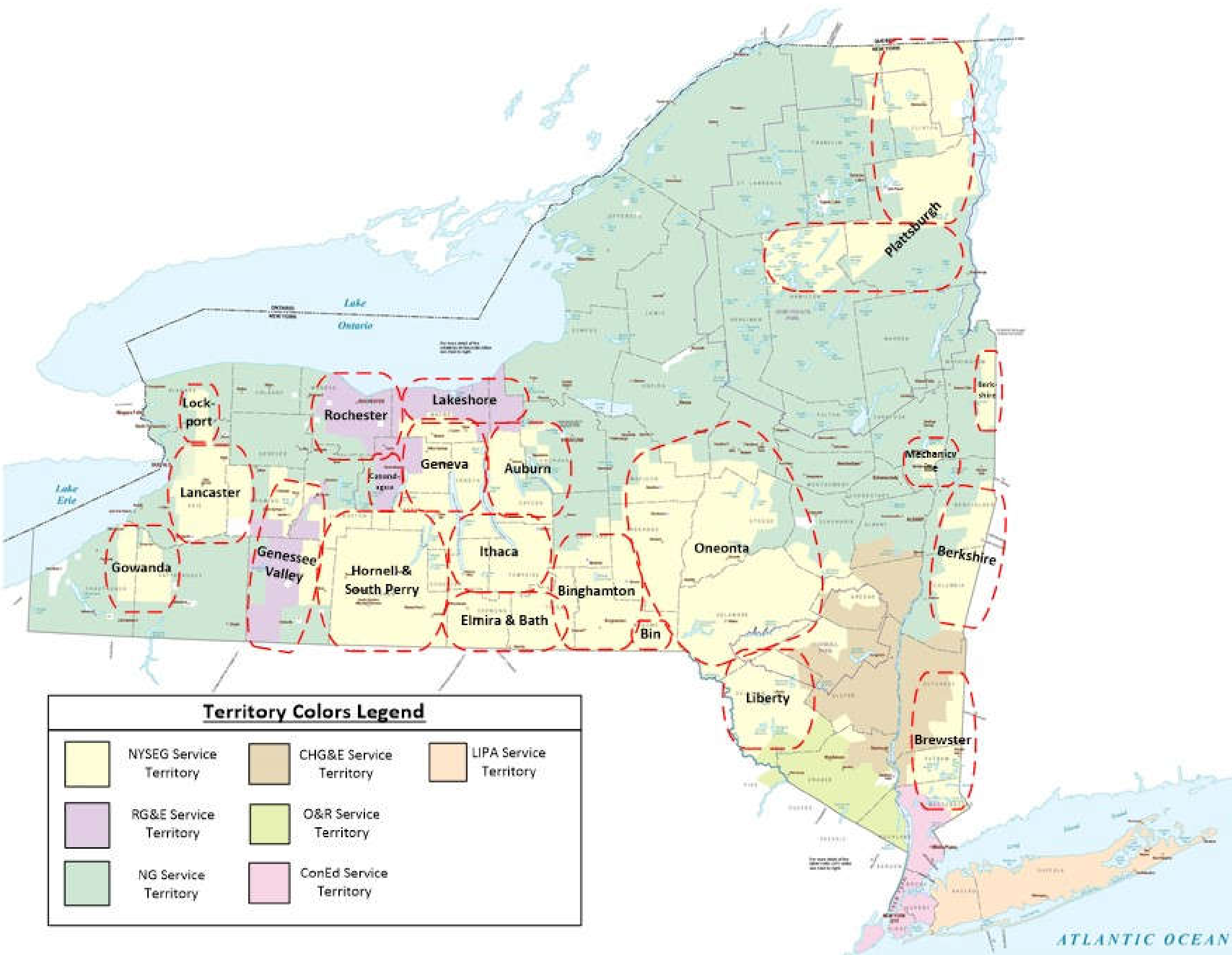


In New York, NYSEG serves approximately 900,000 electricity customers. RG&E serves approximately 380,000 customers, primarily within the city of Rochester and the adjacent municipalities.

The NYSEG and RG&E's transmission systems are predominantly networked and operate at a range of voltage levels including 345, 230, 115, 46, 34.5, and some 11.5 kilovolts (kV) facilities. However, according to the scope in the Commission Order, this study will focus more on "Local" system which include transmission facilities with the operating voltage less than 200 kV. AVANGRID's transmission facilities operating above 200kV are considered to be part of NY's "Bulk transmission system" which will be analyzed by other studies. In addition, AVANGRID makes a further distinction on its Local transmission system and refers to facilities operating below 100kV, and also serving as interconnections between load serving and or switching substations, as Sub-Transmission facilities.

Figure 75 show the service territories of the NYSEG and RGE operating companies and the sub-areas that were referenced in this study. Furthermore, in this Report, "AVANGRID" represents AVANGRID's electric service territories in New York (i.e. NYSEG and RGE).

Figure 75: AVANGRID NYSEG and RG&E Territory



i) Discussion of AVANGRID Study Assumptions, Methodologies, and Description of Local Design Criteria

The NY Utility T&D Technical Subgroup, referred to as the "working group" throughout this document, agreed that each utility would be permitted to make appropriate changes to the NYISO provided cases to create system conditions judged to be most suitable to their local systems. In addition, each utility developed and applied its own unique methodology for estimating the existing available headroom (available capacity in MW's) and existing bottlenecks (limiting elements or facilities) for the Utility Study. For AVANGRID, a number of modifications were made to the starting base cases and methodologies. These changes are broken down into five categories as described in more detail in this section:

1. Study Scenarios

Consistent with the scope of work jointly developed by the working group, the results in this Report are driven from two basic scenarios including “Business as Usual” and “70/30” which are described in more detail below:

Business as Usual (BAU): This scenario represents the conditions where only resources that meet the New York Independent System Operator (NYISO) “inclusion rules” were modeled in the study. These are resources and facilities that have shown significant developmental progress. Consequently, only a limited number of renewable resources have met these criteria and thus have been included in this scenario. As such, their limited combined output was recognized to be less than the renewable resource requirements needed to meet the full CLCPA goals. Two base cases, 2030 peak and 2025 off-peak, were studied to determine the existing capacity headroom on the local system. These study cases did not include any future planned AVANGRID transmission or substation projects where the projected in-service dates are beyond 5 years. The excluded projects may be considered for advancement later if determined to be beneficial to accommodate the renewable goals.

70/30: This scenario models a portfolio of renewable resources that can produce enough energy to meet the State’s 70/30 goal. The type, size, and location of these resources were developed from the NYISO 2019 Congestion Assessment and Resource Integration Study (CARIS). The NYISO provided six (6) base cases with these resources that were developed as part of its 2020 Reliability Needs Assessment (RNA) for use by the working group. After reviewing these cases the working group selected three (3) representative cases as the starting point for the 70/30 scenario studies. These are cases 1, 3, and 6 that represent Peak, Light, and Shoulder load conditions with varying renewable dispatches and a summary of these cases is shown in the figure below. Additionally, the NYISO provided zonal hourly resource output data including for Land-Based Wind (LBW), Off-Shore Wind (OSW), and Utility-Scale Photovoltaic (UPV) as used in its CARIS study. This information is referred to as the “hourly profiles”.

Figure 76: Starting Points 70/30 Scenario Base Cases

NYISO RNA Case #	Case Load	Net Load including BTM[142] solar reductions (MW)	LBW Output (% of Pmax)	OSW Output (% of Pmax)	UPV Output (% of Pmax)
1	Day Peak Load	30,000	10%	20%	45%
3	Light Load	12,500	15%	45%	0%
6	Shoulder Load	21,500	15%	45%	40%

2. Base Case Development

A summary of major modifications that were made to the starting NYISO base cases to facilitate the scope of this study is described below:

Planned Transmission Upgrades ("Firm"): The initial base cases included all NYISO designated "firm" projects. However, AVANGRID has elected to remove those outside the five (5) year horizon (year 2025) since they have less certainly.

DER: Existing DER is usually modeled as a reduction in forecasted load in study models. Where appropriate, AVANGRID modeled explicitly large resources using information from the "SIR Inventory Information" (or distribution DER queue). The outputs of these resources were considered fixed and therefore not adjusted during any study scenarios unless otherwise stated.

Electrical Location of Renewable Resource: The 2019 NYISO CARIS study modeled the additional resources needed to meet the 70/30 goals at voltages 115 kV or higher (Bulk Electric System – BES) regardless of their specific point of interconnection on the local system. AVANGRID made efforts to use available locational data to more accurately model the electrical location of the CARIS resources and then subsequently model them at the nearest appropriate sub-transmission stations (e.g. 34.5kV system).

Fossil Generation Identifications: As specified in the Commission order, to identify options and impacts of past and future fossil generation retirements, the study identified the locations of the remaining active and the recently retired fossil generation in AVANGRID's New York service areas. It also estimated the potential future use capacity of these locations such that they may be re-used for new renewable interconnections. Public information regarding retired fossil units in the past 7 years is shown in the figure below.

[142] BTM = Behind-The-Meter resources

Figure 77: Fossil Retirements – Possible Interconnection Options

Generator	Zone	Status	Unit Type[143]	Fuel Type[144]	Approximate Summer Capability (MW)
Somerset*	A	Retired	ST	BIT	676.4
Monroe Livingston	B	Retired	IC	MTE	2.4
Cayuga I & II	C	Retired	ST	BIT	309
Steuben County LF	C	Retired	IC	MTE	3.2
Auburn - State St.	C	Retired	GT	NG	5.8
Binghamton Cogen	C	Retired	CoGen	-	43.8

* Note: The Somerset unit was modeled off-line throughout this analysis since it is connected to the Bulk System and therefore considered outside this scope of this study.

Resource Addition and Dispatches: Figure 78, below provides a breakdown of additional renewable resources to meet the 70/30 goals based on information provided in the 2019 NYISO CARIS study. This CARIS study allocated approximately 6.8 GW of total capacity within AVANGRID's footprint. In addition to what is shown in the figure below, approximately 7,500 MW of behind-the-meter PV resources was accounted for in the study as a reduction in load and not modeled as discrete generators. The renewables in Figure 78 were modeled in the base cases as generation resources. In addition, Figure 78 shows a comparison of AVANGRID's proportion of New York load and projected renewable capacity.

143 ST = Steam Turbine, IC = Internal Combustion, GT = Gas Turbine, CoGen = Cogeneration

144 BIT = Bituminous Coal, MTE = Methane (Bio Gas), NG =Natural Gas

Figure 78: Zonal Load and Renewable Capacity Allocation

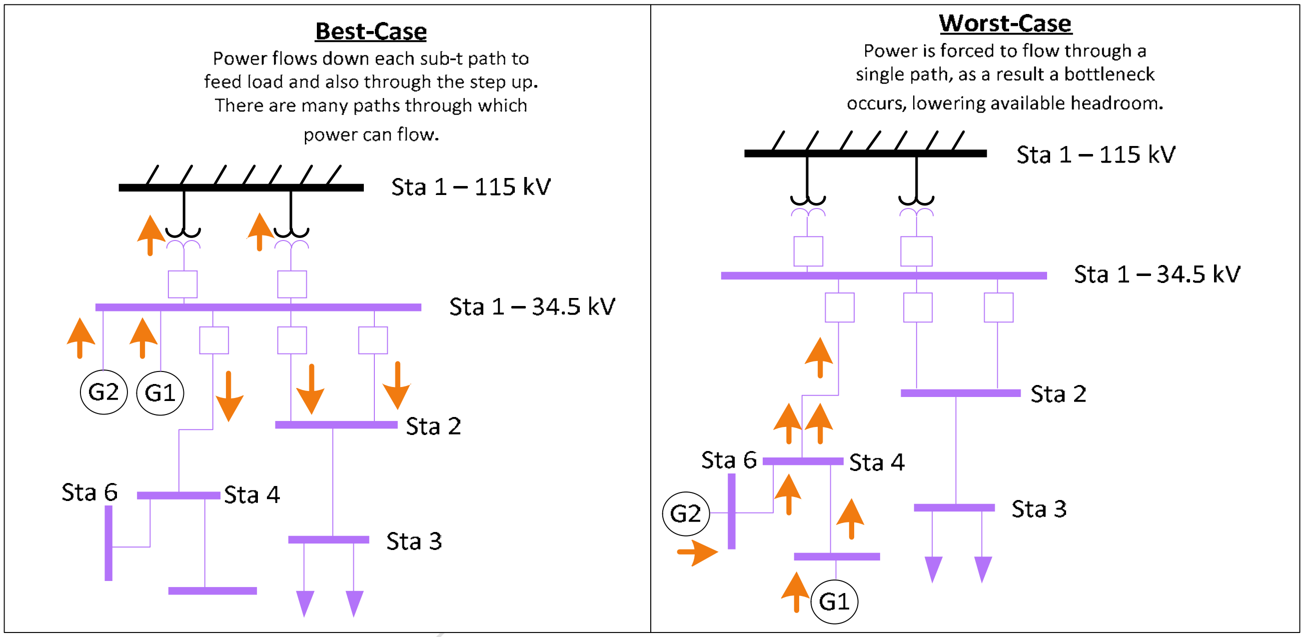
NYISO Zone	New York Renewable Capacity (2019 CARIS)			NY/AVANGRID Renewable Allocation			NY/AVANGRID Load Share		
	OSW (MW)	LBW (MW)	UPV (MW)	NY Total (MW)	AG Total (MW)	% AG	NY Total (MW)	AG Total (MW)	% AG
A		2,286	4,432	6,718	2,288	34%	2,290	572	25%
B		314	505	819	387	47%	1,780	1,467	82%
C		2,411	2,765	5,176	3,131	60%	2,411	1,196	50%
D		1,762		1,762	0	0%	675	55	8%
E		2,000	1,747	3,747	818	22%	928	280	30%
F			3,592	3,592	244	7%	1,839	101	6%
G			2,032	2,032	0	0%	1,639	16	1%
H							599	340	57%
I							1,382	0	0%
J	4,320			4,320	0	0%	11,362	0	0%
K	1,778		77	1,855	0	0%	4,245	0	0%
Totals	6,098	8,773	15,150	30,021	6,868	**23%**	29,150	4,028	**14%**

In order to study the impacts from high renewable output, the output from LBW and UPV resources in upstate area were increased and non-renewable resources were decreased until a bulk constraint was reached. The AVANGRID local system was then analyzed to determine local bottlenecks and constraints that will limit renewable energy from reaching the bulk system. In addition, in order to ensure these renewable output figures are realistic, these dispatches for LBW and UPV resources were compared against the hourly profiles from the 2019 NYISO CARIS study to make sure they are reasonable. This dispatching approach was developed in coordination with AVANGRID's neighboring utilities and included the following three renewable dispatch considerations beyond the starting base cases (i.e. Moderate LBW + Moderate UPV, High LBW, High UPV).

3. Capacity Headroom Analysis

The capacity headroom analysis determines the amount of additional renewable generation in MWs that can be injected into the existing system without exceeding system limit(s). It should be noted that since there is no consistent definition or methodology available for the calculation of "headroom", AVANGRID developed and utilized an approach that it considers sufficiently accurate to meet the objective of the Utility study. Since the amount of headroom can vary by many factors, especially the assumptions of the Point of Interconnection (proxy location(s) selected[145]), and number of proxy location(s) selected, AVANGRID provided the values of the existing capacity in a MW range rather than a specific value. In general, the closer the proxy location(s) are to the BES system, the more likely the resource can (1) serve local load as well as (2) export excess energy; whereas resources farthest from the BES will most likely be limited by smaller distribution and sub-transmission lines before reaching the BES. Figure 79 shows how the estimated capacity headroom can vary based on the proxy location(s) selected.

Figure 79: Example: Sub-Transmission Injection Points



The methodology to estimate existing capacity headroom includes a number of analytic steps summarized at a high level as follows:

1. Addition of new renewable resources at varying locations (POI).
2. Dispatch new resources upwards until a new system limit(s) is reached (e.g. thermal overload).
3. The existing capacity headroom is estimated to be equal to the total increased output in MWs prior to reaching the new system limit(s).
4. Repeat the process under different placement or injection point scenarios if exact locations are not defined.

In addition, it was found that system topology, flow patterns, type of resources, and the directions from the Commission order also impact the headroom analysis. These contributing

[145] Due to the size of the system. there are large number of potential Point of Interconnection (POI) in the system. Avangrid determined the Headroom based on a selected set of POIs. These include the locations that should yield the highest (best-Case) and lowest headroom (Worst-Case) in each study scenario.

factors are summarized below. These contributors could impact both the sub-transmission system and the BES facilities as the results from the study will be provided in Section (ii).

Sub-Transmission (non-BES) Load Pockets: It was important to begin the analysis by defining load pockets based on the system topology particularly at voltages level below 115 kV. These "Load Pockets" are defined as areas that predominantly serve local loads without significantly affecting the regional Bulk System's reliability or power transfers. Accordingly, the study defined a Load Pocket as portion of a sub-transmission network surrounded by step-up transformer(s) interconnecting the sub-transmission system to the BES. The existing capacity headroom on the sub-transmission system are summarized by AVANGRID divisions.

DER Resources: For locations where AVANGRID determined substantial DERs have been interconnected or there are significant DER interconnection requests in the local distribution list queue (DPS SIR Inventory List), the headroom was computed. For this Headroom analysis, all DER interconnections of 1 MW or larger in AVANGRID's service territory were treated as a set of generation injection points. The results are discussed in Section (ii).

Local NYISO Renewable Queue (already in Generation Queue): This analysis also incorporated known local proposed transmission-connected renewable resources (voltage level at the POI less than 200 kV) based on the NYISO's interconnection queue. The results are discussed in Section (ii).

Existing and Retired Fossil Fuel Locations: The headroom methodology was also used to understand how much renewable resources can be interconnected at the POI of already retired fossil units as well as existing fossil units' locations. This analysis includes an assessment of fossil generation retirements along with the potential to repurpose these interconnection points for new renewable generation in an effort to limit renewable interconnection costs. The results are discussed in Section (vi).

4. Bottleneck Analysis Methodology

This analysis determined where there were constraints or "bottlenecks" (i.e. Needs) on the existing system under simulated high renewable dispatches that would limit renewable energy deliverability under normal and contingency conditions. Each identified bottleneck or constraint was then analyzed to determine the main drivers contributing to the limitation.

5. Analysis Criteria

This study utilized criteria based on a subset of AVANGRID's Local Planning Criteria as deemed relevant to the intent of this study. Generally, this study included N-0 and N-1 analysis. AVANGRID analysis assumed that BES renewables (UPV and LBW) can be curtailed in-between contingencies to eliminate overloads, if needed. Therefore, detailed N-1-1 analysis as required by NERC, NPCC, and NYSRC AVANGRID local criteria were not considered. Also, most of the emphasis of the assessment was on thermal needs and any voltage, short circuit, and stability needs will be addressed in the individual generator interconnection study. However, if the analysis determined that a voltage problem (i.e. voltage collapse) could significantly limit renewable energy delivery, the identified needs are addressed as part of the solution development in Section (iv).

ii) Discussion of Existing Capacity "Headroom" within AVANGRID 's System

As discussed in Section (i)), the existing capacity headroom was determined for the sub-transmission system (non-BES) which includes areas of active renewable interest on the local system (DER) as well as the BES systems. In general, the higher the headroom in a given location the more renewables that will be able to connect in that area without requiring significant system upgrades due to thermal constraints. The existing capacity headroom results were presented by NYSEG & RGE divisions and the geographic locations of these divisions are shown in Figure 75 for reference.

The figure below summarizes the existing capacity headroom determined on the sub-transmission system that has strong interactions with the DERs. In addition, an overview of the average existing headroom on the sub-transmission network per injection point in AVANGRID service area is shown in Figure 82.

Figure 80: Headroom for "Non-BES" System

Division	Headroom Range* (MW)		Approx. # of Injection Points**
	Low	High	
Auburn	59	163	4
Berkshire & Mechanicville	129	431	10
Binghamton	179	715	13
Brewster	70	408	6
Elmira & Bath	138	557	9
Genesee Valley	34	77	3
Geneva	146	514	9
Gowanda	17	28	1
Hornell & South Perry	16	978	11
Ithaca	163	428	13
Lakeshore	5	29	4
Lancaster	149	827	14
Liberty	101	255	8
Lockport	46	76	2
Oneonta	62	523	14
Plattsburgh	137	307	14
Rochester & Canandaigua	576	2078	44

Notes:
*The headroom range is provided to show variation in results due to number of injection points, location of injection points and the load level.
** The number of injection points show the maximum number of locations studied for each division which includes known interconnection points and methodology to selecting additional points; the existing capacity headroom is likely to fall between the provided ranges if the number of injection points are met.

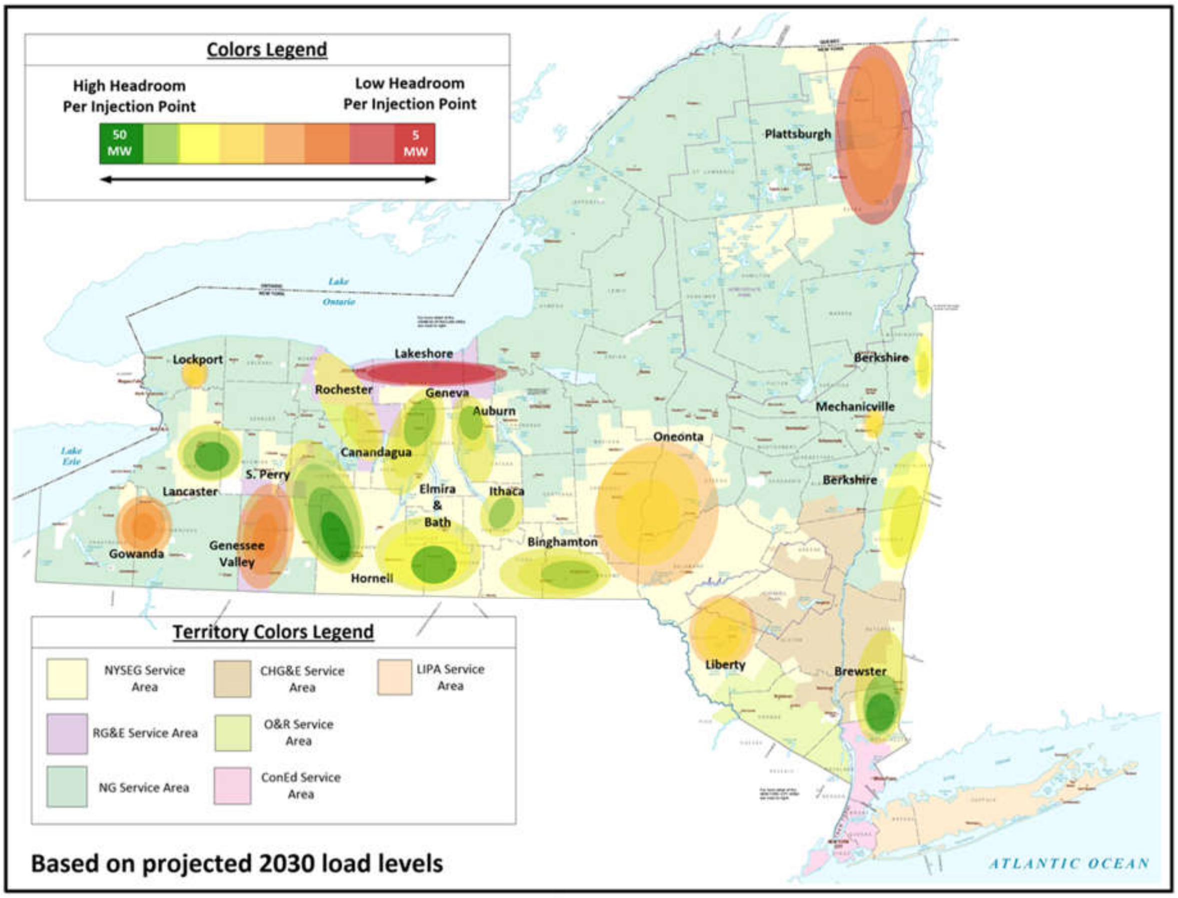
The figure below summarizes the existing capacity headroom on the local BES system that are primarily impacted by Local NYISO Renewable Queue locations.

Figure 81: Headroom for "BES" System (less than 200 kV points)

Division	Headroom Range [1] (MW)		Approx. # of Injection Points[2]
	Low	High	
Auburn	63	66	2
Berkshire & Mechanicville	263	268	1
Binghamton	159	217	4
Brewster	65	78	1
Elmira & Bath	0	41	1
Genesee Valley	8	20	1
Geneva	266	271	3
Gowanda[3]	N/A	N/A	N/A
Hornell & South Perry	263	448	4
Ithaca	178	194	1
Lakeshore[3]	N/A	N/A	N/A
Lancaster	541	560	4
Liberty[3]	N/A	N/A	N/A
Lockport[3]	N/A	N/A	N/A
Oneonta[3]	N/A	N/A	N/A
Plattsburgh	41	42	4
Rochester & Canandaigua	287	289	4

Notes:
1) The headroom range is provided to show variation in results due load level only (the number of injection points and the location of injection points were defined using NYISO Interconnection queue).
2) Number of injection points less than 200 kV in the NYISO Queue at the time of the study.
3) Divisions without known NYISO renewable queue points at the time of the study.

Figure 82: Approximated Sub-Transmission Headroom Per Injection Point in NYSEG/RGE Divisions



iii) Discussion of Bottlenecks or Constraints that Limit Energy Deliverability within AVANGRID's System

This study identified the "bottlenecks" or constraints (i.e. Needs) limiting renewable energy integration across AVANGRID service territory. These bottlenecks include issues found on both the BES and Sub-Transmission facilities. The common driver for these bottlenecks is the output from the assumed renewable resource simulations to meet NY's goals.

Details about each bottleneck are also summarized in the figure below including the location, type, constraint driver and its severity. The violation type refers to whether this is a normal (or pre-contingency, N-0) or post-contingency (N-1) violation. The Main Driver column provides a high-level indicator of which key factor is causing the congestion issue. The last column, Severity (%), provides the degree of the severity for each bottleneck. For N-0 or normal conditions the overload is presented in terms of the elements Normal MVA rating while for N-1 conditions it is appropriately based on the LTE MVA rating.

Figure 83: AVANGRID Local System - Summary of Needs (Bottlenecks)

NYISO Zone	Division	Terminal A	Terminal B	Violation Type	Main Driver	Severity (%)
A	Lockport (LK)	Robinson Rd 230	Robinson Rd 115	N-1	Forecasted UPV	>140
A	Lockport	Robinson Rd 115	Hinman 115	N-1	Forecasted UPV	>200
A	Lockport	Hinman 34.5	Vine 34.5	N-1	Forecasted UPV	>140
A	Lancaster (LN)	Stolle 345	Stolle 115	N-1	Forecasted UPV	>110
A	Lancaster	Stolle 115	Stolle 34.5	N-1	Forecasted UPV	>120
A	Lancaster	Stolle 115	Gardenville 115	N-0, N-1	Forecasted UPV	>140
A	Lancaster	Stolle 115	Erie 115	N-1	Forecasted UPV	>140
A	Lancaster	Pavement 34.5	Cemetery Rd 34.5	N-1	Forecasted UPV	>120
A	Lancaster	Alpine 34.5	Cobble Hill 34.5	N-1	DER	>140
B	Rochester (ROC)	S082 115	Highbanks 115	N-0, N-1	Forecasted LBW	>140
B	Genesee Valley (GV)	Highbanks 115	South Perry 115	N-0, N-1	Forecasted LBW	>140
B	Genesee Valley	Highbanks 115	Highbanks 115	N-0, N-1	DER	>200
B	Genesee Valley	Highbanks 115	Highbanks 115	N-0, N-1	DER	>170
B	Genesee Valley	Highbanks 115	S8373 34.5	N-0, N-1	DER	>170
C	South Perry (SP)	South Perry 115	Meyer 115	N-1	Forecasted LBW and UPV	>200
C	Hornell (HO)	Bennett 115	Palimiter 115 (to NG Homer)	N-0, N-1	Forecasted LBW and UPV	>110
C	Hornell	Bennett 115	Howard/Spencer Hill 115	N-0, N-1	Forecasted LBW and UPV	>200
C	Hornell	Bath 115	Howard/Spencer Hill 115	N-0, N-1	Forecasted LBW and UPV	>200
C	Hornell	Bennett 115	Moraine 115	N-0, N-1	Forecasted LBW and UPV	>200
C	Hornell	Meyer 115	Moraine 115	N-0, N-1	Forecasted LBW and UPV	>200
C	Hornell	Meyer 115	Eelpot 115	N-0, N-1	Forecasted LBW and UPV	>200
C	Hornell	Flat St 115	Eelpot 115	N-0, N-1	Forecasted LBW and UPV	>200
C	Hornell	Flat St 115	Greenidge 115	N-0, N-1	Forecasted LBW and UPV	>200
C	Hornell	Avoca 230	Stoney Ridge 230	N-1	Forecasted LBW and UPV	>100
C	Hornell	Bennett 34.5	Marsh Hill 34.5	N-1	DER	>140
C	Hornell	Troupsburg 34.5	Marsh Hill 34.5	N-1	DER	>110
C	Elmira/Bath (EB)	Bath 115	Montour Falls 115	N-0, N-1	Forecasted LBW	>110
C	Elmira/Bath	Montour Falls 115	Hillside 115	N-1	Forecasted LBW	>120
C	Elmira/Bath	Hickling 115	West Erie 115	N-1	Forecasted LBW	>120
C	Elmira/Bath	Canada Tap	Polly-O 34.5	N-1	Flow through	>120
C	Geneva (GN)	Flat St 115	Greenidge 115	N-0, N-1	Forecasted LBW	>140

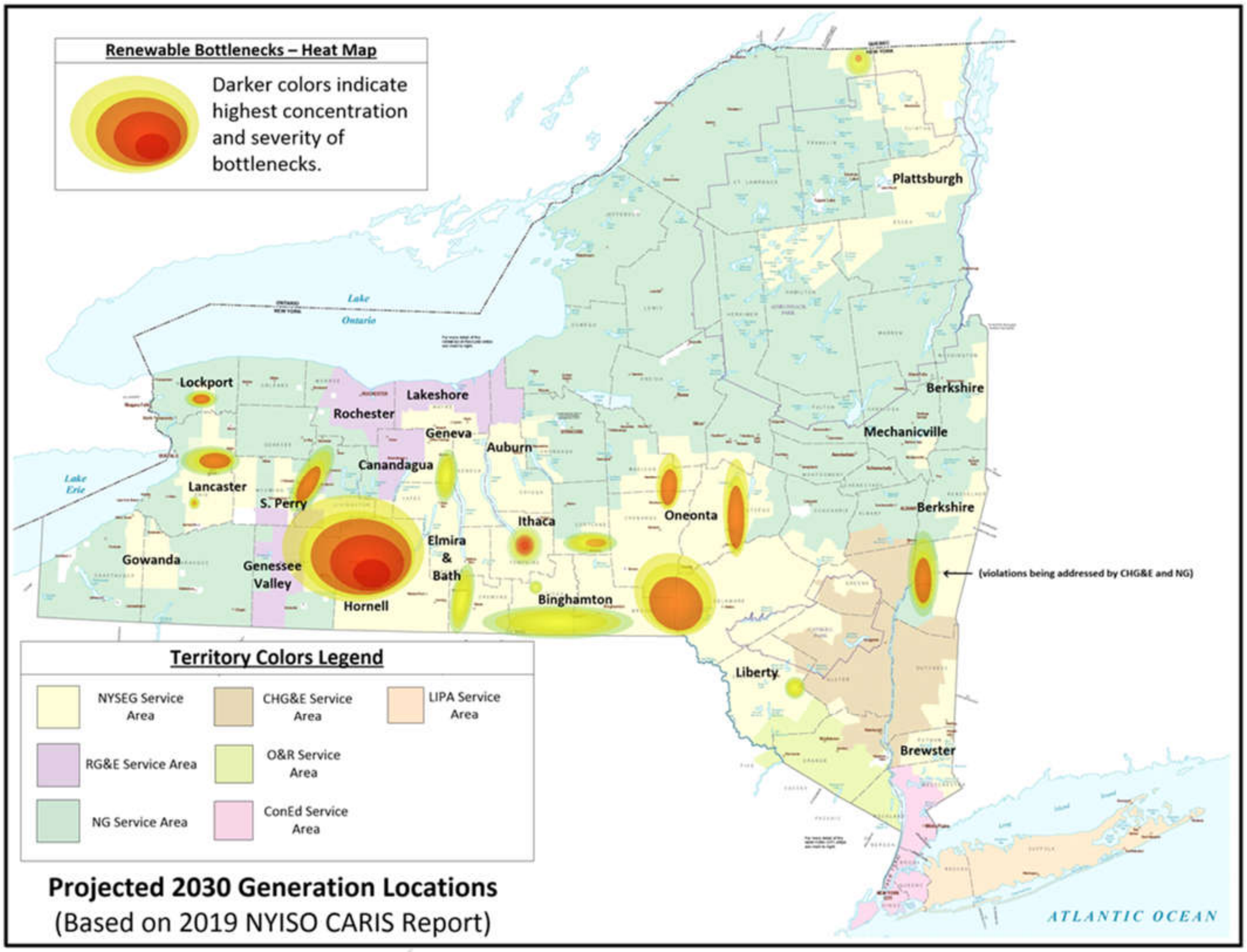
NYISO Zone	Division	Terminal A	Terminal B	Violation Type	Main Driver	Severity (%)
C	Geneva	Border City 115	Hyatt Rd (to NG Elbridge) 115	N-0, N-1	Forecasted UPV	>120
C	Geneva	Border City 115	Guardian 115	N-1	Forecasted UPV	>110
C	Geneva	Border City 115	Farmington115	N-1	Forecasted UPV	>110
C	Geneva	Border City 115	Border City 34.5	N-1	Forecasted UPV	>110
C	Geneva	Border City 115	Border City 34.5	N-1	Forecasted UPV	>110
C	Geneva	Border City 34.5	Oak Corners 34.5	N-1	Forecasted UPV	>170
C	Binghamton (BG)	Oakdale 230/115		N-1	Flow through	>100
C	Binghamton	Hillside 115	South Owego 115	N-1	Flow through	>140
C	Binghamton	Goudey 115 / Oakdale 115	South Owego 115	N-1	Flow through	>120
C	Binghamton	Willet 115	Willet 34.5	N-1	DER + Forecasted UPV	>140
C	Ithaca (IT)	Etna		N-1	Flow through	Voltage Collapse
C	Ithaca	Coddington		N-1	Flow through	Voltage Collapse
C	Ithaca	Etna 115	Willet 115	N-1	Flow through	>170
C	Ithaca	Montour Falls 115	Coddington 115	N-1	Flow through	>140
C	Ithaca	Candor 115	Candor 34.5	N-0, N-1	DER	>120
C	Auburn	Hyatt Rd 34.5	State St 34.5	N-1	Forecasted UPV	>120
C	Auburn	Hyatt Rd 34.5	Seneca Falls 34.5	N-1	Forecasted UPV	>140
D	Plattsburg (PL)	Chateaugay 115	Chateaugay 34.5	N-0, N-1	Forecasted UPV	>200
E	Oneonta (ON)	Jennison		N-1	Flow through	Voltage Collapse
E	Oneonta	East Norwich		N-1	Flow through	Voltage Collapse
E	Oneonta	Colliers		N-1	Flow through	Voltage Collapse
E	Oneonta	East Norwich 115	Jennison 115	N-0, N-1	Forecasted LBW	>170
E	Oneonta	Fraser 115	Jennison 115	N-0, N-1	Forecasted LBW	>200
E	Oneonta	Oakdale 115	Jennison 115	N-0, N-1	Forecasted LBW	>140
E	Oneonta	Stilesville 115	Jennison 115	N-0, N-1	Forecasted LBW	>170
E	Oneonta	Richfield Springs 115	East Springfield 115	N-0, N-1	Forecasted UPV	>120
E	Oneonta	Richfield Springs 115	Colliers 115	N-0, N-1	Forecasted UPV	>120
E	Oneonta	East Norwich 115	Brothertown Rd 115	N-1	Forecasted LBW	Voltage Collapse
E	Oneonta	East Norwich 115	Willet 115	N-1	Forecasted LBW	>170
E/G	Liberty (LI)	West Woodbourne 115	West Woodbourne 69	N-0, N-1	Flow through	>110

Below are some key observations from the study results shown in the figure below:

1. The output from local renewable resources (DER and Utility-Scale) and flow through are two key drivers causing congestion. Consequently, when designing the upgrades, potential impacts from renewable development in the neighboring areas must also be considered.
2. A number of local transmission facilities in AVANGRID's service area have strong interactions with the bulk system. For this reason, it is important that a comprehensive approach considering a larger area is sometimes appropriate rather than narrowly focusing only on areas in the immediate vicinity of the bottleneck. An example would be the Hornell and Ithaca area bottlenecks which also have strong interactions with the 230 kV corridor; in this case a comprehensive solution approach was used.
3. The study results show multiple facilities can experience severe overloads, particularly under contingency conditions. In some cases, these overloads would even exceed the facility's STE ratings meaning that pre-contingency actions such as curtailment would be necessary to prevent such a severe condition.

Figure 84 shows a summary heat map of the renewable bottlenecks across the AVANGRID service territory under this study's projected renewable generation levels. These are also the general locations where mitigating solutions are needed to avoid renewable generation curtailment that could impact the states renewable goals.

Figure 84: Bottleneck Heat Map - AVANGRID Service Areas



iv) Discussion of Potential Projects that would Address Bottlenecks or Constraints that limit Energy Deliverability within AVANGRID 's System

This section describes the upgrades (or solutions) that have been developed to address the bottlenecks (or needs) identified and summarized in section (iii). For each bottleneck, AVANGRID evaluated multiple alternatives to alleviate the congestion and then selected one as the likely "preferred alternative" in consideration of the order of magnitude estimate accuracy available on some projects along with other factors including the state's desire to implement storage and other new technologies.

Following are some of the key factors considered when evaluating alternatives:

1. <u>Synergies:</u> There are a number of existing projects in AVANGRID's long term plan that are driven by either reliability (e.g. Bulk Electric System studies) or asset condition (e.g.

deterioration, obsolescence, etc.) needs that are also beneficial to renewable resource integration goals either in their current form or with some incremental modifications. In many cases this study found that existing proposed projects alone can provide significant renewable integration benefits, but these can be even further enhanced with incremental upgrades. These multi-value projects that address a range of conventional reliability and asset condition needs while also serving to enable renewable resources are often the lowest overall cost when compared to addressing each need and benefit individually. This study makes a general distinction between the project types using the terms Phase 1 and Phase 1+ to indicate synergies with existing or existing expanded projects respectively while Phase 2 projects are those that only serves to provide a CLCPA benefit. Following is a summary of the definitions and identifiers used in this study:

- Phase 1 (X): Existing projects already in AVANGRID's capital plan (driven from Reliability or Asset Condition based needs).
- Phase 1+ (Y): Incremental upgrades to existing planned projects in order to achieve an enhanced renewable resource integration benefit.
- Phase 2 (Z): New upgrades that serve only to provide renewable resource integration benefits (i.e. does not address conventional Reliability or Asset condition needs).

2. Cost: In general, the lowest cost alternative addressing all needs (e.g. reliability, asset condition, CLCPA, etc.) is preferred, however, consideration is also given to the states goals to enable increased levels of storage solutions onto the system. It should be noted that the cost estimates in this study should generally be considered to be at an Order of Magnitude accuracy level since some are based on limited desktop engineering analysis without the benefit of site specific assessments. As such, there may be situations where the estimate accuracy ranges of competing alternatives overlap making a future estimate refinement likely necessary to confirm the low cost alternative.

3. Project In-Service Date: This study provides the estimated in-service dates (ISD) for each project as an indication of how fast each of the projects could be executed once authorized. It should be noted that these ISD's assume the projects can proceed without delay and begin in early 2021. In addition, the schedule also makes the important assumption that Article VII and other permitting processes do not take any longer than one year from the filing date.

4. Renewable Benefit ($/MW): A preliminary indicator of the value of each project is to compare the ratio of the project cost to the system MW capacity benefit provided in terms of a $/MW ratio with lower values indicating more favorable projects. The capacity (MW) benefit is measured by comparing the maximum output of renewable resources the system can accommodate, before and after the upgrade is constructed. This is accomplished by first determining the amount of renewable capacity in the existing system (pre-project) by increasing the renewable resource outputs in the vicinity

of the upgrades. The maximum capacity is determined when the first transmission limit is reached. Next the proposed project is added, and the prior steps are repeated. The difference between the two numbers is the renewable benefit or MW capacity gained with the proposed upgrade.

5. Consideration of New and Emerging Technologies: While there are no clear definitions as to what is considered a new technology, AVANGRID considered the potential utilization of Storage, flow control technologies, and dynamic line ratings as potential solutions to mitigate some bottlenecks. AVANGRID received guidance from the Utility T&D Advance Technology Subgroup and subject matter experts in determining which technologies could be classified as "new and emerging technologies" and also which could be practically implemented. In this study, AVANGRID considered the following three groups of technologies as candidates based on their effectiveness to mitigate the overload and their technological maturity.

    - Energy Storage (ES): In general, storage technology was considered to address bottlenecks requiring significant transmission capacity increases largely to accommodate the intermittent nature of the renewable resources (i.e. overloads that occur a couple of hours per day).
    - Power Flow Control Devices: Power flow control devices can be beneficial by providing a means of controlling and diverting power flows away from constrained areas toward areas with more available capacity.
    - Dynamic Line Ratings (DLR): DLRs may be considered in cases where overloads are marginal and primarily driven by wind resources in an area. This technology provides a means of adjusting facilities ratings based on real time ambient conditions, however, since there was insufficient available information to demonstrate this technologies maturity and practical effectiveness it was not recommended to address any bottlenecks in this study.

Figure 85 summarizes the solution alternatives considered in this study to mitigate all identified bottlenecks. Figure 85 describes a summary of the project attributes including the Project Type (or Phase), Order of Magnitude cost (OOM cost in $M), ISD, Estimated Project Benefit (MW), and an estimate of the Benefit ($M/MW) achieved. In addition, a Preferred solution was selected although it is currently classified as "likely" since it is based on order of magnitude level estimate comparisons which may require further refinements prior to a final determination. Also, considerations beyond cost may influence the final decision for reasons including a desire to pilot new technologies and or non-wire alternatives (e.g. storage, etc.). It should be noted that there are some cases where a reduced project scope could be implemented at a lower cost to reduce the congestion, although it would not completely eliminate it.

Figure 85: Solution Summary Table

Name	Project Type (Execution Phase)		Descriptions	ISD	OOM Cost ($M)	Estimated Project Benefit (MW)	Benefit ($M/MW)	Preferred (Likely)
Lockport Area Phase 1 Upgrades	X1	Phase 1	Rebuild Robinson Rd substation and install a new transformer and reroute several lines in this area	2025	34	400	0.09	X
	X2	Phase 1	Retire part of Hinman substation and reroute existing lines to a nearby substation	2025	--	--	--	--
	Y1	Phase1+	Reconductor 115 kV line	2025	10	130	0.08	X
	Y2	Phase1+	Substation upgrades	2025	--	--	--	--
Lancaster Area Phase 1 Upgrades	X1 Y1	Phase1+	Rebuild and upgrade Stolle Rd substation Install a new transformer	2026	53	675	0.08	X
	X1 Y2	Phase1+	Rebuild and upgrade Stolle Rd substation Install additional transformer and reconfigure substation	2025	--	--	--	--
	X1 Y3	Phase1+	Rebuild and upgrade Stolle Rd substation Reconductor 115 kV lines	2025	--	--	--	--
Lancaster Area Phase 2 Upgrades	Z1	Phase 2	Install up to 10 MW, 6-Hour of Energy Storage	2027	--	10	--	X
	Z2	Phase 2	Install a new transformer and upgrade substation	2025	--	--	--	--
	Z3	Phase 2	Reconductor 34.5 kV line	2024	--	--	--	--
South Perry Area Phase 1 Upgrades	X1	Phase 1	Reconductor the line from Meyer to South Perry substations	2027	49	260	0.19	X
Genesee Valley Area Phase 2 Upgrades	Z1	Phase 2	Build a new 115 kV station, bring in a new source, and add a new transformer at multiple substations. Add Power Flow Control Device - Static Series Synchronous Compensator	2025	--	75	--	X
	Z2	Phase 2	Reconductor multiple 34.5 kV lines and replace transformers in area	2026	--	--	--	--
Hornell Area Phase 2 Upgrades	Z1	Phase 2	Install up to 10 MW, 6-Hour of Energy Storage	2027	--	10	--	X
	Z2	Phase 2	Reconductor 34.5 kV line	2023	--	--	--	--
	Z3	Phase 2	Build a new 34.5 kV line and install a new transformer	2025	--	--	--	--

Name	Project Type (Execution Phase)		Descriptions	ISD	OOM Cost ($M)	Estimated Project Benefit (MW)	Benefit ($M/MW)	Preferred (Likely)
Hornell, Elmira & Bath Phase 2 Reinforcement	X1	Phase 1	Build a new 230/115/34.5 kV station (Wagner Hill) in the vicinity area of Bath substation, reroute existing transmission lines to connect to this new substation	2025	35	70	0.50	X
	Z1	Phase 2	Install 2 additional transformers, add 2 Power Flow Control Devices. Reconductor 115 kV line and build new lines. Install a Power Flow Control Device, and upgrade terminal equipment at several substations	2027	--	500	--	X
	Z2	Phase 2	Reconductor several 115 kV lines	2027	--	--	--	--
	Z3	Phase 2	Expand multiple substations and build multiple lines	2031	--	--	--	--
Elmira & Bath Area Phase 2 Upgrades	Z1	Phase 2	Reconductor portion of a 34.5 kV line	2023	--	8	--	X
Geneva Area Phase 1 Upgrades	X1	Phase 1	Rebuild Border City 115 kV and add capacitor banks at this and Haley Rd substations	2026	76	20	3.80	X
	Y1	Phase1+	Install 115 kV PAR	2025	--	--	--	--
	Y2	Phase1+	Install 115 kV Power Flow Control Device - Static Series Synchronous Compensator	2022	4	8	0.50	X
	Y3	Phase1+	Reroute 115 kV line, upgrade 115 kV terminal equipment	2025	--	--	--	--
Geneva Area Phase 2 Upgrades	Z1	Phase 2	Build new 115 kV line	2025	--	155	--	X
	Z2	Phase 2	Install up to 40 MW, 6-Hour Energy Storage	2027	--	--	--	--
Binghamton Area Phase 1 Reinforcement	X1a	Phase 1	Rebuild Oakdale substation, install a 3-winding transformer and retire Westover 115 kV substation	2025	226	400	0.57	X
	X1b	Phase 1	Reroute 115 kV lines in the area of Etna, Willet, and Clarks Corners substations	2026	60	125	0.48	X

Name	Project Type (Execution Phase)		Descriptions	ISD	OOM Cost ($M)	Estimated Project Benefit (MW)	Benefit ($M/MW)	Preferred (Likely)
	X1c Y1	Phase1+	Reconductor the line between South Owego and Hillside substations Reconductor 115 kV line	2027	245	230	1.07	X
Binghamton Area Phase 2 Upgrades	Z1	Phase 2	Install a new transformer	2025	--	35	--	X
	Z2	Phase 2	Rebuild 34.5 kV substation and reconfigure sub-transmission network	2025	--	--	--	--
	Z3	Phase 2	Install up to 25 MW, 6-Hour of Energy Storage	2027	--	--	--	--
Ithaca Area Phase 1 Reinforcement	X1	Phase 1	Rebuild Etna substation, upgrade Coddington substation and install capacitors	2026	97	140	0.69	X
	Y1	Phase1+	Reconductor 115 kV line	2025	42	123	0.34	X
Ithaca Area Phase 2 Upgrades	Z1	Phase 2	Install up to 10 MW, 6-Hour Energy Storage	2027	--	10	--	X
	Z2	Phase 2	Install a new transformer	2025	--	--	--	--
	Z3	Phase 2	Replace a transformer	2025	--	--	--	--
Plattsburg Area Phase 2 Upgrades	Z1	Phase 2	Add two new transformers	2025	--	--	--	--
	Z2	Phase 2	Replace existing transformer and install a new transformer	2025	---	90	--	X
Oneonta Area Phase 1 Reinforcement	X1	Phase 1	Rebuild and expand East Norwich substation; Rebuild and expand Jennison substation and bring line in and out; Rebuild and expand Colliers 115 kV; Build a new substation called New Morris substation and build line to Collier, Jennison, and Fraser substations	2028	569	160	3.56	X
	Y1	Phase1+	Reconductor 115 kV line, upgrade terminal equipment at multiple 115 kV substations. Install 115 kV Power Flow Control Device - Static Series Synchronous Compensator technology	2027	60	300	0.20	X
	Y2	Phase1+	Reconductor 115 kV lines, upgrade terminal equipment at multiple substations	2027	--	--	--	--
Oneonta Area Phase 2 Upgrades	Z1	Phase 2	Install up to 40 MW, 6-Hour Energy Storage	2027	--	40	--	X
Liberty Area Phase 2 Upgrades	Z1	Phase 2	Install up to 10 MW, 6-Hour Energy Storage	2027	--	10	--	X
	Z2	Phase 2	Install a new transformer	2025	--	--	--	--

Following are some general observations and findings that can be observed from the solution summary the figure above:

1. Synergies: A number of existing projects in AVANGRID's existing capital plan are selected as Preferred projects since they are found to provide substantial CLCPA benefits in either their original form or with some incremental modification. These projects are listed as either Phase 1 or Phase 1+ projects respectively.

2. Cost: In most cases, the lowest cost alternative was selected as the preferred solution. However, in some cases, other factors such as cost estimate accuracy ranges and the desire to implement advanced technologies are considered (e.g. Storage, etc.).

3. Energy Storage: Energy storage was considered and recommended as preferred at several locations based on the preliminary analysis and order of magnitude cost estimates.

4. Power Flow Control Devices: This technology was proposed at several locations including three (3) different technologies (Series Reactors, Phase Angle Regulators, and Static Series Synchronous Compensator devices). Series Reactors were found to have the lowest cost but also provide the least amount of real time operational flexibility as they are static or fixed flow control devices. PAR's tended to be the most expensive but also provided maximum flexibility in responding to varying system power flow conditions. Static Series Synchronous Compensator devices are a newer technology that may offer a balanced solution between cost and flexibility although there is limited industry experience with these and they are not widely available across multiple vendors. Although this study made preliminary recommendations in some cases, further study will be necessary to make a final determination.

5. Renewable Benefit ($/MW): This study found that many existing projects (Phase 1 and Phase 1+) had the highest renewable integration benefit values with the lowest cost per MW of headroom gained. These existing projects also provide the benefit of addressing many other reliability and asset condition needs across the system.

v) Discussion of Potential Projects that would Increase Capacity on the Local Transmission to allow for Interconnection of New Renewable Generation Resources within AVANGRID 's System

As shown in Section (iv), the development of Phase 1, Phase 1+, and Phase 2 projects would create increased headroom in AVANGRID's footprint to allow for new renewable resources to interconnect. This local transmission study identified a number of upgrades that create up to 4 GW of increased capacity on the system. A summary of these projects and the approximated increased capacity benefit from these projects are shown in Figure 85.

vi) Identify the possibility of fossil generation retirements and the impacts and potential availability of those interconnection points

There are several fossil generators in AVANGRID service territory, which are shown in Figure 86. The existing capacity headroom at these locations was computed and the results are shown in Figure 86.

Figure 86: Local Headroom - Potential Fossil Retirement Locations

Division	Headroom Range (MW)		Approximate Location
	Low	High	
Auburn	157	368	State St, Wright Ave
Binghamton	52	52	Binghamton Cogen
Elmira & Bath	43	45	Steuben LF
Genesee Valley	138	148	Not provided*
Geneva	292	327	Not provided
Hornell & South Perry	18	76	Not provided*
Ithaca	0	190	Cayuga
Lockport	294	333	Not provided*
Plattsburgh	230	247	Not provided*

* Note: locations of existing fossil units that have not yet retired.

vii) AVANGRID Local Utility Study Conclusion

This study found that the implementation of AVANGRID's proposed transmission system upgrade projects as described in this Report can enable 6.8GW of renewable resources onto the NYSEG and RGE Local transmission systems. Many of these Projects not only serve to unlock renewable resources, but they also provide substantial system benefits in terms of improved customer reliability and modernization of portions of the New York electric grid. A summary of the order of magnitude costs and schedule are provided in the figure below.

Figure 87: Summary of Order of Magnitude Costs and Schedule by Project Type

Project Type (Execution Phase)	In-Service Years	OOM Cost ($M)
Phase 1	2025-2028	1,146
Phase 1+	2022-2027	414
Phase 2	2023-2027	780
	Total	2,340

To the extent that any Phase 1 or other (as applicable) projects are not currently contemplated in utility rate plans, the Commission should permit the utilities to submit a petition for Commission approval of timely cost recovery of the carrying costs through a transmission surcharge (or other applicable pass through clauses). The surcharge would be designed to allow the utility to recover its CLCPA projects' carrying costs, including depreciation, until its next rate case, at which time the investment would be reflected in base rates.

B. Distribution

AVANGRID, Inc. (AVANGRID) respectfully submits the "Utility Study" report of its New York State Electric and Gas (NYSEG) and Rochester Gas and Electric (RG&E) operating companies in accordance with the New York Public Service Commission's Order dated May 14, 2020. The Order directed each New York electric utility to identify appropriate distribution and local transmission upgrades to achieve the State's climate goals as set out in NY's Climate Leadership and Community Protection Act ("CLCPA"). There are seven (7) sections in this Report. This Report describes two types of projects at the distribution-level of AVANGRID's system (NYSEG, RG&E):

1. Existing capital projects with objectives of deliverability, resilience, security and modernization that also create headroom for customer DG interconnection and contribute to CLCPA goals for 2030. These are considered Phase 1 projects that will deliver headroom in the period 2020 to 2025.
2. New proposed projects with objectives to create headroom for customer DG interconnection in the network areas where there is greatest interconnection interest and lack of existing system capacity. These are considered Phase 2 projects that are not in the current Capital Expenditure Plan, so the timing of their delivery is not yet secured.

The total DG interconnection headroom created in aggregate as a result of existing capital projects is 166 MW. No amendments to these existing CapEx projects are recommended as these projects do not overlap between existing load-related, resilience, asset replacement and customer focused projects and the identified DG interconnection hot-spots.

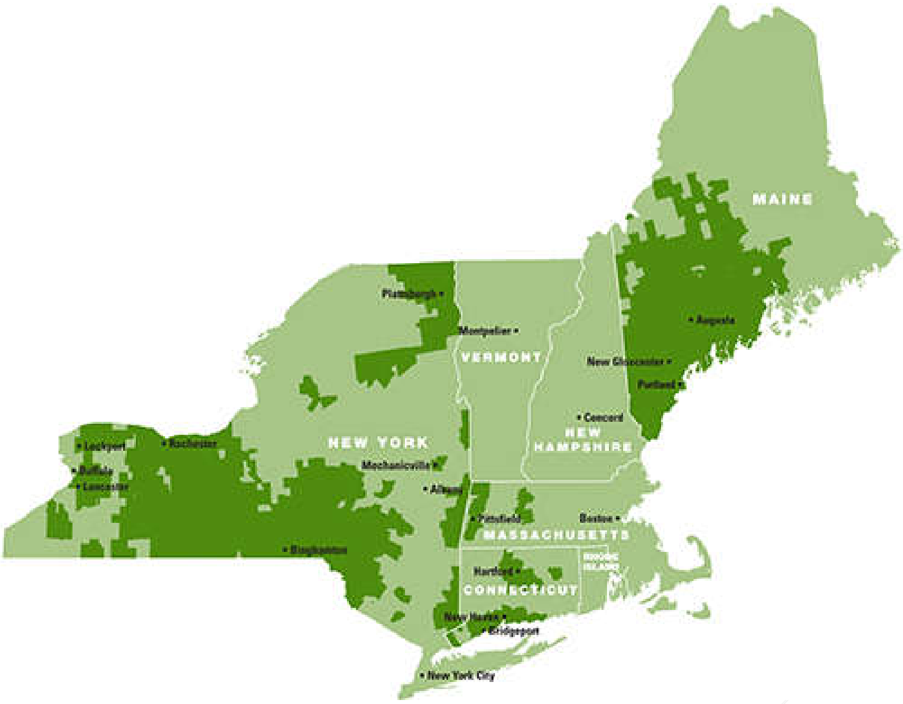
AVANGRID has proposed five specific DG interconnection headroom creating Phase 2 projects at Limestone, Keeseville, Guildford, Woods Corners and Kanona Substations. The total aggregated DG interconnection headroom created as a result of these new projects is estimated to be 88 MW.

AVANGRID has considered the application of Flexible Interconnection Capacity Solution (FICS) for DG and Non-Wires Alternatives (NWA) as targeted solutions across both RG&E and NYSEG network territories. These solutions are evaluated alongside conventional 'wires' options as a means to create cost-effective local distribution DG headroom.

i) Description of AVANGRID and its Service Area (including NYSEG and RGE)

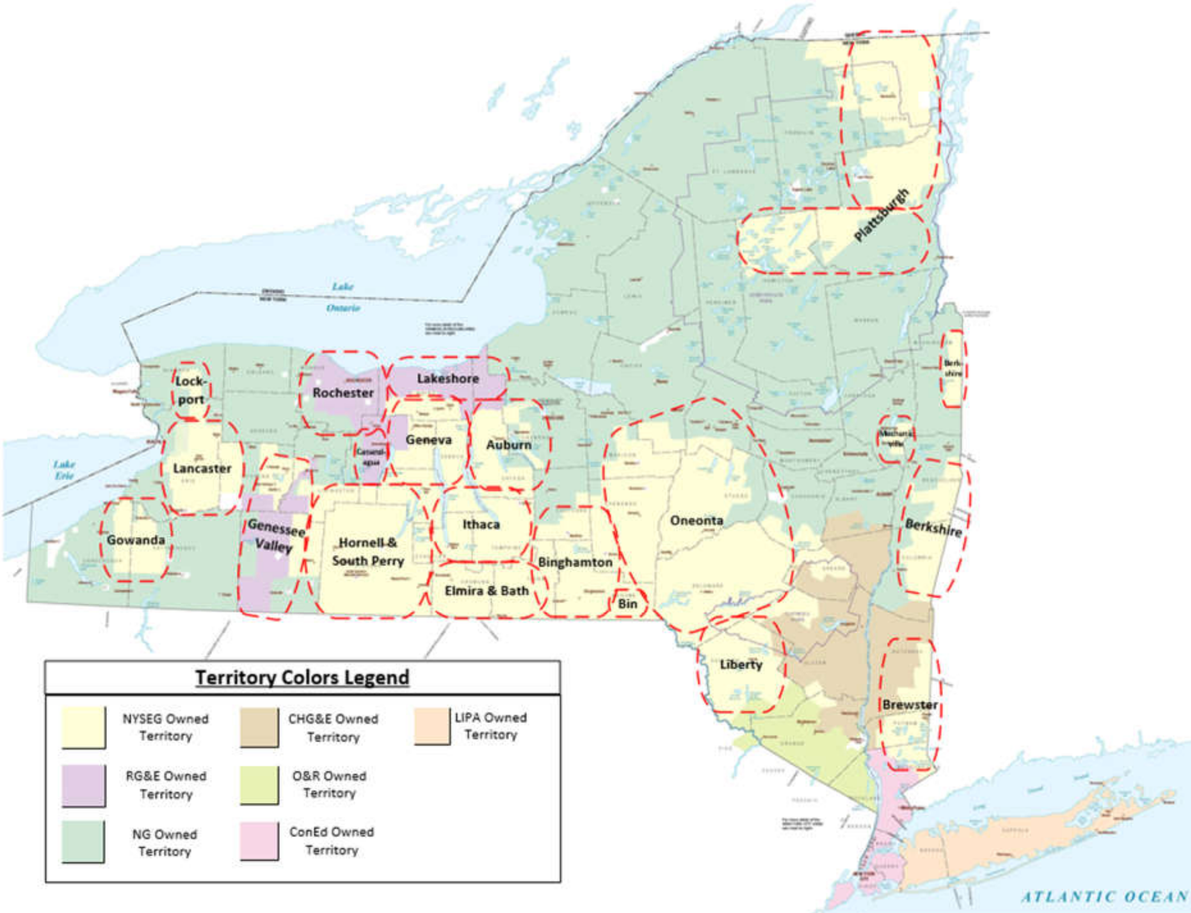
AVANGRID has assets and operations in several U.S. states and has two primary lines of business including its Networks and Renewables companies. The AVANGRID Networks business is shown in Figure 88 below and includes eight electric and natural gas utilities, serving 3.2 million customers in New York (i.e. NYSEG & RGE) and New England. The AVANGRID Renewables business owns and operates 7.1 gigawatts of electricity capacity, primarily through wind power, with a presence in 22 states across the United States.

Figure 88: AVANGRID Networks (Electric + Gas) Service Territories



In New York, NYSEG serves approximately 900,000 electricity customers within 13 operational divisions. RG&E serves approximately 380,000 customers, primarily within the city of Rochester and the adjacent municipalities. The NYSEG and RG&E's transmission systems are predominantly networked and operate at a range of voltage levels including 345, 230, 115, 46, 34.5, and some 11.5 kilovolts (kV) facilities. The NYSEG and RGE distribution systems which supply localized customer loads are predominantly radial in nature and operate at voltage levels between 2.4 – 34.5 kV. Figure 89 shows the service territories of the NYSEG and RGE operating companies, respectively and the appropriate sub-divisions in AVANGRID New York. In this Report, AVANGRID represents AVANGRID's electric service territories in New York (i.e. NYSEG and RGE).

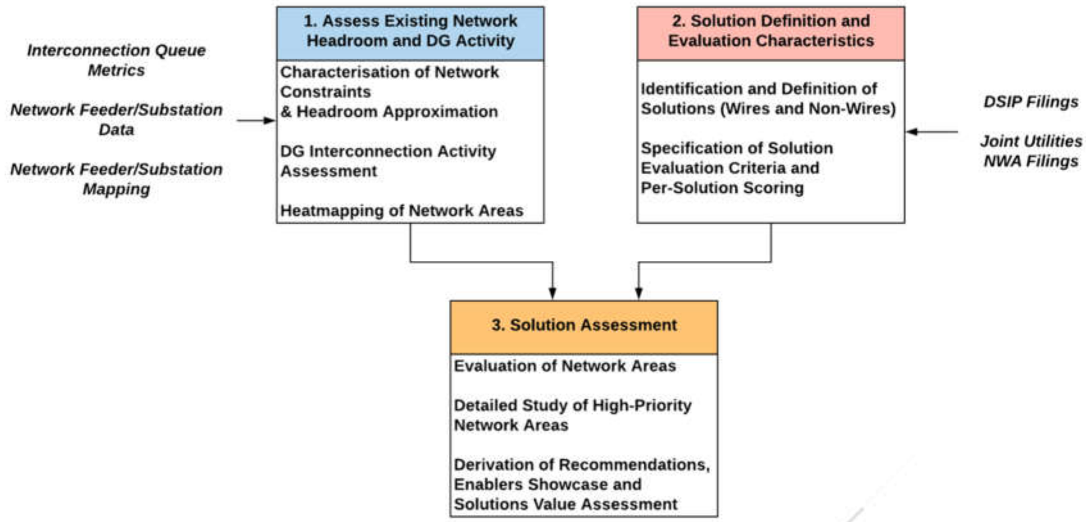
Figure 89: AVANGRID service territory



ii) Discussion of AVANGRID Study Assumptions, Methodologies, and Description of Local Design Criteria

The methodology developed and carried out for analyzing the RG&E and NYSEG distribution networks is well-aligned with the requirements set forth by the Commission Order as well as existing AVANGRID system planning, system operations, and investment planning processes. The study methodology is illustrated in Figure 90.

Figure 90: AVANGRID Distribution Study Methodology



The study methodology is divided into three tracks:

Track 1 ('Assess Existing Network Bottleneck/Headroom and DG Activity') built a full system-wide model of distribution circuits and substations with capacity, loading, DG connected, DG interconnection queue and headroom screens. Additional data collation, cleansing and enhancement has created data and models that will underpin subsequent development of AVANGRID's network to fulfil the New York State (NYS) clean energy goals.

Track 2 ('Solution Definition and Evaluation Characteristics') created definitions of a full AVANGRID suite of interconnection headroom solutions (traditional wires, non-wires and smart-innovative solutions), screens of the DSIP and Capital Expenditure Plan, and means of evaluation of potential solutions for headroom problems. These solutions are at various stages of maturity from established wires solutions to emerging, innovative solutions (including commercial and customer participation) but will all likely play important roles in developing AVANGRID's network to support clean energy deployment.

Track 3 ('Solution Assessment') created more detailed headroom and solution assessment models, detailed models for evaluation of solutions in high priority network areas and proceeded to develop project recommendations in the identified headroom hot-spots.

iii) Evaluation of Existing Headroom, Constraints, Bottlenecks for DG Interconnection

This section details the results of the DG interconnection headroom assessment based on AVANGRID's current distribution network – these include: (1) existing system headroom for DG interconnection, (2) identification of key constraints / bottlenecks of system that limit headroom for DG interconnection, and (3) identification of network areas with insufficient headroom to support DG interconnection currently in the application queue.

The study has taken a system-wide view of NYSEG and RG&E distribution service territories, including all substations and circuits, along with DG interconnection activities in assessing existing headroom. The following activities were undertaken as part of this analysis:

Data Collection – A multitude of data sets were collected and compiled across several AVANGRID departments including Distribution Planning, Transmission Planning, Transmission Services, Projects, Operations, Smart Grid, and NWA groups. The data necessary for conducting the analysis included distribution system information (circuit / substation information, equipment ratings / limits, topologies), load demand, DG interconnection (connected DG, queued applications, interconnection criteria), system reliability, hosting capacity (outputs of EPRI DRIVE tool), cost information (capex, opex), and typical system planning and operational practices. All data and information were combined into the "Universal Dataset."

Distribution System-wide Headroom Model - The models created from the universal dataset include 1697 circuits, 726 substations, and 975 DG interconnection applications with an aggregate capacity of 1500 MW. The model supports CLCPA/Commission study and other purposes.

Evaluation of Existing DG Headroom (System-Wide) – There are a number of planning screens applied to DG sites when studied for interconnection. These screens reflect asset capacity/ampacity limitations, system protection requirements and the need to maintain operation within secure limits such as voltage thresholds. Given the need for high-level modelling to allow study at system-wide scale, the headroom analysis has focused on the most limiting constraint types, where targeted investment can provide significant uplift in DG headroom.

DG Headroom is approximated for each circuit and substation subject to various system constraints. System constraint analysis is performed in line with NYSIR guidelines of AVANGRID and the Joint Utilities (JU). The total effective DG interconnection capacity is calculated based on the most severe system constraint which has the lowest MVA capacity value. The system constraints considered in the study included:

1. Circuit Thermal Headroom
2. Circuit Voltage Rise Headroom
3. Substation Thermal Headroom

Headroom is calculated for each screen considering the cases of connected DG and connected plus queued DG. The queued DG is the pipeline of interconnection applications that are in process.

Identify Existing Bottlenecks / Constraints – The study identified areas of limited DG interconnection capacity based on the underlying system constraints, labelling these as DG interconnection "hot spots". First, the areas with high DG interconnection activity and interest by developers were identified. Next, based on hosting capacity approximation (performed previously), the distribution study screened individual circuits and substations where capacity shortfall was identified for DG interconnection. This identified the network locations where capacity bottlenecks are most acutely preventing DG interconnection. Figure 91 shows the levels of DG interconnection activity and approximated hosting capacity at aggregated level across each AVANGRID division.[146] Whilst in all areas there is sufficient hosting capacity at an aggregate level, i.e. totaled across all circuits and substations, there are specific locations where a shortfall in hosting capacity creates bottlenecks that will limit interconnection for the Queued DG.

Figure 91: DG Interconnection, Hosting Capacity and Capacity Shortfalls.

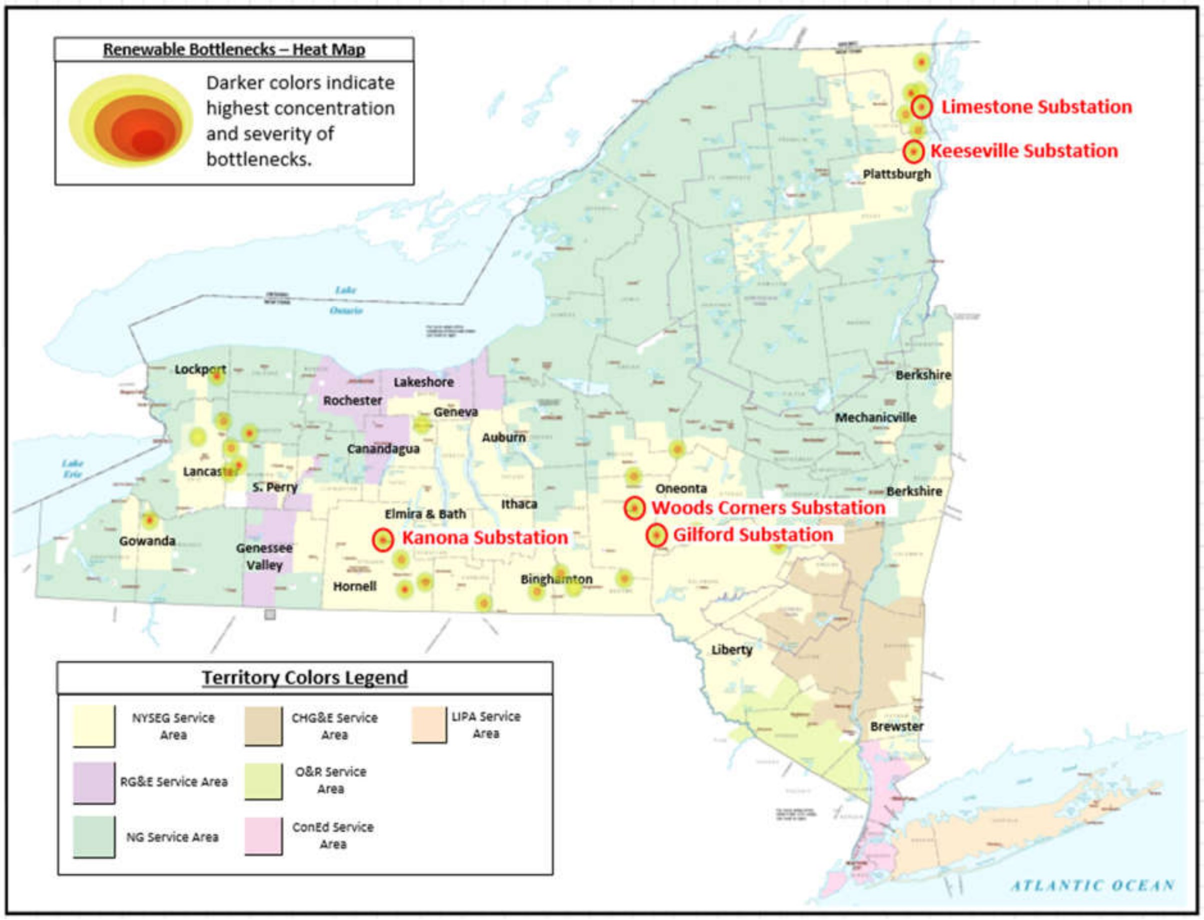
Division	Connected DG (MW)	Queued DG (MW)	Hosting Capacity (MW)	Substation Areas with Hosting Capacity Shortfall
Auburn	15.1	62.0	69.4	6
Binghamton	18.0	131.5	186.2	14
Brewster	15.4	18.0	118.5	3
Canandaigua	11.3	12.2	70.0	3
Elmira	17.9	90.7	92.2	10
Genesee	14.9	118.8	37.1	6
Geneva	27.5	26.6	88.9	6
Hornell	7.2	65.4	89.3	5
Ithaca	10.9	44.3	108.0	6
Lakeshore	8.3	15.6	43.1	3
Lancaster	25.7	85.2	309.6	7
Liberty	14.8	30.5	97.8	8
Lockport	2.4	12.2	27.6	1
Mechanicville	13.6	27.9	83.8	3
Oneonta	18.7	83.6	171.9	11
Plattsburgh	12.9	69.4	72.0	9
Rochester	91.9	69.1	467.5	13
Total	326.6	962.9	2,132.6	114

[146] Circuit / substation areas with no interconnection activity was excluded from the analysis.

1. Distribution Headroom Analysis in Hot-Spot Areas

Based on analysis of circuit and substation system constraints and DG interconnection activity, a series of "Hot Spots" substations were identified – see Figure 92.

Figure 92: Distribution Substation Hot Spots



From the list of hotspot substations that are projected to experience DG headroom problems, the top five substation areas – Keeseville, Kanona, Woods Corners, Guildford, and Limestone – were analyzed and built into new project proposals (detailed in Section 6). These substations reflect areas where the combination of high levels of DG interconnection interest and the existence of capacity bottlenecks would offer high-impact projects to release DG headroom.

2. Distribution and Transmission Study Alignment

The DG interconnection hot-spots have been aligned with the Transmission Study to ensure that proposed solutions for transmission constraints and bottlenecks are assessed for additional benefit on the distribution system. Bottlenecks were identified for transmission/distribution interfaces at 34.5 kV and 69 kV voltage levels; stepping down from higher sub-transmission voltages. Substation transformers and circuits at these voltage levels could limit the deliverability of distribution (<69 kV) DG interconnections. Several proposed sub-transmission projects will alleviate distribution system DG interconnection headroom issues. These projects include 34.5kV substation transformer upgrades, transformer additions, and 34.5 kV circuit re-conductoring / upgrades / additions.

In addition to the five Phase 2 projects, Willet and Candor network areas were also studied in detail due to high levels of DG interconnection activity, with 98 MW of connected and queued DG. The headroom issues are resolved by proposed transmission projects.

The distribution Phase 1 and Phase 2 projects that create DG interconnection headroom are not expected to have a negative impact on the transmission system since they enable the interconnection of DG capacity similar to the levels already present in the interconnection queue. These levels of DG interconnection capacity have already been assessed in the transmission study, so the effect of the distribution projects should not have a material impact on the existing and new headroom in the transmission network.

iv) Synergies with Capital Expenditure Projects

This section reviews the existing AVANGRID Capital Expenditure (CapEx) plan, identifies relevant DG headroom projects and assesses their headroom contribution.

The CapEx Plan consists of Transmission and Distribution investment projects that are driven by multiple factors such as security of supply (grid resilience), load growth, and condition-related asset renewal. A review of the Capital Plan has identified the investment projects that will have a direct benefit for the DG headroom of the distribution network – see list of project in the figure below. Whilst the primary impetus for these projects is not necessarily increasing the hosting capacity of the distribution network, it is noted that each project does provide overall benefit for generation interconnection in capacity terms.

The total aggregated DG interconnection headroom created as a result of existing distribution capital projects is 166 MW. No amendments to current CapEx plan projects are proposed as there are strong rationales for the load serving deliverability, resilience, security and asset condition/health in in the current projects. With the exception of one substation area (Hilldale), there is appears to be little DG interconnection activity at these project areas. As some substations / circuits are upgraded to higher voltage levels (e.g. 4.8 kV to 12 kV), DG interconnection interest may increase as a result[147]. At present, no modifications are

[147] Higher voltage levels may signal to DG developers that more interconnection capacity is available. However, it is just one of several factors. DG interconnection interest is driven by a variety of factors such as ease of interconnection (e.g. hosting capacity map indication), land availability / price, energy yield (e.g. solar irradiance), etc.

recommended as there exists adequate headroom to accommodate the level of DG interconnection interest at these project locations.

Figure 93: Capital Plan (Phase 1) Projects that Increase DG Headroom

Company	Project Name	Project Description	Primary Voltage	Secondary Voltage	Existing Headroom	New Headroom	Net Increase in Headroom
NYSEG	Hilldale Substation[148]	Transformer Upgrade / Replacement	34.5 kV	12.5 kV	7.4 MW	33.1 MW	25.7 MW
RG&E	Station 43	34.5kV Transformers Upgrade; 12kV Circuit Upgrade	34.5 kV	34.5 kV	11.3 MW	35.5 MW	24.2 MW
RG&E	Station 46	34.5kV Transformers Upgrade; 12kV Circuit Upgrade	34.5 kV	4.16 kV	11.9 MW	35.6 MW	23.7 MW
RG&E	Station 49	115/34.5kV Transformers Upgrade	34.5 kV	4.16 kV	20.3 MW	60.5 MW	40.2 MW
RG&E	Station 117	13.2kV Circuit Upgrade	34.5 kV	4.16 kV	4.7 MW	17.6 MW	12.9 MW
NYSEG	Amenia Substation	12kV Circuit Upgrade	46 kV	4.8 kV	5.0 MW	28.6 MW	23.7 MW
NYSEG	Dingle Ridge Substation	Transformer Upgrade / Replacement	46 kV	4.8 kV	8.8 MW	17.7 MW	8.9 MW
NYSEG	Sloan Substation	12kV Circuit Upgrade; Additional 12kV circuits; 34.5kV Transformer Upgrade	34.5 kV	4.8 kV	8.4 MW	35.0 MW	26.6 MW

Existing Substation Headroom: The remaining headroom for new generation interconnection at present, accounting for the capacity of generation currently connected to the network.
New Substation Headroom: The estimated headroom for new generation interconnection, accounting for existing generation sites, following the planned investment projects.
Net Increase in Headroom: The increase in headroom for new generation interconnection, accounting for existing generation sites, following the planned investment projects.

v) Discussion of Potential Projects that would Increase Capacity on the Distribution System to allow for Interconnection of New Renewable Generation Resources within AVANGRID's System (Phase 2 Projects)

This section presents the process to short-list options that are considered as viable alternative to the headroom hot-spots.

An exercise of scanning, scoping and defining potential project options identified a list of 25 potential headroom creating and interconnection barrier options. These are organized below under the classifications of traditional 'wires' options, customer and third-party provided

[148] An NWA solicitation is anticipated for early 2021 that could defer or replace the need for this project.

services of 'non-wires alternative' options, and new and emerging technologies based on 'smart innovative' options:

1. Wires Options:
    a) Complete 12kV Substation & Circuit Upgrade and Conversion
    b) Substation Transformer bank addition
    c) Substation Transformer up-rating
    d) Cables / Wires N-1 upgrades
    e) Cables / Wires upgrade / re-conductoring
    f) Switching / Topology change (static)
    g) Voltage Regulation Upgrades: LTC / Regulation upgrades / Capacitor banks
2. Non-Wires Alternative (NWA) Options
    a) Load relief and grid support from Non-Wires Alternatives (typically energy storage or demand flexibility)
    b) Demand Response (DR)
    c) EV Smart / Managed Charging
    d) Customer Energy Efficiency (not an applicable option)
    e) ToU & Other Pricing (not an applicable option)
    f) Market Services
3. Smart Innovative Options
    a) Flexible Interconnection Capacity Solution (FICS) for DG
    b) Auto-switching for N-1 Contingency
    c) FLISR (not an applicable option)
    d) DTT upgrades (not an applicable option)
    e) Smart Inverter Controls
    f) Volt-Var Optimization (VVO)

This full options list was evaluated using a multi-criteria evaluation process, inputs for AVANGRID subject matter experts across various departments, and assessment of the network headroom challenges identified in modelling. An example of the screening process is illustrated in Figure 94.

Figure 94: Example of multi-criteria screening of DG headroom options

Solution	Solution Category	Criterion & Weighting					Weighted Score	Ranking - All	Ranking - NWA & Smart Innovative	Ranking - NWA	Ranking - Smart Innovative
		Headroom / Energy Release	Technology Readiness	Costs	Lead Time	Technology Enabling Systems					
		2	2	3	1	1					
12kV voltage upgrade & meshing	Wires Solutions	5	5	1	3	5	31	11			
Transformer bank addition	Wires Solutions	3	5	2	3	5	30	12			
Transformer up-rating	Wires Solutions	4	5	2	3	5	32	9			
Cables / Wires N-1 upgrades	Wires Solutions	4	5	2	4	5	33	4			
Cables / Wires upgrade / re-conductoring	Wires Solutions	4	5	2	4	5	33	4			
Switching / Topology change (static)	Wires Solutions	2	5	5	4	5	38	2			
Voltage Solutions: LTC / Regulation upgrades / Capacitor banks	Wires Solutions	1	5	4	4	5	33	4			
Load relief and grid support from BESS/BESS+PV,	Non Wires Solutions	3	5	1	2	3	24	16	9	6	
Demand Response (DR)	Non Wires Solutions	1	5	3	3	2	26	15	8	5	
EV Smart / Managed Charging	Non Wires Solutions	1	3	5	3	3	29	13	6	3	
Customer Energy Efficiency	Non Wires Solutions	1	5	3	1	5	27	14	7	4	
ToU & Other Pricing	Non Wires Solutions	1	5	5	1	5	33	4	3	1	
Market Services	Non Wires Solutions	1	5	5	3	2	32	9	5	2	
FICS	Smart Innovative Solutions	3	5	5	3	3	37	3	2		2
Auto-switching for N-1 Contingency	Smart Innovative Solutions	5	5	5	4	2	41	1	1		1
FLISR	Smart Innovative Solutions	1	5	2	2	2	22	17	10		4
DTT upgrades	Smart Innovative Solutions	1	5	5	3	3	33	4	3		3
Smart Inverter Controls	Smart Innovative Solutions	1	4	2	2	4	22	17	10		4
Volt-Var Optimization (VVO)	Smart Innovative Solutions	2	4	2	2	2	22	17	10		4

The potential options were subsequently organized into the options that are viable in different timeframes in relation to the current headroom shortfalls in specific network locations, possible deployment in the 2030 planning horizon, and less mature options for resolving headroom problems:

1. Options ready for deployment for DG interconnection and headroom problems now or in the short-to-medium term:
    a) Complete 12kV Substation & Circuit Upgrade and Conversion
    b) Substation Transformer up-rating
    c) Cables / Wires upgrade / re-conductoring
    d) Switching / Topology change (static)
    e) Voltage Regulation Upgrades: LTC / Regulation upgrades / Capacitor banks
    f) Flexible Interconnection Capacity Solution (FICS) for DG
2. Options ready for deployment the medium-to-longer term
    a) Non-Wires Alternative (NWA), specifically Battery Energy Storage
    b) Auto-switching for N-1 Contingency
    c) EV Smart / Managed Charging
    d) Smart Inverter Controls
    e) Volt-Var Optimization (VVO)

The remaining options were not considered as viable candidates to provide headroom in the near-to-medium term.

1) Identification of Least Cost Traditional Upgrade Projects to Increase Headroom

The distribution study has assessed the full set of conventional network options as upgrades to increase hosting capacity and create headroom in interconnection hot-spots. Least cost upgrade options were identified that could generally increase DG headroom by alleviating existing circuit and substation bottlenecks / constraints. These options included:

- Substation Transformer upgrade
- Substation Transformer Bank Addition
- Substation 12 kV Circuit Uprating and Meshing

These options are described in the subsections that follow.

Substation Transformer Upgrade

Description: Replace existing substation supply transformer with higher rated transformers. This will potentially require associated HV side cable, lines and switchgear associated with each transformer.

DG Headroom Impact: This option can address both demand and DG thermal headroom. Transformer voltage regulation can be considered to assist with improved voltage headroom if required. For transformer supplies to lower voltage substations the option to move to 12kV on the LV side should be considered. Note that fault level issues need to be considered on moving to a larger circuit rating.

Substation Transformer Bank Addition

Description: Where a transformer is added to a substation with a single existing transformer supply, this would be treated as adding redundant supply capacity i.e. moving from N-0 to N-1. The increase in thermal headroom would be limited to the long-term emergency rating of the transformers for demand. This could be operated in parallel with existing transformer/transformers where LV side fault ratings permit or run with a split LV busbar (open bus-section breaker added with circuits allocated to on or other busbar section) or as a hot standby where there is more than one existing transformer providing N-1 redundancy and where fault levels do not permit parallel operation of the additional transformer.

DG Headroom Impact: For generator export the full new transformer capacity could be used assuming generation export is reduced on entering an N-1 condition (DG inter-trip, or DERMS). Where a third hot standby transformer supply circuit is added, this could increase demand and DG headroom by the transformer MVA rating (all assumed to have the same MVA rating).

Complete 12kV Substation & Circuit Upgrade and Conversion

Description: This option replaces lower voltage distribution circuits and transformers (e.g. 4kV) with 12kV. This will include the replacement of existing cables and overhead wires with equivalents having a higher ampacity / thermal rating to increase overall circuit headroom. This option may also include uprating from single-phase to three-phase circuits.

DG Headroom Impact: This option can be applied at any voltage level and can directly increase thermal headroom for generation and demand assuming no other constraining factors.

2) Identification of Potential New or Emerging Options

In addition to the traditional wires options highlighted above, the distribution study has considered a broad set of non-wires alternative options (following the definition and assessment process agreed with the Joint Utilities) and smart innovative options that feature in AVANGRID's grid modernization and NY REV Demo programs, as detailed in the 2020 Distributed System Implementation Plan (DSIP). Enabling technologies are also a central component in the Grid Modernization investments set out in AVANGRID's Capital Expenditure Plan and DSIP.

The smart innovative and non-wires options considered viable for the purposes of DG interconnection headroom are:

1. Flexible Interconnection Capacity Solution (FICS) for DG
2. Non-Wires Alternative (NWA): Battery Energy Storage

These options are described in subsections below.

The RG&E and NYSEG DSIP (July 2020) describes the priorities for developments to enable the companies to deliver Distributed System Platform (DSP) capabilities to serve customers and NYS clean energy goals. Of particular importance to the goals of headroom for DG interconnection are the following DSIP programs, projects and priorities:

1. *Grid Automation* program to enable *Measurement, Monitoring and Control (MM&C)* of power flows in the networks to accommodate large numbers and combined capacity of clean energy assets (generation, storage and beneficial electrification loads)
2. This study makes use of improved network data integrity and accuracy (targeted in the DSIP) for the purposes of assessing interconnection headroom and conventional and new options to enhance that headroom. The system-wide headroom model constructed and utilized in this study will be valuable for assessing further headroom creating network investments as future needs arise.
3. *Advanced DMS (D-SCADA, VVO, FLISR and DERMS)* control system implementation to optimize the grid and interconnected DER to achieve better customer and clean energy goals.

There are several other areas described in the DSIP that support future headroom and clean energy goals. Many of these are evident in the long-list of non-wires and smart-innovative options listed above.

Flexible Interconnection Capacity Solution (FICS) for DG

AVANGRID's Flexible Interconnection Capacity Solution (FICS) is a smart, innovative technology option aimed at resolving grid interconnection, headroom and capacity problems for DG. FICS is a new grid management paradigm that employs grid sensing and controls technology that departs from traditional utility system planning. FICS utilizes real-time data to maintain grid reliability and safety relative to DG operation. Typically, it is quicker and cheaper for customers to obtain interconnection with a FICS option than to wait and meet the expense of grid equipment.

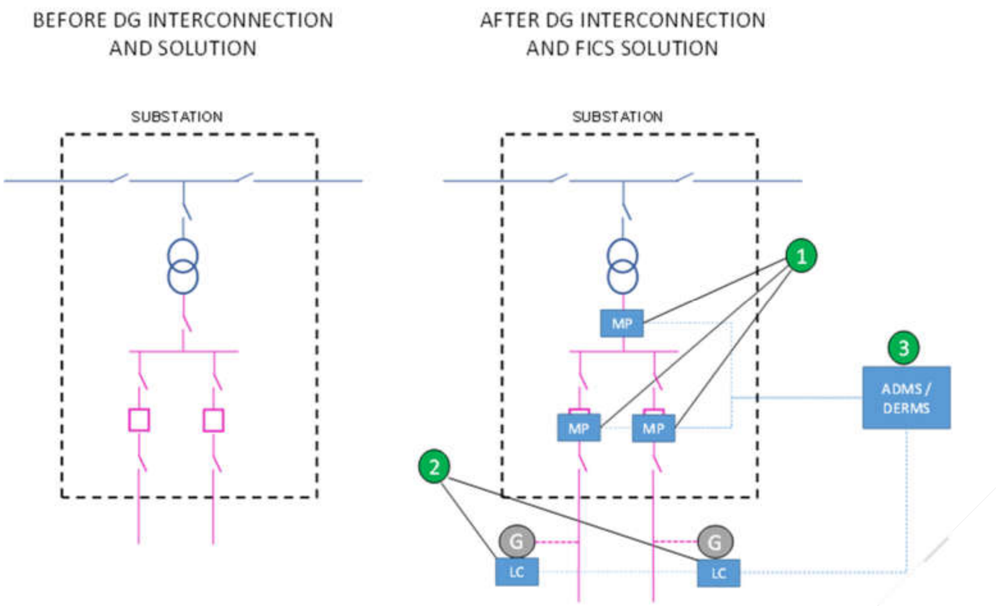
1. FICS monitors and manages network conditions

A range of interconnection problems can be resolved through monitoring grid and DG conditions in real-time (e.g. power flow, direction, voltage, DG export) and comparing this with known equipment and system limits including thermal capacity of lines/cables/transformers, voltage limits, voltage step limits, reverse power flow limits of regulators, harmonics limits from inverter connected DG. Measurement equipment continuously monitor selected parts of the system and as grid and DG conditions approach those limits, control instructions are sent to DG units and network assets to take incremental actions to restore the network to a safe operating state within the limits. This real-time control of DG can allow network interconnection in bottleneck areas without the need for conventional 'wires' expense and delay.

2. FICS requires Monitoring, Measurement & Control Equipment

The example FICS project illustrated in Figure 95 shows Measurement Points (MP) where the network measurements are taken. Measurements are also taken at the Generating (G) units through the Local Controllers (LC). Measurements are gathered in the DER Management System (DERMS) at an AVANGRID control center. The DERMS also receives data from the Advanced Distribution Management System (ADMS) at the AVANGRID control center and computes the required changes in DG operation to maintain safe and secure network operation. This is communicated back to the LCs to implement the new operating point if required. The LCs also contain local intelligence to take safe action should any part of the control and communication system fail.

Figure 95: Example FICS Project with Equipment and Communications Links



The example FICS deployment in Figure 95 shows MPs at constraints on two circuits into the substation and one further constraint at the transformer. Two generators are shown with LCs, one on each of the constrained circuits. Conditions might dictate that one or both generators would be instructed to a lower export setpoint if the transformer approached its operating limits. The generators would only be subject to curtailment for their respective circuit constraints.

FICS leverages AVANGRID's REVDemo project which is now being rolled out in AVANGRID services territories. FICS also leverages investments in Monitoring, Measurement and Control (MM&C) as part of AVANGRID's Distributed System Implementation Plan (DSIP). Through these programs, it is possible to meet CLCPA goals through creation of more interconnection headroom, while providing AVANGRID customers with the option of quicker and cheaper interconnection.

3. DG Export Curtailment

To maintain the network within its safe operating limits, DG is instructed to reduce export to the system when grid conditions dictate. Curtailment is requested only at the moment in time when the network approaches its operating limits and is removed as soon as those conditions relax. The FICS technology that AVANGRID is deploying is highly location specific in the application of DG export reduction and calculates and recalculates any curtailment on a second-by-second basis to reduce the impact on DG developers.

Curtailment of DG export tends to occur at times when local load demand is low (so more DG export will require to flow upwards into the grid) and when other DG output is high (so more DG power compete for the same network capacity). Advanced analytical methods can provide an accurate estimate of expected curtailment for DG of specific technology, operating in a specific network location and with a range of operating conditions for the DG unit itself and for neighboring DG and load customers.

Experience of similar FICS deployments over the last decade shows that DG interconnection in a headroom constrained network area can be doubled at the expense of 5-10% DG curtailment.

4. Interconnection process and FICS costs

An interconnection process that provides customers with the FICS option alongside a conventional interconnection will provide information on the equipment required, the costs and the cost allocation between customer and AVANGRID.

Implementing a FICS project involves:

- Measurement Points (MP) installed on each circuit, node with a headroom constraint.
- Extending MM&C monitoring, communications, data infrastructure to new 'FICS Zone' if required.
- Extension of DERMS (Vestal) infrastructure to incorporate new 'FICS Zone'.
- FICS Local Controllers (LC) installed at each FICS DG customer site.

Non-Wires Alternatives (NWA): Battery Energy Storage

AVANGRID already has a Commission and JU standard process for procuring load relief services from customers and third parties. These are known as Non-Wires Alternatives (NWA), as they are alternative approaches to resolving network constraints or problems.

A similar approach to procuring generation export constraint relief services can be deployed to enable customers and third parties to provide network capacity and headroom options. Many of the processes already in operation for load relief non-wires options can be adapted for the planning, procurement, implementation and operation of an export NWA.

The option requirements could involve the connection of suitably sized (power rating and energy storage capacity) energy storage either behind-the-meter (BTM) at customer premises or front-of-the-meter (FTM) connected to the network or located at a substation. These could be single flexible demand (turn up) or energy storage assets or aggregated units, distributed within the distribution network.

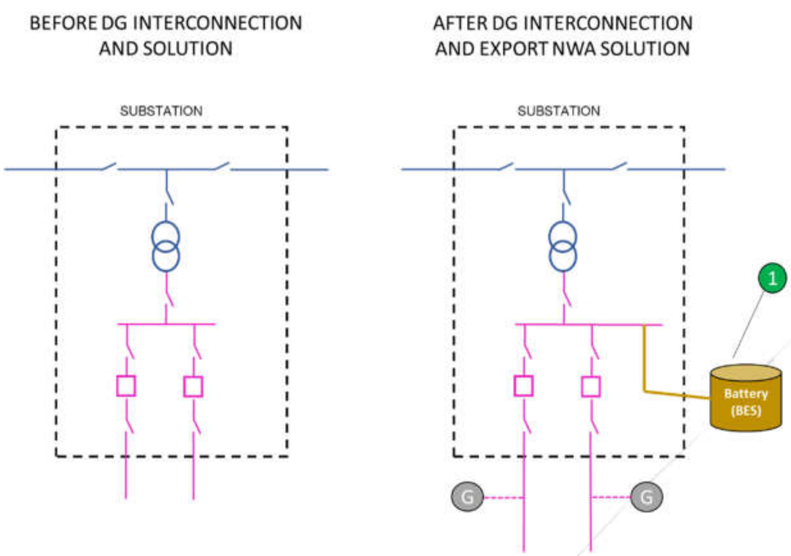
An ADMS, DERMS or other dispatch system is required to issue schedule and control signals to provide headroom and export relief at the appropriate times. BTM NWA based options require suitable contractual arrangements and, possibly for wider network options, some form of market trading or schedule optimization platform for provision of other system and market services.

The option can be used to reduce demand or generation loading on constrained circuits at peak usage times to create thermal headroom. The option can be used to improve voltage regulation, reduce harmonics, peak load reduction for demand and generation and improve supply security and resiliency.

An NWA solicitation would be required to finalize costs and determine final technology specifications from qualified bidders. A solicitation should take place for every application when the order of magnitude estimate is competitive with other solution options.

Figure 96 below provides an example illustration of the NWA battery energy storage solution.

Figure 96: Example of Non-Wires Alternative (Battery Energy Storage) Project



vi) Discussion of Potential Projects that would Increase Capacity on the Distribution System to allow for Interconnection of New Renewable Generation Resources within AVANGRID's System (Phase 2 Projects)

The study has identified a series of additional projects that will deliver additional DG interconnection headroom in network areas where there is high levels of generator interconnection activity and existing system constraints / bottlenecks. These distribution hot-spots areas were identified as specific network substations and circuits where grid capacity constraints, or bottlenecks, will block further interconnection DG developments. The study has focused on the areas where substation-level capacity issues will block additional generation interconnection across the entire area served by the substation. Locational-specific circuit-level issues (e.g. conductor thermal overload, overvoltage) could exist that would require additional solutions / upgrades to be implemented but this is outside the scope of the study.

The five proposed new Phase 2 projects – **Limestone**, **Keeseville**, **Guildford**, **Woods Corners** and **Kanona** Substations – are estimated to create a total increase in aggregated DG interconnection headroom of **88 MW**. These projects represent the most cost-effective set of projects that leverage existing capital expenditure plans, that exploit conventional options as well as non-wires options and smart-innovative options with a strong data-centric evidence base using the methodologies set out above.

A summary of projects #1-#5 and their assessed options is presented in Figure 97 and Figure 98.

Note on Cost Estimate: In general, the lowest cost alternative addressing all needs (e.g. reliability, asset condition, CLCPA, etc.) is preferred, however, consideration is also given to the states goals to enable more storage solutions onto the system also. In addition, the cost estimates in this study are considered as Order of Magnitude (OOM) level based on a limited desktop engineering analysis. As such, there may be situations where the estimate accuracy ranges of competing alternatives overlap making a future estimate refinement necessary to verify which alternative is in fact the lowest cost. These estimate refinements, if necessary, will likely require substantially more detailed site specific engineering detail considerations as compared to the OOM estimates available for many of the projects evaluated in this study.

Figure 97: Analysis of System Need and Alternative Solutions Proposed

Project	Primary Voltage	Secondary Voltage	Connected + Queued DG	Transformer Capacity	Substation Peak Load	Existing Substation Headroom	New Substation Headroom with Alternative Solutions			
							12kV upgrade (MW)	Transformer Replacement / Addition	FICS (MW)	NWA Energy Storage
Limestone	46 kV	12.5 kV	11.8 MW	10.5 MVA	6.7 MW	8.8 MW	n/a	17.7 MW	11.4	11.7 MW
Keeseville	46 kV	4.8 kV	2.8 MW	2.5 MVA	1.5 MW	2.1 MW	28.2	n/a	3.0	2.8 MW
Guildford	46 kV	4.8 kV	4.6 MW	2.5 MVA	1.7 MW	2.1 MW	28.2	n/a	3.0	4.5 MW
Woods Corner	46 kV	8.32 kV	10.0 MW	8.4 MVA	4.6 MW	7.0 MW	28.7	n/a	9.0	10.0 MW
Kanona	34.5 kV	12.5 kV	16.0 MW	10.5 MVA	4.8 MW	6.6 MW	n/a	15.5 MW	8.6	14.0 MW

Connected + Queued DG: The total volume of DG either connected to the network or in the interconnection queue awaiting connection, at that substation.
Transformer Capacity: the MVA continuous rating of the substation transformer(s).
Substation Peak Load: The MW 5-year average peak load at the substation transformer(s).
Existing Substation Headroom: The remaining headroom for new generation interconnection at present, accounting for the capacity of generation currently connected to the substation and in the interconnection queue.
New Substation Headroom [12kV upgrade option/transformer replacement option/FICS/NWA Energy Storage option]: The estimated headroom for new generation interconnection, accounting for existing generation sites, following the planned investment projects of 12kV Upgrade/Transformer Replacement/FICS deployment

Figure 98: Export Constraint NWA Requirement

Project	Primary Voltage	Secondary Voltage	Connected + Queued DG	Transformer Capacity	Substation Peak Load	Power Requirement for Energy Storage	Duration Requirement for Energy Storage
Limestone	46 kV	12.5 kV	11.8 MW	10.5 MVA	6.7 MW	1.5 MW	6-Hour
Keeseville	46 kV	4.8 kV	2.8 MW	2.5 MVA	1.5 MW	0.5 MW	4-Hour
Guildford	46 kV	4.8 kV	4.6 MW	2.5 MVA	1.7 MW	2.1 MW	8-Hour
Woods Corner	46 kV	8.32 kV	10.0 MW	8.4 MVA	4.6 MW	2.1 MW	6-Hour
Kanona	34.5 kV	12.5 kV	16.0 MW	10.5 MVA	4.8 MW	6.5 MW	8-Hour

Primary/Secondary Voltage: The Primary (HV) and Secondary (LV) voltage levels at the substation.
Connected + Queued DG: The total volume of DG either connected to the network or in the interconnection queue awaiting connection, at that substation.
Transformer Capacity: the MVA continuous rating of the substation transformer(s).
Substation Peak Load: The MW 5-year average peak load at the substation transformer(s).
Power Requirement for NWA: The MW rating of service provision required from Non-Wires Alternatives required to accommodate the queued DG and avoid headroom constraint.
Duration Requirement for Energy Storage: The hour duration rating of service provision required from Non-Wires Alternatives required to accommodate the queued DG and avoid headroom constraint.

1) Project #1: Limestone Substation

Figure 99: Project Overview

Utility Area	NYSEG
Utility Division	Plattsburgh
Project Name	Limestone Substation
Primary Voltage	46 kV
Secondary Voltage	12.5 kV
Transformer Rating	10.5 MVA
Substation Peak Load	6.7 MW
Connected DG	0.1 MW
Queued DG	11.7 MW
Description of System Need	Substation transformer observed capacity constraint with an additional 2.9 MW of substation capacity required to accommodate Queued DG. There is sufficient DG headroom on 12.5kV circuits.
Existing Headroom	8.8 MW
Estimated Headroom Increase with Recommended Solution	5.5 MW (Solution #2 + Solution #3)
Estimated Cost for Recommended Solution	-- (Solution #2 + Solution #3)
Proposed In-Service Date	2023

Figure 100: Evaluation of Options for Increasing DG Headroom

Solution	Description	Capacity Gained (MW)	Order of Magnitude Cost ($)	Headroom Increase ($/MW)
# 1	Transformer Upgrade - Replace existing 10.5MVA (46/12.5kV) transformer with a new 22.4MVA (46/12.5kV) transformer;	8.9 MW	--	--
#2	Flexible Interconnection Capacity Solution (FICS) for DG [149] - FICS Measurement Points (MP) for real-time monitoring of power flow through the substation transformer; - FICS Local Controller (LC) for each controlled FICS DG site; - FICS central ADMS/DERMS control system and integration of MPs and LCs to ADMS/DERMS.	2.6 MW	--	--
#3	Battery Energy Storage Solution - Procurement of non-wires solution (e.g. battery energy storage) at substation. Estimated minimum storage requirement of 1.5MW Rating and 6-hour storage capacity.	2.9 MW	--	--

Preferred Solution Alternative: Combination of Solution #2 (Flexible Interconnection Capacity Solution for DG) and Solution #3 (Battery Energy Storage Solution). FICS and BESS can deploy incrementally and are complimentary as FICS is based on dialing down DG output while BESS absorbs excess DG output. Based on order of interconnection, FICS is first deployed to accommodate new DG without need for any substantial upgrades or new deployments. Once FICS capacity becomes limited (i.e. due to high curtailment), BESS is then deployed to address any additional power outflows from additional DG. The deployment of both solutions yields an approximate combined 5.5 MW DG headroom, with a unit cost of $1.3M per MW.

[149] Solution #2: Based on relatively high levels of substation load, FICS can address the headroom issues and accommodated generation up to installed capacity 11.5 MVA. An approximation of headroom uplift indicates that it will offer similar levels of headroom to the transformer upgrade option. In the case of FICS, headroom uplift is defined as the MVA volume of generation that can connect before export curtailment levels become excessive, i.e. ensuring curtailment is below 10% of annual production.

2) *Project #2: Keeseville Substation*

Figure 101: Project Overview

Utility Area	NYSEG
Utility Division	Plattsburgh
Project Name	Keeseville Substation
Primary Voltage	46 kV
Secondary Voltage	4.8 kV
Transformer Rating	2.5 MVA
Substation Peak Load	1.5 MW
Connected DG	0.0 MW
Queued DG	2.8 MW
Description of System Need	Substation transformer observes capacity constraint with additional 0.7 MW substation capacity required to accommodate Queued DG. There is sufficient DG headroom on the 4.8kV circuits.
Existing Headroom	2.1 MW
Estimated Headroom Increase with Recommended Solution	26.1 MW (Solution #1)
Estimated Cost for Recommended Solution	-- (Solution #1)
Proposed In-Service Date	2025

Figure 102: Evaluation of Options for Increasing DG Headroom:

Solution	Description	Capacity Gained (MW)	Order of Magnitude Cost ($)	Headroom Increase ($/MW)
# 1	Complete 12kV Substation & Circuit Upgrade and Conversion[150] 12kV upgrade to the substation and associated circuits will address capacity headroom challenges, fully accommodating queued DG. There is 28.2 MW substation capacity (above queued DG) once this reinforcement is delivered. - Replace existing 2.5MVA (46/4.8 kV) transformer in substation bank #2 with 37.3MVA (46/12.5kV) transformer; - Upgrade 4.8kV Circuit to 12.5kV; - Replace downstream secondary transformations from 4.8kV to 12.5kV.	26.1 MW	--	--
#2	Flexible Interconnection Capacity Solution (FICS) for DG[151] - FICS Measurement Points (MP) for real-time monitoring of power flow through the substation transformer; - FICS Local Controller (LC) for each controlled FICS DG site; - FICS central ADMS/DERMS control system and integration of MPs and LCs to ADMS/DERMS.	0.9 MW	--	--
#3	Battery Energy Storage Solution - Procurement of non-wires solution (e.g. battery energy storage) at substation. Estimated minimum storage requirement of 0.5 MW, 4-hour storage capacity.	0.7 MW	--	--

Preferred Solution Alternative: Solution #1 – Complete 12kV Substation & Circuit Upgrade and Conversion. This delivers significant levels of capacity to the substation on a cost-effective basis, both improving substation and circuit headroom for future DG interconnection.

[150] Solution #1: 12kV upgrade to the substation and associated circuits will address capacity headroom challenges, fully accommodating queued DG. There is 14.3MVA substation capacity (above queued DG) once this reinforcement is delivered

[151] Solution #2: FICS can deliver sufficient headroom increase to accommodate Queued DG and this could present a temporary solution to accelerate connection of DG ahead of the 12kV Mesh reinforcement.

3) *Project #3: Guilford Substation*

Figure 103: Project Overview:

Utility Area	NYSEG
Utility Division	Oneonta
Project Name	Guilford Substation
Primary Voltage	46 kV
Secondary Voltage	4.8 kV
Transformer Rating	2.5 MVA
Substation Peak Load	1.7 MW
Connected DG	0.1 MW
Queued DG	4.5 MW
Description of System Need	Substation transformer observes capacity constraint with additional 2.4 MW capacity required to accommodate Queued DG. There is insufficient headroom on 4.8kV circuits.
Existing Headroom	2.1 MW
Estimated Headroom Increase with Recommended Solution	26.1 MW (Solution #1)
Estimated Cost for Recommended Solution	-- (Solution #1)
Proposed In-Service Date	2025

Figure 104: Evaluation of Options for Increasing DG Headroom

Solution	Description	Capacity Gained (MW)	Order of Magnitude Cost ($)	Headroom Increase ($/MW)
# 1	Complete 12kV Substation & Circuit Upgrade and Conversion[152] 12kV upgrade to the substation and associated circuits will address capacity headroom challenges, fully accommodating queued DG. There is 28.1MVA substation capacity (above queued DG) once this reinforcement is delivered. - Replace existing 2.5MVA (46/4.8 kV) transformer in substation with 37.3MVA (46/4.8kV) transformer; - Upgrade 4.8kV Circuit to 12.5kV conductor; - Replace secondary transformations from 4.8kV to 12.5kV.	26.1 MW	--	--

Preferred Solution Alternative: Solution #1 – Complete 12kV Substation & Circuit Upgrade and Conversion. Other solution alternatives were considered but did not result in sufficient headroom to accommodate queued DG. The preferred solution delivers significant levels of capacity to the substation, both improving substation and circuit headroom for future DG interconnection.

[152] There is 12.5MVA of additional substation capacity available for DG beyond the queued customers, however the 12kV circuits may limit development to the lower level of 5.2MVA.

4) *Project #4: Wood Corners Substation*

Figure 105: Project Overview

Utility Area	NYSEG
Utility Division	Oneonta
Project Name	Woods Corners Substation
Primary Voltage	46 kV
Secondary Voltage	8.32 kV
Transformer Rating	8.4 MVA
Substation Peak Load	4.6 MW
Connected DG	0.0 MW
Queued DG	10.0 MW
Description of System Need	Substation transformer observes capacity constraint with additional 3 MW capacity required to accommodate Queued DG. There is also insufficient aggregate hosting capacity on the 8.32kV circuits.
Existing Headroom	7.0 MW
Estimated Headroom Increase with Recommended Solution	21.7 MW (Solution #1)
Estimated Cost for Recommended Solution	-- (Solution #1)
Proposed In-Service Date	2025

Figure 106: Evaluation of Options for Increasing DG Headroom

Solution	Description	Capacity Gained (MW)	Order of Magnitude Cost ($)	Headroom Increase ($/MW)
# 1	Complete 12kV Substation & Circuit Upgrade and Conversion[153] 12kV upgrade to the substation and associated circuits will address capacity headroom challenges, fully accommodating queued DG. There is 18.7MVA substation capacity (above queued DG) once this reinforcement is delivered. - Replace existing 2.5MVA (46/8.32 kV) transformer in substation with 37.3MVA (46/12.5kV) transformer; - Upgrade 4.8kV Circuit to 12.5kV conductor; - Replace downstream secondary transformations from 4.8kV to 12.5kV.	21.7 MW	--	--
#2	Flexible Interconnection Capacity Solution (FICS) for DG[154] - FICS Measurement Points (MP) for real-time monitoring of power flow through the substation transformer; - FICS Local Controller (LC) for each controlled FICS DG site; - FICS central ADMS/DERMS control system and integration of MPs and LCs to ADMS/DERMS.	2.0 MW	--	--

[153] Solution #1: 12kV upgrade to substation and associated circuits addresses the capacity issues at substation and circuits. Following this solution there is 18.7MVA of additional substation capacity available for generation beyond the queued sites.

[154] Solution #2: FICS can deliver sufficient headroom increase to accommodate up to 9MW of DG – this could present a temporary solution to accelerate connection of DG ahead of the 12kV Mesh reinforcement.

Preferred Solution Alternative: Solution #1 – Complete 12kV Substation & Circuit Upgrade and Conversion. Solution #2 does not provide enough DG headroom increase to accommodate current DG queued applications.

5) Project #5: Kanona Substation

Figure 107: Project Overview

Utility Area	NYSEG
Utility Division	Elmira
Project Name	Kanona Substation
Primary Voltage	34.5 kV
Secondary Voltage	12.5 kV
Transformer Rating	10.5 MVA
Substation Peak Load	4.8 MW
Connected DG	2.0 MW
Queued DG	14.0 MW
Description of System Need	Substation transformer observed capacity constraint with an additional 7.4 MW of capacity required to accommodate Queued DG. There is insufficient headroom on 12.5kV circuits.
Existing Headroom	6.6 MW
Estimated Headroom Increase with Recommended Solution	8.9 MW (Solution #1)
Estimated Cost for Recommended Solution	-- (Solution #1)
Proposed In-Service Date	2025

Figure 108: Evaluation of Options for Increasing DG Headroom

Solution	Description	Capacity Gained (MW)	Order of Magnitude Cost ($)	Headroom Increase ($/MW)
# 1	Transformer Upgrade - Replace existing 10.5MVA (46/12.5kV) transformer with a new 22.4MVA (46/12.5kV) transformer; *Additional upgrades required on 12.5kV circuits to increase headroom.	8.9 MW	--	--
#2	Flexible Interconnection Capacity Solution (FICS) for DG[155] - FICS Measurement Points (MP) for real-time monitoring of power flow through the substation transformer; - FICS Local Controller (LC) for each controlled FICS DG site; - FICS central ADMS/DERMS control system and integration of MPs and LCs to ADMS/DERMS.	2.1 MW	--	--

[155] Solution #2: Given the high levels of constraint, FICS is unable to address the capacity headroom issues at the substation. It may however address some of the circuit-level issues to accommodate a smaller proportion of the DG queue ahead of reinforcement. FICS would address the circuit-level headroom issues, providing an additional 1MVA of capacity beyond the queued & connected DG.

Preferred Solution Alternative: Solution #1 – Transformer Upgrade. Solution #2 delivers insufficient capacity to accommodate the existing DG application queue.

vii) AVANGRID Distribution Study Conclusion

This study found that targeted upgrades to the AVANGRID distribution system can provide system capabilities to support the state's CLCPA goals. The study also found that many previously planned upgrades, as designed, provide additional significant benefits to meeting these CLCPA goals.

This study found that the implementation of AVANGRID's proposed distribution system upgrade projects can enable additional renewable resources onto the NYSEG and RGE Local transmission systems. Many of these Projects not only serve to unlock renewable resources, but they also provide substantial system benefits in terms of improved customer reliability and modernization of portions of the New York electric grid. A summary of the order of magnitude costs and schedule are provided in the figure below.

Figure 109: Summary of Order of Magnitude Costs and Schedule by Project Type

Project Type (Execution Phase)	In-Service Years	OOM Cost ($M)
Phase 1	2021-2027	229
Phase 2	2023-2025	125
	Total	354

Figure 110 below, provides a summary of the project alternatives and their associated capacity improvements that were evaluated as part of this study.

Figure 110: Summary of Distribution Phase 1 and Phase 2 Projects

Division	Bottleneck Descriptions		Project Descriptions							
	Violation	Main Drivers	Name	Type	Descriptions	ISD	Order of Magnitude Cost ($)	Capacity Gained (MW)	Headroom Increase ($/MW)	Preferred Solution
Liberty	Substation Transformer	Capacity	Hilldale Substation[156]	Phase 1 (Existing Project)	Transformer Upgrade / Replacement	2024	$32M	25.7 MW	$1.2M / MW	X
Rochester	Substation Transformer; Conductors	Asset Condition, Reliability & Resiliency	Station 43	Phase 1 (Existing Project)	34.5kV Transformers Upgrade; 12kV Circuit Upgrade	2026	$47M	24.2 MW	$1.9M / MW	X
	Substation Transformer; Conductors	Asset Condition, Reliability & Resiliency	Station 46	Phase 1 (Existing Project)	34.5kV Transformers Upgrade; 12kV Circuit Upgrade	2025	$49M	23.7 MW	$2.1M / MW	X
	Substation Transformer	Asset Condition, Reliability & Resiliency	Station 49	Phase 1 (Existing Project)	115/34.5kV Transformers Upgrade	2021	$19M	20.1 MW	$0.9M / MW	X
	Substation Transformer; Conductors	Asset Condition, Reliability & Resiliency	Station 117	Phase 1 (Existing Project)	13.2kV Mesh Upgrade	2026	$25M	12.9 MW	$1.9M / MW	X
Brewster	Substation Transformer; Conductors	Capacity	Amenia Substation	Phase 1 (Existing Project)	12kV Circuit Upgrade	2021	$13M	23.7 MW	$0.5M / MW	X
	Substation Transformer	Capacity	Dingle Ridge Substation	Phase 1 (Existing Project)	Transformer Upgrade / Replacement	2021	$16M	8.9 MW	$1.8M / MW	X

[156] An NWA solicitation is anticipated for early 2021 that could defer or replace the need for this project.

Division	Bottleneck Descriptions		Project Descriptions							
	Violation	Main Drivers	Name	Type	Descriptions	ISD	Order of Magnitude Cost ($)	Capacity Gained (MW)	Headroom Increase ($/MW)	Preferred Solution
Lancaster	Substation Transformer; Conductors	Capacity	Sloan Substation	Phase 1 (Existing Project)	12kV Circuit Upgrade; Additional 12kV circuits; 34.5kV Transformer Upgrade	2027	$28M	26.6 MW	$1.3M / MW	X
Elmira	Substation Transformer	DG Interconnection	Kanona Substation	Phase 2 (New Project) – Alt 1	Transformer Upgrade	2025	--	8.9 MW	--	X
				Phase 2 (New Project) – Alt 1	Flexible Interconnection Capacity Solution (FICS) for DG	2023	--	2.1 MW	--	
Plattsburgh	Substation Transformer	DG Interconnection	Limestone Substation	Phase 2 (New Project) – Alt 1	Transformer Upgrade	2025	--	8.9 MW	--	
				Phase 2 (New Project) – Alt 2	Flexible Interconnection Capacity Solution (FICS) for DG	2023	--	2.6 MW	--	X
				Phase 2 (New Project) – Alt 3	Battery Energy Storage Solution	2023	--	2.9 MW	--	X
	Substation Transformer	DG Interconnection	Keeseville Substation	Phase 2 (New Project) – Alt 1	Complete 12kV Substation & Circuit Upgrade and Conversion	2025	--	26.1 MW	--	X
				Phase 2 (New Project) – Alt 2	Flexible Interconnection Capacity Solution (FICS) for DG	2023	--	0.9 MW	--	
				Phase 2 (New Project) – Alt 3	Battery Energy Storage Solution	2023	--	0.7 MW	--	

Division	Bottleneck Descriptions		Project Descriptions							
	Violation	Main Drivers	Name	Type	Descriptions	ISD	Order of Magnitude Cost ($)	Capacity Gained (MW)	Headroom Increase ($/MW)	Preferred Solution
Oneonta	Substation Transformer	DG Interconnection	Guildford Substation	Phase 2 (New Project) – Alt 1	Complete 12kV Substation & Circuit Upgrade and Conversion	2025	--	26.1 MW	--	X
	Substation Transformer	DG Interconnection	Woods Corners Substation	Phase 2 (New Project) – Alt 1	Complete 12kV Substation & Circuit Upgrade and Conversion	2025	--	21.7 MW	--	X
				Phase 2 (New Project) – Alt 2	Flexible Interconnection Capacity Solution (FICS) for DG	2023	--	2.0 MW	--	

VII. ORANGE & ROCKLAND UTILITIES

A. Transmission

i) Description of O&R and its Service Territory

O&R's study area is the portion of the New York Control Area located in Zone G in the Lower Hudson Valley Area. O&R's electric service territory is comprised of Rockland County, portions of Orange County, and portions of Sullivan County. O&R's service territory is further divided into three (3) divisions, *i.e.*, Eastern, Central and Western. O&R's transmission system includes facilities operated at voltages between 34.5 kV and 345 kV (O&R also operates 34.5 kV distribution facilities). O&R interconnects with the State bulk power system through seven (7) bulk power 345/138 kV transformer interfaces (*i.e.*, West Haverstraw Bank 194, Bowline Bank 455, Ramapo Bank 1300 & 2300, Sugarloaf Bank 1112, Middletown Tap Bank 114 and South Mahwah Bank 258). Although O&R owns no generation, several power plants connected to the bulk power system are located within its service territory (*i.e*. Bowline, CPV Valley). Furthermore, approximately 70 MW of small hydro electric and gas turbines exist within the O&R service territory and are connected to the O&R's 69 kV and 34.5 kV transmission systems. Figure 111 below shows the O&R service territory.

Figure 111: O&R Service Territory

ii) Discussion of O&R's Study Assumptions and Description of Local Design Criteria

1. Study Cases

O&R used the following cases in this study:

1. 2020 O&R summer case;
2. NYISO's 2030 Reliability Needs Assessment ("RNA") case, also referred to as the "business-as-usual" summer case; and
3. "Enhanced" summer case with transmission renewable projects added to this case (see discussion in Section IV).

Study cases 2 & 3 above modeled the independent distribution station peak load with consideration of (1) the 8760- load profile, (2) load curve of the Distribution Photo-voltaic ("PV"), and (3) evening peak load.

2. Transmission Planning Design Criteria

The O&R transmission system shall be designed to serve load when the system is in normal configuration (N-0), as well as during single contingency events (N-1). Under normal configuration, no transmission facility shall exceed its normal thermal ratings and no thermal violations shall be observed in all divisions. During N-1 conditions, O&R transmission system shall be designed to sustain single contingency events such as an outage of a single transmission circuit, transformer or a bus section without loss of load. During any of the above contingencies, <u>no facility will be loaded above its normal rating</u>. When the normal rating is exceeded during a single contingency event, T&S Engineering shall propose system reinforcements and/or improvements to mitigate the violation(s). Both N-0 and N-1 criteria were based on *NERC Standard TPL-001-4 Table 1 Category P0 - No contingency condition and Category P1 – Single Contingency condition,* respectively. All bus voltages for both conditions shall be within 0.95 to 1.05 per unit of their nominal voltage.

Based on these criteria, O&R has included in its 2021-2030 capital budget several transmission projects aimed at mitigating the various thermal as well as voltage violations in its system, summarized in Figure 112 below. Note that several 2020 capital projects are included in the table; these projects are expected to be completed before year-end.

Figure 112: 2021-2030 Transmission Capital Projects

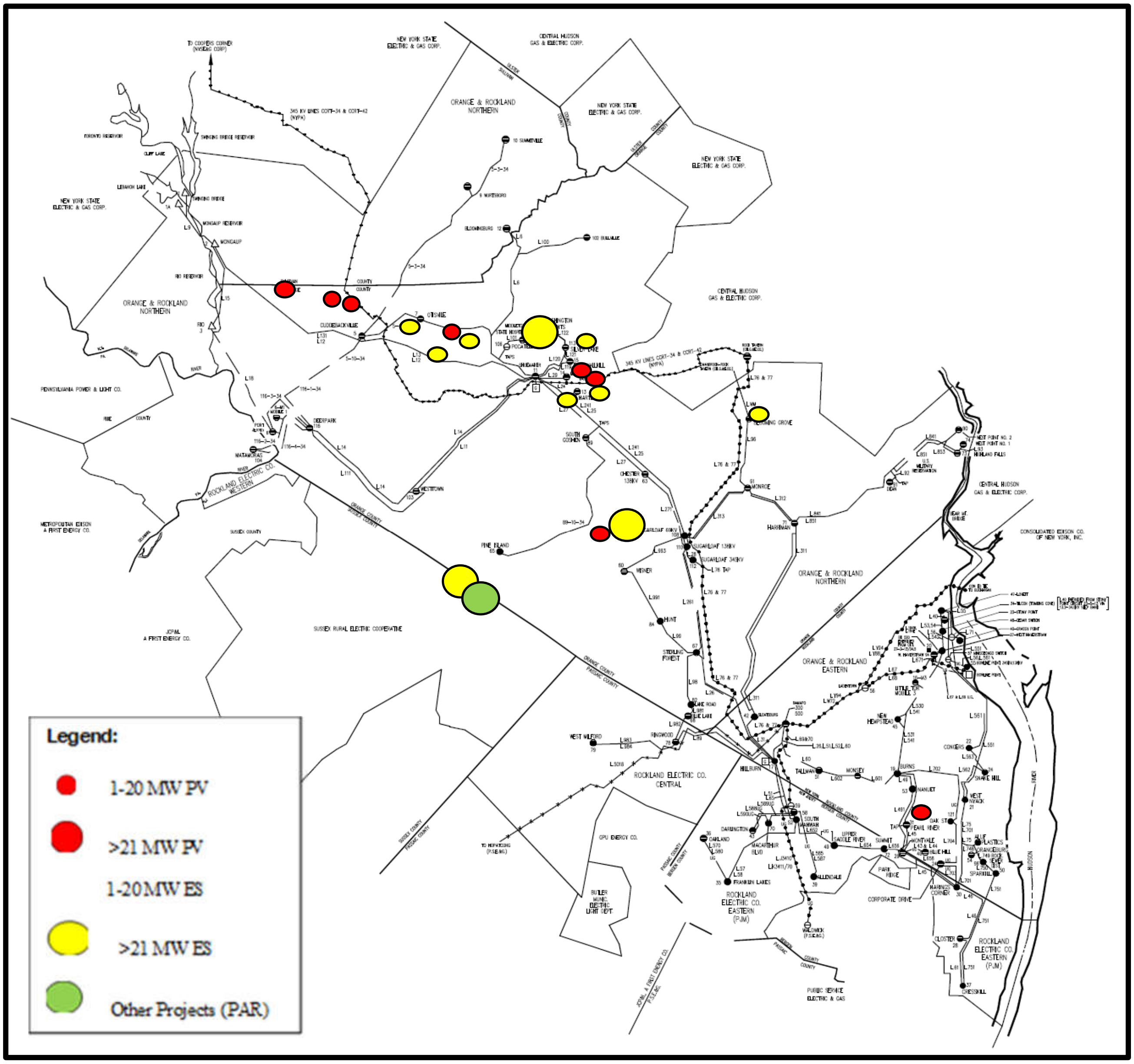
Project Name/Description	Division	In-Service Year	Remarks
Sloatsburg Switch Upgrade	Eastern	2020	Year-end completion date
Line 47/Harings Corner Terminal/Closter Station Re-configuration	Eastern	2020	Year-end completion date
Line 111 Extension into Port Jervis (Port Jervis 69kV)	Western	2021	
Port Jervis Sub 69kV UG Intrastation Tie (Port Jervis 69kV)	Western	2021	
Line 51 Upgrade	Eastern	2023	
Lovett 345 kV Station	Eastern	2023	
West Point 69kV (Upgrade of Transmission Lines 841, 851, and 853 to 69kV Design and Construction)	Central	2025	
Line 705/West Nyack 2nd Auto-bank	Eastern	2027	
New Shoemaker 34.5kV, 69 & 138Yards	Western	2028	High level project scope
Line 120 Extension to Silver Lake to Washington Heights	Western	2029	High level project scope
West Nyack 138kV Yard	Eastern	2030	High level project scope
Harings Corner 138kV Yard	Eastern	2030	High level project scope
Western Division 34.5 kV Sub-transmission upgrade	Western	2030	High level project scope

3. *NYISO Transmission Interconnection Queue*

O&R is currently tracking the NYISO Interconnection Queue with the proposed renewable generation projects, including PV, Energy Storage (“ES”) and other projects. Figure 113 shows the proposed location of all renewable generation projects (as of August 31, 2020). Note that majority of the proposed projects are in the Central and Western Divisions of the O&R service territory.

O&R’s Central and Western Divisions contain current and former farmlands and open spaces that offer opportunities for developers to site their PV and ES projects. Based on this, O&R has developed a flexible investment approach that prioritizes the removal of older transmission facilities while installing system improvements that will provide capacity for normal load growth and accommodate current and future renewable generation projects.

Figure 113: PV, ES and Other Projects (Proposed Location)



iii) Discussion of a possibility of fossil generation retirements and the impacts and potential availability of those interconnection points

O&R owns no generation. However, several large power plants connected to the bulk power system are located within the O&R service territory (*i.e.*, Bowline, CPV Valley). The retirement of these plants will not cause reliability violations in O&R's local transmission system. However, the NYISO is responsible for the reliability studies to determine the impact of these retirements in the bulk power system. Furthermore, approximately 70 MW of small hydro electric and gas turbines exist within the O&R service territory and is connected to O&R's 69 kV and 34.5 kV transmission systems. Because of their relatively small sizes and locations, the retirement of these generators also will not impact O&R's local transmission system.

iv) Discussion of Existing Capacity "Headroom" within O&R's Transmission System

O&R determined the existing headroom capacity in 2020 and compared it with the 2030 "enhanced" summer case. The 2030 "enhanced" summer case included the proposed transmission renewable projects in the NYISO interconnection queue, as well as the 2021-2030 capital transmission projects listed in Figure 113 above. The summary of results and findings is set forth in Figure 114 below. The black numbers indicate the headroom available for that particular equipment. The negative (-) red numbers indicate that the headroom for that particular equipment has exceeded its normal rating.

Figure 114: Capacity Headroom

ELEMENT NAME	TERMINAL STATIONS	AVAILABLE HEADROOM (MW Based on Normal Rating)		RELATED RENEWABLE PROJECTS
		2020 O&R Summer Case	2030 70 x 30 "Enhanced" Summer Case – Added Projects	
Line 4	Shoemaker – Pocatello	2	3	
Line 6	Shoemaker – Pocatello – Decker Switch – Bloomingburg – Wurtsboro	2	6	
Line 100	Decker Switch – Bullville	5	15	
Line 12	Shoemaker -Mongaup	31	-14	PV, ES
Line 13	Shoemaker-Cuddebackville	31	-12	PV, ES
Line 18	Rio-Port Jervis	12	7	
Line 24	Shoemaker- Hartley-Sugarloaf	33	-7	PV
Line 25	Shoemaker-South Goshen-Sugarloaf	33	-35	PV
Lines 26	Ramapo-Sterling Forest	139	-73	AC TRANSMISSION, PV
Line 98	Lake Road-Sterling Forest	12	-18	PV
Line 261	Sterling Forest-Sugarloaf	66	-18	AC TRANSMISSION, PV
Line 312	Harriman-Monroe	18	1	PV
Line 131A	Mongaup- Cuddebackville	31	-13	PV, ES
Line 131B	Mongaup-Cuddeackville	31	-14	PV, ES
5-3-34.5 kV	Cuddebackville – Bullville	-20	-12	Solution: Line 120 Extension (2031)

The study results indicate that available headroom on O&R's transmission system will decrease in 2030 due to the addition of PV and ES projects in the NYISO queue. If left unaddressed, renewable generation connected to these lines would be curtailed under peak load conditions. Even with the addition of other O&R transmission projects through 2030, the headroom deficiency on some transmission lines will remain. As discussed further below, O&R has identified multi-value transmission projects that can help increase the available headroom on the system, thereby unbottling generation on these lines.

v) Discussion of Bottlenecks or Constraints that Limit Energy Deliverability within O&R System

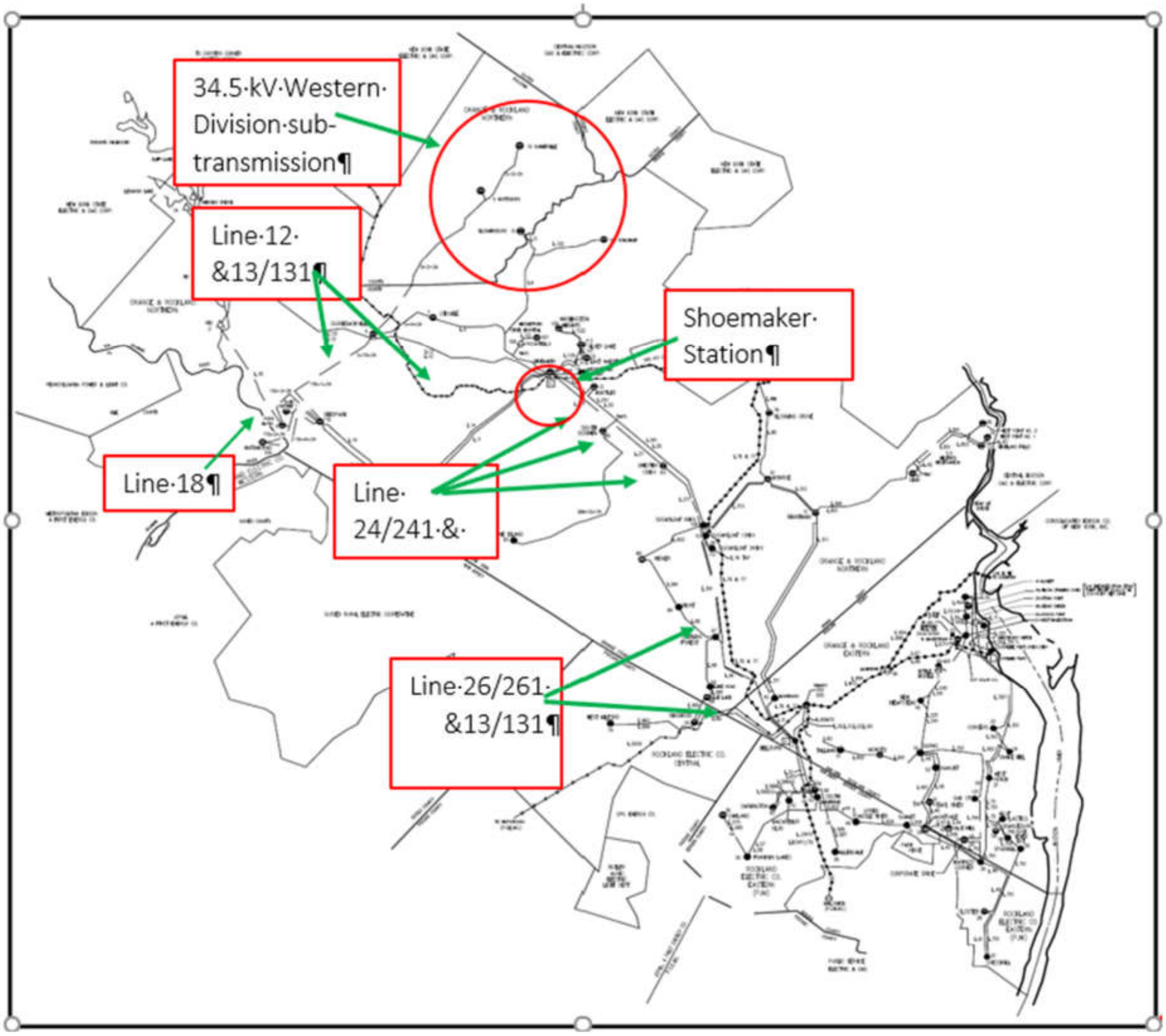
The headroom analysis in Section IV above identifies several lines in the O&R Western Division that develop ratings capacity constraints for future growth of system expansion for potential renewable interconnection.

vi) Discussion of Potential Projects that would Address Bottlenecks or Constraints that limit Energy Deliverability within O&R's System

O&R is well positioned to develop and implement multi-value projects that will enable utility-scale distributed energy resources and storage interconnections, unbottle capacity limited facilities, and facilitate the upgrade of aging and obsolete infrastructure. O&R is informed by the NYISO queue on targeted development areas that align very well with "no regrets" investment containing all the attributes described above. As noted previously, O&R's Central and Western Division contain farmlands and open spaces that offer opportunities for developers to site their PV and ES projects which will assist in meeting CLCPA's targets. O&R has developed a flexible investment approach that prioritizes the removal of older facilities while installing systems that will provide capacity for normal load growth and accommodate renewable projects. This approach will facilitate the achievement of the CLCPA's goals.

O&R believes that the upgrades of the Central and Western Division transmission system qualify for multi-value no regrets investments and will continue to review the best timing for project execution moving forward (see Figure 115). Constraints related to project timing include scheduling constraints to perform obsolescence projects that are difficult to schedule when consideration of higher impact reliability jobs take priority.

Figure 115: Location of Proposed Phase 1-CLCPA Transmission Projects



O&R also must consider other constraints for the challenging process of upgrading existing facilities while maintaining continuity of service.

The projects listed below, with the exception of the upgrade of the 34.5 kV Western Division sub-transmission system and Shoemaker 138kV and 69kV Station Upgrade, are not currently part of O&R's 10-year plan but have been identified by O&R as potential future projects that will replace aging infrastructures, support load growth and allow the integration of renewables. As noted above, O&R's flexible investment approach focuses on multi-value Phase 1 transmission projects, which are set forth in Figure 116 below. O&R did not identify any Phase 2 transmission projects in its study.

Figure 116: O&R Phase 1 CLCPA Transmission Projects

Project Name	Zone	Terminal A	Terminal B	Project Description	Proposed I/S Date	OOM ($M)	NET MW BENEFIT
TL Lines 12 & 13/131*	G	Shoemaker	Cuddebackville, Mongaup	Upgrade of 69kV Transmission Lines 12 & 13/131	2027		109
Shoemaker 34.5, 69 and 13kV Station Upgrade*	G	Shoemaker	Shoemaker	Upgrade of Shoemaker Station	2028		-
Western Division 34.5 kV System	G	Shoemaker	Pocatello – Decker Switch- Bloomingburg -– Wurtsboro	Upgrade of 34.5 kV Western Division sub-transmission system	2029		50
TL Line 18 to 69kV	G	Rio	Port Jervis	Upgrade of 34.5kV Line 18 to 69kV	2030		99
TL Lines 24/241 & 25	G	Shoemaker	South Goshen, Hartley Road, Sugarloaf	Upgrade of 69kV Transmission Lines 24/241 & 25	2033		98
TL Lines 26 and 261	G	Sugarloaf	Sterling Forest, Ramapo	Upgrade of 138kV Transmission Lines 26 and 261	2036		144
					Total:	$417	500 MW

* These projects have spending in the upcoming proposed ORU rate case for 2022 through 2024.

1. *Upgrade of 69kV Transmission Lines 12 & 13/131*

Line 12 (Shoemaker-Mongaup) and Line 13/131 (Shoemaker-Cuddebackville-Mongaup) are parallel 69 kV transmission lines built in 1927. The foundations of the lattice towers that support these facilities are direct embedded grillages which are prone to deterioration over time. In addition, Figure 116 above shows that headroom on lines 12, 13, 131A, and 131B will decrease to -12-14 MW by 2030 due to the addition of PV and ES resources anticipated, based on the NYISO queue, as well as load growth in the area. To increase headroom, O&R would replace these lines, eliminating the existing 4/0 copper conductor, and constructing the new facilities with 795 MCM ACSR or larger conductor. The capacity increase in Line 12 & Line 13/131 will significantly improve their available headroom to unbottle current renewable projects, as well as future generation projects in the area that are planning to interconnect to these lines.

2. *Upgrade of Shoemaker 34.5, 69 and 138kV Substations*

The original 69kV Shoemaker Substation went into service in the early 1930's and has been in continuous service serving the Western Division. Currently the 69kV yard serves the local distribution system, as well as a switching station connecting to 14 other substations. During the 1950's, as the load continued to grow, O&R constructed a 34.5kV yard to serve the Western Division. In the 1970's, to reinforce the system further, O&R constructed a 138kV yard which currently supplies the 69 and 34.5kV yards. As shown in Figure 114above, Line 4 and Line 6 terminate at these substations and have limited available headroom by 2030. By upgrading the substation, particularly the 34.5 kV yard, it would be possible to terminate larger conductors thereby increasing the capability on these lines. This project calls for the construction of new 138 and 69kV stations adjacent to the existing stations. The preliminary design will consist of two new air insulated stations. The 138kV yard will have two 138/69 kV, 196MVA autotransformers and two 138/13.2kV, 50 MVA distribution transformers supplying a switchgear line up. In addition, there will be 138/34.5kV, 50MVA autotransformer to supply a new 34.5kV switchgear. The 138 and 69kV yards will have new control buildings. O&R will construct the new stations on property presently owned by O&R.

3. Upgrade of 34.5 kV Western Division sub-transmission system

The 34.5 kV Western Division sub-transmission system is a group of 34.5 kV lines that originate from Shoemaker Station and feed several distribution stations. This group of lines is comprised of Line 4 (Shoemaker – Pocatello), Line 6 (Shoemaker – Pocatello – Decker Switch – Bloomingburg – Wurtsboro) and Line 100 (Decker Switch – Bullville). These lines were built circa 1924 and are supported primarily by wood poles with some lattice towers. Many of the wood poles are original to the line and some of the foundations of the lattice towers that support these facilities have direct embedded grillages which are prone to deterioration over time. Moreover, O&R's study found that system headroom on line 6 will be used up by 2030 due to the addition of renewables and load growth. O&R would rebuild these lines using 795 MCM ACSR or larger conductor. The capacity increase of Line 4, Line 6 and Line 100 will significantly improve their available headroom to allow the interconnection of future generation projects in the area.

4. Upgrade of 34.5kV Line 18 to 69kV

Line 18 is a 34.5 kV transmission line built in 1928 and runs from Rio Station to Port Jervis Station. Line 18 is supported by wood poles and lattice steel towers. Many of the wood poles are original to the line and the foundations of the lattice towers that support these facilities are direct embedded grillages which are prone to deterioration over time. In addition, as shown in Figure 114, Line 18 has only 7 MW of headroom by 2030. To further increase headroom for the future addition of renewables and to meet load growth in the area, O&R would remove the existing 2/0 copper conductors and structures, replacing them with a 69kV line with 795 MCM ACSR or larger conductor. The capacity increase in Line 18 will significantly improve its available headroom to allow the interconnection of future generation projects in the area.

5. Upgrade of 69kV Transmission Lines 24/241 & 25

Line 24/241 (Shoemaker- Hartley-Sugarloaf) and Line 25 (Shoemaker-South Goshen-Sugarloaf) are parallel 69kV transmission lines built in 1929. The foundations of the lattice towers that support these facilities are direct embedded grillages which are prone to deterioration over time. As shown in Figure 114, Lines 24, and 25 have negative headroom of -7 and -35 MW by 2030, respectively, due to the assumed additions of PV and ES, along with load growth. To increase headroom, O&R would replace these lines, eliminating the existing 336 MCM ACSR conductor, and constructing the new facilities with 795 MCM ACSR or larger conductor. The capacity increase of Line 24/241 & Line 25 will significantly improve their available headroom to unbottle current renewable projects, as well as future generation projects in the area that are planning to interconnect to these lines.

6. Upgrade of 138kV Transmission Lines 26 and 261

Lines 26 (Ramapo-Sterling Forest) and 261 (Sterling Forest-Sugarloaf) are 138kV transmission lines built in 1929. The foundations of the lattice towers that support these facilities are direct embedded grillages which are prone to deterioration over time. As shown in Figure 114, lines 26 and 261 have negative headroom of -73 and -18 MW by 2030, respectively, due to the assumed additions of PV and ES, along with load growth. To increase headroom, O&R would replace these lines, eliminating the existing 336.4 MCM ACSR conductor, and constructing the new facilities with 795 MCM ACSR or larger conductor. The capacity increase of Lines 26 and 261 will significantly improve their available headroom to allow the interconnection of future generation projects in the area.

vii) Potential Projects that would Increase Capacity on the Local Transmission and Distribution System to allow for Interconnection of New Renewable Generation Resources within O&R's System

In addition to Phase 1 proposed transmission projects identified in Section VI, O&R's Phase 1 proposed distribution projects will be discussed in the Distribution report.

viii) Summary of Transmission Projects

This study allowed O&R to develop and plan for multi-value projects that will enable utility-scale distributed energy resources and storage interconnections, unbottle capacity limited facilities, and facilitate the upgrade of aging and obsolete infrastructure. O&R used the NYISO's transmission renewable projects queue to align its "no regrets" investment. Therefore, O&R recommends the following O&R transmission projects to support the CLCPA:

1. Upgrade of 69kV Transmission Lines 12 & 13/131;
2. Upgrade of Shoemaker 34.5, 69 and 138kV substation;
3. Upgrade of 34.5 kV Western Division sub-transmission system;
4. Upgrade of 34.5kV Line 18 to 69kV; and
5. Upgrade of 138kV Transmission Lines 26 and 261.

B. Distribution

i) Introduction

To achieve the clean energy goals outlined in the CLCPA, significant local transmission and distribution investment will be required to eliminate system constraints that inhibit the interconnection of DER, increase transmission and distribution hosting capacity, and provide the necessary headroom to support the anticipated load due to beneficial electrification.

Each year, O&R invests significant capital resources in well-prioritized traditional infrastructure improvements designed to improve system reliability, address aging or obsolescent equipment, and provide for the future capacity needs of the communities we serve. As per the May 14 Order, O&R considered the following:

- Determine where existing "headroom" exists on the system;
- Identify existing constraints/bottlenecks that limit energy deliverability;
- Identify synergies with the traditional capital investment plan to identify multi-value projects;
- Identify new/emerging technologies that can accompany or completement traditional upgrades;
- Identify least cost upgrade projects to increase the capacity of the existing system;
- Identify new projects which would increase capacity and allow for interconnection of new renewable generation sources; and
- Identify the possibility of fossil generation retirements.

To determine where existing headroom exists, O&R conducted a planning analysis at the substation level using the 2030 base (business as usual) summer peak forecast.[157] To identify any gaps between the base forecast and the 70x30 CLCPA goals, O&R compared modifier assumptions in the base forecast to the CLCPA projections in O&R's Long-Range Plan ("LRP"). As a result, O&R used a higher EV adoption rate for this analysis (see Figure 117). To determine available 'headroom' by substation, O&R conducted a planning analysis to determine the maximum load each station can support while still meeting the Distribution Design Standards for loss of bank.

[157] Based on 2019 Summer Peak Forecast.

Figure 117:. 2030 Base Case versus CLCPA Modifier Assumptions

Load Modifier	2030 Base Forecast Assumption	2030 CLCPA Assumption	Comment
EV	68MW	214MW	~146MW additional EV considered
Space Heating	None	None	System remains summer peaking in 2030. Additional sensitivity analysis performed for later years 2030+.
PV	76MW (coincident), 321MW (nameplate)	Same	PV forecast includes adoption assumptions for small projects (<50kW) plus 100 percent of DER queue
EE	154MW (includes 10MW DR and 7MW of Organic EE)	Same	EE Reduction assumptions same for base versus CLCPA forecast.
Storage	81MW (83MW Nameplate)	Same	Storage assumptions same for base case versus CLCPA forecast
DG/CHP	29MW	Same	DG/CHP assumptions same for base case versus CLCPA forecast

In addition to the CLCPA 70x30 case, O&R performed additional sensitivity analysis in O&R's LRP to determine the impact of the 2040 and 2050 CLCPA goals. While O&R identified no additional projects at this time, assumptions regarding adoption rates, technologies, and policy may drive the need for future capital projects to support winter peaking loads beyond 2030.

As seen in

Figure 118, O&R identified fourteen NY substations with potential “headroom” issues by 2030, due to either base load growth or higher EV adoption rates. O&R then compared these results to the current ten-year capital investment plan to determine synergies with existing projects and/or programs. As shown in Figure 119, constrained areas align well with existing budgeted projects.

Figure 118:. 2030 Summer Peak Substation Base Forecast with Incremental CLCPA EV Load

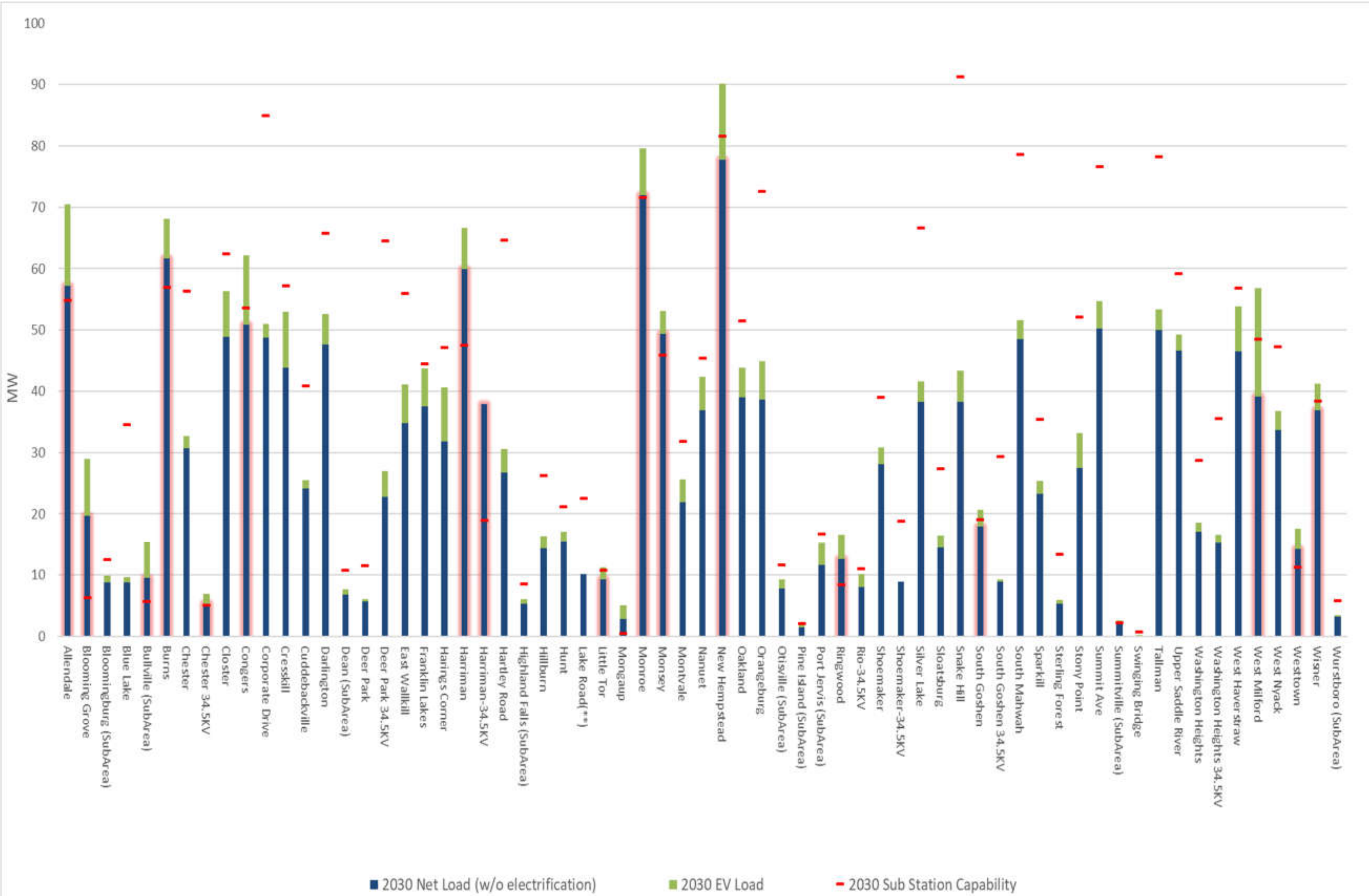


Figure 119: NY Distribution Substations with Potential 2030 Capacity Constraints

Substation	Solution	Budget Year
Blooming Grove	New Blooming Grove Substation	2023
Bullville	Bullville Substation Upgrade	2027
Burns	Burns 3rd Bank/Upgrade remaining two banks & switchgear	2026/2028
Chester 34.5kV	New South Goshen Station will provide relief to S Goshen 34.5kV which will increase backup to Chester 34.5kV	2032
Congers	Little Tor Substation/Congers Bank & Switchgear Upgrades	2023/2030
Harriman	Woodbury Substation/Harriman Upgrade	2025/unbudgeted
Harriman 34.5kV	Line 841/851 Upgrade	Currently in Study Phase
Little Tor Mobile	Little Tor Substation	2023
Mongaup	Mongaup Upgrade	unbudgeted
Monroe	Woodbury Substation	2025
Monsey	Monsey NWA	In progress
New Hempstead	Little Tor Substation/Burns 3rd Bank	2023/
South Goshen	New South Goshen Substation	2032
Westtown	Westtown 2nd Bank	2029
Wisner	W. Warwick NWA/W. Warwick Substation	In progress/2028

Consistent with the May 14 Order, O&R also considered constrained areas or areas with known bottlenecks. Due to the high penetration of distribution sided resources in O&R's Western Division, the Westtown and Bullville Substations are at/near maximum hosting capacity based on the full interconnection queue. O&R recommends the upgrade of these stations as Phase 1 projects. These upgrades will eliminate bank/circuit thermal capacity constraints and allow increased interconnection of DERs in these areas. Bullville is also limited by the existing 34.5kV sub-transmission system that supplies the station. Upgrade of these lines (see Western 34.5kV upgrades in the transmission portion of this document) is also required to reach the full hosting capacity of the substation.

The May 14 Order also directs the Utilities to identify new technologies that can accompany/complement traditional upgrades. This approach was taken with several of the Phase 1 recommended projects. The Bullville, Blooming Grove, and Woodbury substation projects will be traditional investments designed with an area reserved for on-site energy storage. O&R envisions that this 'hybrid' approach can leverage battery technology to capture excess local generation, reduce peak loading on equipment, and improve load factor. This additional storage capability is critical to achieving CLCPA targets for storage and balancing the bi-directional flow of energy. In addition, the proposed Woodbury Battery project will use a mobile battery technology to reduce local circuit peak to support new area load growth until the new Woodbury substation is constructed. See Phase 1 project descriptions for additional detail on these projects.

In addition, O&R has been modernizing its electric delivery system for over 15 years by investing in key systems and technologies directly in line with its Distributed System Implementation Plan ("DSIP"). This includes smart grid automation, Distribution Supervisory Control and Data Acquisition Systems ("DSCADA") and Advanced Distribution Management System ("ADMS"), a robust communication plan, and Advanced Metering Infrastructure ("AMI"). O&R views these systems and technologies as critical to improving the safety, reliability, and operation of the distribution system as well as foundational investments in the transition to Distributed System Platform ("DSP") provider. O&R views implementation of these technologies as critical to support the CLCPA and Reforming the Energy Vision ("REV") goals (see Figure 120). Additional detail on the Companies programs can be found in the 2020 DSIP filing.

Figure 120:. Grid Modernization and DSP Investment

Program/Project	2021	2022	2023	2024	2025	Commentary/Work Plan
MOAB Upgrade Program	$1.2M	$1.2M	$1.2M	$1.2M	$1.2M	Replace manual field switches with DSCADA controlled motor operated switches
DA Smart Grid Expansion Projects NY	$4.5M	$8.3M	$8.3M	$8.3M	$8.0M	Deploy Smart Grid Automation (Reclosers/MOABS)
NYSERDA PON 4074	$0.8M	$1.1M	$0.2M	-	-	Westtown Automation
ADMS	$4.5M	$6.8M	$4.7M	-	-	ADMS system
ADMS – Phase 2 (DERMS)	-	-	$3.9M	$1.5M	$1.5M	DERMS
Grid Mod 4G-5G	$1.5M	$1.2M	$1.2M	$1.2M	$1.2M	Communication
DA RTU Replacement	$0.08M	$0.6M	$0.8M	$1.2M	$1.6M	DSCADA RTU Upgrades
Total	$12.6M	$19.2M	$20.3M	$13.4M	$13.5M	

O&R also continues its foundational Clean Energy initiatives detailed in its 2020 DSIP Plan that includes Grid Modernization projects, non-wires alternatives, EV make ready programs and Bulk Storage solicitations. The five (5) year spending plan is shown in Figure 121.

Figure 121: CLCPA Initiatives

Program/Project	2021	2022	2023	2024	2025	Commentary/Work Plan
Non-Wires Alternative Solutions	$5.4M	$44.1M	$40.7M	$4.6M	$4.7M	Pomona Monsey West Warwick Hillburn Mountain Lodge Park Sparkill
EV Make Ready Infrastructure Program	$5.2M	$5.2M	$5.2M	$4.2M	$4.2M	Make Ready Incentives Future Proofing Fleet Assessment Service Implementation Costs
Bulk Storage Solicitation	$1M	$1M	$14M	-	-	
Total	$11.6M	$50.3M	$59.9M	$8.8M	$8.9M	

ii) Non-Wires Alternatives (“NWA”)

O&R envisions NWA to be an integral part of deploying DERs to achieve CLCPA goals. Currently New York State is ranked #1 for NWA in the country. O&R will continue to execute NWA projects to further the State’s goals of deploying DERs and integrating it with their overall system planning and system operations.

O&R continues to pursue NWA projects where non-traditional technology can be used to address system constraints and defer traditional capital investment. Over the next five years, O&R is investing approximately $99.5 million in six NWA solutions (see Figure 121). Additional detail regarding each of these proposed NWA projects can be found in the 2020 DSIP filing.

iii) EV Make Ready Infrastructure Program

Over the next five years O&R is planning to spend approximately $24 million on the electric vehicle (“EV”) make-ready investments (see Figure 121). Additional details can be found in O&R’s EV Make Ready Implementation Plan. The Make Ready Infrastructure will support the State’s goal to deploy 850,000 EVs by 2025.

iv) Bulk Storage Solicitation

The Commission mandated that O&R procure 10MW of storage as part of a Bulk Solicitation initiative. O&R’s first round solicitation did not yield any winning vendors. O&R has conducted multiple rounds of review with vendors, Commission and NYSERDA to understand how to amend its RFP to meet the market needs. O&R is on track to issue a new RFP for the Bulk Storage Solicitation in Q2, 2021. This $16 million investment in ES will advance the CLCPA’s goals for energy storage.

v) Phase 1 Distribution Projects

Based on the multi-value approach O&R has taken with the study, all the recommended distribution projects in this Report are being considered Phase 1 (projects included in O&R's capital plan). To address the CLCPA's goals, many of the designs have been modified to facilitate DER interconnection, increase hosting capacity and support future beneficial electrification. Where appropriate, new substations are being designed with provisions for future on-site ES to advance the CLCPA's goals and balance the bi-directional flow of energy. This ES will be used to capture local excess generation, reduce station peak load and improve load factor. No new Phase 2 projects were identified, and retirement of fossil fuel generation does not apply to O&R.

As stated in the Transmission study section of this Report, O&R's Central and Western Divisions contain farmlands and open spaces that offer opportunities for developers to site their PV and ES projects which will assist in meeting the CLCPA's targets. O&R has developed a flexible investment approach that prioritizes the removal of older facilities while installing systems that will provide capacity for normal load growth and accommodate renewable projects. Figure 122 details O&R's Phase 1 project portfolio.

Figure 122: O&R Phase 1 CLCPA Distribution Projects

Project Name	Related CLCPA Transmission Project	Project Description	Proposed I/S Date	OOM ($M)	Net MW Benefit
Bullville Substation*	Western Division 34.5 kV System	Upgrade existing 25MVA single bank substation with provisions for modular utility owned storage.	2027		33
Bloomingburg Substation	Western Division 34.5 kV System	Upgrade existing 20MVA single bank substation	2030		38
Wurtsboro Substation	Western Division 34.5 kV System	Upgrade existing 5MVA single bank substation and convert 4.8kV area	2029		30
Rio Substation	Line 18	Upgrade existing 18MVA single bank substation	2030		21
Shoemaker Substation	Shoemaker Campus Upgrade	Construct new 138kV transmission yard and upgrade existing 35MVA single bank substation	2028		41
Blooming Grove Substation*	NA	Upgrade existing 25MVA single bank substation with provisions for modular utility owned storage.	2023		51
Woodbury Substation*	NA	New Substation to support load growth, reliability, and hosting capacity in the Harriman Area (Monroe, Blooming Grove, Woodbury, Harriman).	2025		76
Woodbury Batteries*	NA	Utility owned batteries to support area growth that could potentially have mobile capability to interconnect into future substations.	2023		-

Project Name	Related CLCPA Transmission Project	Project Description	Proposed I/S Date	OOM ($M)	Net MW Benefit
Westtown Second Bank/UG Exits	NA	Improve reliability for loss of Bank 1103 and increase hosting capacity in this area (bank limitation reached).	2029		18
			Total	156	308

* These projects have spending in the upcoming proposed ORU rate case for 2022 through 2024.

1. *Bullville Substation*

The Bullville Substation is a single-bank station on the edge of the service territory with one 25MVA, 34.5/13.2kV transformer serving three 13.2kV distribution circuits. The 34.5kV feed to the station is radial from Line 100 with manual backup from a long 34.5kV distribution circuit. The ability for this station to serve load and host DER is currently limited by the 34.5kV sub-transmission system.

Once the 34.5kV transmission system is upgraded (see Western Division 34.5kV CLCPA transmission project), the constraint will become the single 25MVA transformer. To address station reliability, age and obsolescence issues, and minimum approach distance (“MAD”) concerns, the station is budgeted to be upgraded to a two-bank station in 2027.

The new station will have two larger 35MVA banks with additional circuits to support reliability and improve DER hosting capacity. Additional space at the substation site will be reserved for future on-site ES. This ES will be sized to store excess generation during the day which can be discharged in the evening to reduce station peak and improve station load factor.

Estimated Substation DER Hosting Capacity Increase: 33MW

2. *Bloomingburg Substation*

The Bloomingburg Substation is a single bank station with one 20MVA, 34.5/13.2kV transformer serving two 13.2kV distribution circuits. The ability for this station to serve load and host DER is currently limited by the station bank/circuit capacity. The 34.5kV feed to the station is radial from a long 34.5kV circuit that also serves area load directly. Transmission backup is automatic from another long radial 34.5kV circuit that serves two substations and distributed load. Once the 34.5kV transmission system is upgraded (see Western Division 34.5kV CLCPA transmission project), the station will be supplied from the new reliable transmission loop. To address station reliability, age and obsolescence issues, and MAD concerns, the station is budgeted to be upgraded to a two-bank station in 2030. The new station will have two larger 35MVA banks with additional circuits to support area reliability and improve DER hosting capacity.

Estimated Substation DER Hosting Capacity Increase: 38MW

3. *Wurtsboro Substation*

The Wurtsboro Substation is a single bank station with one 5MVA, 34.5/4.8kV transformer serving two 4.8kV distribution circuits. The ability for this station to serve load and host DER is severely limited by the 4.8kV area operating voltage, small bank size, and circuit capacity. The 34.5kV feed to the station is radial from a long 34.5kV circuit that also serves one additional substation and other area load directly. Transmission backup is automatic from another long radial 34.5kV circuit that serves one substation and other distributed load. Once the 34.5kV transmission system is upgraded (see Western Division 34.5kV CLCPA transmission project), the station will be supplied from the new reliable transmission loop. To address station reliability, age and obsolescence issues, and MAD concerns, the station is budgeted to be upgraded in 2029. The new station will have provisions for two banks. One 35MVA transformer will be installed initially, with the ability to install a second when needed to support area load/DER hosting capacity. Other area projects are currently planned to begin the conversion of the area from 4.8kV to 13.2kV to improve reliability, hosting capacity, and prepare for the future station upgrade.

Estimated Substation DER Hosting Capacity Increase: 30MW

4. *Rio Substation*

The Rio Substation is a single-bank station on the edge of the service territory with one 18MVA, 69/34.5kV transformer (Bank 53) serving one 34.5kV distribution circuit. For loss of Bank 53, 34.5kV Line 18 can provide 100 percent bank backup. In 2010, to improve circuit reliability, O&R installed two 5 MVA, 34.5/13.2kV transformers outside the Rio substation and part of the Rio load area was converted to 13.2kV. Each transformer supplied one 13.2kV circuit allowing the load area to be split and distribution automation to be installed. This significantly improved area reliability and prepared for the future upgrade of the Rio Substation. Although Bank 53 has a higher rating, the 5MVA banks limit the ability of the station to serve load and host DER. With the proposed upgrade of Line 18 (see Upgrade of 34.5kV Line 18 to 69kV CLCPA Transmission Project), Rio will no longer have backup for loss of Bank 53. To meet Design Standards, during the upgrade of Line 18 the station will be upgraded to a two- bank design. The new station will have two larger 20MVA banks with additional circuits to support reliability and improve DER hosting capacity. At that time, the 5MVA transformers will be removed significantly increasing area hosting capacity.

Estimated Substation DER Hosting Capacity Increase: 21MW

5. *Shoemaker Substation*

The Shoemaker Substation is an energy hub located in the Western Division of O&R's service territory. The existing campus includes transmission yards operating at 138kV, 69kV, and 34.5kV. The 69kV yard is the most critical transmission station in the Western Division. Nearly all of the Western Division Substations are supplied either directly or indirectly from the 69kV yard.

In addition, the area is experiencing high interest from developers to interconnect BESS/PV projects at both the distribution and transmission level.

Due to age (civil conditions), equipment obsolescence, and to improve both transmission and distribution reliability, the Shoemaker campus is scheduled to be rebuilt in 2028 (see Shoemaker Station Upgrade CLCPA Transmission Project). The upgraded station will also function as an area 'clean energy hub' by redistributing excess green energy from area stations with lower load to locations of higher demand.

As part of the upgrade, the existing 35MVA, 69/13.2kV transformer will be replaced with two 50MVA, 138/13.2kV transformers with five additional circuit positions to support area reliability and improve DER hosting capacity.

Estimated Substation DER Hosting Capacity Increase: 41MW (distribution only)

6. *Blooming Grove Substation*

The existing 69kV Blooming Grove Substation is a single bank substation with one 25MVA, 69/13.2kV transformer serving four 13.2kV distribution circuits. The northern portion of the load area served by Blooming Grove borders Central Hudson's service territory. This limits distribution tie capability to the two circuit ties to the south (along Routes 94 and 208). Due to the limited switchable backup, the station does not meet the distribution design standard for loss of bank.

In late 2018, O&R issued an NWA request for proposals to solve for the loss of Bank 276. While O&R received several proposals, a thorough third-party and internal review determined that none were technically viable and/or in the spirit of New York State's REV initiative as they relied heavily on fossil fuel generation. As a result, the traditional solution was re-prioritized in the budget and is currently scheduled for completion in 2023.

To address station reliability, age and obsolescence issues, and MAD concerns, the station is budgeted to be upgraded to a two-bank station in 2023. The new station will have two larger 50MVA banks with additional circuits to support reliability and improve DER hosting capacity. Additional space at the substation site will be reserved for future on-site energy storage. This storage will be sized to store excess generation during the day which can be discharged in the evening to reduce station peak and improve station load factor.

Estimated Substation DER Hosting Capacity Increase: 51MW

7. *Woodbury Substation*

A new area substation is required by June 2026 to meet the projected demand in the rapidly growing municipalities of the Village/Town of Monroe, Woodbury, Palm Tree, and Harriman. O&R has evaluated several area parcels and is working to secure a site. The overall project scope includes the construction of the new Woodbury Substation, the underground transmission extension of existing 69kV Transmission Line 312 to feed the new substation, and the associated new substation distribution circuit exits.

The new station will be constructed with two 50MVA, 69/13.2kV transformer banks with provisions to install a third future transformer. The switchgear will be designed with 15 circuit positions to support area load growth, reliability, and improve DER hosting capacity. At this time, natural gas service may not be available to several of the proposed subdivisions. To support the potential for additional electric load due to electric heating, the station is being designed with larger transformers, additional circuit positions, and the ability to expand the station.

An area at the substation site will be reserved for future on-site ES to reduce station peak demand and improve station load factor as local DER penetration increases.

Estimated Substation DER Hosting Capacity Increase: 76MW

8. Woodbury Batteries

A new area substation (see Woodbury Substation project) is required by June 2026 to meet the projected demand in the rapidly growing municipalities of the Village/Town of Monroe, Woodbury, Palm Tree, and Harriman. Until the substation project is completed, approximately 3MW/12MWH mobile batteries are needed at two locations to meet the peak load in this area. This load relief will prevent thermal issues on existing equipment and allow O&R to meet projected load demand until completion of the proposed Woodbury Substation in 2026. At that time, the batteries will no longer be required at that location and can be re-used at other locations or stored for future use.

Estimated Substation DER Hosting Capacity Increase: N/A

9. Westtown Second Bank/UG Exits

The Westtown Substation is a single-bank station with one 35MVA, 69/13.2kV transformer serving four 13.2kV distribution circuits. Although the 2019 WN peak load on the station was only 12.4 MVA, the bank is currently closed to new large DER interconnections to prevent thermal violations of the bank. While the station currently passes the Design Standard for loss of bank, it has limited outside ties which make the station difficult to offload for emergency or scheduled work. Due to the high penetration of DER in the area, additional distribution switching is usually required to disconnect large generators before transferring load between circuits/stations.

To improve area reliability and re-open the station to new DER interconnections, a second 35MVA transformer should be installed with four additional circuit positions. O&R will install new underground exits as part of the project to reduce circuit exposure and unbottle DER hosting capacity on constrained circuits. The existing station is already constructed to accept a second bank. Additional work is needed to modify or replace the existing switchgear and install new underground exits.

Estimated Substation DER Hosting Capacity Increase: 18MW

vi) Conclusion

Orange and Rockland has provided details for proposed Transmission and Distribution Phase 1 type projects that can be seen as multi-value with no regrets. The projects will enable renewable generation interconnection as well as remedy the condition of aging assets. While the vast majority of the projects are in the current ten (10) year budget plan, O&R has included incremental Transmission investment in the next proposed rate case for our January 2021 filing (first rate year 2022). This includes the Line 12/13/131 upgrade project, which is the first of several 69kV projects scheduled for upgrade.

The remaining CLCPA Phase 1 Distribution projects are in alignment with O&R's base budget plan with no acceleration proposed in the upcoming rate case.

Part 3: Advanced Technologies Working Group

I. INTRODUCTION

The goal of the Advanced Technologies Working Group (ATWG) is to develop plans for the Utility Transmission and Distribution Investment Working Group to further the goals of the Climate Leadership and Community Protection Act (CLCPA) by considering roles and opportunities for grid investments in advanced technologies that apply to the Utilities, transmission owners, and operators. The working group focuses on developing research and development plans for new and/or underutilized technologies and innovations necessary to meet and advance New York's clean energy goals. The context for the ATWG's initial focus are:

I. The transmission system, especially the sub-transmission system (138/115 kV) and below.
II. The 70% renewable energy by 2030 targets.

II. OBJECTIVE

To address these goals, the working group is developing plans to study, evaluate, pilot, demonstrate, and deploy new and/or underutilized technologies and innovations that are able to increase electric power throughput, increase electric grid flexibility, increase renewable energy hosting capacities, increase the electric power system efficiencies and reduce overall system costs. Among the questions being considered are the following:

- Are there existing technologies that can improve the efficiency of the grid that are being underutilized?
- Are there research and development opportunities for new or emerging technologies?
- How should we organize the State's research and development effort?
- How do we coordinate work with other State, National, and International research and development stakeholders (EPRI, Universities, National Labs, DOE, ARPAe, etc.)?
- How do we coordinate this work with the other technical analysis and policy working group teams?
- How will the Utilities integrate new technologies into planning and operations?

III. PRIORITIZED ISSUES

The group has prioritized several issues as being key to achieving CLCPA goals. These include the need to:

- Alleviate transmission system bottlenecks to allow for better deliverability of renewable energy throughout the State,
- Unbottle constrained resources to allow more hydro and/or wind imports and the ability to reduce system congestion,
- Optimize utilization of existing transmission capacity and right of ways, and
- Increase circuit load factor through dynamic ratings.

To address transmission system bottlenecks, the group has developed a list of potential technology solutions that could include:

- Utilizing energy storage for transmission and distribution services,
- Investigating low-frequency AC transmission systems,
- Utilizing high voltage DC grids,
- Utilizing and coordinating deployment of flexible AC transmission system components,
- Utilizing dynamic and ambient adjusted transmission line and cable rating systems,
- Utilizing dynamic, closed-loop voltage and reactive power controls,
- Improving operator situational awareness,
- Utilizing wide-area monitoring systems,
- Developing new decision support tools,
- Developing new advanced energy management automation,
- Developing new advanced contingency analysis tools,
- Utilizing dynamic power flow controllers, and
- Developing new renewable energy siting tools.

To address the optimized utilization of existing transmission capacity and rights of way, the group has developed a list of potential technology solutions that could include:

- Transformer, cable and transmission line monitoring systems,
- Advanced sensor placement tools,
- Advanced transmission and sub-transmission voltage regulation systems,
- Dynamic line and equipment rating systems,
- Energy storage for grid services,
- Advanced high-temperature-low-sag conductors and new composite conductors,
- New compact tower designs,
- Power flow controllers,
- Global information system utilization,
- Sulfur hexafluoride monitoring and alternative systems,
- Modular solid-state transformers and other advanced grid control devices, and
- Improved ability of transmission lines to redirect flow to underutilized lines.

IV. POTENTIAL TECHNOLOGY SOLUTIONS

The working group engaged the Electric Power Research Institute (EPRI) to develop potential technology solution summaries for the highest prioritized technology categories which included an overview of their technologies, key application considerations, their commercial readiness level, vendor landscape, and field/lab testing experience. The developed summary information, use cases, and/or case studies for these solutions categories included: dynamic line ratings and improved transmission utilization; power flow control devices and distributed or centralized flexible AC transmission systems (FACTS); energy storage for transmission and distribution services; improved operator situational awareness; transformer monitoring; advanced high-temperature, low sag conductors; compact tower designs; and sulfur hexafluoride or alternative fluid monitoring systems. Below is a brief overview of each of the potential technology solution summaries.

A. Dynamic line ratings and improved transmission utilization:

There are several factors, including line clearance, thermal rating limits, contingency conditions, that contribute to the overall rating of a transmission line. While other solutions exist for increasing capacity, many efficient solutions have been exhausted or are not feasible. For example, re-tensioning a line can be used to mitigate clearance concerns. However, the conductor, tower, and foundations must all be capable of supporting increased mechanical load for this to be a viable option. Increasing tension can also lead to vibration issues which are detrimental to conductor health if mitigation methods are not deployed. Real time or dynamic rating technologies seek to leverage the time-varying changes in the environment. Utilities using static ratings have more capacity available most of the time due to the conservative nature of the rating method. A static rating is simplest for design and operations as it never changes. The rating today is the same as the rating tomorrow. The odds of the true capacity of the line being lower than a static rating defines the rating risk. Ratings risk tolerance varies by utility and can vary within a utility transmission system. Case studies and available literature show that most utilities would have additional capacity available between 80% and 99% of the time. The amount of extra capacity depends on the real time weather conditions and is examined in the technology summary.

B. Power flow control devices – distributed and centralized FACTS:

Power flow control devices, in addition to traditional transmission technologies, provide a suite of alternatives to direct the flow of power more efficiently on the grid, improving flexibility and enabling the grid to be more responsive and resilient. Traditional technology solutions to control power flow—such as phase-shifting transformers (PSTs)—have been used extensively for reducing loop flows or to maintain scheduled power flow on certain paths. They have also been used in some cases to reduce overloads by diverting power flow from heavily loaded lines to other lines with spare capacity, increasing the utilization of existing transmission assets and consequently reducing the need for certain transmission upgrades. In recent years, new power flow control technologies have been developed. Relative to the more traditional power flow technologies such as PSTs, flexible AC transmission systems (FACTS), and high voltage direct current (HVDC) technologies, the new PFC devices are simpler, more compact, and scalable. Some of these new PFCs have great potential but still are at an intermediate stage of development, while others are already commercially available, such as the distributed series compensator technology, developed and commercialized by vendors.

C. Energy storage for T&D services:

Energy storage is increasingly being considered for many transmission and distribution (T&D) grid applications to potentially enhance system reliability, support grid flexibility, defer capital projects, and ease the integration of variable renewable generation. Central to the State's policies and mandates is the need to enhance power system flexibility to effectively manage renewable energy deployment and the associated increase in variability. As power systems begin to integrate higher penetrations of variable, renewable, inverter-based generation in place of conventional fossil-fuel fired synchronous generation, grid-scale energy storage could become an increasingly important device that can help maintain the load-generation balance of the system and provide the flexibility needed on the T&D system. Pumped hydro storage (PHS) and compressed air energy storage (CAES) are long-established bulk energy storage technologies. Utility-scale lithium ion battery storage has expanded dramatically, as decreasing lithium ion battery costs make this an increasingly cost-effective solution to meet T&D non-wire, reliability, and ancillary service needs. Redox flow batteries, sodium sulfur batteries, thermal energy storage (both latent and sensible heat), and adiabatic compressed air energy storage are all in various stages of demonstration. This information provides a concise overview of a wide variety of existing and emerging energy storage technologies being considered for T&D systems. It describes the main technical characteristics, application considerations, readiness of the technology, and vendor landscape. It also discusses implementation and performance of different energy storage technologies. In this Report, energy storage systems greater than 10 MW and four or more hours of duration, are considered as bulk and transmission and sub-transmission-connected energy storage.

D. Improved operator situational awareness:

Recent changes and trends in electrical energy—both on the generation side, with increasing levels of electricity generation from renewable energy sources such as wind and solar, and on the energy consumption side, with new and more efficient consumption technologies—are changing use patterns and dynamical characteristics of the entire infrastructure. Traditional situational awareness tools available to system operators in the energy management system (EMS) will not be adequate due to a stochastic environment with faster dynamics resulting from these changes. Developing advanced analytical tools to perform system security analysis and based on that provide integrated decision support solutions using cognitive systems engineering to the system operators will be necessary. This section discusses some of the advanced situational awareness tools in various stages of technology readiness being developed to meet the future needs. Some of the tools discussed are those using synchrophasor technology, dynamic security analysis, advanced short-term forecasting tools for much granular real and reactive power load as well as solar and wind generation, and much faster simulation and analytical tools. In addition, a comprehensive monitoring system would ensure the operators that all the advanced situational awareness tools are functioning as planned.

E. Transformer monitoring:

Large substation transformers that interconnect different voltage levels of the grid are major capital assets that are essential to the reliable delivery of economic power. Transformers can also perform a critical role in supporting utility efforts to increase power flows through existing transmission corridors to optimize grid utilization. Given the importance of transformers in a power system—and their high cost and long lead time for replacement—managing transformer fleets to maintain high levels of health and performance presents ongoing challenges for utilities striving to employ their assets to the fullest extent possible while maintaining system reliability and controlling costs. The challenges are compounded by transformer demographics. A high percentage of installed transformers are approaching or have exceeded their 40-year design lives. Replacing large numbers of these aging assets is neither practical nor financially feasible, so utilities seek to get as much performance and remaining life as possible from their transformer fleets. System abnormalities, loading, switching, and ambient conditions normally contribute to transformer accelerated aging and sudden failure. Therefore, central to transformer management is effective monitoring to gain a comprehensive view of transformer health, which can help utilities assess equipment condition, diagnose incipient degradation, anticipate problems, prevent failures and extend transformer life. Provided results are properly interpreted, monitoring offers intelligence to support repair/refurbish/ replace decisions that maximize performance and minimize costs. In short, monitoring can help utilities ensure that transformers stay healthy and perform critical functions such as supporting sustained additional loads, and not be the weak links in the power delivery chain.

F. Advanced high-temperature, low sag (HTLS) conductors:

More than 80% of bare stranded overhead conductors used in transmission lines consist of a combination of 1350-H19 (nearly pure aluminum, 1350, drawn to the highest temper possible—H19) wires, stranded in one or more helical layers around a core consisting of one or more steel strands. The steel strands are coated by one of several different methods to resist corrosion. By varying the size of the steel core while keeping the cross-sectional area of aluminum constant, the composite tensile strength of aluminum cable steel reinforced (ACSR) conductors can be varied over a range of 3 to 1. The mechanical and electrical properties of ACSR (and all aluminum conductors, such as AAC, AAAC, and ACAR) are quite stable with time, as long as the temperature of the aluminum strands remains less than 100°C. Above 100°C, the work-hardened aluminum strands lose tensile strength with time at an increasing rate with temperature. The steel core strands, however, are unaffected by operation at temperatures up to at least 300°C (although conventional “hot-dip” galvanizing may be damaged by prolonged exposure to temperatures above 200°C). The sag-temperature behavior of ACSR is also dependent on the size of the steel core. At moderate to low conductor temperatures, the thermal elongation rate of ACSR is between that of steel (11.5 micro strain per °C) and that of aluminum (23 micro strain per °C). For example, with Drake ACSR, the thermal elongation is 18.9 micro strain per °C up to a temperature about 70°C but decreases to the thermal elongation rate of the steel core alone (11.5 micro strain per °C) at higher temperatures. High temperature low sag (HTLS) conductors are able to operate continuously at temperatures above 100°C (the HT part) without any reduction in breaking strength. In addition, they exhibit thermal elongation rates that are less than ACSR (the LS part). This characteristic allows the HTLS conductor to sag less than a conventional ACSR conductor at any temperature, especially elevated temperatures.

G. Compact tower designs:

Increasing transmission transfer capacity within existing right of ways is a potentially efficient and economic approach to solving thermal constraints. A compact transmission line may, be defined as a line where the lateral dimensions of the line - tower height, tower width, and minimum right-of-way width - are reduced relative to older existing lines of the same voltage class. There are numerous compact tower designs for horizontal, vertical, and phase compaction that can be considered to increase transfer capacity. The technology summary examines each of the line compaction designs and explores the associated advantages and disadvantages.

H. SF6 monitoring/ SF6 alternatives:

Electric utilities are facing increasing regulatory pressure and technical challenges related to the management of sulfur hexafluoride (SF6), which is widely used as an arc-quenching medium and as electrical insulation in gas-insulated substations (GIS) and gas-insulated lines (GIL). SF6 is a powerful greenhouse gas and at times can produce toxic decomposition products under certain fault conditions. Several countries outside of the United States and some U.S. states have implemented or are considering regulations to limit SF6 emissions above certain thresholds. In addition, alternatives to SF6 have emerged. The twin challenges of increasing regulatory scrutiny and the existence of potential SF6 replacements put the industry on the brink of significant technological disruption in this area. The issues associated with SF6 management and emerging SF6 alternatives are of concern especially for utilities seeking to build new substations and lines to alleviate transmission bottlenecks, reduce congestion and allow delivery of power from renewable sources from remote or distant locations. Gas-insulated substations and lines offer many benefits including compact size, modularity, physical security and protection from pollution and harsh environments. Their compactness and modularity make them especially suitable when new substations are needed in areas where land space is limited and/or expensive, or in communities that desire visually unobtrusive power infrastructure. The industry thus has two high-priority needs regarding GIS/GIL and SF6: effective monitoring and diagnostic technologies to support SF6 management, and answers to significant questions about the dielectric performance, safe and effective handling, operation, maintenance, and disposal of SF6 alternatives. Also needed is a clear understanding of the tradeoffs and expectations utilities may experience when using the new technologies.

V. CONSIDERATIONS

A. Forum / Venue / Evaluation Plan

As part of this section, the working group is providing some high-level recommendations for better planning the investment in and implementation of new technologies and innovations for the New York state electricity grid. The following three items are of great value in the evaluation and coordinated implementation process:

i) Operation of a joint utility R&D advisory working group:

As transmission and distribution grids are evolving, it is becoming increasingly evident that the grid operates in an integrated manner. In an environment like NY, where a highly interconnected electricity grid is owned by several transmission owners, proper coordination among all these stakeholders is needed to optimize the grid operation and performance. This also applies to the deployment of advanced technologies, especially the ones that are utilized for improving the power system operation and control. Many of these technologies only provide their true value and maximum potential if deployed strategically in a coordinated way. For New York to be able to more effectively utilize and adopt new technologies, it is, therefore, of high importance to maintain proper coordination among all relevant stakeholders on this topic. This will allow new ideas to be thoroughly discussed and evaluated from a holistic perspective, identifying the best use cases for them, which can provide maximum value to the grid overall. It will also allow for pilot or demonstration projects as well as the coordinated optimal deployment when a technology reaches a potential implementation stage.

A second significant benefit of an ongoing advisory working group is the continuous exchange of information between transmission owners and other stakeholders in a more comprehensive and formalized way. This will lead to sharing experiences with specific technologies or products, therefore avoiding duplication of effort leading to similar learnings or mistakes. Coordination would also avoid duplication of research resources and funds. When it comes to new technologies and ideas, it is important and valuable to have some initial joint R&D efforts until a technology is brought to a fairly mature level and could then be adopted up by entities who are more interested in it or get the most value out of it for actual implementation and deployment. Such an advisory group could coordinate such initial research and development stages.

Consequently, this collaborative process will result in improved prioritization of R&D work, better focus on technologies that provide value to the overall grid, and therefore, overall a more streamlined and optimized decision and investment making process in NY's roadmap for adopting and utilizing new technologies for successfully achieving its CLCPA goals.

ii) Creation of a research and development venue:

In many cases, appropriate evaluation of new technologies cannot be performed only by literature surveys, shared experiences, or developer/vendor information. Specific grid details or requirements might make it difficult or inaccurate to extrapolate performance and benefits based on experience from others. In such cases, further specific studies or demonstrations are needed to appropriately evaluate a technology and obtain more confidence in it. Given that actual field demonstrations are often complex and risky, realistic studies, tests, and demonstrations taking place in a controlled laboratory environment provide a very good alternative to experiment with and further develop new technologies. This approach has been successfully used in many other places worldwide, such as in Europe (e.g. https://www.hvdccentre.com/) Asia (e.g. https://www.kepri.re.kr:20808/newEng/index, http://eng.csg.cn/Press_release/News_2019/201909/t20190916_303623.html), and Canada (e.g. http://www.hydroquebec.com/innovation/en/institut-recherche.html, http://energymanitoba.com/partners-members/manitoba-hvdc-research-centre/). Such a laboratory environment should have several key features and provide key capabilities that would allow stakeholders to properly experiment, study, test, and evaluate new ideas and technologies in an accurate and realistic way and also allow them to gain experience working with them and operating them prior to field deployments. Some crucial capabilities include, at a high-level:

- The venue should provide a collaborative environment where utility personnel can work with various other stakeholders as well as technology providers.
- The venue should have research, development, and testing capabilities spanning a wide area of technologies that relate to the electricity grid operation at all levels (transmission, sub transmission, distribution).
- The venue should provide a large variety of analytical and physical tools that would allow people to run studies and experiment with software or hardware equipment and new apparatus or techniques.
- The venue should provide a variety of modeling and simulation tools and capabilities that would facilitate studies and experimentation. Such tools should be using actual grid models and data that can mimic the reality as much as possible. In order for such an environment to be useful and successful, such models should be kept up to date and provide a high-fidelity representation of the grid at various levels and domains to support a variety of different studies.
- The venue should have the capabilities, policies, and processes in place to appropriately secure confidential data and ensure proper utilization of such data accordioning to utility and governmental policies and guidelines.

- The venue should have enough space and other capabilities to accommodate demonstration and testing of larger-scale hardware equipment. Such a lab should go beyond performing traditional model based studies and should be able to provide capabilities to test software and equipment in set ups as close as possible to real field conditions, providing capabilities for new system configuration, preliminary commissioning testing prior to moving to the field commissioning, as well as training for personnel on the actual equipment in a safe lab-based training environment. The venue should be able to support such equipment configuration, commissioning, and training needs for new technologies.
- The venue should be able to serve as a "one-stop shopping" location, where new technology developers and vendors can reach out to the entire group of NY electricity grid stakeholders and present their ideas for a more collaborative and coordinated discussion and evaluation.

Development of such an environment would allow NY stakeholders to work more closely together and seek collaborative solutions to common issues, avoiding duplication of investment and effort, in particular at earlier R&D stages. It would also provide NY utilities a controlled environment that they can experiment and test (or even to some extent develop and expand) new technologies without having to solely rely on vendor or other third-party information and experience. Such an environment could also be leveraged by manufacturers or renewable energy developers for some of their more detailed and advanced studies, potentially resulting in reduced project development costs.

iii) Coordinated technology evaluation plans:

Based on the above two items, a coordinated pilot implementation plan can be devised for a potentially useful new technology. The plan would approximately follow the high-level process presented below:

- A new idea or a new technology is proposed as a solution for addressing one or more specific issues on the NY grid resulting for CLCPA goals.
- The idea is presented and discussed in the joint utility advisory working group.
- Utilities discuss any knowledge or experience that they may have with this technology and potentially seek input and information from vendors or other entities or utilities outside NY.
- If the idea is deemed of interest and value by some of the NY utilities and is seen as having good potential for benefiting the NY grid, a study or a lab testing and demonstration project is defined to further evaluate the technology in a more systematic way and its applicability and benefit for the NY grid.
- Based on the lab evaluation, if the idea is determined as viable for moving forward, a preliminary plan for pilot implementation(s) is created and a cost/benefit analysis is

performed. Lab testing can be used to assist, facilitate, and de-risk the specific pilot implementation.

- Based on the pilot outcomes, the idea/technology is picked up by the entity or entities that are more appropriate for implementation and large-scale deployments, either based on the fact/estimation that they get the most value of this technology, or based on the fact/estimation that implementation in their system(s) would provide the most benefit for the grid. At this stage, deployment of this technology becomes a regular utility project that follows all the existing or updated implementation policies and procedures.

B. Benefit and Cost Analysis

The group has gathered information for the cost and benefit analysis of potential technology solutions; and provided some recommendations.

A BCA of any Research & Development (R&D) project should consider both quantitative and qualitative factors to make a base case for the investment. It should also compare similar projects to determine the potential benefits, risks, and likelihood of success. A BCA should be conducted before allocating funds to any project. A thorough analysis of a project should identify all potential benefits and the probability of achieving goals, compared with the all-in associated costs. The outcome of the analysis should help decision makers determine if the project is feasible and if it should proceed, or if the funds are better spent elsewhere. If a project is to go ahead, the benefits should be compared to the costs to meet the intended goals. A thorough BCA should identify the purpose and goals behind the project, gather business and project requirements, identify all of the resources to be used, determine the metrics to measure success, and consider other potential options.

The Utilities have developed a BCA Analysis Handbook that provides a framework based on the February 26, 2015 Order Adopting Regulatory Policy Framework and Implementation Plan. The BCA determination recognizes that the Reforming the Energy Vision (REV) is a long term, far reaching initiative that will eventually touch most parts of the Utilities' infrastructure and business practices. The BCA framework recognizes that a quantified analysis on the wide-ranging set of potential benefits in a REV approach against hypothetical future cost scenarios under both REV and conventional approaches would be artificial and counterproductive. Such an effort would distract from the far more important task of carefully phasing the implementation of REV so that actual expenditures are considered in light of potential benefits recognizing that in this multi-phased implementation process, benefits and costs will be considered with increasing specificity. The Utilities have prepared a BCA Handbook to provide a foundational methodology along with valuation assumptions to support a variety of utility programs and projects. The BCA Handbook was issued with the expectation that it will be revised and refined over time and as informed by new opportunities that REV provides, experience gained from programs and project deployment, and experience gained from transmission and distribution grid system enhancements. The Handbook typically covers the following four categories of utility expenditures, as required per the BCA Order: investments in distributed system platform (DSP) capabilities; procurement of distributed energy resources (DER) through competitive selection; procurement of DER through tariffs; and energy efficiency programs. The Handbook was prepared consistent with the BCA Order list of principles of the BCA Framework. These principles stated that the BCA Handbook should establish the BCA Framework, be based on transparent assumptions and methodologies, list all benefits and costs including those that are localized and more granular, avoid combining or conflating different benefits and costs, assess portfolios rather than individual measures or investments (allowing for consideration of potential synergies and economies among measures), address the full lifetime of the investment while reflecting sensitivities on key assumptions, and compare benefits and costs to traditional alternatives instead of valuing them in isolation. Given these principles and framework guidance, the purpose of the BCA Handbook is to provide the methodology for calculating benefits and costs of their programs, projects and investments using the input assumptions as provided within and/or referenced to external sources.

The Transmission Policy Working Group has developed recommended changes by including CLCPA benefits in the scope of the Transmission Planning criteria. This effort will allow the development of transmission upgrades that may not be justifiable under the current transmission criteria which focus more on system reliability. This approach can be applied to the full range of potential local transmission and distribution projects that have the potential to unlock CLCPA benefits. The methodology is focused on additional CLCPA-related metrics, and uses a simple, easily repeatable methodology that would include a combination of metrics enhancements and understanding of project contributions to CLCPA. These objectives would include a BCA to establish relative cost-effectiveness, net benefits to capture the scale of benefit achieved, and incremental cost of additional hosting capacity to evaluate distribution projects. Key preliminary recommendations being considered are for the Commission to accept the proposed local transmission-related BCA guidelines for CLCPA projects to allow a transmission owner to efficiently prioritize its CLCPA-related investments.

The Department of Energy (DOE) developed guidance for evaluators who conduct impact assessments to determine the economic benefits and costs, energy benefits, environmental benefits, and other impacts of the Office of Energy Efficiency and Renewable Energy's (EERE) R&D projects. The impact assessments covered in their guide are intended to address the following questions of interest to managers of DOE, Congress, the general public, and other stakeholders: to what extent has the project produced energy and economic benefits relative to the next best alternative; to what extent has the project achieved environmental benefits, and enhanced societal benefits; to what extent has the project cultivated a knowledgebase in the research community that has impacted innovations in today's markets; would today's commercialized technologies likely have happened at the same time, and with the same scope and scale, without the project efforts; and was the public investment worth it? In addition to energy and economic impacts, the approach should quantify emissions reduction, environmental and other health benefits, health cost avoidance, energy policy benefits, and knowledge creation and diffusion. It addresses attribution of benefits through the use of the counterfactual model which seeks to compare outcomes with what would likely have happened in the absence of the R&D project. The method presented in this guide builds on the R&D impact assessment approach used by the National Institute of Standards and Technology (NIST) and improves on the approach employed by the National Research Council (NRC).

A study completed by several European agencies that explored the BCA of R&D projects found that the use of BCA to evaluate these types of projects have often been hindered by the intangible nature and the uncertainty associated to the achievement of R&D results. The core of their BCA is an evaluation of the project socio-economic benefits and costs. The net effect on society is computed by a quantitative performance indicator (the net present value, or the internal rate of return, or a benefit/cost ratio). In line with the general BCA fundamentals, a BCA model of these type of projects should make use of: shadow prices to capture social costs and benefits beyond the market or other observable values; a counterfactual scenario to ensure that all costs and benefits are estimated in incremental terms relative to a 'without project' world; discounting to convert any past and future value in their present equivalent; and a consistent framework to identify social benefits by looking at the different categories of agents (producers, consumers, tax payers, rate payers). The project evaluations are dividing social benefits in two broad classes. The first is benefits accruing to different categories of direct and indirect users of the infrastructure services, such as firms benefitting from technological spillovers, consumers benefitting from innovative services and products, and the general public. The second is the identification of use-beneficiaries that is project specific reflecting the social value of the discovery potential of the research project.

The goal of the working group is to coordinate and evaluate all BCA options for each R&D project pursued in this effort and continue to improve on these BCA methods as new and underutilized technologies are being evaluated in New York State.

C. Impediments / Mitigations

Figure 123 summarizes key issues that utilities consider as the factors that could delay or prevent the implementation of new technology solutions in the three highest-prioritized technology categories. Generally, while these technologies may have demonstrated their technical capabilities to facilitate the CLCPA, these issues could introduce some uncertainties or make it difficult to benchmark these new technologies against the conventional solutions.

Figure 123: Technology Solutions

Technology Solution	Impediment	Mitigation
Dynamic Line Ratings (DLR) and improved overhead and	Effectiveness: It is difficult to ensure the higher ratings can always be achieved when they are needed in the future. Particularly, if the ratings	Additional studies should be conducted to better determine the future benefits from DLR and the

underground cable transmission utilization	are depending upon critical factors such as the wind speed that has high variability. This could make it difficult to compare the benefits of DLR against the conventional solutions	extent that DLR could be effectively utilized in the local and bulk transmission system.
Power flow control devices – distributed and centralized	Coordination: Power flow control devices do not increase system capability but redirect power. Increasing the utilization of this technology may create planning operational complexity since it could impact wider areas.	A comprehensive study should be conducted to evaluate potential impacts from large-scale power flow control utilization and the systems needed to ensure that the operations of these devices will be well coordinated.
Energy storage for T&D services	Cost Estimate: Sufficient cost estimate for a storage project is needed to allow it to be compared against conventional solutions. Currently, it is difficult to come up with this level of estimate.	A guidance document and compilation of project experience should be developed to help facilitate cost estimation.
	Specifications: Detailed specifications of Storage require more information that may not be available at this point. For example, future congestion pattern is needed to develop the specifications of the Storage	Additional studies at a more granular level should be conducted to provide relevant information regarding future benefits.
	Benefit quantifications: The true benefits or use cases for Storage are still unclear. This can put Storage in disadvantage positions when benchmarking it with conventional solutions.	Similar to the above, additional studies should be conducted to understand benefits and impacts of the various use cases. A guideline to quantify the benefit could be useful as well.

VI. CONCLUSIONS / RECOMMENDATIONS

In summary, the group concludes the following:

- The group has prioritized several issues and potential technology solutions as being key to achieving CLCPA goals. These technology solutions are consistent with the transmission needs identified by the Technical Analysis working group.
- A survey of the group found that various members are already implementing either operationally or in R&D pilots some of the technology solutions identified and reviewed in this study. For those technology solutions already being implemented by some, there is opportunity for knowledge transfer among the members of the group. Through knowledge transfer, members can learn from each other so as, to be in better position to assess further adoption of the technology solutions. The figure below provides an overview of the implementation of these technology solutions among the group members.

Technology Solution	Avangrid	Central Hudson	Consolidated Edison	LIPA/PSEG LI	National Grid	Orange and Rockland	NYPA
Dynamic line ratings and improved transmission utilization	Ongoing Pilot (NYSERDA Future Grid Challenge)	Past R&D pilot with mixed results	Use on underground transmission lines	Limited use on underground transmission lines	Demonstrated in New England; currently deploying Line Vision technology in Upstate NY	Limited success with past installations, waiting for technology to mature	R&D pilots only with various technologies
Power flow control devices – distributed and centralized	Several PARs used in Rochester; proposed Smartwire technology as alternative for ongoing Utility Study	Pilot temporary Smartwires project on 115kV, proposed permanent project on 345kV (in NYISO gold book)	Use of PARs at transmission level	Limited use of PARs at transmission level	Demonstrated Smart Wires technology in New England	-	Planning for potential pilot
Energy storage for T&D services	NWA solicitation for any new transmission project; A few storage systems installed; Proposed several storage systems for ongoing Utility Study	In design battery storage project per PSC order	Limited installations of utility owned energy storage	Limited installations of BESS on distribution system with PPA. Potential developer owned BESS on both T&D system	Limited installations of utility owned energy storage	Actively working with developers as well as planning on installing battery storage along with the construction of new distribution substations	One pilot at transmission level but mainly as generation asset
Improved operator situational awareness	ongoing improvement on alarms	Various technologies in use, in investigation phase	Efforts have been on improving the managing of alarm information	-	proposed	Improving alarm information by getting discrete alarms	Mainly work phasor measurement units
Transformer monitoring	-Various types of monitoring in use throughout system	Various types of monitoring in use throughout system	Various types of monitoring currently in use throughout the system	Various types of monitoring currently in use throughout the system	Various types of monitoring in use throughout system	In operational use for predictive maintenance and asset management	In operational use for predictive maintenance and asset management
Advanced high-temperature, low sag (HTLS)	Proposed at one location for CapEx project; will be considered in the future	-	-	Use of ACSS on OH transmission lines	Demonstrated in New England	Use of ACSS on a number of transmission projects in past with success; only installed steel core conductors, with both conventional (round) and trapezoidal stranding	-
Compact tower designs	-	-	-	-	-	-	-

SF6 monitoring/SF6 alternatives	SF6 monitoring system are used in the current/planned facilities	69kV vacuum breaker installed in one location	SF6 monitoring in use to help identify leaks for repairs	Utilization of 69kV vacuum breakers currently under review	SF6 monitoring in use to help identify leaks for repairs, currently discussing low voltage vacuum breaker pilot	-	-

- It would be beneficial for the joint utilities to share R&D knowledge on a regular basis. This helps to increase awareness of state-of-the-art and emerging technologies among the joint utilities, thereby creating greater interest to assess the technologies and possibly leading to their use.
- In furthering the goals of the CLCPA, it would be more cost-effective for the joint utilities to work together than separately to test out and assess the use of new technologies. However, there are issues that need to be addressed before this can happen. Foremost among the issues is the need for funding, which NYSERDA can help cover most, if not, all the funding requirements. Another issue is the need for a governance structure to select, among many things, which joint R&D projects will be funded.
- The challenges of adopting advanced technologies include the following:
    - Advanced technologies typically include an inherent risk of not meeting expectations or even failure. Therefore, their results and effectiveness are not guaranteed until thoroughly tested and evaluated and until enough field operating experience is obtained.
    - Advanced technologies are not typically a substitute to more traditional solutions or system upgrades, but they can be used to supplement such solutions and ensure that additional value is extracted from such solutions in longer timeframes.
    - Advanced technologies may need close coordination between stakeholders in order to result in implementations that are effective and provide value. In many cases, unless deployed in a wider scale and in a coordinated way, benefits might not be demonstrated by a few individual pilot installations.
    - Advanced technology solutions might typically require upfront effort and funding for testing and pilot projects, which by themselves do not demonstrate benefits. These efforts are needed, however, in order to make the technology more mature, obtain operational experience, and move the technology to a stage that it can be reliably deployed and start demonstrating benefits. This implies that many new technologies might not have a valid "business case" as there are upfront sunk costs, and the benefits may have to be over longer-term to substantially surpass the upfront costs. In addition, many benefits may not be easily quantifiable and may need additional actions and assumptions to occur prior to being materialized.
    - Advanced technologies are not equally suited throughout the system and the State. The regional and local environment and existing transmission configurations will have to be considered as to where would be appropriate to incorporate the various advanced technologies.
- Any joint R&D projects should initially focus on these three technology solutions: dynamic line ratings, power flow control devices, and energy storage for T&D services, because although additional capacity would be needed on the transmission network, these technologies could enhance operator flexibility to ensure reliability and reduce

system congestion furthering the goals of CLCPA in integrating greater amounts of renewables.

- The above three chosen technology focus areas are not a direct replacement for additional system capacity. When system upgrades are needed to mitigate the challenges of the future, Transmission Operators are encouraged to utilize new technologies such as HTLS and innovative tower design in project design when such technologies are more cost effective than traditional ones.
- New York State has a wealth of R&D resources such as NYPA's small-scale Advanced Grid Innovation Laboratory for Energy (AGILe), academic institutions and a national laboratory that should be utilized to help the joint utilities to further the goals of the CLCPA prior to the development of new resources.
- The intangible nature and the uncertainty associated with the achievement of R&D results often hinder the BCA of R&D projects. More specifically the risk resides primarily with the anticipated benefits in the BCA calculation, because the benefits are dependent on the success of the R&D project. Therefore, the anticipated benefits in the BCA calculation should be risk adjusted based on the project's likelihood of success. This will help guide the selection of projects with greater likelihood of success while not precluding projects with potentially home run benefits.

Based on these conclusions, the group believes there is an opportunity to create a New York State focused R&D consortium to be comprised of, at minimum, the New York State investor owned utilities ("IOUs"), NYPA, LIPA, the NYISO and NYSERDA to expedite the assessment and adoption of state-of-the-art and advanced technologies that are already being used elsewhere in the U.S. or the world. This R&D consortium would also help each IOU to identify and assess which of the state-of-the-art technologies it should implement or expand their use, consistent with how best to further the goals of the CLCPA while also addressing the need to provide affordable, safe and reliable service to its customers.

Therefore, the Advanced Technologies working group recommends the following:

1. A New York R&D consortium should be created with the initial task to identify two to three R&D projects, preferably one project for each of the three technology solutions: dynamic line ratings, power flow control devices, and energy storage for T&D services. These initial projects should demonstrate the use and benefits of the selected technologies. The selected technologies should be state-of-the-art and commercially available.
2. The R&D consortium will initially include all the New York State IOUs, NYPA, LIPA, the NYISO and NYSERDA and may be expanded over time to include academic institutions in New York State as well as possibly Brookhaven National Laboratory on Long Island.
3. The projects proposed should be evaluated based on the potential benefits and costs of the project but should also be risk adjusted based on the project's likelihood of success.

4. Projects selected by the R&D consortium should be funded through NYSERDA, with the IOUs, NYPA and LIPA participating in the project having the opportunity to choose to support the project through co-funding or in-kind contribution on a project by project basis. Any IOU co-funding would be limited to the extent that the funding is within the IOU's Commission approved rate plan and that the advanced technologies being investigated by the R&D projects support their deployment in the IOU's capital plan. For TOs that are not co-funding the projects, they can support the projects through an advisory role, in-kind participation, or even choosing to host the demonstrations or piloting of the advanced technologies. The Commission should support incremental funds sought for these projects by NYSERDA and / or through IOU rate proceedings.
5. The R&D consortium will further investigate specific needs, capabilities, and plans for the establishment of a collaborative R&D and testing venue, first assessing existing resources in New York State, which could be utilized as part of the evaluation of currently new or future advanced technologies.

The Advanced Technologies working group anticipates it will take at least six months to: establish the R&D consortium with the necessary governance structure and legal agreements in place; establish the criteria for project selection; identify the candidate projects for evaluation and selection; and select two to three projects from the project candidate list and prepare the work scope for each selected project. R&D projects typically run one to two years once the work scope is finalized.

Respectfully submitted,

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Appendices

APPENDIX A: TRADITIONAL PLANNING CRITERIA

A foundational input for both the Net Benefits and Benefit/Cost Ratio is the quantity of MWh of unbottled renewables. There are multiple approaches for this type of calculation, and there is no one-size-fits-all approach that must be used. In some cases, different approaches may be applicable for different parts of a utility's transmission system. Each utility will determine the approach that is appropriate for the unique topology of its system, and will, if necessary, provide evidence to the Commission that the chosen methodology(ies) provides reliable results. Utilities are currently considering three methodologies.

A. Production Cost Modeling

Production cost modeling is a tool for simulating and studying the electric market in a defined area. Typical uses include day-ahead market simulation, long-term market impact studies, future year production cost, planning and market efficiency simulation, multi-day resource and ancillary services optimization, and congestion and outage analyses. For production cost modeling many available tools are available to utilize. For example, a Linear Programming-based Security Constrained Economic Dispatch (SCED) and/or Security Constrained Unit Commitment (SCUC) can be used to perform both short- and long-term market simulation.

Inputs for a production cost model include generator data (nameplate capacity, operating characteristics, fixed costs, cost curves, hourly profiles for renewables, etc.), demand data (hourly by zone), fuel prices, emissions rates and prices, transmission topology, monitored branches, contingencies, interface definitions, and outage schedules. One production cost modeling software package, PROBE-LT, reads in load flow models and CSV files of the input data and solves the dispatch iteratively. Each day in a long-term study period can be solved consecutively, carrying over the prior day's units' statuses. Common outputs include the overall production cost of running the system in the defined area, locational marginal pricing at a nodal level, generator dispatch, flows over monitored branches, and congestion impacts, all reportable with hourly granularity. These results provide an overview of market performance over the defined time of the study. By way of example, National Grid used PROBE-LT and production cost modeling for its Multi-Value Transmission projects included in its current rate case. In that case, production cost modeling served as a tool to evaluate the interactions and system impacts of load and renewable profiles overlaid over the course of a year. Production cost modeling should be one of the tools available to the Utilities as they seek to prioritize projects in support of the CLCPA mandates.

B. DFAX

This proposed approach estimates the quantity of MWh of unbottled renewables by comparing the amount of renewable energy curtailments (MWh) before and after the proposed upgrade over 1-year period (8760 hours). The difference in curtailed renewable energy between the two scenarios is the curtailment reduction benefit. This approach may be appropriate for addressing the characteristics of many bottlenecks in the service territories that are not load pockets, but rather are the facilities that also deliver renewable power through its service area and to the bulk power system. This approach also satisfies the need to allow the Utilities to perform initial benefit/cost analysis on a large number of CLCPA-related projects quickly and consistently for those areas where boundaries of load pockets are difficult to define.

By way of comparison to the other methodologies described in this filing, an approach that relies on Load Duration Curve works well for an area that consists of clearly defined load pockets, but would be very challenging to implement in areas where the boundaries of load pockets do not exist or very difficult to define for most of the bottlenecks. Conversely, the DFAX-based approach may be challenging to implement for constrained areas that depend on Phase Angle Regulated (PAR) ties. In addition, while Production Cost Modeling (PCM) is a powerful tool, it requires complex, expensive software, and specialized training. PCM results are highly dependent upon study assumptions, and results can give a false sense of precision when compared to other methods.

i) The proposed method

In this section, the term "bottleneck" refers to transmission facility that was identified as the limitation that prevents renewable resources from delivering energy to the load. In addition, the term "driver" represents any factor that could impact power flow on the bottleneck. For example, if a study determines that the thermal limit of transmission line A is not enough to accommodate the output from renewable resources X, Y, and Z, from this context, line A is the bottleneck and resources X, Y, and Z are the drivers. Below are the key concepts and components of the methodology.

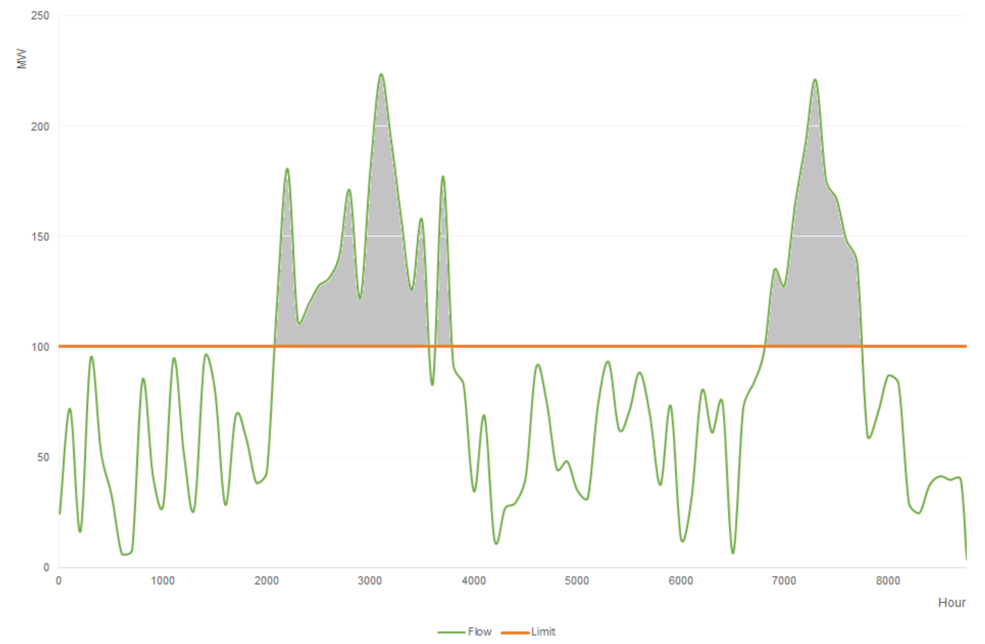
1) Data Requirements: Three main types of data are required for the calculation.
    a. Details of the bottlenecks and conditions they were identified. This information is obtained from other studies such as the work performed by the Utility T&D technical subgroup.
    b. Power flow base cases. These contain the initial system conditions and network topology that will be used to calculate DFAX.
    c. Hourly data (such as renewable output) from each driver over 1-year. For example, if the output from Land-Based Wind (LBW) is impacting the flow on a bottleneck, the expected hourly output (8760 data points) must be provided.
2) Distribution Factors (DFAX) or Shift Factor: These indexes are calculated and used to estimate the flow on the bottleneck for each hour. It indicates the proportion

of the changes at a driver that would appear on the bottleneck. For example, if the output from a LBW is impacting the flow on the bottleneck, DFAX can estimate the changes of power flow on the bottleneck for every 1 MW change from LBW output. This concept has been widely used in power industry and it is similar to the technique that has been used in commercial PCM packages such as GridView, and others.

3) DFAX Calculation: DFAX are calculated from Power Flow software and they are assumed to be constant if the network topology stays the same. First, potential drivers that could impact power flow on the bottlenecks are determined. Then, power flow on the bottlenecks after increasing the output from each driver by a certain amount (i.e. 10 MW) is compared with the power flow on the same facility at previous hour. DFAX is equal to the flow difference divided by the incremental output from the driver. A potential driver has DFAX very small or zero DFAX on the bottleneck may be considered to have negligible impacts.
    a. Example[158], assuming LBW X is a potential driver for the bottleneck (Line) A and power flow on this line at Hour 0 is 100 MW. DFAX can be calculated by increasing the output from LBW X by 10 MW then solve the power flow. If the new power flow on Line A = 105 MW, DFAX is 0.5 (or 50%).
4) Hourly (8760) power flow calculation: Power flow on a bottleneck at each hour is calculated by adjusting the amount of power flow on this facility from the previous hour with all the changes from all drivers that occur within an hour. For example, if load, LBW, and Utility Photovoltaic (UPV) are determined to impact the flow on Line A, power flow on Line A at each hour is the summation of:
    a. Power flow on this line from the previous hour (H0)
    b. Impact from load change within an hour (Load DFAX multiplied by load change)
    c. Impact from LBW change within an hour (LBW DFAX multiplied by LBW output change)
    d. Impact from UPV change within an hour (UPV DFAX multiplied by LBW output change)
    e. Power flow on Line A (H1) = a + b + c +d
5) Curtailed Renewable Energy Calculation: The amount of curtailed renewable energy (MWh) for each hour is determined by the amount of the flow that exceeds facility rating. For example, assuming the rating of the bottleneck is 100 MW and the power flow on the bottleneck is shown as green line in Figure 1, the curtailed renewable energy over a 1-year period is represented by the gray-shaded area in this figure.

[158] For demonstrating the concept only. The actual power flow program may employ different technique to perform the same task.

Figure 124: Hourly flow and curtailed energy



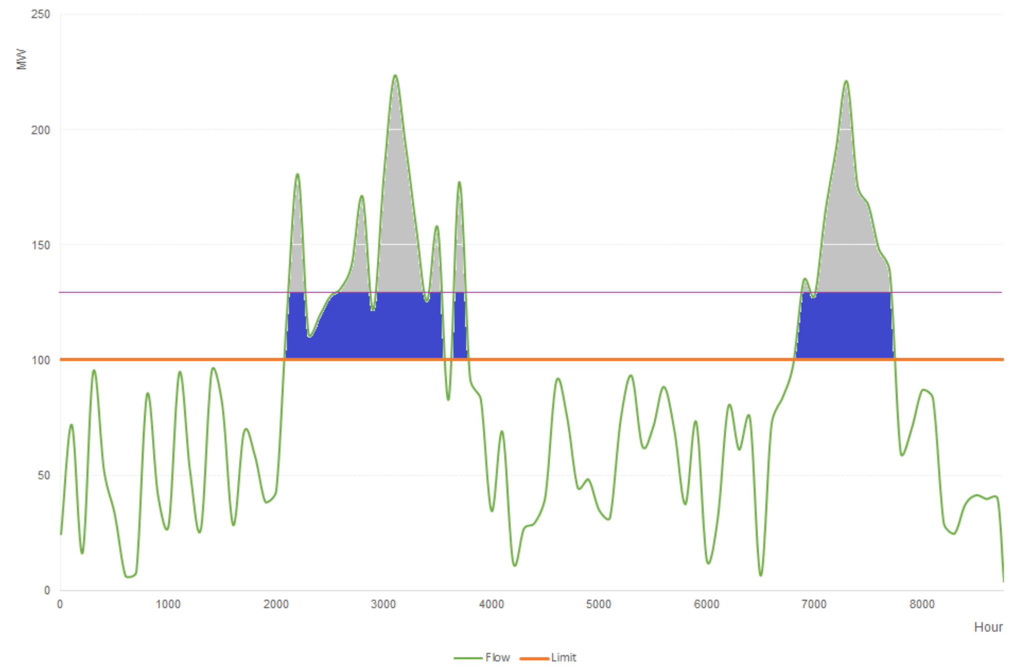
This curtailment value can also be easily calculated using spreadsheet approach. For example, as shown in table 1, the total amount of congestion energy over 6-hour period is 110 MWh.

Figure 125: Example of curtailment calculation

Hr	Flow (MW)	Limit (MW)	Curtailment (MWh)
1	90	100	0
2	80	100	0
3	120	100	20
4	95	100	0
5	170	100	70
6	120	100	20
…	…	…	…
…	…	..	…
…	…	..	…
Total		110	

Curtailment reduction calculation: With the upgrade, the curtailment reduction benefit is calculated by comparing the curtailed renewable energy before and after the upgrade. As shown in Figure 2, assuming the upgrade increases the rating of Line A to 130 MW (pink line), the area shown in blue represents congestion energy reduction by the upgrade. In some cases, an upgrade could result in different shape of power flow plot due to impedance changes. If needed, DFAX can be recalculated to estimate the new flow.

Figure 126: Hourly flow before and after the upgrade as well as curtailment reduction



Similar to the above, this benefit can also be calculated using spreadsheet.

Figure 127: Example of curtailment reduction calculation

Hr	Flow (MW)	Existing System		With Upgrade A			With Upgrade B		
		Limit (MW)	Curtailment (MWh)	Limit (MW)	Curtailment (MWh)	Curtailment Saving (MWh)	Limit (MW)	Curtailment (MWh)	Curtailment Saving (MWh)
1	240	200	40	250	0	40	350	0	40
2	260	200	60	250	10	50	350	0	60
3	270	200	70	250	20	50	350	0	70
4	270	200	70	250	20	50	350	0	70
5	200	200	0	250	0	0	350	0	0
6	200	200	0	250	0	0	350	0	0
7	160	200	0	250	0	0	350	0	0
8	160	200	0	250	0	0	350	0	0
9	220	200	20	250	0	20	350	0	20
10	270	200	70	250	20	50	350	0	70
…	…	…	…	…	…	…	…	…	…
…	…	…	…	…	…	…	…	…	…
Total (MWh)			330		70	260		0	330

From this example, for over a 10-hour period, up to 330 MWh of curtailed renewable energy can be observed over the existing system (no upgrade). With upgrade A, the rating of the bottleneck increases to 250 MW, the curtailed renewable energy drops to 70 MWh and the curtailment reduction benefit from this upgrade is 260 MWh. If a larger upgrade is built as shown as upgrade B, curtailments of renewables no longer exist in the system at the studied level of renewable energy development.

C. Load Duration Curve

i) Load Duration Curve Method to Calculate Unbottled Energy

Another method the utilities may use to identify the amount of energy unbottled by a project is to compare the load or generation hourly profile to the transfer capability into or out of the generation or load pocket. This method is best applied to stand alone or embedded load pockets (see diagrams below), which are common in New York City and other parts of the state. In other areas, particularly upstate, constrained areas may be hard to define due to external power transfers. For those types of pockets, one of the other methods proposed in this Report may be more appropriate. However, in the case of a standalone or embedded load pocket, this approach is a reasonable simplification of the dynamics of the load pocket and offers the benefits of ease of calculation and consideration of the full 8760 profile of the year.

Figure 128: Stand Alone Constrained Area

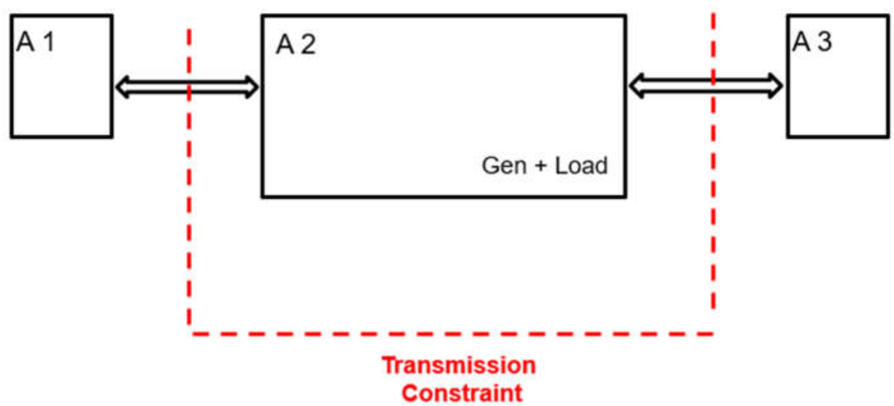


Figure 129: Embedded Constrained Area

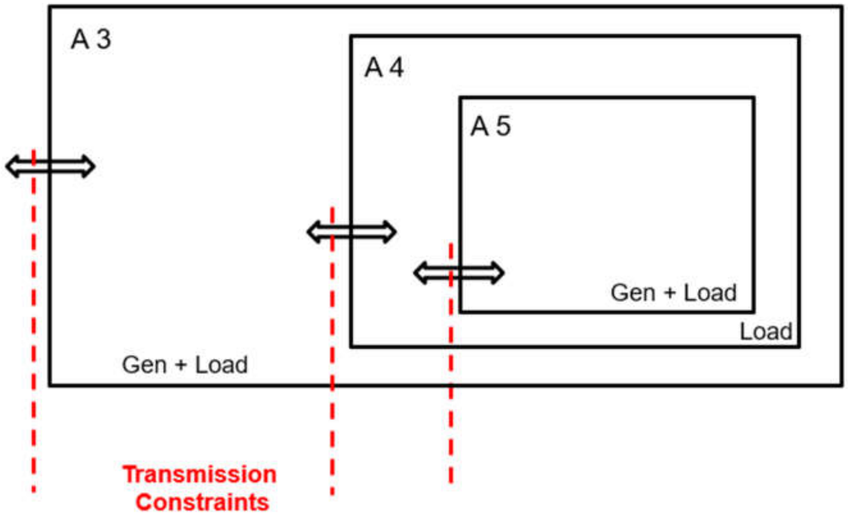
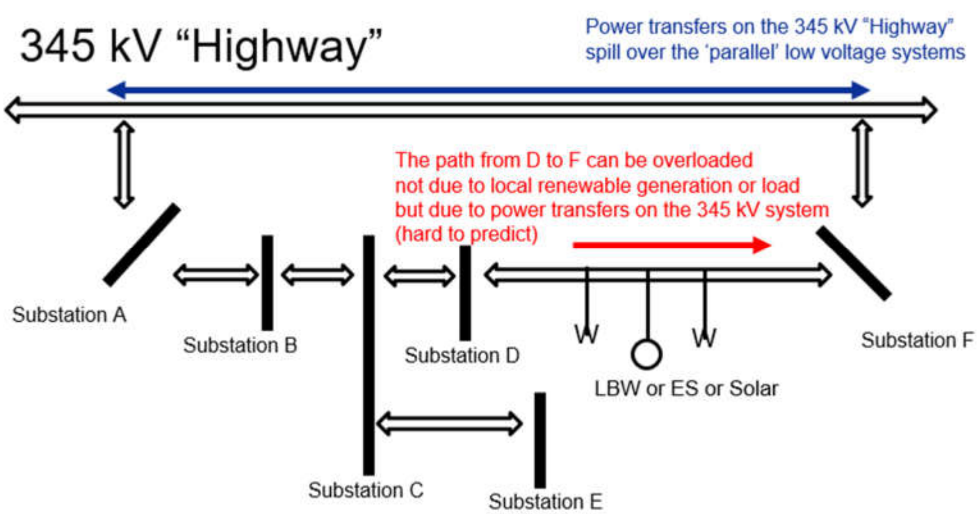


Figure 130: Constrained Area Impacted by External Transfers



ii) Methodology

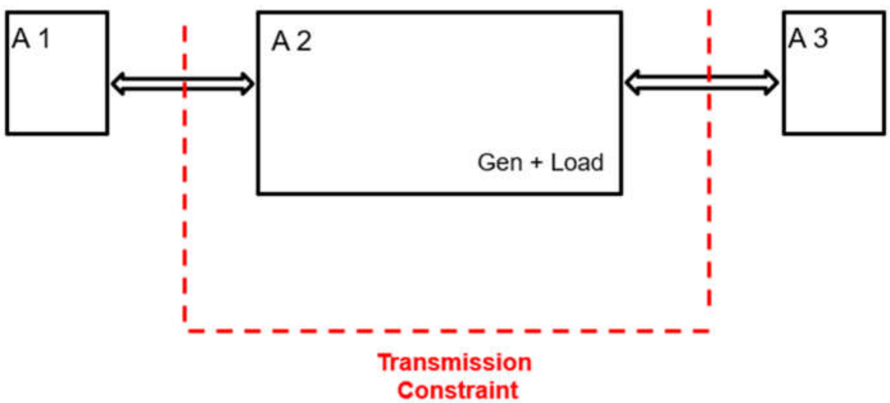
The steps below outline the approach for using the load duration curve approach to calculate the number of MWhs unbottled by a project. The approach may be applied to either generation or load pockets. The steps, described further below, include

- Step 1: Identify Constrained Area
- Step 2: Identify current Design Capability
- Step 3: Identify future Design Capability with project
- Step 4: Compile hourly load and generation profiles
- Step 5: Compare Design Capability to hourly profile

- **Step 6:** Calculate MWhs unbottled by project

Step 1: Identify Constrained Area

Identify a Constrained Area on the utility Transmission System. This may be either an already established (operationally) Constrained Area, or one that is identified through power flow analysis.



Step 2: Identify Design Capability

Identify how much power can be imported to (for a load pocket) or exported from (for a generation pocket) the Area, based on the design criteria for the Constrained Area. This should be done for both the summer and winter operating seasons, due to differences in feeder ratings, and include Renewable Resources.

Step 3: Identify future Design Capability with project

Using the same approach as under Step 2, identify the Design Capability to import or export power with the proposed project in place.

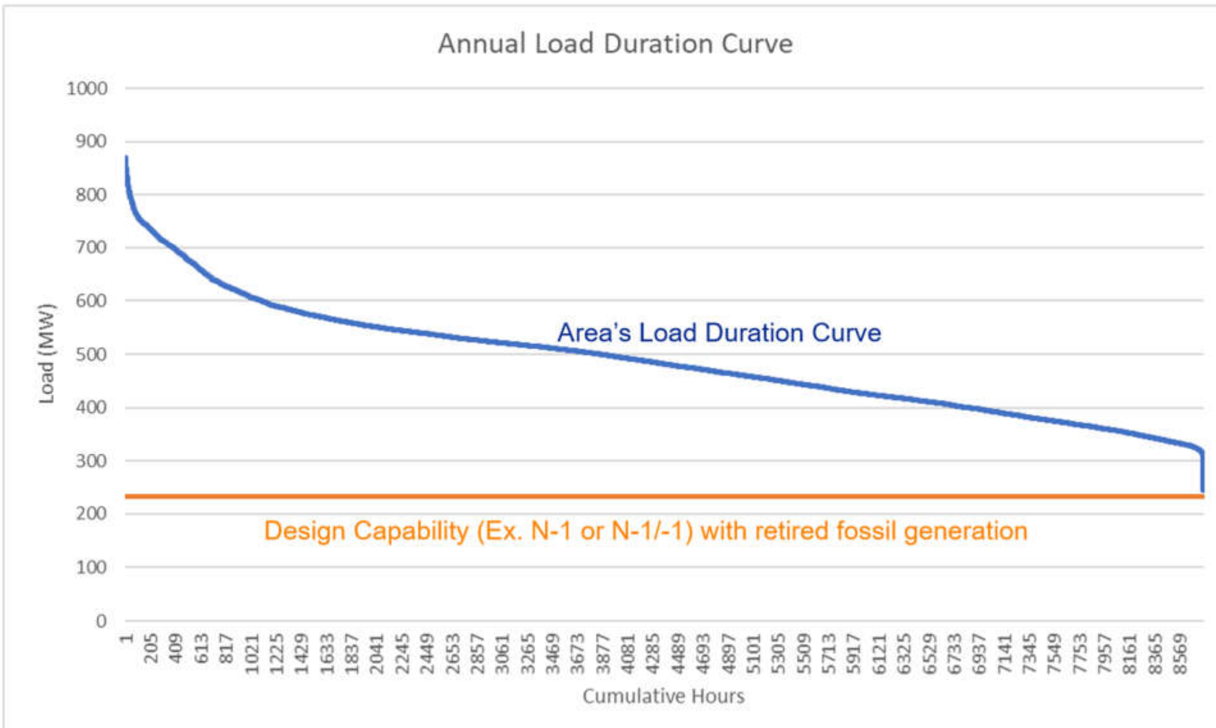
Step 4: Compile hourly load and generation profiles

Compile a historical load profile (8760 hours in a year) for the identified Constrained Area. This information is available from utilities' Plant Information (PI) data systems. For a generation pocket, the hourly generation profile for renewables within the pocket will also need to be calculated. This can be derived from NREL wind shape data or other sources.

Step 5: Compare Design Capability to hourly profile

Compare the Design Capability with and without the project to the hourly load profile, as illustrated in the charts below. Area above the Design Capability line represents the Constrained Area's bottled generation or load that cannot be fed due to a constraint.

Figure 131: Load pocket – without project



Note: load curve has been sorted from peak hour (left) to lowest load hour (right). Data is illustrative only.

Figure 132: Load pocket – with project

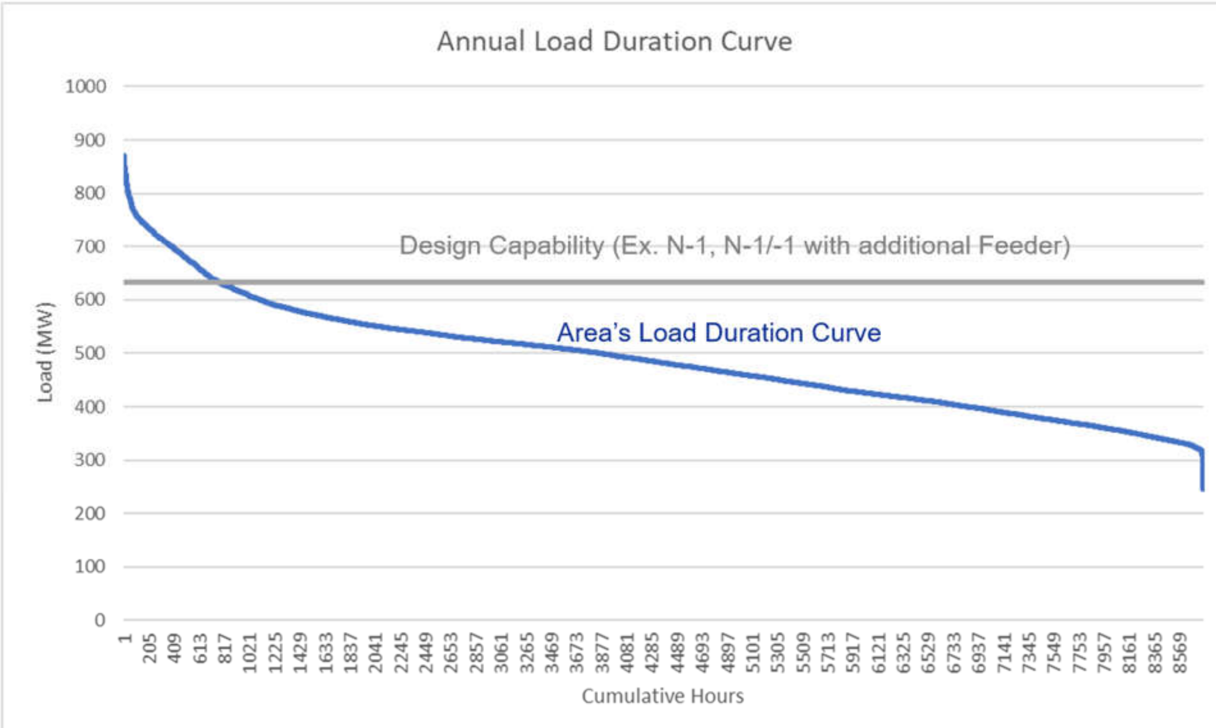


Figure 133: Generation pocket – without project

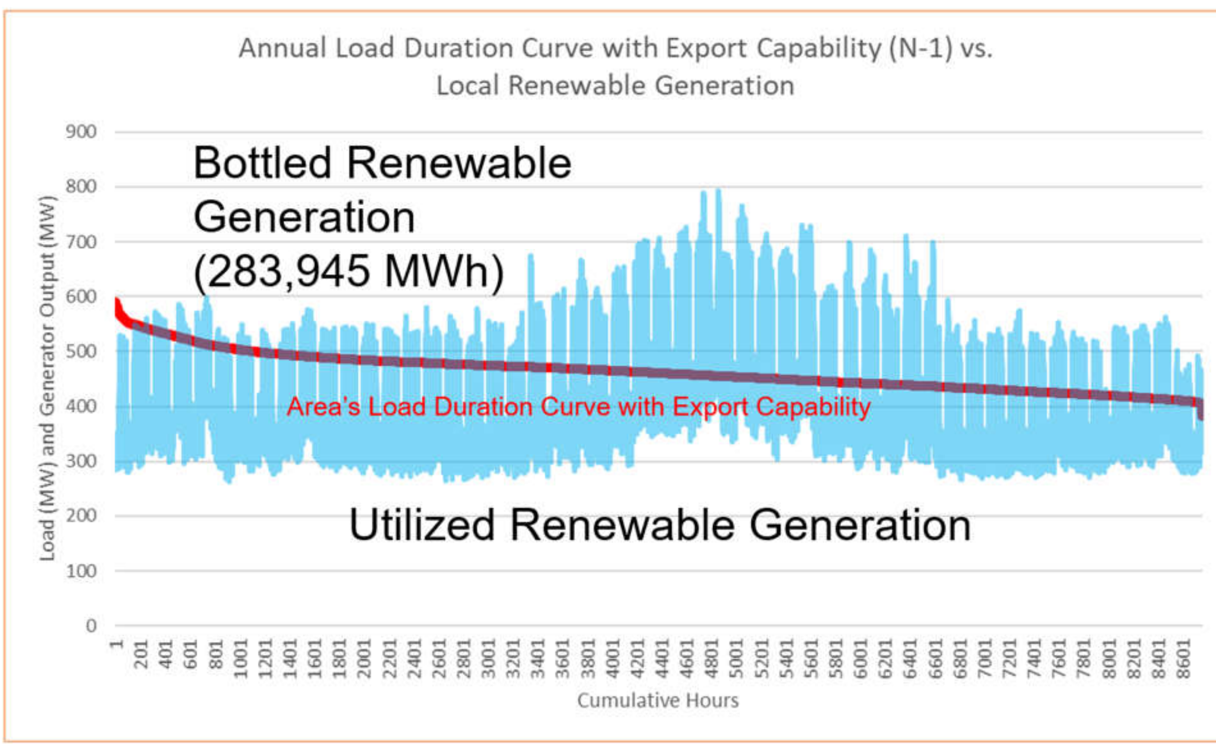
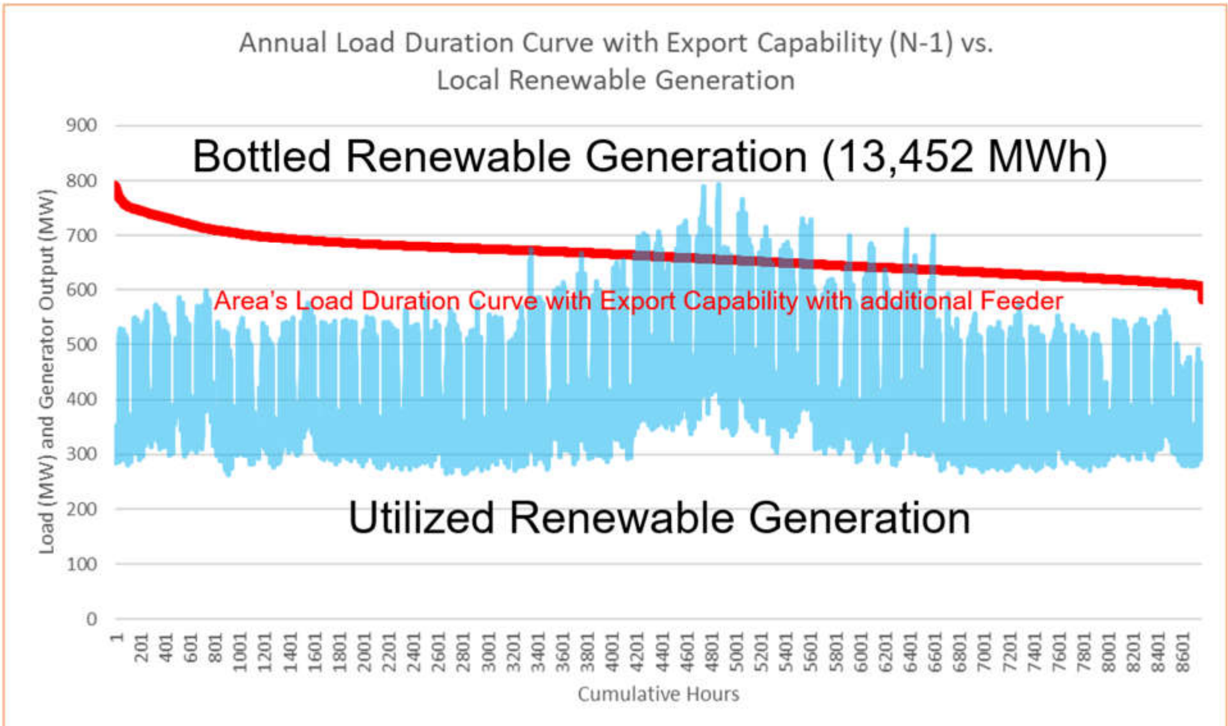


Figure 134: Generation pocket – with project



Step 6: Calculate MWhs unbottled by project

The area between the Design Capability post-project and Design Capability pre-project represents the number of MWhs unbottled by the project. This number would then be fed into the benefit cost analysis as the “MWh” (or “Inc MWh”) factor in the equation.

APPENDIX B: BCA EXAMPLE CALCULATIONS

Assumptions

Project Cost (Millions$)	$ 50.0
Utility after-tax WACC: 6.811% (NYSEG rate used to calculate revenue requirement example)	
Discount Rate (Wtd. Avg. after-tax utility WACC	7.073%

Outputs

Benefit/Cost Ratio	1.38
Net Benefits (Millions$)	$25.5
PV Benefits (Millions$)	$92.5
PV Costs (Millions$)	$67.0

Conversion of ICAP Price to $/MWh

A	B	C	D = (A x B x 12 x 1000)/(C x 8760)
ICAP Price ($/kW-month)	ICAP Credit %	Capacity Factor	ICAP Price in $/MWh
$ 7.28	20%	30%	$ 6.65

A	B	C	D	E	F = (B+C+D)/(1-E)	G	H = F x G	I = ATRR	J = H - I
Year	LBMP ($/MWh)*	REC ($/MWh)*	ICAP ($/MWh)*	Curtailment %*	Curtailed Energy Value ($/MWh)	Unbottled MWh*	Benefit (Millions$)	Cost (Millions$)	Net Benefit (Millions$)
2021	$31.97	$20.00	$6.65	7.0%	$63.03	-	$0.0	$0.0	$0.0
2022	$34.04	$20.00	$6.65	7.0%	$65.26	-	$0.0	$0.0	$0.0
2023	$38.09	$20.00	$6.65	7.0%	$69.61	-	$0.0	$0.0	$0.0
2024	$40.11	$20.00	$6.65	7.0%	$71.78	-	$0.0	$0.0	$0.0
2025	$44.39	$20.00	$6.65	7.0%	$76.39	100,000	$7.6	$8.3	($0.6)
2026	$45.85	$20.00	$6.65	7.0%	$77.96	100,000	$7.8	$8.1	($0.3)
2027	$47.12	$20.00	$6.65	7.0%	$79.32	100,000	$7.9	$7.9	$0.0
2028	$49.16	$20.00	$6.65	7.0%	$81.52	100,000	$8.2	$7.8	$0.4
2029	$50.14	$20.00	$6.65	7.0%	$82.57	100,000	$8.3	$7.6	$0.7
2030	$51.15	$20.00	$6.65	7.0%	$83.65	100,000	$8.4	$7.4	$0.9
2031	$52.17	$20.00	$6.65	7.0%	$84.75	100,000	$8.5	$7.3	$1.2
2032	$53.21	$20.00	$6.65	7.0%	$85.87	100,000	$8.6	$7.2	$1.4
2033	$54.28	$20.00	$6.65	7.0%	$87.02	100,000	$8.7	$7.0	$1.7
2034	$55.36	$20.00	$6.65	7.0%	$88.19	100,000	$8.8	$6.9	$2.0
2035	$56.47	$20.00	$6.65	7.0%	$89.38	100,000	$8.9	$6.7	$2.2
2036	$57.60	$20.00	$6.65	7.0%	$90.59	100,000	$9.1	$6.6	$2.5
2037	$58.75	$20.00	$6.65	7.0%	$91.83	100,000	$9.2	$6.4	$2.7
2038	$59.93	$20.00	$6.65	7.0%	$93.09	100,000	$9.3	$6.3	$3.0
2039	$61.12	$20.00	$6.65	7.0%	$94.38	100,000	$9.4	$6.2	$3.3
2040	$62.35	$20.00	$6.65	7.0%	$95.70	100,000	$9.6	$6.0	$3.5
2041	$63.59	$20.00	$6.65	7.0%	$97.04	100,000	$9.7	$5.9	$3.8
2042	$64.87	$20.00	$6.65	7.0%	$98.40	100,000	$9.8	$5.9	$4.0
2043	$66.16	$20.00	$6.65	7.0%	$99.80	100,000	$10.0	$5.8	$4.2
2044	$67.49	$20.00	$6.65	7.0%	$101.22	100,000	$10.1	$5.7	$4.4
2045	$68.84	$20.00	$6.65	7.0%	$102.67	100,000	$10.3	$5.6	$4.6
2046	$70.21	$20.00	$6.65	7.0%	$104.15	100,000	$10.4	$5.6	$4.8
2047	$71.62	$20.00	$6.65	7.0%	$105.66	100,000	$10.6	$5.5	$5.1
2048	$73.05	$20.00	$6.65	7.0%	$107.20	100,000	$10.7	$5.4	$5.3
2049	$74.51	$20.00	$6.65	7.0%	$108.77	100,000	$10.9	$5.4	$5.5
2050	$76.00	$20.00	$6.65	7.0%	$110.38	100,000	$11.0	$5.3	$5.8
2051	$77.52	$20.00	$6.65	7.0%	$112.01	100,000	$11.2	$5.2	$6.0
2052	$79.07	$20.00	$6.65	7.0%	$113.68	100,000	$11.4	$5.1	$6.2
2053	$80.65	$20.00	$6.65	7.0%	$115.38	100,000	$11.5	$5.1	$6.5
2054	$82.27	$20.00	$6.65	7.0%	$117.11	100,000	$11.7	$5.0	$6.7
2055	$83.91	$20.00	$6.65	7.0%	$118.88	100,000	$11.9	$3.3	$8.6
2056	$85.59	$20.00	$6.65	7.0%	$120.69	100,000	$12.1	$3.4	$8.7
2057	$87.30	$20.00	$6.65	7.0%	$122.53	100,000	$12.3	$3.4	$8.8
2058	$89.05	$20.00	$6.65	7.0%	$124.40	100,000	$12.4	$3.4	$9.0
2059	$90.83	$20.00	$6.65	7.0%	$126.32	100,000	$12.6	$3.5	$9.2
2060	$92.64	$20.00	$6.65	7.0%	$128.27	100,000	$12.8	$3.5	$9.3
2061	$94.50	$20.00	$6.65	7.0%	$130.27	100,000	$13.0	$3.6	$9.5
2062	$96.39	$20.00	$6.65	7.0%	$132.30	100,000	$13.2	$3.6	$9.6
2063	$98.31	$20.00	$6.65	7.0%	$134.37	100,000	$13.4	$3.6	$9.8
2064	$100.28	$20.00	$6.65	7.0%	$136.48	100,000	$13.6	$3.7	$10.0

*Prices, curtailment percentage and unbottled energy are illustrative only, and prices are in nominal dollars.