COORDINATED GRID PLANNING PROCESS: CYCLE 1 REPORT

MAY 4, 2026

JOINT UTILITIES
OF NEW YORK

The Joint Utilities prepared this report to summarize the work that has been conducted since early 2024 to implement the Coordinated Grid Planning Process, a structured approach to assessing and planning the electric grid in New York State to accommodate an unprecedented capacity of clean energy resources that will enter service in the coming decades.

This work has benefited from deep collaboration among the Joint Utilities, the Department of Public Service Staff, the New York State Energy Research and Development Authority, the New York Independent System Operator, the Energy Policy Planning Advisory Council, and countless stakeholders that have engaged in this planning cycle.

CONTENTS

TABLE OF FIGURES

APPENDICES

EXECUTIVE SUMMARY

On August 13, 2023, the Public Service Commission (the Commission) initiated the Coordinated Grid Planning Process (CGPP), requiring New York's investor-owned electric utilities (the Joint Utilities)[1] and the Department of Public Service Staff (DPS Staff) to submit a **least-cost portfolio of local transmission projects to facilitate delivery of new energy resources.**[2] **The Commission should have confidence in approving the projects included here** as they (i) were identified and vetted through multiple phases of prescribed engineering and modeling analyses, (ii) are technically feasible and cost-effective, and (iii) can be undertaken today. Importantly, these projects can help manage risk against policy and economic uncertainty, as the projects proposed in this first CGPP cycle address priority system needs that are required under a range of plausible future conditions.

CGPP Cycle 1 represents a first-of-its-kind coordinated planning effort among the Joint Utilities, DPS Staff, the New York State Energy Research and Development Authority (NYSERDA), the New York Independent System Operator (NYISO), and a broad range of stakeholders engaged through the Energy Policy Planning Advisory Council (EPPAC). This report and the set of projects proposed herein have been developed over two years and have involved unprecedented collaboration and analysis. The Joint Utilities' coordinated long-term planning efforts mark a significant step forward in supporting New York

1 For this filing the Joint Utilities include Central Hudson Gas & Electric Corp. (Central Hudson); Consolidated Edison Company of New York, Inc. (Con Edison); 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).

2 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* (the CGPP Proceeding), Order Approving a Coordinated Grid Planning Process (August 17, 2023) (the CGPP Order).

State's ambitious clean energy goals while enhancing grid reliability, resilience, and capacity for economic development.

PLANNING FRAMEWORK AND SCENARIOS

At the foundation of CGPP Cycle 1 was a structured, multi-stage analytical process with intentional channels for stakeholder engagement. The Joint Utilities, with DPS Staff, NYSERDA, and stakeholders, developed a set of clean-energy-buildout scenarios for use throughout the cycle. These scenarios were not intended to predict a single future system configuration, but rather to represent a reasonable range of least cost pathways to comply with State policies and test how different assumptions regarding load growth, generator costs, technology adoption, and transmission constraints affect projected needs for transmission investment.

The three scenarios the CGPP ultimately evaluated are referred to as the State Scenario, the High-Capital Cost, Low-Operating Cost (HCLO) Scenario, and the High-Transmission Impact Scenario. The State Scenario aligns with the Climate Action Council's Integration Analysis and NYISO planning assumptions and is also one of the three NYISO System and Resource Outlook scenarios. It reflects significant electrification-driven load growth, large-scale deployment of renewable resources (including offshore wind and utility-scale solar), increasing reliance on energy storage, and the introduction of dispatchable emissions-free resources (DEFRs).[3] The HCLO Scenario explores the effect that innovative, high-capital cost, low-operating cost DEFR options would have on the need for transmission infrastructure. The High-Transmission Impact Scenario was designed to test a future with higher customer energy demands, and a corresponding higher need for transmission infrastructure.

Headroom describes the electric grid's projected ability to accommodate additional generation capacity before thermal limitations of the system are reached. It is a planning construct used to assess how much capacity can be integrated into the grid, either under current conditions or following specific grid investments, without creating reliability concerns.

SYSTEM NEEDS AND SOLUTIONS: THE CGPP PORTFOLIO

The capacity expansion[4] modeling completed in the first phase of work (i.e., CGPP Stage 1) identified a need to build substantial amounts of new energy resources to meet forecasted load growth and policy requirements. These resources were modeled on a scale that, in many locations, exceeded the available capacity of the existing local transmission system. These

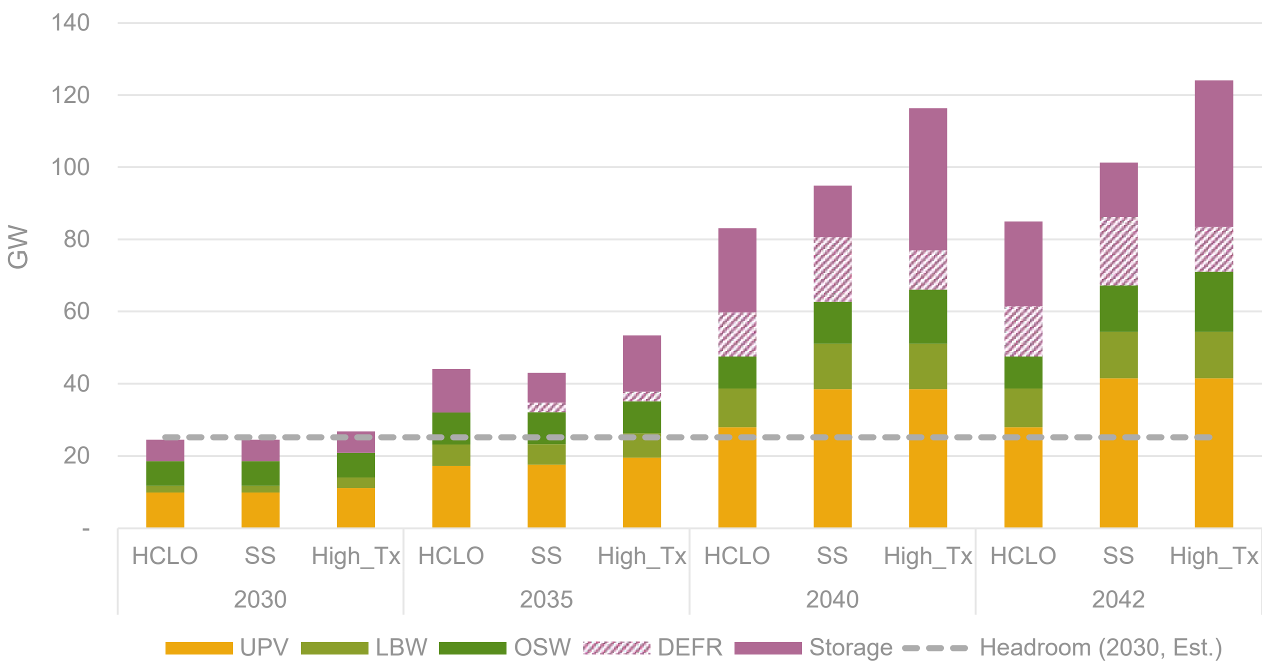
3 "DEFR" refers to a range of technologies including long duration energy storage, small modular nuclear reactors, hydrogen thermal generation, etc.

4 A capacity expansion model solves for the least-cost combination of investments that achieve state policy under assumptions about the future.

results[5] highlighted the need for local transmission projects to create sufficient "headroom" for the level and geographic distribution of the incremental resources selected by the model.[6]

Figure 1, below, illustrates existing headroom and the zonal distribution of new capacity that emerged from CGPP Stage 1, making clear the need for more local transmission capacity to enable these new resources. The Joint Utilities further applied advanced power flow and short-circuit models across scenarios, target years, and various seasonal conditions to identify thermal, voltage, and reliability constraints that would require infrastructure solutions to resolve.

Figure 1: Cumulative Clean Energy Capacity Additions under the Three CGPP Scenarios (Statewide, MW)



In total, the Joint Utilities developed a portfolio of 25 detailed local transmission project sets for consideration by the capacity expansion model.[7] (See Figure 2, below.) More than half of these project

5 The economic capacity expansion modelling completed by the NYISO that informs the project recommendations is calibrated to optimize for a least-cost portfolio of projects that create sufficient headroom (which is a function of assumptions concerning future electricity demand, energy policy, localized project costs, and performance by technology type.

6 The Joint Utilities are not proposing standalone distribution upgrade projects in this CGPP cycle. Distribution system assumptions and constraints were reflected in load and DER forecasts and informed the assessment of local transmission needs. Distribution–transmission interdependencies were accounted for in quantifying incremental headroom needs.

7 Each project (or "project set") discussed in this report may have many component elements. That is, each project discussed above (and appearing in Figure 3, below) represents a complex set of sub-projects that are designed to create headroom when combined.

sets (13 out of 25) involved the application of advanced technologies, which the Joint Utilities evaluated in collaboration with the Advanced Technologies Working Group (ATWG) at the Commission's direction. One advanced technology considered, but ultimately not proposed here, was energy storage as a transmission asset. Figure 1 illustrates that each CGPP Scenario reflects high storage penetration (*e.g.*, 13.6 GW in 2040 in the State Scenario) in CGPP Stage 5.

This preliminary portfolio of 25 project sets represented an estimated $20 billion investment. In addition to the local projects, NYSERDA developed a set of conceptual bulk transmission system projects. Together, these local and conceptual bulk projects represented the upper-bound investment scenario that NYISO evaluated as part of its modeling analysis.

Figure 2: Summary of Headroom-Producing project sets the Joint Utilities developed in this first CGPP cycle.

Company	Project Sets Developed in CGPP Cycle 1	Total Headroom Unlocked (MW)
Central Hudson	2	466
Con Edison and Orange & Rockland	3	2,548
National Grid	6	4,720
NYSEG and RG&E	11	2,870
PSEG-LIPA	3	1,614
Total	**25**	**12,218**

The NYISO evaluated this complete set of local project sets and the conceptual bulk solutions developed by NYSERDA using a capacity expansion model to select projects needed to achieve the State's policy objectives. The model selected various project sets in each CGPP Scenario.

Based on these modeling results and in accordance with the Commission's direction to submit specific recommended projects, the Joint Utilities identified a subset of seven local solutions by focusing on those project sets that were consistently selected by the capacity expansion model across scenarios, resulting in the CGPP Portfolio recommended in this report. (See Figure 3, below.) All seven projects in this portfolio were selected in multiple CGPP planning scenarios. This portfolio represents a least-cost plan for meeting the State's targets and is suitable for Commission consideration today. Notably, following NYISO's identification of potentially beneficial projects through its modeling, an additional assessment was conducted to down-select projects recommended for development. This utility-driven refinement informed the final CGPP Portfolio that is deliverable, beneficial, and at least cost. The Joint Utilities plan to conduct additional analysis on the projects that are not part of the CGPP Portfolio in future CGPP cycles.

Figure 3: The CGPP Portfolio.

Project Name/Identifier	Has Adv. Tech. Elements	NYCA[8] Zone	Incremental Headroom (MW)	Project Cost ($ millions)[9]	Earliest Available to the Model	Earliest Need-by Date
Con Edison Project #1		I-to-J	750	$2,316	2033	2033
Con Edison Project #2		J	1500	$1,309	2033	2035
National Grid Oneida County Transmission Upgrade	Y	E	1440	$1,077	2035	2035
National Grid Mohawk Valley Transmission Upgrade	Y	F	900	$1,110	2035	2038
RG&E Rochester Cat 1		B	130	$92	2032	2038
NYSEG Hornell/Elmira/Bath Cat 1	Y	C	740	$1,884	2035	2040
NYSEG Binghampton Cat 1		C	920	$885	2034	2040

CONCEPTUAL BULK SOLUTIONS, KEY POLICY PRIORITIES

The CGPP Portfolio was developed with explicit consideration of conceptual bulk transmission solutions provided by NYSERDA. Modeling results indicate a potential need for a single bulk solution around 2040, with the analyses consistently selecting a conceptual West-to-East bulk transmission solution in that timeframe across all scenarios.[10] The capacity expansion modeling analysis demonstrates that the selection of the project sets in the CGPP Portfolio does not change materially based on the availability of the conceptual bulk solutions.

In addition, each of the CGPP Portfolio project sets have been evaluated closely for alignment with a range of New York policy initiatives. Three of the seven projects in the portfolio contain advanced, grid-enhancing technology (GET) elements.[11] Only a small subset of components of the seven projects are expected to affect disadvantaged communities (DACs).

SYSTEM NEEDS PERSIST AMID A SHIFTING CLEAN ENERGY PATHWAY

New York's clean energy transition has evolved since CLCPA-era planning assumptions were developed. The Joint Utilities have endeavored to manage increasing uncertainty around the timing and pathway for

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8 NYCA: New York Control Area, the NYISO-defined electric system area encompassing New York State and subdivided into 11 load zones (Zones A–K).

9 Con Edison and National Grid project cost estimates are in $2035. NYSEG and RG&E project costs are the sum of annual cash flows (please see NYSEG/RG&E Appendix for more details).

10 If the Commission finds that there is a need to pursue one or more bulk system projects, these will most likely be pursued through the NYISO's Public Policy Transmission Need (PTTN) process. Please see the CGPP Principles section of this Report for additional information.

11 The Joint Utilities proposed opportunities to minimize the cost of adding headroom through the deployment of GETs, but did not include storage as a transmission asset in any of the project sets in the CGPP Portfolio. However, the least cost results from CGPP indicate that between 13.8 and 25.8 GWs of battery storage (depending on the scenario) will be built by 2040 to provide an optimal and reliable supply of clean energy.

achieving the State's policy targets, recognizing that the analysis has taken place during a period in which inflation, supply-chain- disruptions, rising interest rates, permitting and interconnection constraints, growing electric load, changing federal policy support, offshore wind uncertainty, and heightened affordability concerns are top of mind for policymakers and customers alike. These factors have materially altered the State's planning context, with stakeholders, ongoing proceedings, and the Governor acknowledging the shrinking path for the State to achieve the 70 percent renewable electricity target by 2030.[12,13] The latest State Energy Plan explicitly acknowledges that several environmental milestones are not achievable on the original timeline under current conditions, and reframes planning priorities to focus on reliability, affordability, and implementation feasibility.[14]

Despite these changes to the New York energy landscape, the CGPP Portfolio still addresses priority transmission system needs. Critically, the CGPP modeling found that the entire CGPP Portfolio was necessary across all three CGPP Scenarios, which together represent a diverse and plausible set of futures designed by the State, the Joint Utilities, and other stakeholders. Indeed, the purpose of scenario-based planning is risk mitigation: Planners can minimize the risk of poor investments by selecting only those projects that are valuable across a variety of—or all—futures. Thus, notwithstanding the changes to New York's energy landscape since the start of CGPP Cycle 1, the CGPP was designed to produce no-regrets solutions that are robust in the face of uncertainty and are expected to provide the most value to customers.

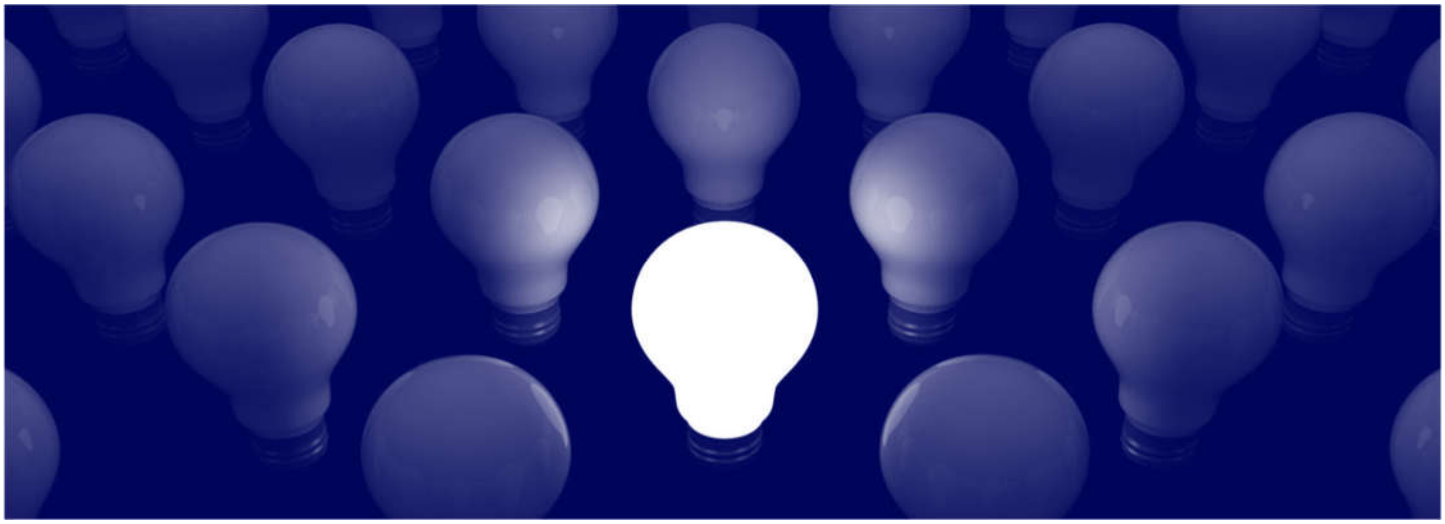
Accordingly, **the CGPP Portfolio presented in this report is deliberately constrained to balance affordability impacts while maintaining consistency with the established objectives and analytical framework of the CGPP.** Con Edison, National Grid, NYSEG, and RG&E respectfully request the Commission's approval to pursue the development of the identified projects to meet these needs and support the State's vision of a clean, reliable, and affordable energy future.

12 Governor Kathy Hochul, "Climate Action and Affordability Can and Must Go Hand-In-Hand," *Empire Report New York* (March 20, 2026).

13 State of New York Public Service Commission, Case 15-E-0302. Proceeding on Motion of the Commission to Implement a Large-Scale Renewable Program and Clean Energy Standard, Order Adopting Clean Energy Standard Biennial Review as Final and Making Other Findings (Issued and Effective May 15, 2025)

14 2025 New York State Energy Plan. Available at: https://energyplan.ny.gov/-/media/Project/EnergyPlan/files/2025-Energy-Plan/2025-NY-State-Energy-Plan.pdf

INTRODUCTION



The CGPP originates from a sequence of State policy actions beginning with the Climate Leadership and Community Protection Act (CLCPA), which established New York's overarching clean-energy and emissions-reduction requirements. To implement those mandates, the Legislature enacted the Accelerated Renewable Energy Growth and Community Benefit Act (AREGCBA),[15] the enabling statute that directed the modernization and expansion of the State's transmission and distribution systems. Pursuant to AREGCBA, the Commission instructed the Joint Utilities to design a coordinated long-term planning framework,[16] resulting in the development of the CGPP.[17] The Commission's August 2023 Order[18] establishing the study structure and sequencing for CGPP Cycle 1 while providing flexibility for utilities and stakeholders to refine assumptions as planning advances.

This report represents the final step in the Joint Utilities' fulfillment of the first Commission-mandated planning cycle. Working in collaboration with DPS Staff, NYSERDA, the NYISO, and other stakeholders, the Joint Utilities have developed and executed this coordinated planning approach to address the evolving challenges of integrating large-scale clean energy generation resources, energy storage, and distributed energy resources (DERs). This approach also supports the grid's ability to accommodate increasing electrification demands, advance economic development, and enable the implementation of smart grid technologies. The Joint Utilities' coordinated long-term planning efforts mark a significant step

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15 See, *infra*, note 2.

16 CGPP Proceeding, Order on Local Transmission and Distribution Planning Process and Phase 2 Project Proposals (September 9, 2021).

17 CGPP Proceeding, Coordinated Grid Planning Proposal (December 27, 2022).

18 CGPP Proceeding, Order Approving a Coordinated Grid Planning Process (August 17, 2023) (The CGPP Order)

forward in supporting New York State's ambitious clean energy goals while enhancing grid reliability, resilience, and capacity for economic development.

This report is the culmination of over two years of complex and collaborative long-term system planning. It describes the key stages and features of the Joint Utilities' work to complete Cycle 1, including the definition of planning scenarios, identification of system constraints, prioritization of grid infrastructure investments, and stakeholder engagement throughout the planning process. Ultimately, Con Edison, National Grid, NYSEG, and RG&E propose a portfolio of local transmission system solutions for Commission consideration.

The remainder of the report is organized in six key sections:

1. *The Coordinated Grid Planning Process* presents the objectives and stages of analysis as they were planned and as they have taken place.
2. Foundation Setting: CGPP Stage 1 introduces the core assumptions and scenarios that were defined in collaboration with stakeholders.
3. System Needs & Solutions: CGPP Stages 2, 3, and 4 describes the system conditions and limitations that have informed the development of candidate projects for consideration as components of a Statewide local transmission project portfolio.
4. Least Cost Planning Assessment: CGPP Stage 5 describes the results of the capacity expansion analysis that included project sets developed pursuant to Stages 1-4, including evaluation of conceptual bulk transmission system projects, resulting in a portfolio of projects for which utilities are seeking approval and cost recovery.[19]
5. The Conclusion summarizes the analyses and proposals described in this report.
6. Appendices provide additional details on analytical results, project descriptions, and other aspects of Cycle 1.

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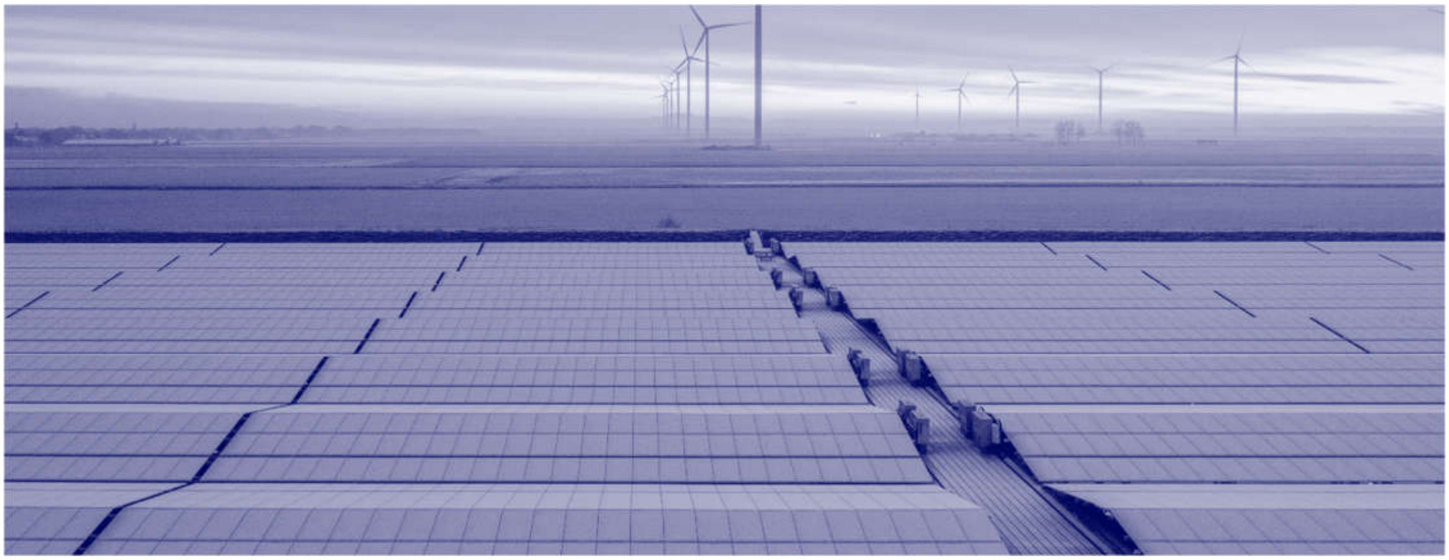
[19] Con Edison, National Grid, NYSEG, and RG&E plan to recover Commission-approved local transmission project costs using the Cost Sharing and Revenue Agreement (CSRA), which the Commission approved in this proceeding. The CSRA provides a transparent mechanism for allocating and recovering the costs of qualifying local transmission projects in a manner that reflects shared system benefits and advances uniform statewide planning objectives. Recovery under the CSRA is appropriate for the projects proposed in this cycle, as they were developed through the Commission-directed CGPP framework and provide demonstrable benefits beyond individual utility service territories. See CGPP Proceeding, *Order Accepting Compliance Filings* (issued May 12, 2022).

THE COORDINATED GRID PLANNING PROCESS



PRINCIPLES

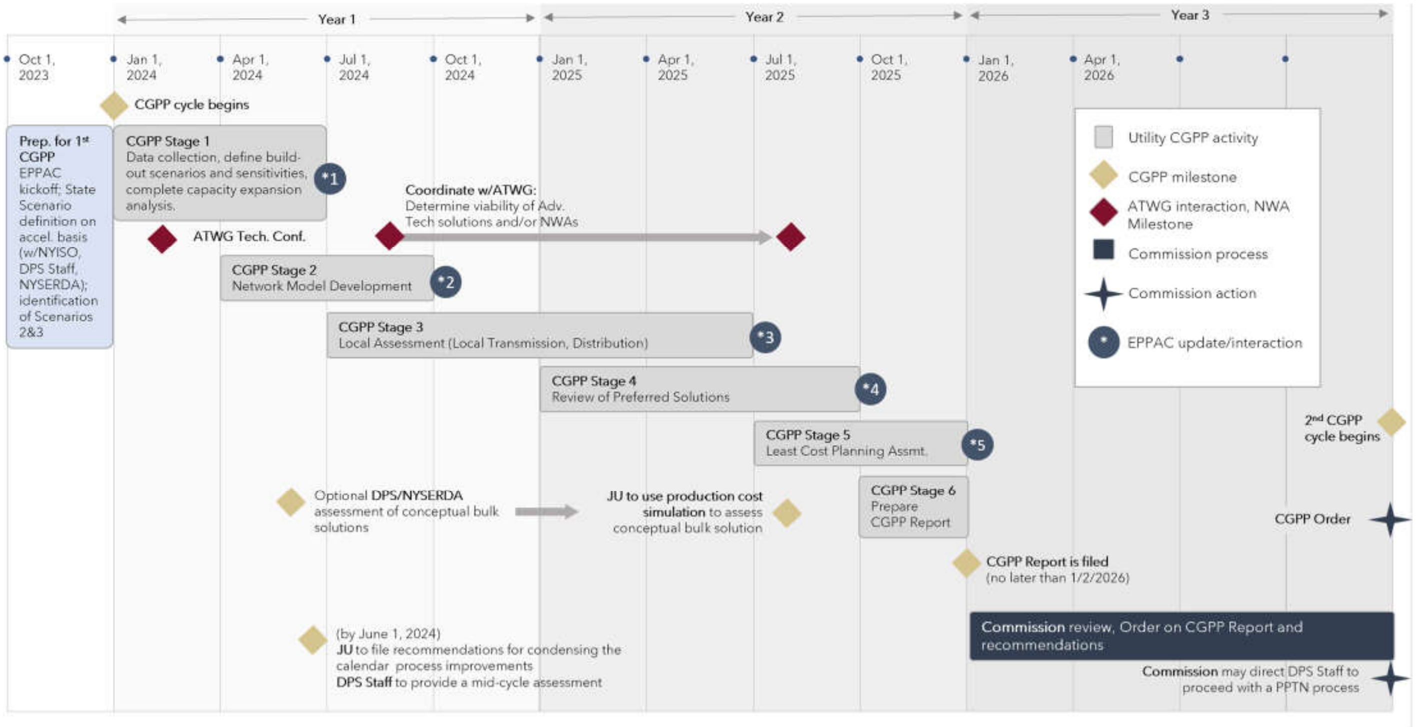
The CGPP is built on a set of foundational principles designed to make the State's local and bulk transmission planning process robust, more transparent and participatory, and aligned with achieving the State's clean energy goals at the least cost. Ultimately, the CGPP is a process grounded in rigorous technical modeling and stakeholder input that results in utilities recommending a portfolio of grid investments that would enable the State to achieve its climate targets at the least possible cost, along with information for the Commission's consideration regarding potential bulk needs to be addressed through the Public Policy Transmission Need (PPTN) Planning Process. This section introduces certain key features and themes of the CGPP process, such as:

- **Phased and Cyclical Structure:** As refined by the Commission's November 2025 Order, the CGPP is designed as a multi-stage, cyclical planning process that is coordinated with NYISO planning through aligned scenarios, shared data and modeling assumptions, synchronized timelines, and complementary analytical roles. In addition, at the Commission's direction,[20] the CGPP includes evaluation of the Joint Utilities' local solutions alongside conceptual bulk transmission solutions prepared at a preliminary level by NYSERDA.
- **Technical Rigor:** Each phase of the CGPP is grounded in integrated planning and engineering analyses—including capacity expansion modeling, power flow studies, and short circuit analysis—used to identify system constraints, evaluate performance under multiple futures, and inform cost-effective solution development.

[20] CGPP Proceeding, CGPP Order, pp. 30-31.

- **Actionable Portfolio Development:** This CGPP cycle has produced a defined portfolio of near-term bulk and local transmission projects for Commission consideration. This portfolio of projects was selected based on their collective ability to maximize transmission capacity for emissions-free generation and to be feasibly constructed within required schedules. The applicable utilities have completed technical assessments for these local projects, including quality cost estimates and evaluation of DAC impacts, system reliability impacts, and achievement of policy objectives.
- **Stakeholder Engagement:** The CGPP incorporates structured stakeholder engagement through the EPPAC, a Commission-convened forum of technically experienced stakeholders that provides input on scenario development, modeling assumptions, sensitivities, and emerging issues throughout the planning cycle. The EPPAC is discussed in detail in Appendix B, including a description of specific consultative sessions that the Joint Utilities and others have hosted to convey information and plans related to progress on CGPP stages.
- **Advanced ("Grid Enhancing") Technologies:** GETs are evaluated as potential solutions, or components of larger solutions, using standardized screening criteria developed with the ATWG to assess where they may cost-effectively address identified system needs.
- **DAC Considerations:** The Joint Utilities apply a framework based on the Commission's guidance to categorize CGPP projects, document justifications, and, where appropriate, evaluate alternatives for projects that are partially or wholly located in disadvantaged communities, supporting transparent and consistent consideration of impacts and tradeoffs.

Figure 4: CGPP Timeline (per August 17, 2023 Order).



FOUNDATION SETTING: CGPP STAGE 1 (CAPACITY EXPANSION MODELING)

October 2023 – December 2024

BACKGROUND

The purpose of CGPP Stage 1 was to develop three policy-compliant capacity expansion scenarios (referred to throughout this Report as CGPP Scenarios). They were intended to test how different assumptions concerning load growth, candidate resources, and technology adoption would influence the build-out of generation, and thus long-term infrastructure needs on the bulk transmission and local systems. The three CGPP Scenarios were designed to represent a reasonable range of future system conditions. The goal of the scenario development process was not to predict a single future, but to understand the future needs of the electric system across a range of plausible pathways.

DPS Staff hosted a series of EPPAC meetings beginning in the 3rd quarter of 2023 to solicit ideas and discussion about CGPP Scenarios from the stakeholder community. The Joint Utilities, DPS Staff, the EPPAC, and NYISO set a baseline generation buildout in the *State Scenario* and developed two alternative scenarios: the *Low-Transmission Impact Scenario* and the *High-Transmission Impact Scenario*. These scenarios made different assumptions about certain key variables (e.g., DER adoption) that will influence the evolution of the grid.

Figure 5: Scenario Comparison

Scenario	What It Represents	Why It's Included
State Scenario	Policy-aligned baseline reflecting Climate Action Council Integration Analysis + NYISO assumptions	Serves as the core planning case anchored in State policy objectives
Low Transmission Impact *(Later Replaced with the HCLO Scenario)*	Higher DER adoption, lower storage costs, more flexible load	Tests how local resources could reduce transmission build needs
High-Transmission Impact	Higher peak load, no EV flexibility, increased utility-scale buildout	Tests upper-bound transmission needs under more stressed system conditions
High Capital, Low Operating Cost (HCLO) Scenario[21]	Includes an additional high-capital cost, low-operating cost DEFR option	Assesses the need for T&D investment in the case that innovative DEFRs are able to offset need for renewable resources in various regions

These CGPP Scenarios (along with a set of related sensitivities) were then evaluated using capacity expansion modeling to reveal the need for additional grid infrastructure to achieve State policy under each set of varied assumptions. Capacity expansion is a type of long-term planning model used to simulate how the electricity system may evolve over time.[22] The model was configured to identify the least-cost mix of new generation, storage, and transmission resources needed to meet forecasted electricity demand and policy goals (e.g., greenhouse gas emissions limits or clean generation portfolio features) over a multi-decade horizon. A capacity expansion model determines the combination of resource and infrastructure investments that minimizes total system cost while satisfying state policy requirements, given a defined set of assumptions about future conditions.
The Joint Utilities engaged the NYISO to conduct capacity expansion modeling for the CGPP under a *Requested Economic Planning Study* (REPS) Agreement.[23]

The NYISO presented final capacity expansion results for the three CGPP Scenarios in a sequence of EPPAC meetings in the summer of 2024. As is discussed below, the Joint Utilities, in collaboration with DPS Staff and the EPPAC, determined that the Low-Transmission Impact Scenario was not sufficiently distinct from the State Scenario. As a result, the Low-Transmission Impact Scenario was ultimately replaced with a *HCLO Cost DEFR Sensitivity* to achieve a better contrast between scenarios without sacrificing plausibility.

21 The HCLO Scenario was initially a sensitivity run on the State Scenario. As discussed below, it was elevated to being a principal Scenario when modeling results indicated that the Low Transmission Impact Scenario was too similar in effect to the State Scenario.

22 NYISO uses capacity expansion modeling in other processes such as the System & Resource Outlook, which began in 2021.

23 A REPS evaluation is a specific type of analysis conducted by the NYISO as part of its transmission planning process.

Figure 6: Core Components of CGPP Stage 1

Scenario Development

Develop up to three scenarios that represent potential futures for the New York State economy in terms of demand growth and profile, the deployment of technologies and sources of demand, etc.

Capacity Expansion Modeling

Determine the least-cost buildout of generation, energy storage, and transmission resources consistent with State policies and the CGPP Scenario assumptions.

Analysis of Sensitivities

Explore variations of CGPP Scenarios to evaluate how changing specific assumptions materially affect resource buildout. Sensitivity analysis can inform key features of local transmission developments that are ultimately proposed in the CGPP cycle.

As the capacity expansion model placed generation resources, it also accounted for costs of the necessary transmission investments. Accordingly, the model placed generation to minimize the overall cost of the generation and transmission build-out subject to county-level resource potentials determined by NYSERDA.

In the capacity expansion model, the capability of the local transmission system to accept generator capacity additions is represented entirely by a metric called "headroom." ***Headroom*** describes the electric grid's projected ability to accommodate additional generation capacity before thermal limitations of the system are reached. It is a planning construct used to assess how much capacity can be integrated into the grid, either under current conditions or following specific grid investments, without creating reliability concerns.

Interconnecting the generation built under the CGPP Scenarios would require significant expansion of both bulk and local transmission systems to facilitate efficient delivery of renewable energy from resource-rich locations to areas of high electricity demand. The outcomes of Stage 1 thus provide a critical foundation, guiding subsequent analyses as to the grid investments truly necessary to realize New York's clean energy transition goals at the least cost.

STATE SCENARIO

The State Scenario, which aligns closely with the assumptions of the Climate Action Council's Integration Analysis[24] (specifically Scenario 2 of the Integration Analysis) and complies with state energy policies, reflects critical inputs such as projected load growth, anticipated DER deployment across the state, resource retirements, and other key planning factors. The scenario leverages existing state and

24 New York State Climate Action Council Scoping Plan 2022, climate.ny.gov/ScopingPlan

NYISO studies, ensuring consistency and comprehensiveness in the modeling assumptions. The State Scenario was primarily developed by DPS Staff based on key assumptions in the NYISO's System Resource Outlook, Gold Book, and the State's Climate Action Council's Scoping Plan.[25]

The State Scenario served as the foundation on which other scenarios, such as the Low-Transmission Impact and High-Transmission Impact Scenarios, were designed.[26]

Key assumptions of the State Scenario include the following:

<u>Policy Attainment</u>

- Achieve a 70% renewable energy threshold beginning in 2030.
- Deploy 6 GW of energy storage and 10 GW of DER by 2030.
- Most of the fossil fleet remains available through 2039 to support capacity and energy needs but is fully replaced by zero-emission resources by 2040, achieving a zero-emissions electric grid by 2040, including net-zero imports from neighboring regions such as IESO (Ontario's electric system operator), PJM, and ISO-NE starting in 2040.

<u>Energy Demand and Peak Loads</u>

- Based on the "Scenario 2" forecast from the Climate Action Council's Integration Analysis, with adjustments for planned large load projects and electrolysis demand outlined in the Integration Analysis Annex 1 and 2.
- Assumes doubling of the energy demand by 2042 compared to 2021.
- Includes load from electrolysis and charging energy storage resources, and considers the impact of additional load flexibility, particularly from electric vehicle (EV) charging.
- Assumes that 50% of economy-wide hydrogen demand is met by in-state electrolysis on an annual basis.

<u>Generation Resources</u>

- Candidate generators for expansion include land-based wind (LBW), offshore wind (OSW), utility-scale photovoltaic (UPV), 4-hour and 8-hour battery storage, and DEFRs, specifically new or retrofitted hydrogen combustion turbines (CT) and hydrogen combined-cycle (CC) units.
- Capital costs for these candidate renewable resources are determined by technology type, based on the NYSERDA Supply Curve Analysis, and are adjusted on a zonal basis.
- Assumes age-based retirements for fossil fuel generators.

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[25] New York State Climate Action Council Scoping Plan 2022, p. 119.
See: https://climate.ny.gov/resources/scoping-plan

[26] That is, the other CGPP Scenarios (and sensitivities, which are discussed below) are modifications of key features of the State Scenario.

Transmission Considerations

- Headroom (MW) was the single metric used to represent intra- and sub-zonal local transmission constraints in the capacity expansion model.
- A generic local headroom cost assumption of $0.389M/MW was used in Stage 1 as a proxy for local transmission expansion costs.
- Implements a 15% compounding cost for every additional 1 GW of incremental headroom required in a zone, influencing the distribution of new generation capacity on a zonal basis.

LOW-TRANSMISSION IMPACT SCENARIO

The Low Transmission Impact Scenario differs from the State Scenario in its assumptions regarding energy storage costs, distributed energy resources (DER), and flexible electric vehicle (EV) loads. Key assumption changes include:

- Lower energy storage costs: Battery costs for both 4-hour and 8-hour storage systems are 20% lower in 2025 and 12% lower in 2042.
- Higher DER penetration: The scenario assumes 40% more behind-the-meter photovoltaic (BTM-PV) capacity by 2042 compared to the State Scenario.
- More flexible EV load: EV charging flexibility is assumed to be 30% higher by 2042.

All other assumptions remain consistent with the State Scenario. This Scenario was designed to test a future in which statewide policies, technology costs, and customer adoption trends evolve in ways that make DERs and flexible load more prominent. It tests how a more favorable policy and technology environment could reduce transmission needs and lower overall system costs. It shows which local transmission projects remain necessary even in a more decentralized, lower-transmission-need future.

These assumptions result in greater local generation and storage deployment, particularly in Zone J (New York City), which offsets the need for upstate hydrogen capacity and UPV expansion. While this shift reduces transmission constraints and infrastructure requirements, it also presents challenges in ensuring sufficient firm capacity, as BTM-PV does not contribute to system reliability in the same way as utility-scale resources. Additionally, the Low Transmission Impact Scenario sees a temporary increase in fossil generation and CO_2 emissions between 2030 and 2035 before deeper decarbonization measures take effect.

The Low-Transmission Impact Scenario was ultimately replaced with Sensitivity 5 (described below as the “Alternate DEFR Option with Additional Constraints”) because the results were too similar to the State Scenario.

HIGH TRANSMISSION IMPACT SCENARIO

The High Transmission Impact Scenario differs from the State Scenario by incorporating assumptions that lead to higher transmission requirements, including increased energy demand and different technology options. Key assumption changes relative to the State Scenario include:

- Higher energy demand and peak load: Energy demand increases by 15 TWh and peak load by 5 GW by 2042.
- No EV load flexibility: Unlike the State Scenario, EV load shifting is removed, increasing peak demand.
- Hydrogen fuel cell adoption: Hydrogen CT and CC units are replaced by hydrogen fuel cells as a capacity expansion candidate, significantly impacting resource selection and operating costs.

All other key assumptions remain aligned with the State Scenario.

This Scenario reflects a future with a more conservative (i.e., higher) peak load estimate and little to no load flexibility, requiring more utility-scale resources to meet peak needs. These assumptions create conditions that both stress the transmission system and accelerate the transition away from fossil generation. Modeling this pathway helps identify which local transmission and conceptual bulk system upgrades are needed under more demanding system conditions.

These assumption changes drive substantial increases in energy storage and OSW deployment, particularly downstate in Zones J (New York City) and K (Long Island), to manage higher peak loads and offset the removal of flexible demand resources. Due to the higher capital costs of hydrogen fuel cells compared to hydrogen CT (including retrofits), battery storage becomes a more economically viable option, leading to an 11 GW increase in battery deployment upstate and a 15 GW increase downstate. The scenario also results in a 4 GW increase in offshore wind capacity downstate, reinforcing the need for expanded transmission infrastructure. While this scenario enables a more rapid transition away from fossil fuels, it also introduces challenges related to grid reliability, higher upfront infrastructure costs, and potential system stress during peak periods.

CGPP SENSITIVITIES

Stakeholders in the EPPAC provided preferences that shaped the assumptions and constraints that define CGPP Scenarios. In response to stakeholder interest, the Joint Utilities made a sequence of formal requests to the NYISO for capacity expansion sensitivity runs to provide a better understanding of how changes in policy, technology, and market conditions might influence the capacity buildout. The Joint Utilities ultimately requested ten sensitivities, which are listed below in Figure 7.

The sensitivities focus on different approaches to capacity requirements, renewable energy zones, and distributed energy resources. They include variations such as relaxation of the limits that apply to zonal interfaces on the bulk transmission system, local capacity requirements, alternative assumptions for distributed energy flexible resources, and the removal of headroom constraints for renewable zones. Sensitivities also explore higher levels of DERs, the impact of electrolysis, and the inclusion of stringent emissions targets. Stakeholders were interested in exploring the effects of removing specific transmission projects and distributed energy generators from certain zones.

Two sensitivities (Sensitivities 1 & 2) were designed to fulfill the Commission's requirement that the Joint Utilities and DPS Staff evaluate the potential need for bulk system solutions.[27] On reviewing the results of these two sensitivities, DPS Staff requested that NYSERDA engage a consultant[28] to identify potential bulk solutions in specific regions of the State and to estimate potential system benefits and costs that can be included in CGPP Stage 5 analyses and project selection.

Figure 7: Capacity Expansion Model Sensitivity List

#	Sensitivity Name	Description, Objective
1	Copper Sheet[29] without Locational Capacity Requirement (LCR)[30]	*Purpose*: Consistent with the CGPP Order, this sensitivity was designed to identify potential bulk transmission needs by evaluating how the model's least-cost solution changed when existing bulk constraints were relaxed. Sensitivity 1 was the first of two "copper sheet" sensitivities based on the State Scenario. LCRs[31] and effective load carrying capability (ELCC) limits were relaxed (with the exception of New York Control Area (NYCA) ELCCs, which remained in place). As a result, the model was free to locate generating resources wherever it wanted to minimize costs. Even knowing that this would not lead to a feasible outcome, it is still helpful for identifying the upper bounds of a build-out without these constraints, as it could signal that the model's outputs hinge significantly on bulk transfer limits. *Conclusion*: At the NYCA level, there was no significant impact to the capacity build-out results in terms of total resources. Within zones, the predominate change was a shift of battery resources from downstate to upstate zones (primarily west of Central East). The redistribution of capacity expansion candidates (excluding storage) between NYCA zones was limited.
2	Copper Sheet with LCR	This sensitivity was identical to Sensitivity 1, except that all LCR requirements and all ELCCs (NYCA and locality ELCCs) were left in place. *Conclusion*: the results were similar to Sensitivity 1, but with fewer shifts in storage resources due to these resources being needed to satisfy local capacity requirements. Generally speaking, capacity availability was more limiting than bulk transmission. As noted above, following a review of the results of Sensitivities 1 & 2 and at DPS Staff's request, NYSERDA engaged Quanta to evaluate representative bulk solutions that were evaluated in the Stage 5 capacity expansion modeling effort to further illustrate the size and shape of potential needs on the bulk transmission system.

27 CGPP Proceeding, CGPP Order, pp. 30-31
28 NYSERDA engaged Quanta to evaluate the need for conceptual bulk solutions in the CGPP analysis.
29 The term "copper sheet" refers to a system condition where there are no transmission constraints, allowing electricity to flow without limitation between any locations in the State.
30 LCRs are minimum amounts of capacity that must be sited within specific zones to ensure local reliability and meet deliverability needs.
31 The NYISO has set LCRs as a percentage of forecasted peak load to ensure reliability, particularly in constrained zones.

#	Sensitivity Name	Description, Objective
3	Alternate Dispatchable Emission-Free Resources (DEFR) Assumptions	*Purpose*: Evaluate NYCA-level resource outcomes with DEFR options as (i) high-capital, low-operating (HCLO) resource resembling nuclear SMR, and (ii) hydrogen fuel cells. HCLO DEFRs were allowed to build in zones A-G. Note: this sensitivity does not include hydrogen CT or CC as DEFR options. *Conclusion*: the HCLO DEFR resource plays a uniquely prominent role in Sensitivity 3, supplying roughly 18 percent of NYCA-wide generation in 2042 and providing a high proportion of firm capacity relative to nameplate capability. The HCLO DEFR meaningfully reduces the need for additional resources, especially OSW, UPV, and LBW, compared to the State Scenario. Overall, this sensitivity highlights that an HCLO DEFR resource can significantly alter long-term resource mix decisions beyond the mid-2030s.
4	Concentrated Renewable Zones	*Purpose*: Explore the State Scenario with no headroom constraint, no annual UPV build limit, and inclusive of the assumptions described in Sensitivity 1 (above), making this a third "copper sheet" variant. This sensitivity was designed to explore the potential for concentrated renewable energy zones after removing all electrical constraints. *Conclusion*: Removing UPV build limits drives a substantial shift in the resource mix. In this sensitivity, approximately 10 GW of additional UPV capacity is built by 2042, paired with roughly 5 GW of additional battery storage to manage variability and meet capacity needs. This expanded UPV-and-storage build largely offsets OSW, LBW, and DEFR capacity relative to the State Scenario, resulting in OSW being developed only to the minimum levels required to meet CLCPA targets (9 GW of OSW by 2035). DEFR retrofits remain selectively preferred for capacity, but these resources contribute limited energy.
5	Alternate DEFR Option with Additional Constraints	*Purpose*: Explore the State Scenario with additional DEFR options: (i) high-capital, low-operating (HCLO) (i.e., resembling the characteristics of nuclear) and (ii) hydrogen fuel cells. Note: This sensitivity does not include hydrogen CT or CC as DEFR options. The HCLO DEFR option, as compared to Sensitivity 3, is further constrained with (i) a maximum allowable capacity of 500 MW in Zones F and G and (ii) application of the zonal capital cost multipliers utilized in the 2023-2042 System & Resource Outlook. *Conclusion*: Sensitivity 5 largely tracks what was observed in Sensitivity 3, indicating broadly consistent system behavior under similar conditions. Removing the retrofit hydrogen CT option shifts capacity provision toward battery storage, reducing reliance on DEFRs for capacity. The HCLO DEFR resource supplies a substantial share of energy (approximately 17% in 2042), thereby displacing additional OSW, UPV, and LBW relative to the State Scenario. OSW capacity remains at the CLCPA minimum, and neither UPV nor LBW reaches assumed supply curve or build rate limits. This Sensitivity replaced the Low-Transmission Impact Scenario and is referred to as the HCLO Scenario throughout this Report.
6	Higher DER	*Purpose*: Evaluate the Low-Transmission Impact Scenario with higher levels of BTM-PV and 50% more load flexibility to account for higher managed charging, load flexibility, and vehicle to grid flexibility. *Conclusion*: A significant expansion of behind-the-meter PV drives a reallocation of generation away from UPV and OSW, with approximately 16 GW of additional BTM PV capacity and 20 TWh of incremental generation by 2042 relative to the State Scenario. This increase is supported by greater load flexibility and additional battery storage, primarily long duration resources with high firm capacity, which together reduce the need for UPV, OSW, and some DEFR capacity while maintaining reliability requirements. These results highlight the strong substitute effect of distributed generation, flexible load, and storage on utility-scale resource needs when higher levels of BTM PV adoption are assumed.
7	Removal of DEFR Generators from Downstate	*Purpose*: Three separate tests on the High Transmission Impact Scenario. Each test assumes no DEFR generator option in Zones J & K with varying transmission constraint assumptions for each test. *Conclusion*: Removing DEFR availability in Zones J and K while retaining transmission and locality constraints drives a substantial buildout of storage and OSW concentrated in Zone J. Nevertheless, this still results in unserved energy during the summer peak, underscoring the binding nature of both capacity and deliverability constraints. Relaxing locality requirements allows more resources to shift upstate and out of Zone J, although transmission limitations and energy needs continue to retain some battery capacity in Zone J and increase OSW development in Zone K, with summer peak unserved energy persisting. Only under a copper sheet configuration, which fully relaxes transmission line limits, do DEFR and battery resources

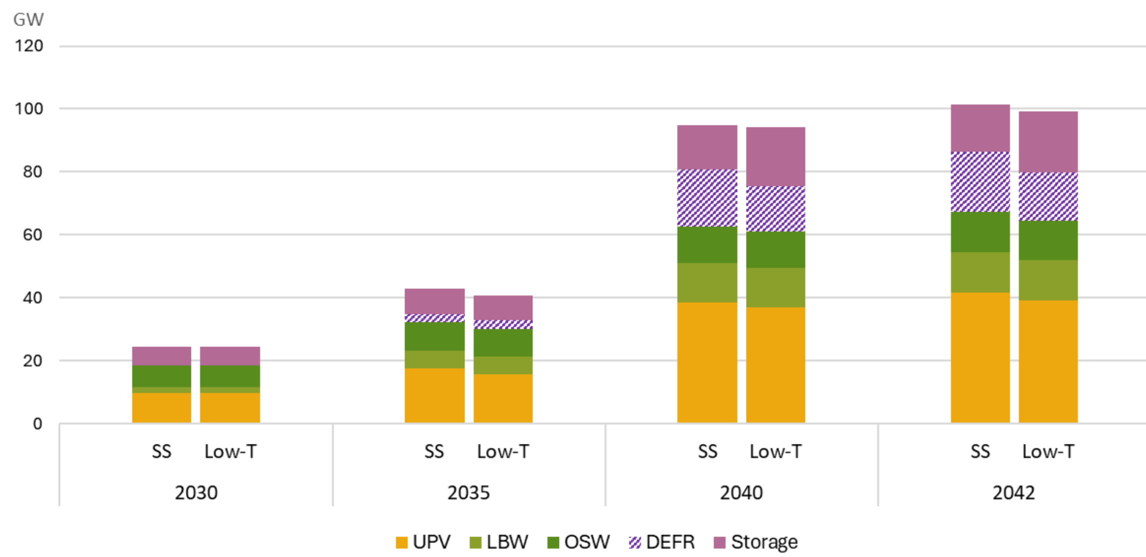
#	Sensitivity Name	Description, Objective
		shift out of Zones J and K without any unserved energy, indicating that transmission constraints are the primary driver of locational resource requirements and reliability outcomes.
8	Impact of Electrolysis (2-part)	*Purpose*: Part A) State Scenario with fixed “rest-of- economy” electrolysis loads distributed as a proportion of native zonal load, model optimized generator electrolysis. Part B) High-Transmission Need Scenario with fixed rest-of-economy electrolysis loads removed, model optimized generator electrolysis *Conclusion*: Applying fixed rest-of-economy electrolysis to the State Scenario shifts energy balancing from predominantly midday solar to a more diverse mix, including batteries, DEFR generation, and net imports during morning, overnight, and shoulder periods, with minimal impact on NYCA-level or zonal capacity. In contrast, *removing* rest-of-economy electrolysis from the High-Transmission Impact Scenario reduces net demand by approximately 14 TWh by 2042, leading primarily to a reduction in OSW capacity and generation in Zone K. Aside from this OSW displacement, the results show limited changes to zonal capacity distribution, with modest increases in DEFR and batteries to meet energy needs during periods of low to no solar generation.
9	Inclusion of 2039 Targets (2-part)	*Purpose*: Clarify the sequencing of investments required to meet full CLCPA compliance in 2040 (i.e., identify the last units needed to be introduced for compliance) by modeling “near” compliance with emissions targets in 2039. This will help determine whether there is a material ramp in costs while approaching full policy attainment. Part A) Sensitivity 5 assuming a 95% zero-emissions target and net zero imports by 2039 Part B) Sensitivity 5 assuming a 90% zero-emissions target and net zero imports by 2039 *Conclusion*: Introducing an additional zero-emission constraint in 2039 has minimal effect on system outcomes in other modeled years, indicating that near-term and long-term resource trajectories are largely unchanged, with differences concentrated in the specific year where the constraint binds. Across cases, most of the fossil fleet remains available through 2039 to support capacity and energy needs—albeit at reduced levels—but is fully replaced by zero-emission resources by 2040, requiring the addition of approximately 17–18 GW of new clean capacity between 2039 and 2040 depending on the stringency of the target. Importantly, both the 95% and 90% zero-emission pathways achieve compliance primarily through incremental battery and DEFR capacity, with similar levels of OSW, LBW, and PV deployment, demonstrating that deeper emissions reductions are met through firm and flexible resources rather than additional variable generation.
10	No CPNY	*Purpose*: State Scenario with the removal of the Clean Path New York transmission project (CPNY). *Conclusion*: Reduced transmission capability from upstate to downstate following removal of the CPNY interface leads to greater reliance on downstate resources, including a modest increase in OSW capacity and higher utilization of DEFR to meet energy needs. By 2042, approximately 400 MW of additional OSW capacity is developed relative to the State Scenario, reflecting the need to replace constrained imports. Storage capacity in Zone J increases by roughly 1.3 GW to support higher LCR obligations that can no longer be offset by CPNY transfer capability.

REPLACING LOW-TRANSMISSION IMPACT SCENARIO

As noted above, the three CGPP Scenarios were designed to represent a reasonable range of future system conditions. However, a review of the capacity expansion modeling results for the Low-Transmission Impact Scenario indicated that its build-out and other results were substantially similar to those of the State Scenario. This similarity is illustrated in Figure 8, which compares the capacity additions for different generation types in key evaluation years for both Scenarios.

As mentioned earlier, given the limited differentiation between the Low-Transmission Impact and State Scenarios, the Joint Utilities replaced the Low-Transmission Impact Scenario with Sensitivity 5, which evaluated the inclusion of a High-Capital Cost, Low-Operating Cost (HCLO) DEFR. The HCLO Scenario evaluates an alternative long-term system pathway in which a nuclear-like, firm, DEFR resource is available, allowing the analysis to assess how a fundamentally different DEFR assumption could affect generation mix and transmission needs.

Figure 8: Cumulative Capacity Additions, Comparison of Scenarios.



After extensive consultation with DPS Staff, NYSERDA, and the EPPAC, Sensitivity 5 (which includes an alternate, high-capital cost, low-operating cost DEFR option) was promoted to replace the Low-Transmission Impact Scenario in the remainder of the CGPP cycle's stages.

SCENARIO MODELING RESULTS

Summary results for the clean energy capacity buildout, organized by technology and by NYCA zones, are presented below for each CGPP planning scenario. These summaries from the NYISO's capacity expansion analysis highlight the relative scale and composition of resource development across scenarios. Figure 9 depicts the Statewide resource build-out across the three CGPP Scenarios and across years. Figure 10 illustrates the existing and incremental headroom by zone from each scenario, all for 2042. Figure 11, Figure 12, and Figure 13 illustrate zonal resource build-out for the HCLO, State, and High-Transmission Impact Scenarios (respectively), by year.

The underlying capacity expansion modeling results contain extensive additional detail and are not reproduced here. These results are provided in their entirety in Appendix C.

Figure 9: Cumulative Capacity Additions by Scenario (GW).

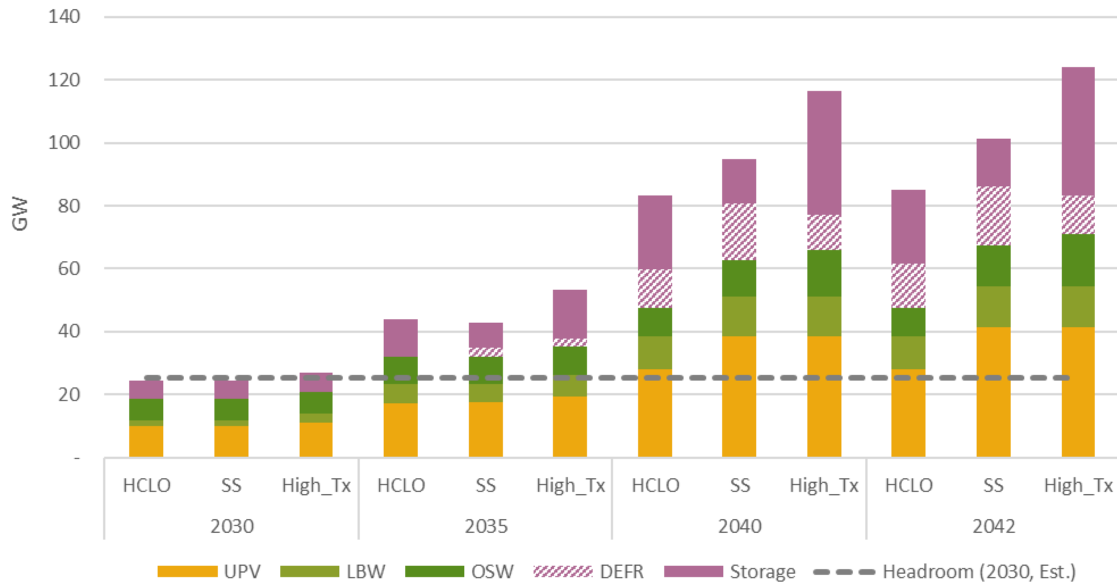
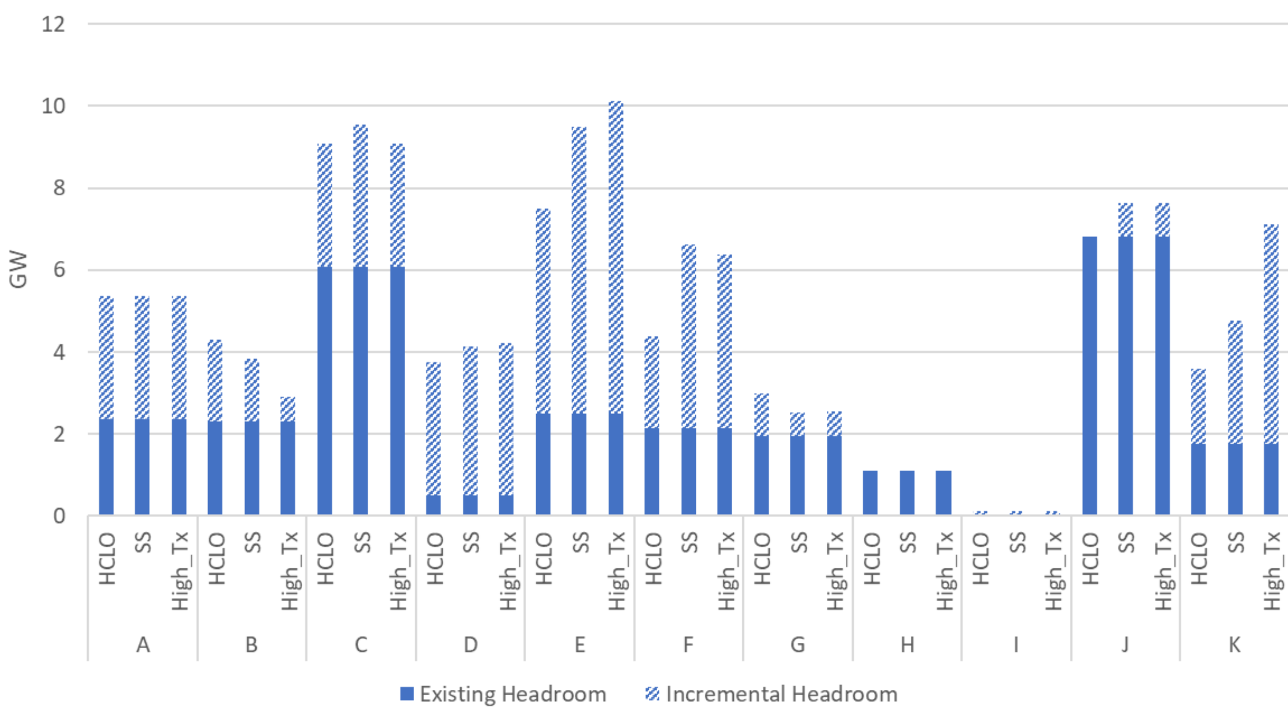
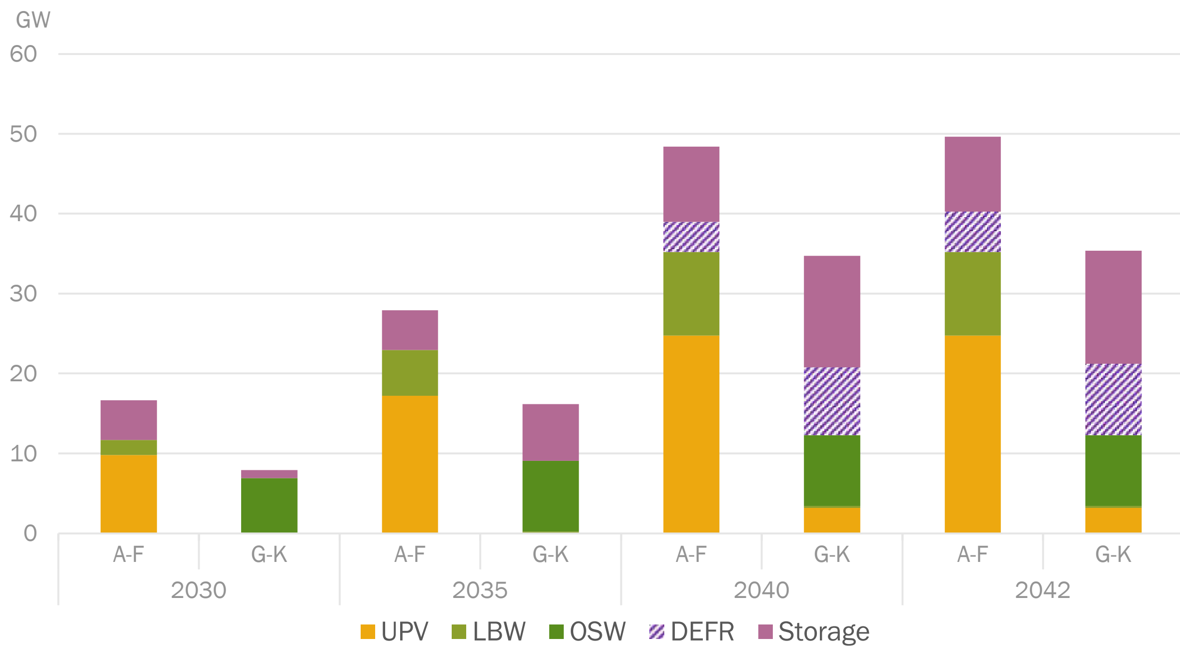


Figure 10: CGPP Stage 1 Existing and Incremental Headroom in 2042 by NYCA Zone, Scenario (GW).



HCLO Scenario

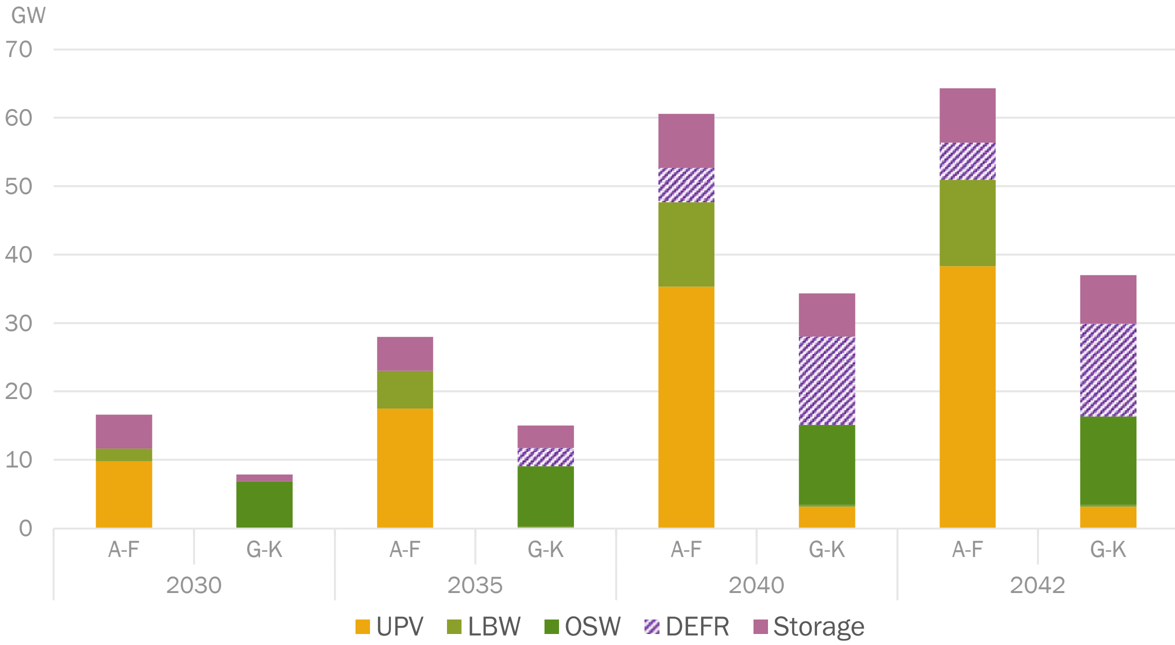
Figure 11: HCLO Scenario Cumulative Capacity Additions - Upstate vs Downstate



Capacity (Summer MW)						
	2021	**2025**	**2030**	**2035**	**2040**	**2042**
Nuclear	4,378	3,342	3,342	3,342	3,342	3,342
Fossil	26,345	25,753	22,424	15,022	-	-
DEFR - HCLO	-	-	-	-	4,276	5,525
Hydrogen - Fuel Cell	-	-	-	-	7,999	8,407
Hydro	4,868	6,294	7,544	7,665	7,665	7,665
LBW	2,227	3,291	4,815	8,858	13,676	13,676
OSW	0	136	6,990	9,000	9,000	9,000
UPV	32	3,135	11,270	18,676	29,337	29,337
BTM-PV	2,116	5,384	8,972	8,973	12,019	12,019
Storage	1,405	2,905	7,405	13,503	24,797	25,014
Total	**41,686**	**50,562**	**73,081**	**85,362**	**99,836**	**100,053**
Annual Peak (MW)	**30,397**	**29,568**	**29,861**	**37,047**	**45,062**	**47,046**

State Scenario

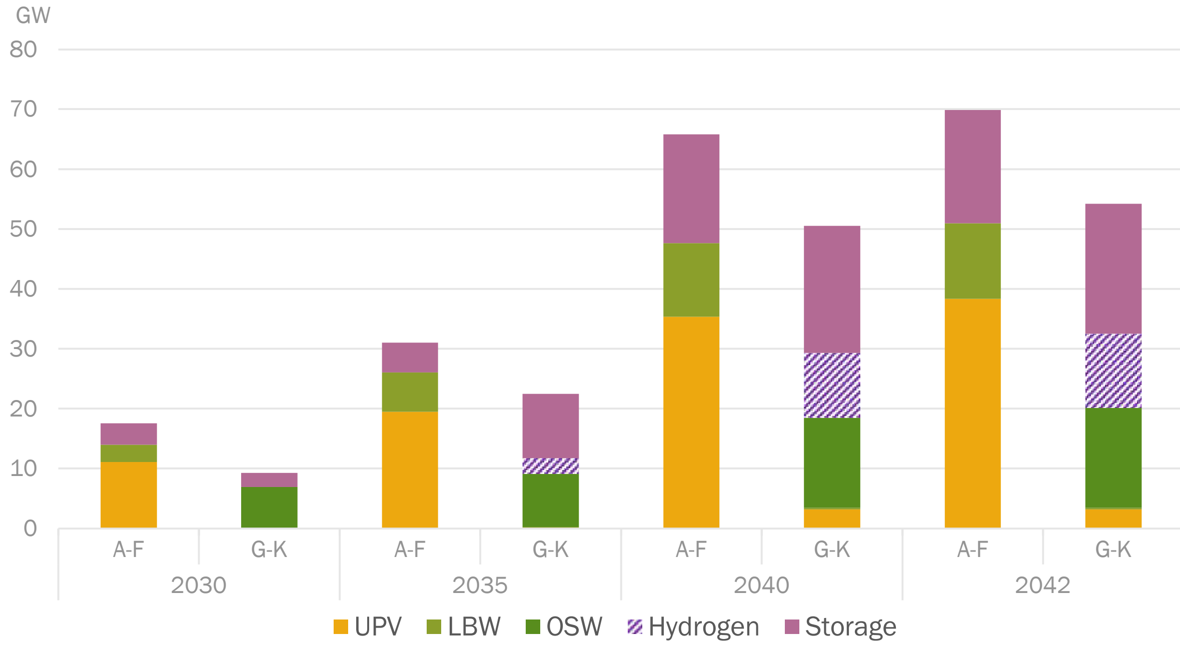
Figure 12: State Scenario Cumulative Capacity Additions - Upstate vs Downstate.



Capacity (Summer MW)						
	2021	**2025**	**2030**	**2035**	**2040**	**2042**
Nuclear	4,378	3,342	3,342	3,342	3,342	3,342
Fossil	26,345	25,753	22,424	15,022	-	-
Hydrogen - New CC	-	-	-	-	-	-
Hydrogen - New CT	-	-	-	-	3,062	3,244
Hydrogen - Retrofit CC	-	-	-	-	10,273	11,183
Hydrogen - Retrofit CT	-	-	-	2,676	4,558	4,558
Hydro	4,868	6,294	7,544	7,665	7,665	7,665
LBW	2,227	3,291	4,815	8,658	15,549	15,819
OSW	0	136	6,990	9,000	11,809	13,048
UPV	32	3,135	11,265	18,963	39,903	42,903
BTM-PV	2,116	5,384	8,972	8,973	12,019	12,019
Storage	1,405	2,905	7,405	9,678	15,729	16,503
Total	**41,686**	**50,562**	**73,080**	**84,299**	**123,909**	**130,285**
Annual Peak (MW)	**30,397**	**29,568**	**29,861**	**37,047**	**45,062**	**47,046**

High-Transmission Impact

Figure 13: High-Transmission Impact Scenario Cumulative Capacity Additions - Upstate vs Downstate



Capacity (Summer MW)						
	2021	**2025**	**2030**	**2035**	**2040**	**2042**
Nuclear	4,378	3,342	3,342	3,342	3,342	3,342
Fossil	26,345	25,753	22,424	15,022	-	-
Hydrogen - Fuel Cell	-	-	-	2,629	10,863	12,426
Hydro	4,868	6,294	7,665	7,665	7,665	7,665
LBW	2,227	3,291	5,820	9,715	15,549	15,819
OSW	0	136	6,990	9,000	15,157	16,798
UPV	32	3,135	12,541	20,912	39,903	42,903
BTM-PV	2,116	5,384	8,972	8,973	12,019	12,019
Storage	1,405	2,905	7,405	17,145	40,819	42,117
Total	**41,686**	**50,562**	**75,482**	**92,097**	**134,454**	**140,664**
Annual Peak (MW)	**30,919**	**29,784**	**31,115**	**41,046**	**50,145**	**52,405**

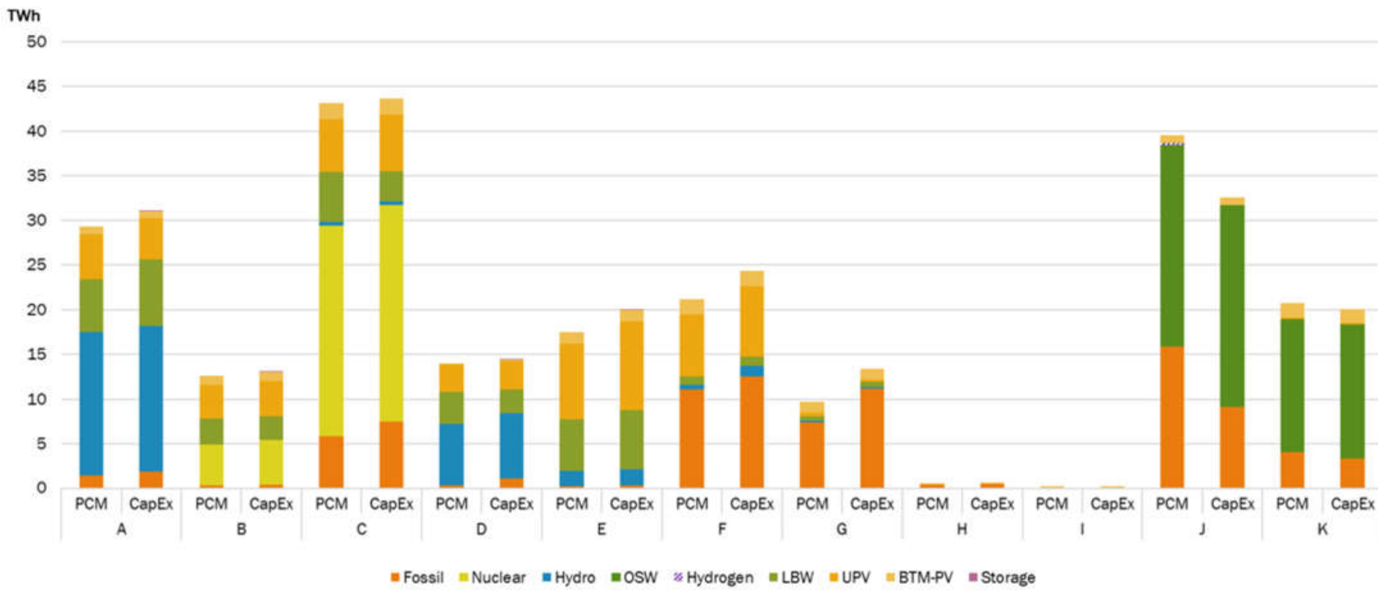
PRODUCTION COST MODELING

The Joint Utilities engaged the NYISO to conduct production cost modeling of resource buildouts for the CGPP scenarios. This modeling effort built on the Stage 1 capacity expansion model results and was done concurrently with work on Stages 2-5 of the CGPP process.

Production cost models are chronological, hourly dispatch models that minimize the total system production costs given demand, fuel and emissions prices, generator-specific operating characteristics and costs, and an underlying nodal power flow which recognizes and accounts for the impacts of specific constraints. Resource mixes resulting from capacity expansion modeling are often run in production cost models to simulate day-to-day market operations and test the buildout at a more granular level. The Joint Utilities provided NYISO with nodal generator placements for the generic zonal capacity expansion resource buildout. It should be noted that this model was not secured for local transmission constraints. However, the results provide useful insight into bulk transmission constraints.

NYISO ran the GE Multi-Area Production Simulation model for 2035 for each of the three CGPP scenarios. Zonal generation, shown in Figure 14, and resource curtailment were comparable across the three scenarios due primarily to similar resource mixes for 2035 and generator placement continuity across scenarios.

Figure 14: 2035 Zonal Generation from Production Cost and Capacity Expansion Models



Reasonable alignment between Capacity Expansion and Production Cost models on generation.
Reminder that much of the generation is prescribed by renewable shapes or is must run.

PCM = production cost model, CapEx = capacity expansion model

Major interface utilization was also similar across the three scenarios, where Central East had the highest utilization rate and was the most congested interface—indicative of economic impacts associated with transmission bottlenecks.

The production cost modeling results verified that the capacity expansion resource buildouts, which cover only specific time periods in a year, were reasonable proxies for annual operations (generation and carbon emissions) and provided further insight into hourly LBMPs, generation, curtailment, and congestion associated with the scenario resource mixes. Additional production cost analysis on Stage 1 capacity expansion results was limited due to the significant changes observed in Stage 5 capacity expansion runs and limited time. More extensive use of production cost modeling will occur in CGPP Cycle 2.[32]

32 CGPP Proceeding, Order Modifying Coordinated Grid Planning Process (November 13, 2025) (CGPP Modification Order), p. 20.

SYSTEM NEEDS & SOLUTIONS: CGPP STAGES 2, 3, AND 4

PURPOSE

In CGPP Stages 2, 3, and 4, the Joint Utilities expanded on the results from Stage 1 by modeling and evaluating the New York electric system under a range of conditions to identify constraints that can be addressed through the deployment of grid investments, including advanced technologies. Based on the zonal build-outs from each CGPP Scenario in Stage 1, the Joint Utilities developed nodal placements for specific generation and storage resources and then applied detailed short circuit and power flow models to assess the local transmission system under different system conditions and for different years. These models simulate the way electricity flows throughout the power grid and allow planners to understand how the system reacts to a range of operating conditions that can be expected to materialize as new demands occur, new generation comes online, and as the electric system evolves more generally.

CGPP Stages 2 through 4 moved from the described scenario-specific nodal buildouts to an engineered set of candidate solutions. **Stage 2** established the common technical foundation by developing standardized study cases and network models that reflect each scenario and study year. **Stage 3** used those cases to identify the specific local transmission limitations that emerge under future conditions and to develop candidate solutions—ranging from conventional infrastructure upgrades to advanced technologies—along with preliminary scope, timing, and cost information. **Stage 4** then validated and refined the resulting solution set through cross-utility review, confirming that projects work together across scenarios and do not create adverse interactions. These stages produced a coordinated set of preferred solutions suitable for inclusion in the Stage 5 least-cost planning assessment (i.e., candidate solutions for the NYISO's capacity expansion model to select the least-cost portfolio of projects that achieves State policy).

CGPP STAGE 2: NETWORK MODEL DEVELOPMENT

January 2025 – June 2025 (approximate)

Advanced Power Flow and Short-Circuit Model Development

In CGPP Stage 2 the Joint Utilities translated the generation build-out that was developed in Stage 1, which was specified at a zonal level, into a detailed nodal representation suitable for power system analysis. The CGPP Stage 1 results identified the scale and general location of new generation by NYCA zones, which can cover many hundreds or thousands of square miles. In CGPP Stage those resources were assigned to specific network bus locations based on the existing transmission topology, interconnection points, and generator characteristics. This nodal modeling step allowed the analysis in subsequent CGPP stages to reflect localized system conditions, power flows, and constraints that cannot be captured through zonal representation alone.

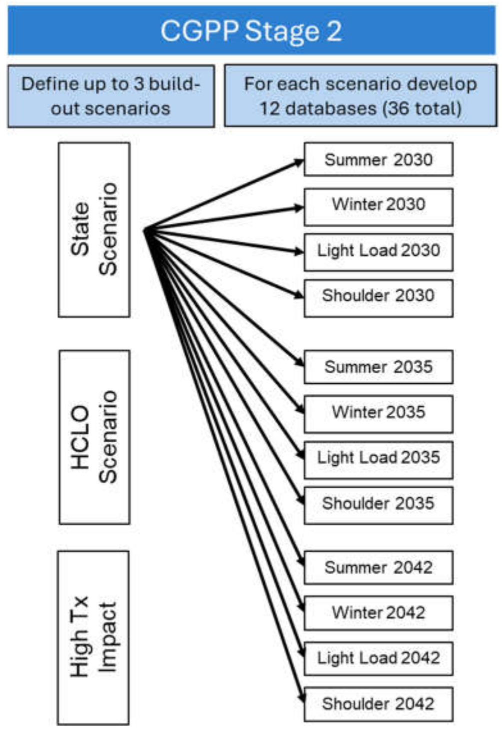
Between December 2023 and March 2024, the Joint Utilities conducted a competitive procurement process to identify a vendor to support CGPP Stage 2. Specifically, the Joint Utilities sought a technical consultant to conduct advanced power flow system modeling and analysis to assess the need for future local transmission infrastructure investments due to constraints that appear as clean energy resources (i.e., the resources from the Stage 1 capacity expansion work) are connected to the existing power grid. In late March 2024, Siemens PTI (Siemens) was selected.

Siemens' scope of work included comprehensive power flow and short circuit modeling. It produced 20-year base cases in collaboration with the Joint Utilities, providing a foundation for evaluating system needs on a nodal basis under various future scenarios.

A key component of the modeling effort involved establishing short circuit and power flow models across 36 distinct cases. These cases were structured around the three CGPP Scenarios, three target years (2030, 2035, and 2042), and four seasonal representations, capturing a wide range of system conditions and planning assumptions. (See Figure 15, below.) This set of 36 system conditions, together with three short-circuit cases—one per scenario— was specified in the Commission's CGPP Order.[33]

[33] CGPP Proceeding, CGPP Order, pp. 13

Figure 15: Siemens PTI prepared 12 power flow cases for each Scenario (i.e., a total of 36 cases) in CGPP Stage 2.



Modeling Inputs and Data Sources

Siemens' power flow analysis applied several key data sources. These data sources included (i) the most recent version of the NYISO's FERC Form 715 database, which provides detailed information on the transmission system, and (ii) the NYISO's Load and Capacity Data, commonly referred to as the Gold Book, which offers critical insights into historical and forecasted load and generation capacity. While the NYISO materials typically support a 10-year reliability planning horizon, Siemens worked closely with the Joint Utilities to extend the modeling framework to a 20-year planning horizon.

Scenario-Based Network Modeling

To enhance the granularity of the analysis, the zonal generation build-out, typically represented in a "pipe and bubble" format,[34] was mapped onto a nodal model at the substation level in collaboration with the Joint Utilities. This nodal model required the designation of specific generation interconnection points and unit-level technical specifications. DERs assumed in each scenario were modeled as load

[34] The "pipe and bubble" format represents generation and transfers at an aggregate zonal level, rather than at specific substations, and is therefore refined through nodal mapping for detailed, local system analysis. In the NYCA, each zone (A-K) is represented as a "bubble," and the transmission facilities that bridge the zones at specific interfaces are the 'pipes.'

modifiers.[35] These DERs were represented in the nodal models using assumed distribution-level locations consistent with the planning assumptions for each scenario.

Model Refinements

During the evaluation of resource placement at the nodal level, the Joint Utilities identified the need to refine their approach based on the modeling Siemens had completed. The output from the capacity expansion modeling indicated substantial capacities of new resources would be integrated into local transmission systems. This magnitude of capacity additions presented challenges, as the available siting locations were insufficient to accommodate modeled growth, resulting in impractical placements for incremental generation in several areas.

Each utility undertook varying levels of adjustments to the nodal models by applying utility-specific distribution and transmission planning data, conducting detailed local assessments, and applying tailored planning techniques. The modified siting methodology was described to the EPPAC on September 15, 2025. These refinements ensured that resource siting was both technically feasible and reflected operational realities for each of the Joint Utilities.

CGPP STAGE 3: LOCAL ASSESSMENTS, SOLUTION DEVELOPMENT

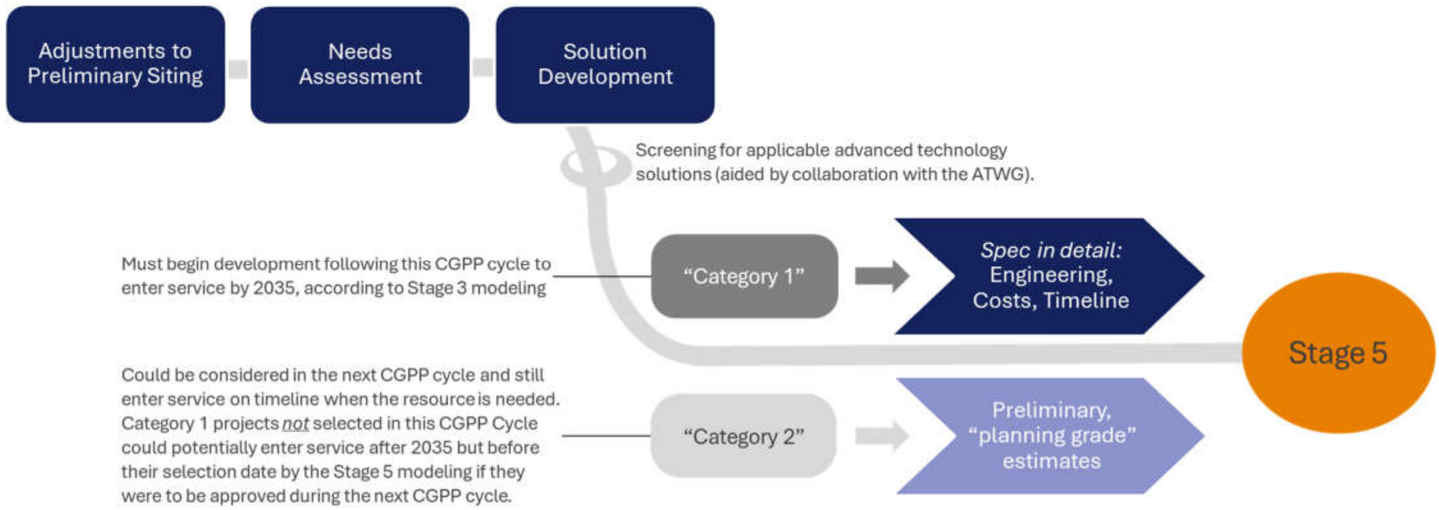
April 2025 – December 2025 (approximate)

Purpose

CGPP Stage 3 centered on identifying system needs and developing candidate solutions across local transmission networks. This stage built directly on the more granular network models developed in Stage 2 and sought to address the headroom deficits resulting from the capacity expansion modeling exercise of CGPP Stage 1.

[35] In utility planning, distributed energy resources are often referred to as "load modifiers" indicating that they are modeled and treated as reducing (or reshaping) customer electricity demand rather than as a supply-side generator or capacity resource.

Figure 16: CGPP Stage 3 Workflow



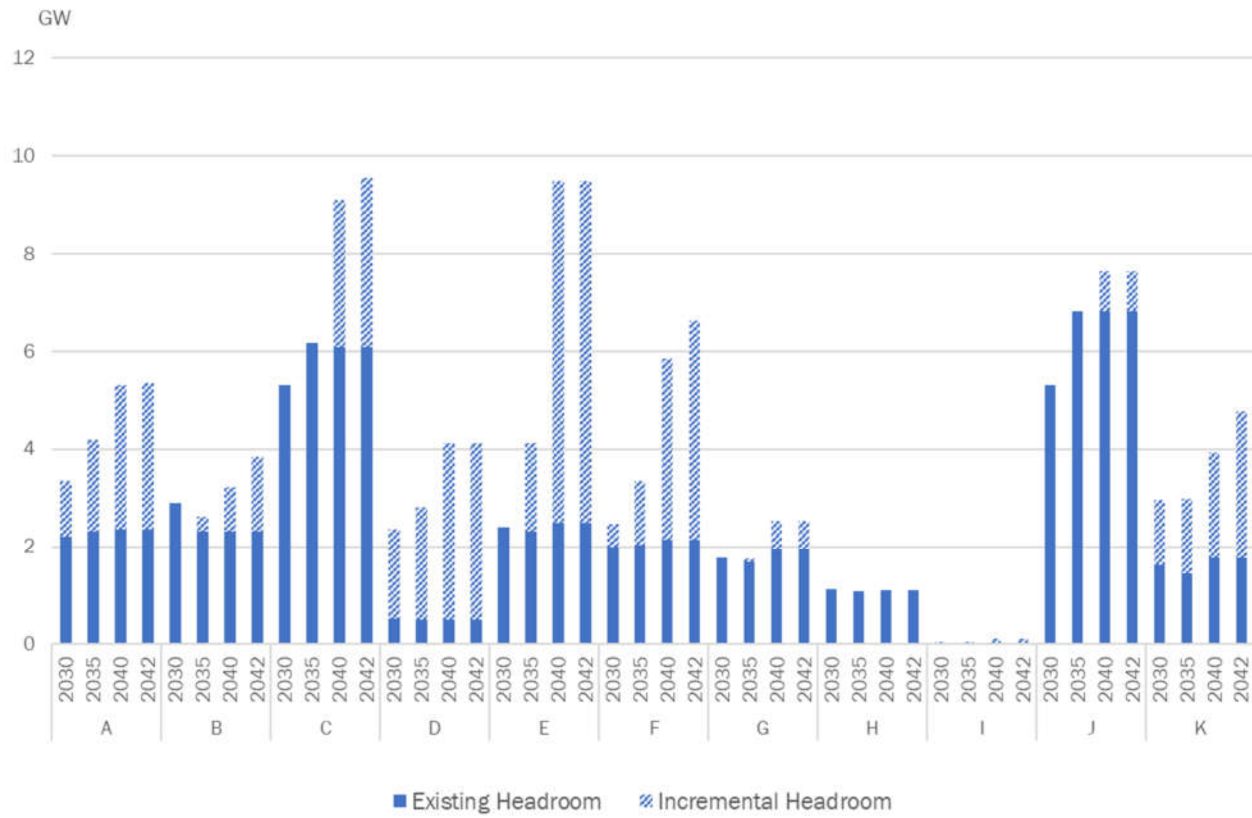
System Needs Identification

Using the 36 steady-state and 3 short circuit cases developed in Stage 2, the Joint Utilities conducted scenario-based assessments to identify system constraints under multiple future conditions. Specifically, the Joint Utilities' planning engineers evaluated conditions on the local transmission system to understand how the generation buildout may produce the following types of constraints:

- Thermal overloads;
- Voltage violations;
- Point of Interconnection (POI) constraints (particularly in Zone J); and
- Reliability risks.

These constraints were driven by the placement of large quantities of generation resources that confirmed the substantial needs for additional headroom which were observed in the Stage 1 capacity expansion modeling, as illustrated in Figure 17, below.

Figure 17: Existing and incremental headroom across each NYCA zone.



The Joint Utilities evaluated local constraints independently of bulk system limitations, which were assumed to be addressed through NYISO processes or future PPTN filings. This was an assumption applied for the purpose of the Stage 3 local constraint analysis; it did not change the plan to consider NYSERDA's conceptual bulk transmission projects in CGPP Stage 5, the project selection stage of the CGPP.

The Joint Utilities' planners evaluated available local transmission headroom to identify deficits arising from the Stage 1 capacity expansion results and the nodal resource placement developed in Stage 2. These headroom deficits resulted in different constraints that informed development of the candidates for solution projects.

Solution Development

The Joint Utilities developed a portfolio of projects to address the constraints within each planning zone that were identified in the needs assessment. In developing these solutions, the Joint Utilities drew from three broad categories of projects:

- **Conventional infrastructure upgrades**, including reconductoring, transformer replacements, protection and control upgrades, substation expansions, and construction of new transmission lines or substations.
- **Advanced Technologies**, that may increase the utilization and operational flexibility of existing assets without requiring substantial physical expansion. The ATWG developed Advanced Technology Screening criteria to assist the CGPP planners in evaluating these technologies.

Projects were grounded in the Joint Utilities' individual planning processes, which integrate load forecasting, generation and storage interconnection assumptions, reliability criteria (e.g., N-1 and N-1-1 contingencies where applicable), and power quality standards.

Advanced Technologies

The four advanced technologies the Joint Utilities considered as alternatives to, or components of, larger solution designs are: Dynamic Line Ratings, Energy Storage as a Transmission Asset, Power Flow Controllers, and Advanced Conductors. Each is defined in Figure 18 below based on input from the ATWG.

Specific to the CGPP, the ATWG provided input to support solution development during Stage 3 of the planning process through the development of screening criteria and technical guidance. The screening criteria and technical guidance helped the Joint Utilities interpret the constraints analyses from Stage 3 to determine where advanced technologies could, potentially, yield more cost-effective solution designs.

Figure 18: Advanced Technologies Definitions

Technology	Definition
Dynamic Line Rating	A technology that uses real-time or near real-time environmental and line condition data to safely increase the usable capacity of existing transmission lines above static ratings under favorable conditions.
Energy Storage as a Transmission Asset	The use of grid-connected energy storage resources to provide transmission services, such as relieving congestion, addressing overloads, or supporting voltage, by shifting energy across time or locations.
Power Flow Controllers	Advanced devices installed on transmission lines that actively control power flows by adjusting line impedance or phase angle to redirect electricity and alleviate congestion on the grid.
Advanced Conductors	High-performance transmission line conductors designed to carry more power than conventional conductors while fitting on existing structures, enabling capacity increases without new rights of way.

The screening criteria, as summarized in Figure 19, provide an indication of how each advanced technology was considered relative to the modeling results in Stage 3. For example, if the modeling results from Stage 3 indicated overloads below 200 MW, advanced power flow controllers could be considered as a potential solution. Such consideration, however, is contingent on satisfaction of other screening criteria (e.g., availability of a parallel path with sufficient excess capacity to enable effective power-flow redistribution).

The Joint Utilities emphasize that the screening criteria described below are not a strictly interpreted and decisive test for whether and where these technologies should be incorporated in solution designs. Instead, the screening criteria serve as common and transparent technical guidance to help identify the most promising applications based on the modeling results from Stage 3. The Joint Utilities endeavored to find opportunities to use these technologies where they could contribute to least-cost planning solutions aligned with the objectives of CGPP.

To illustrate this distinction, there were many instances in the Stage 3 modeling in which system overloads exceeded the incremental capacity that could reasonably be achieved through an advanced technology alone. However, that did not preclude the Joint Utilities from using advanced technologies to complement traditional solution designs where they could still provide cost-effective system benefits. The detailed description of the projects for which the companies are seeking approval are included in Appendix A. These appendices include descriptions of the applicability of advanced technologies to the specific needs each project was designed to address.

Figure 19: Summary of the Screening Criteria Developed by the ATWG.

Information for CGPP Analysis	Dynamic Line Rating	T&D Energy Storage[36]	Advanced Power Flow Control
Grid Needs and AT Suitability	• Transmission line overload caused by peak renewable energy output • Underground cable overload caused by peak demand	• Infrastructure overload or voltage violation caused by peak renewable energy overload • Infrastructure overload or voltage violation caused by peak demand	• Transmission congestion caused by peak renewable energy output or peak demand.
Primary Use Cases	• Increase overhead transmission line capability to avoid overloading during periods of peak renewable energy output.	• Flexible Capacity • Large-Scale Renewable Enablement • Bridge-to-Wires	• Shift power flow between parallel transmission paths to alleviate congestion and unlock additional capability.

36 Energy storage, while having potential capacity increases of 100-400 MW, is not available on a continuous basis. Given that hourly transmission line loading can vary significantly across different lines and may last longer than 4-8 hours or occur at intervals too short for the storage to re-charge, the snapshot-based power flow modeling is not able to fully determine whether energy storage can resolve a need. Despite this constraint, the Joint Utilities evaluated certain applications for energy storage but found that other technologies could more efficiently resolve the needs. The capacity expansion model did build varying amounts of market-based energy storage across all scenarios.

Information for CGPP Analysis	Dynamic Line Rating	T&D Energy Storage[36]	Advanced Power Flow Control
Capacity Increase	• 10% to 25% of the existing line rating • Increases are applicable to normal and emergency ratings	• 100 MW to 400 MW for four hours	• Up to 200 MW between two locations (e.g., substations)
Availability	• 70% to 90%+ based on case study reports	• Duration (i.e., stored energy) of the solution • Sufficient power must be available to charge the ESR when not in use	• Need excess capacity over a parallel path with which to shift flow
Proposed Power Flow Modeling	• New rating applied to line segment	• Simplified generator model for the energy storage resource (ESR)	• Modified impedance on a line segment
Economic and Cost Assumptions	• Approximately $50,000 per mile of line	• $1,777 - $1,888 per kW (except Zone J)	• $8 million to $20 million per project

The Joint Utilities emphasize that they have and will continue to collectively evaluate each of these technologies for potential use in their own system planning beyond the scope of the CGPP. More information describing each utilities' efforts to study, pilot, and deploy these technologies is included in the ATWG 2025 Annual Report.[37]

<u>Key Planning Screens</u>

For each constraint, whether it was wholly solvable by a traditional planning solution or included advanced technologies as part of the solution design, the Joint Utilities developed one or more potential projects and evaluated them against a consistent set of criteria, including:

- **Technical feasibility**, assessing whether the solution could reliably resolve the identified violation or deficiency under applicable planning criteria and operational constraints.
- **Cost-effectiveness**, including capital costs, lifecycle costs, and where applicable, comparison to the avoided or deferred costs of traditional infrastructure investments.
- **Ease of Execution**, considering permitting complexity, constructability, siting constraints, interdependence with other projects, and the likelihood of achieving in-service dates aligned with system need.

<u>Multi-Value and "No Regrets" Investments</u>

37 CGPP Proceeding, Advanced Technologies Working Group 2025 Annual Report (February 2, 2026).

Many of the candidate projects provide multiple value streams beyond addressing the constraints identified through the network model analysis in CGPP Stage 3. Additional benefits included improved operational flexibility, enhanced reliability and resilience, and reduced congestion or losses.

In several cases, these projects may not have been triggered as near-term priorities under traditional load growth assumptions or planning horizons extending to 2040. However, under a State policy-driven resource buildout, system conditions and constraint timing change. These projects are justified for earlier deployment to ensure deliverability, reliability, and cost-effective integration of anticipated clean energy resources.

<u>Right-Sizing and Phased Development</u>
Projects were designed to be appropriately sized to meet forecasted needs. Where feasible, the Joint Utilities developed scalable or phased solutions that align the scale of the projects with expected growth in load and resource interconnections through 2035 and 2042.

The Joint Utilities applied a two-tier designation to distinguish projects based on development maturity and timing criticality. (See Figure 16, above.) “Category 1” projects are those that have been advanced to a level of definition (i.e., rate case-quality estimates of scope, cost) sufficient to support the Commission’s review in this first CGPP cycle. “Category 2” projects represent solutions that are expected to be needed later in the planning horizon—generally around 2040—and therefore have been developed at a more conceptual or “planning grade” level at this stage.38

The Joint Utilities are not seeking Commission approval to proceed with any construction of Category 2 projects at this time. Instead, the categorization is intended to provide transparency regarding relative readiness and timing, while preserving flexibility to continue evaluating the necessity, scope, and optimal configuration of specific solutions in future CGPP cycles as system conditions, forecasts, and related policy initiatives evolve.

DAC Considerations

During CGPP Cycle 1, the Joint Utilities undertook efforts to better understand how DAC[39] and environmental justice considerations may be reflected in transmission planning. In 2024, the Joint

[38] This categorization of projects based on engineering specification and cost and schedule estimation is consistent with the direction provide in the Commission’s CGPP Modification Order. *See*, CGPP Proceeding, CGPP Modification Order, pp. 29-30.

[39] Disadvantaged Communities (DACs) are communities identified pursuant to the Climate Leadership and Community Protection Act as bearing burdens of negative public health effects, environmental pollution, and climate change impacts, and possessing associated socioeconomic vulnerabilities. More information regarding the criteria can be found

Utilities applied for and were selected to participate in the Inclusive Transmission Planning Technical Assistance program administered by the U.S. Department of Energy's Pacific Northwest National Laboratory (PNNL). The program offered no-cost educational and technical support to utilities and system planners on equity matters and was pursued to supplement the CGPP with external expertise without creating additional costs to customers.

The Joint Utilities initiated preliminary scoping discussions with PNNL to explore potential approaches for evaluating equity considerations in transmission planning that could inform future CGPP cycles. However, before substantive technical assistance could be undertaken, the program was paused and subsequently discontinued due to changes affecting federally funded national laboratory activities. While the engagement did not proceed, this effort demonstrates the Joint Utilities' proactive approach to identifying cost-effective resources to inform future enhancements to the CGPP framework. For the first CGPP cycle, the actions taken by the Joint Utilities with respect to disadvantaged communities and equity considerations are described below.

The CGPP Order directs the Joint Utilities to identify proposed projects that would be partially or wholly located within DACs and to justify the inclusion of any projects that may have material effects on those communities. In response, the Joint Utilities undertook a deliberate and structured review of DAC intersections across the proposed CGPP portfolio, consistent with the Commission's intent.

A significant majority of the proposed project sets (Figure 3, above) do not intersect DACs. Project components that are partially or wholly located within a DAC represent approximately 7.9% of the overall portfolio.[40] Importantly, many of the project components within the CGPP portfolio that affect DACs involve rebuilds, replacements, or expansions of existing assets that are already located within DAC geographies today,[41] and do not introduce new infrastructure footprints into those communities. Supporting documentation and project-specific details are provided in the individual utility appendices.

Common Framework for DAC Assessment

To ensure consistency, transparency, and analytical rigor, the Joint Utilities developed and applied a common framework to assess project sets that are partially or wholly located within DACs. This

in the New York State Climate Justice Working Group 2023 DAC Criteria Final report: https://climate.ny.gov/resources/disadvantaged-communities-criteria/

40 Measured in terms of transmission line miles in the CGPP Portfolio, which is introduced in the discussion of CGPP Stage 5. This does not account for substation projects. The DAC impacts of substation projects are discussed at length in each company's contribution to Appendix A.

41 Each project in the CGPP Cycle 1 portfolio can be thought of as (i) a "greenfield" construction project that may require new parcels of land or right of way, or (ii) a rebuild or expansion of an existing asset that leverage existing electric system infrastructure in some fashion that maintains grid congruity.

framework is intended to support the Commission's review, as directed in the CGPP Order[42] by presenting project information and comparing the potential burdens of proposed CGPP projects (based on what is known at this stage of development) with those of plausible conceptual alternatives that could, potentially, avoid or diminish potential DAC burdens.[43]

The Joint Utilities' approach reflects an appropriate level of scrutiny for this phase of planning, while recognizing the technical, siting, and system constraints associated with transmission development. The framework is designed to ensure that DAC considerations are explicitly evaluated and documented. If the Commission approves any of the CGPP Portfolio project sets, the Article VIII permitting process requires comprehensive analysis of route selection and reasonable alternatives, including evaluation and characterization of potential burdens to DACs.

<u>Project Justifications and Alternatives Assessment</u>

For project elements located wholly or partially within a DAC the Joint Utilities conducted an assessment using a set of justification criteria. The CGPP Order recognizes that projects located within DACs may be justified and identifies several potential bases for justification, including the availability of non-DAC alternatives, constructability, congruity with the existing grid, cost considerations, and potential environmental impacts.[44] Consistent with this guidance, the Joint Utilities applied the following criteria for this assessment:

- *Availability of Viable Alternatives*: An assessment of whether alternative project configurations, routes, or solutions exist that could reasonably meet the same underlying system need.
- *Constructability*: An evaluation of whether an alternative could be reasonably constructed given physical, permitting, and logistical constraints, including siting limitations, right-of-way availability, environmental restrictions, and construction complexity.
- *Grid Congruity*: Consideration of whether project implementation would be consistent with the physical, operational, and electrical features of the existing transmission system, including the ability to meet system performance requirements.

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42 CGPP Proceeding, CGPP Order, p. 38. The Commission directed that "[t]o the extent Stage 5 results in a recommended project that would be partially or wholly located in a disadvantaged community, the CGPP final report shall justify that decision based upon, among other things, available alternatives not located within such communities, issues related to constructability, congruity with the existing grid, cost, and potential environmental impacts. The justification must provide details related to the elements of a project to located in the disadvantaged community, including whether it is to be sited in an existing right-of-way, the zoning of the relevant area, and the project's relative proximity to residential communities."

43 The Joint Utilities' assessment approach, described below, has been applied only to Category 1 projects that (i) were selected by the capacity expansion model in CGPP Stage 5 and (ii) are partially or wholly located in a DAC. More detail on the features and potential impacts of each component project can be found in utility-specific appendices.

44 CGPP Proceeding, CGPP Order, p. 38.

- *Cost* (including whether alternatives are cost-prohibitive): An evaluation of whether an alternative would result in materially higher costs than the proposed project. An alternative may be considered cost-prohibitive if it imposes a significantly greater customer burden without commensurate system or societal benefits.
- *Environmental Impacts*: A qualitative comparison of the potential environmental impacts of an alternative relative to the proposed project, including impacts that may arise from additional routing, land acquisition, and/or disturbance.

If, based on this analysis, no alternative is viable, constructible, cost-effective, environmentally preferable, and/or congruent with the existing grid, the proposed project may be justified for advancement notwithstanding its location within or intersection with a DAC.

<u>Conceptual Evaluations of DAC-Avoidance Tradeoffs</u>

The Joint Utilities explored the implications of avoiding or minimizing DAC intersections across several key dimensions, which may include, among others, the following:

- Additional miles of transmission required to reroute around a DAC and the associated incremental costs (estimated mileage and added costs in $ millions);
- Acquisition costs for additional transmission rights-of-way (ROW) or land required to site infrastructure such as a substation (incremental costs in $ millions);
- Potential impacts on communities and natural resources of alternative routing, including the loss of residential areas and undeveloped or greenfield areas;
- Additional upgrade or reinforcement costs for other system components required to make an alternative feasible (incremental costs in $ millions); and
- Infrastructure removal impacts within the DAC including construction activity associated with decommissioning existing facilities.

Each of the Joint Utilities with project sets in the CGPP Portfolio that have components that are located wholly or partially in a DAC conducted an alternatives assessment consistent with the description above. The results of these alternatives assessments, including identified alternatives, associated impacts, and potential benefits, are documented in the respective utility appendices.

<u>Scope and Limitations of the Assessment</u>

Each company performed these assessments in a manner tailored to the specific characteristics of its system and the projects it proposed. The resulting analyses are intended to provide the Commission with insight into the relative viability of potential alternatives for illustrative and screening purposes. A full engineering review, including detailed routing studies and constructability analyses, would be required to confirm feasibility and viability. Consistent with standard transmission development practice, such detailed engineering and routing work would occur later in the development process should a project set be approved.

Solutions Development Conclusion:

In total, the Joint Utilities developed 25 project sets (See Figure 20 and Appendices A-C for more details), which unlocked 12.2 GW of headroom and addressed deficits created by the Stage 1 capacity expansion buildouts and the nodal resource placement completed in Stage 2. This portfolio represents an estimated investment of approximately $20 billion.

Figure 20: Stage 3 Solution Development Projects

Project Name/Identifier	Line Miles	New/ Rebuilt Substations	Substation Upgrades/ Expansions	Cat 1/ Cat 2	NYCA Zone	Incremental Headroom*	Earliest Available to the Model
Central Hudson 2035 Project	65	1	14	Cat 1	G	281	2035
Central Hudson 2042 Project	37	0	3	Cat 2	G	185	2042
Con Edison Project #1	16	1	2	Cat 1	I-to-J	750	2033
Con Edison Project #2	0	1	0	Cat 1	J	1500	2033
NG Zone A 2040 Project	235	2	6	Cat 2	A	740	2040
NG Zone B 2035 Project	90	0	2	Cat 1	B	480	2035
NG Zone C 2035 Project	19	0	2	Cat 1	C	190	2035
NG Zone E 2035 Project	197	4	4	Cat 1	E	970	2035
National Grid Oneida County Transmission Upgrade	123	3	2	Cat 1	E	1440	2035
National Grid Mohawk Valley Transmission Upgrade	109	2	10	Cat 1	F	900	2035
LIPA Project A	15	0	2	Cat 1	K	500	2035
LIPA Project B	9	1	1	Cat 2	K	885	2040
LIPA Project C	6	0	2	Cat 2	K	229	2040
O&R Project 1	39	4	0	Cat 1	G	298	2035
NYSEG Lancaster Cat 1	0	1	0	Cat 1	A	120	2031
RG&E Rochester Cat 1	8	0	4	Cat 1	B	130	2032
RG&E Rochester Cat 2	5	0	1	Cat 2	B	80	2035
NYSEG Geneva/Auburn Cat 1	5	0	3	Cat 1	C	50	2035
NYSEG Hornell/Elmira/Bath Cat 1	136	1	9	Cat 1	C	740	2035
NYSEG Binghampton Cat 1	85	0	2	Cat 1	C	920	2034
NYSEG Hornell/Elmira/Bath Cat 2	65	0	3	Cat 2	C	430	2035
RG&E Genesee Valley Cat 2	99	1	2	Cat 2	B	60	2042
NYSEG Ithaca Cat 1	27	0	0	Cat 1	C	70	2035
NYSEG Oneonta Cat 1	9	3	0	Cat 1	E	100	2035
NYSEG Oneonta Cat 2	10	0	1	Cat 2	E	170	2035

CGPP STAGE 4: REVIEW OF PREFERRED SOLUTIONS

June 2025 – November 2025 (approximate)

Purpose

CGPP Stage 4 reviewed, validated, and refined the portfolio of proposed local transmission solutions to ensure they function cohesively when evaluated together across all CGPP Scenarios. This stage built directly on the system models developed in Stage 2 and the candidate solutions developed in Stage 3. It focused on identifying and resolving any cross-utility interactions or adverse impacts through a Statewide system impact review, as directed by the Commission.

Collaboration among the Joint Utilities (Project Reviews)

The Joint Utilities undertook coordinated and structured collaboration throughout CGPP Stage 3 to ensure that projects under development were complementary and did not result in duplicative solutions. As part of this effort, the Joint Utilities met in person in June 2025 to exchange information and present proposed projects under consideration, initiating the Stage 4 collaborative review process while Stage 3 project development was underway. Prior to this in-person meeting, the Joint Utilities discussed a framework for collaboratively refining project designs should adverse interactions or duplicative solutions be identified. During the meeting, each of the Joint Utilities reviewed its assessment of its transmission system to confirm that proposed projects did not introduce adverse system impacts in other regions. In parallel, the utilities evaluated whether projects located in a neighboring utility's service territory could address or mitigate identified system needs, thereby avoiding redundant investments.

Coordination was not limited to discrete meetings but occurred continuously throughout Stage 3. The Joint Utilities held weekly working sessions to share information regarding emerging constraints and to discuss whether constraints identified in one utility's analysis may also manifest on neighboring transmission systems. When such constraints were identified, the utilities worked together to develop solutions in a manner intended to prevent duplication of projects or overlapping scope. For example, RG&E identified an overload on a National Grid transmission line and notified National Grid. Planning experts from both companies met to review the issue, during which National Grid confirmed that it had independently identified the same constraint and had developed a proposed solution. The utilities coordinated on the appropriate path forward, ensuring that the constraint would be addressed through a single, aligned solution rather than through parallel or duplicative projects.

This collaborative approach reflects the interconnected nature of portions of the New York transmission system, particularly among the NYSEG, RG&E, and National Grid service territories. While each company routinely monitors adjacent facilities as part of its Stage 3 studies, calculations of available headroom during Stage 3 were initially calculated for resources connecting to a single company's facilities. During

Stage 4, however, the Joint Utilities jointly evaluated portions of the transmission system that are strongly tied across company boundaries to assess the net headroom benefit on a coordinated basis. This analysis demonstrated that for certain headroom projects developed in NYSEG's Berkshire, Mechanicville, and Lancaster regions, the same, or similar, quantities of generation enabled by these projects could feasibly interconnect on nearby National Grid facilities, effectively bypassing NYSEG constraints. From a Statewide planning perspective, these projects therefore did not provide an incremental headroom benefit or provided a materially reduced benefit. Although such projects could enable alternative interconnection opportunities, NYSEG determined that they were not cost-effective when evaluated on a coordinated, system-wide basis.

The Joint Utilities will continue to evaluate refinements to headroom analysis and coordinated planning methodologies in future CGPP cycles to ensure that cross-system interactions continue to be identified early and are addressed in a unified and cost-effective way.

LEAST COST PLANNING ASSESSMENT: CGPP STAGE 5

December 2025 – April 2026 (approximate)

In CGPP Stage 5, the Joint Utilities, in coordination with the NYISO, conducted a capacity expansion modeling analysis based on a modified version of the framework employed in CGPP Stage 1. In Stage 5, the generic statewide assumption for the cost of headroom additions used in Stage 1 was replaced with location-specific transmission solutions developed during CGPP Stages 2 through 4, including corresponding cost and deliverability estimates. This refinement enabled a more accurate optimization of the zonal generation buildout and transmission investments for the Commission's consideration.

In addition, Stage 5 evaluated conceptual bulk transmission solutions developed by NYSERDA, which were less detailed than the local transmission solutions, to identify potential systemwide bulk transmission needs. The primary output of Stage 5 was the capacity expansion model's selection of a least-cost portfolio of projects that were tested in each of the three CGPP planning scenarios.

EVOLUTION OF MODELING ASSUMPTIONS FROM STAGE 1 TO STAGE 5

In both CGPP Stages 1 and 5, the capacity expansion model represented interconnection constraints using a simplified, zonal approach. Specifically, each new generation resource was required to consume available local headroom within the zone in which it was sited. Headroom functioned as a proxy for local thermal limitations that had not yet been quantified through detailed engineering analysis. Under this framework, incremental generation could be added only where unused headroom existed, or where the model elected to fund additional local transmission upgrades to create new headroom using a generic assumed cost.

This approach effectively imposed a zonal deliverability constraint within the capacity expansion model in both Stages 1 and 5. However, Stage 1 accounted for headroom expansion opportunities using a generic cost assumption, while Stage 5 used engineered project costs and headroom benefit calculations.

A single, Statewide proxy cost for headroom expansion was applied in Stage 1 because detailed, project-specific cost estimates for local transmission upgrades were not yet available. These were developed later during CGPP Stages 2 and 3. The proxy headroom cost used in Stage 1 was intended solely as an interim placeholder, and it was later determined to be an underestimation of the true $/MW cost of local system upgrades. This underestimation was not known at the outset of the CGPP cycle, and the Commission has since directed modifications to the proxy headroom methodology to address this issue in future planning cycles.

Because the modeled cost of expanding local headroom was understated, *the Stage 1 capacity expansion model frequently selected portfolios that expanded headroom in zones with access to low-cost renewable resources, even when other zones had unused headroom that could accommodate new generation without additional transmission investment*. As a result, the Stage 1 cost structure tended to bias outcomes toward pairing low-cost generation with newly constructed local transmission, because this option often appeared cheaper than siting generation in higher cost regions where no transmission upgrades were needed.

In CGPP Stage 3, the Joint Utilities developed detailed local transmission solutions including defined scopes, routing, equipment selection, and cost estimates. CGPP Stage 5 incorporated these location-specific upgrades as a $/MW value into the capacity expansion model for associated headroom-expansion options. With the availability of project-level cost inputs—and without the availability of artificially low-cost generic headroom additions—the model transitioned from a more hypothetical representation of energy deliverability constraints to one grounded in discrete, engineering-validated transmission projects with associated costs.

This refinement materially altered the economic tradeoffs recognized by the model. In nearly all locations, the actual cost of creating incremental local headroom was substantially higher than the generic statewide proxy applied in Stage 1. As a result, many transmission expansions that appeared cost-effective under the early-stage assumptions were no longer selected once accurate, location-specific costs were reflected. Instead, the capacity expansion model increasingly favored siting generation in regions with higher inherent levelized costs of energy when doing so avoided costly local transmission upgrades.

This shift from generic to engineering-informed assumptions underscored the sensitivity of capacity expansion outcomes to the representation of local system constraints and transmission costs. More importantly, it demonstrated the risk of overstating the economic attractiveness of transmission expansion when costs are represented using simplified proxy values rather than site-specific data. The Commission's November 2025 Order Modifying the CGPP directed changes to the Stage 1 methodology to incorporate more refined local headroom cost estimates earlier in the planning process in recognition of these issues. The Commission provided this direction and improvement for the second CGPP cycle to reduce divergence between early-stage modeling results and later engineering-validated outcomes.

CONCEPTUAL BULK TRANSMISSION SOLUTIONS

As discussed above, following the review of Stage 1 scenario and sensitivity capacity expansion modeling results, DPS Staff requested that NYSERDA engage a consultant to identify potential bulk solutions for the New York grid system, with estimates of system benefits and costs for evaluation alongside of the Joint Utilities' local transmission projects in CGPP Stage 5.[45] NYSERDA retained Quanta to perform this work. The resulting conceptual bulk transmission solutions are summarized in Figure 21, below.[46]

The conceptual bulk transmission solutions are "conceptual" in the sense that the project benefits and costs in Figure 21 do not reflect the level of engineering detail and precision that applies to the local transmission projects. This was by design and is consistent with the Commission's direction.[47] To the extent the Commission determines that the analysis indicates a bulk system need that should be addressed through a PPTN, it will direct the NYISO to solicit project proposals from the transmission developer community for specified corridors. Further, if the Commission decides to proceed with a PPTN, the Joint Utilities urge that the process be structured to ensure coordination with, and cost-effective integration of existing transmission facilities and any new facilities planned or maintained by the local transmission owner. In order to maintain accountability for safe and reliable service, assets used to directly serve retail customers should always be planned and maintained by the local transmission owner. As with the 25 local transmission solutions developed by the Joint Utilities, all conceptual bulk transmission solutions developed by Quanta on behalf of NYSERDA and DPS Staff were provided to the NYISO capacity expansion model in Stage 5 as candidate projects for selection in the least-cost portfolio of investments.

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[45] CGPP Proceeding, CGPP Order, pp. 30-31. The conceptual bulk projects developed through NYSERDA's analysis are illustrative in nature and should not be interpreted as proposed or predetermined transmission facilities. These representative projects are used solely to explore whether potential system needs of a given magnitude and profile may justify seeking solutions through a Public Policy Transmission Need (PPTN) process.

[46] See also: Quanta Technology Development of Conceptual Bulk Solutions, *presented to EPPAC on October 27, 2025, https://dps.ny.gov/system/files/documents/2025/10/20-e-0197-october-27-2025-eppac-meeting-materials.pdf*

[47] *See infra*, note 45.

Figure 21: Conceptual Bulk Transmission Solutions

Project Name/Identifier	Zonal and Interface Transfers	Increase in Transfer Limit (MW)	Project Cost ($ 2025, millions)	Dollar Vintage (year)	In-Service (year)
West-to-East Concept *All increases in zonal transfer limits come at the same single cost.*	A-B	0	$2,400	2025	2035
	A-C	640			
	B-C	0			
	C-E / Volney East	1,890			
	E-F	428			
	E-G / Marcy South	850			
	E-H	1,240			
	G-H / UPNY-ConEd	570			
	Dysinger East	530			
	West Central	570			
	Central East	350			
	Total East	1,100			
	UPNY-SENY	850			
North-to-South Concept (Alternative B)	D-F	2,820	$3,200	2025	2035
	D-E (Moses South)	160			
Extension to Zone J *Can only be selected if the West-to-East concept is also selected. Cannot be selected if the E-J Option is selected.*	H-J	2,570	$12,000	2025	2035
	G-H / UPNY-ConEd	655			
	Sprainbrook - Dunwoodie South	0			
E-J Option *Can only be selected if the West-to-East concept is also selected. Cannot be selected if the Extension to Zone J is selected.*	E-J	1,200	$8,000	2025	2035

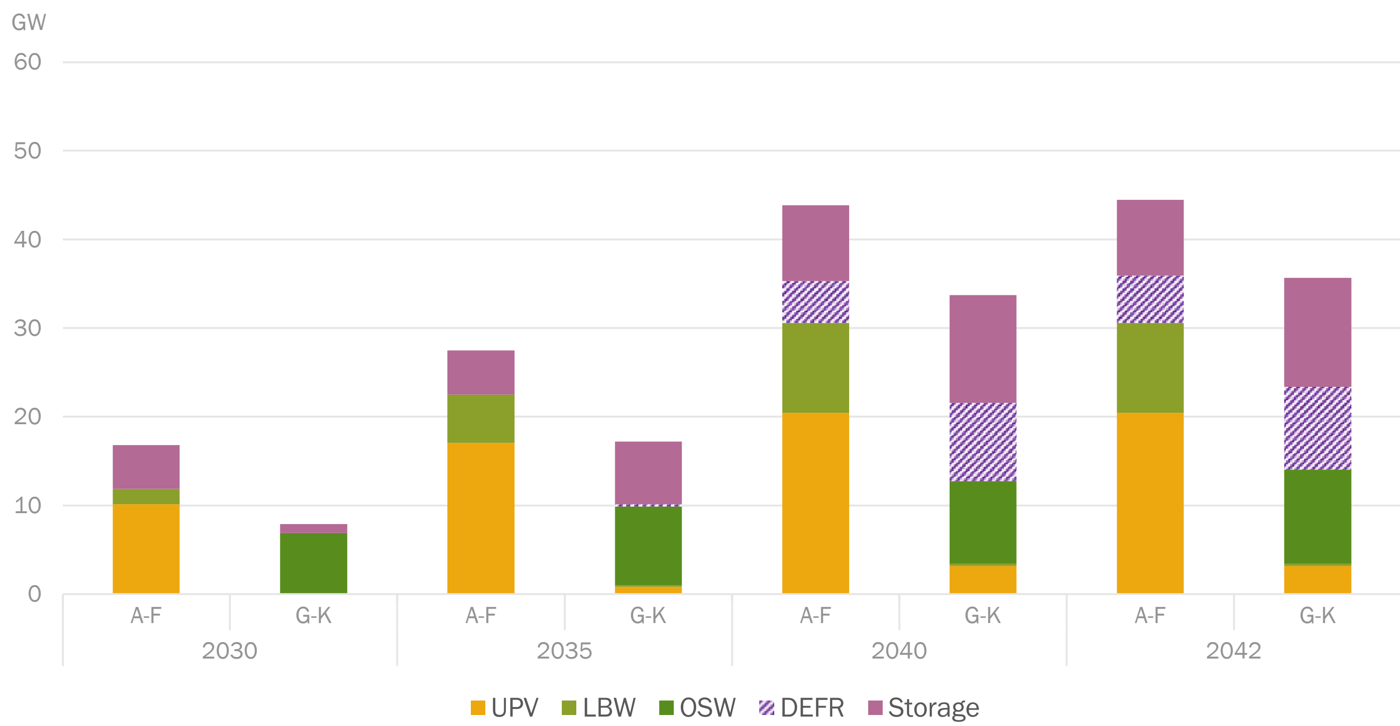
SCENARIO MODELING RESULTS

Results from the Stage 5 capacity expansion analysis are summarized in the figures below, with resource additions organized by technology type and by NYCA zone for each CGPP Scenario. These summaries reflect the relative magnitude and mix of new resource development across scenarios. Statewide capacity additions over time for the three CGPP Scenarios are shown in Figure 22 (HCLO Scenario), Figure 23 (State Scenario), and Figure 24 (High-Transmission Impact Scenario).

The full set of capacity expansion model outputs contains a substantially greater level of detail that is not reproduced here. Complete results are provided in Appendix D.

HCLO Scenario

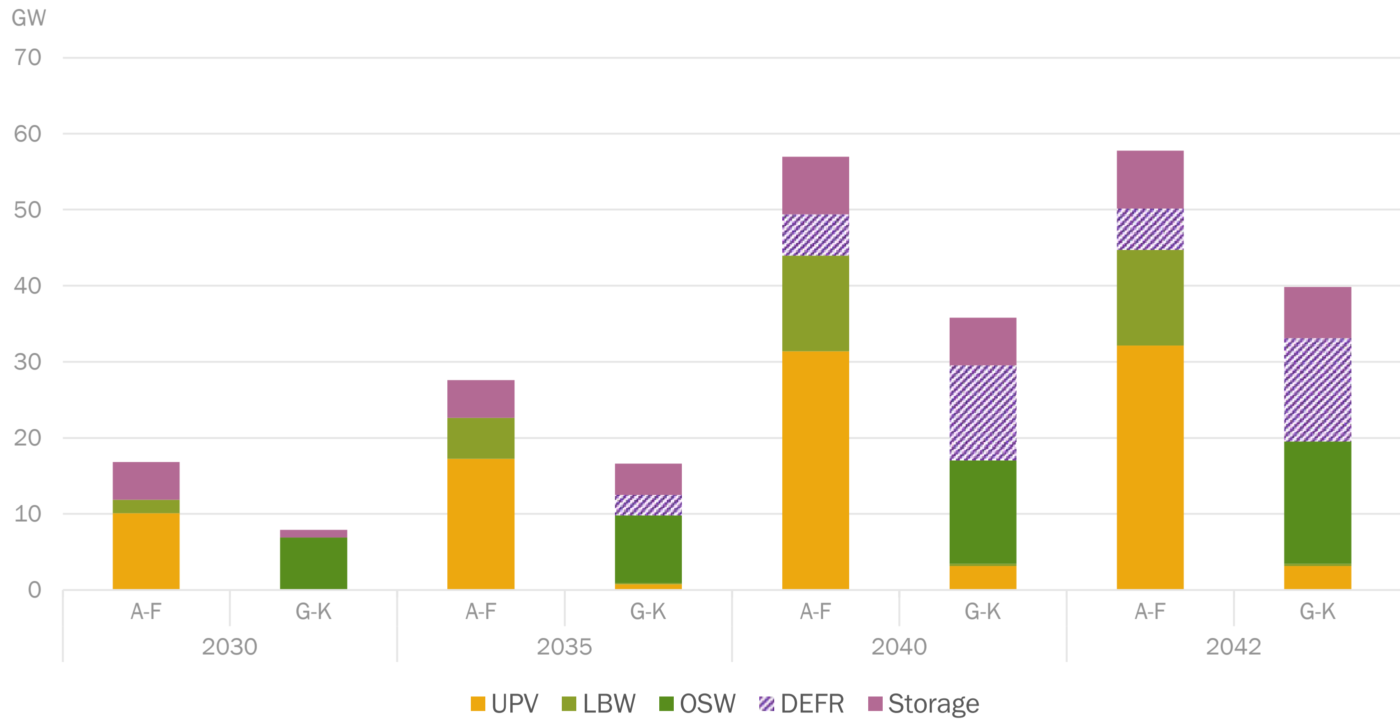
Figure 22: HCLO Scenario Cumulative Capacity Additions - Upstate vs Downstate (Stage 5)



Capacity Additions (MW)				
	2030	**2035**	**2040**	**2042**
UPV	10,151	17,891	23,596	23,596
LBW	1,738	5,634	10,401	10,401
OSW	6,854	8,864	9,303	10,612
DEFR		261	13,592	1,466
Storage	5,950	12,014	20,653	20,857
Total	**24,693**	**44,664**	**77,545**	**80,132**

State Scenario

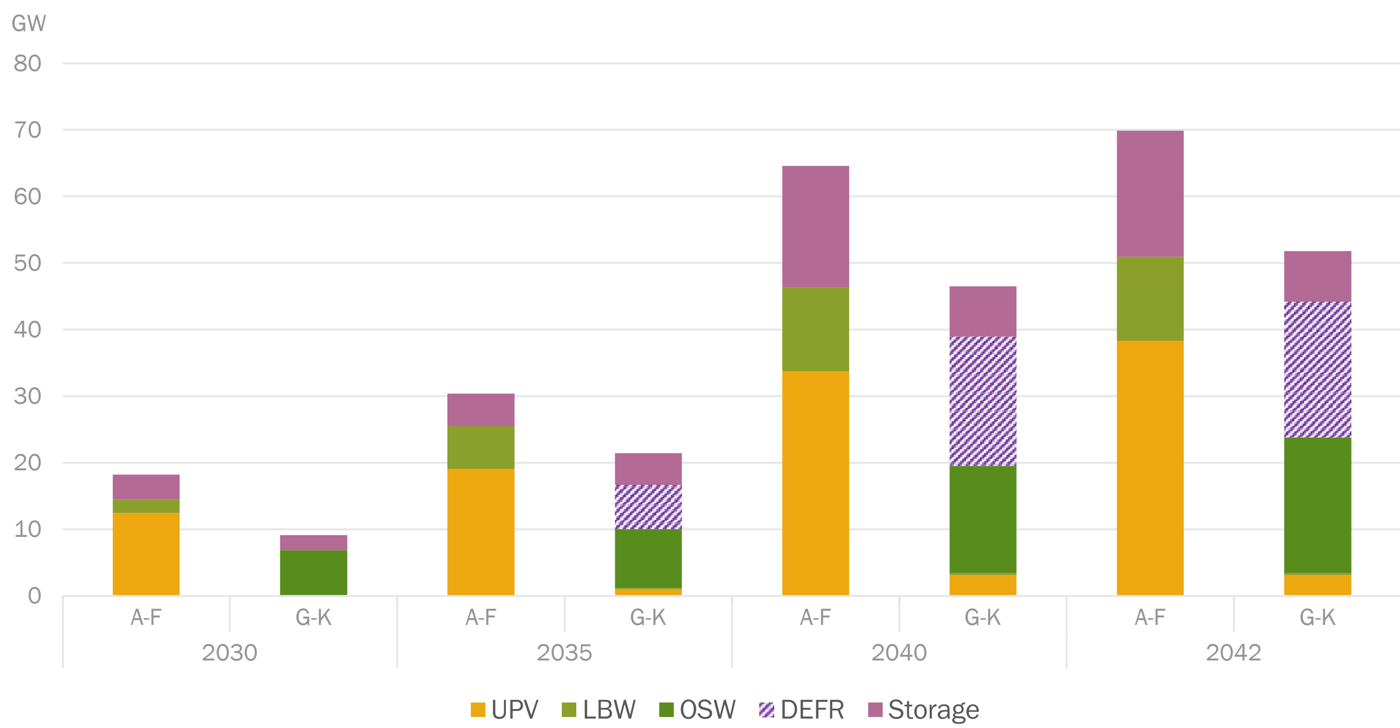
Figure 23: State Scenario Cumulative Capacity Additions - Upstate vs Downstate (Stage 5)



Capacity Additions (MW)				
	2030	**2035**	**2040**	**2042**
UPV	10,144	17,993	34,529	35,294
LBW	1,742	5,569	12,868	12,868
OSW	6,854	8,864	13,611	16,108
DEFR		2,676	17,929	18,985
Storage	5,950	9,101	13,863	14,311
Total	24,690	44,203	92,800	97,566

High-Transmission Impact Scenario

Figure 24: High-Transmission Impact Scenario Cumulative Capacity Additions - Upstate vs Downstate (Stage 5)



Capacity Additions (MW)				
	2030	2035	2040	2042
UPV	12,466	20,100	36,883	41,475
LBW	2,067	6,550	12,868	12,868
OSW	6,854	8,864	16,073	20,368
DEFR		6,626	19,443	20,379
Storage	5,950	9,684	25,800	26,554
Total	27,337	51,824	111,067	121,644

STAGE 5 CAPACITY EXPANSION MODELING: THE JOINT UTILITIES PROJECT PORTFOLIO

The collection of 25 local transmission projects (Figure 20) and four conceptual bulk solutions (Figure 21) was provided to the capacity expansion model as a set of candidate projects for scenario modeling in CGPP Stage 5. The Joint Utilities also requested a variant with no conceptual bulk solutions available to the model to validate projected needs. This variant, run for each of the three CGPP Scenarios, revealed that inclusion of conceptual bulk solutions did not displace or eliminate any of the selected local transmission projects. In some scenarios, the need dates for the selected local transmission projects changed if no conceptual bulk solutions were available. Some were needed sooner; others were deferred until later.

Figure 25 illustrates the results of the scenario assessment for each of the 25 local transmission projects in the initial Stage 3 solution set that was evaluated in the Stage 5 capacity expansion modeling analysis.

Figure 25: Local Transmission Project Selection Years Across CGPP Scenarios With and Without Conceptual Bulk Solutions

Local Projects	State Scenario w/out bulk	State Scenario w/bulk	HCLO Scenario w/out bulk	HCLO Scenario w/Bulk	High Transmission Impact Scenario w/out bulk	High Transmission Impact Scenario w/bulk
Central Hudson 2035 Project	-	-	-	-	2041	-
Central Hudson 2042 Project	-	-	-	-	-	-
Con Edison Project #1	-	2039	2039	2039	2033	2033
Con Edison Project #2	2039	2040	2037	2041	2035	2035
LIPA Project A	2041	2041	-	-	2040	2040
LIPA Project B	2041	2041	-	-	2040	2040
LIPA Project C	-	-	-	-	2040	2040
NG Zone A 2040 Project	-	-	-	-	2040	2040
NG Zone B 2035 Project	-	-	-	-	2040	2040
NG Zone C 2035 Project	2040	2040	2040	2040	2039	2039
NG Zone E 2035 Project	2040	2040	-	-	2039	2039
National Grid Oneida County Transmission Upgrade	2037	2037	2036	2037	2035	2035
National Grid Mohawk Valley Transmission Upgrade	2040	2040	2039	2040	2038	2038
NYSEG Binghampton Cat 1	2041	2040	2041	2040	2040	2040
NYSEG Geneva/Auburn Cat 1	-	-	-	-	2040	2040
NYSEG Hornell/Elmira/Bath Cat 1	2041	2040	2041	2040	2040	2040
NYSEG Hornell/Elmira/Bath Cat 2	2041	2040	-	-	-	-
NYSEG Ithaca Cat 1	-	-	-	-	2041	-
NYSEG Lancaster Cat 1	2040	2040	-	-	2040	2040
NYSEG Oneonta Cat 1	-	2040	-	-	2040	2040

Local Projects	State Scenario w/out bulk	State Scenario w/bulk	HCLO Scenario w/out bulk	HCLO Scenario w/Bulk	High Transmission Impact Scenario w/out bulk	High Transmission Impact Scenario w/bulk
NYSEG Oneonta Cat 2	-	2040	-	-	2040	2040
O&R Project 1	-	-	-	-	2041	-
RG&E Genesee Valley Cat 2	-	-	-	-	-	-
RG&E Rochester Cat 1	2040	2040	2040	2040	2038	2038
RG&E Rochester Cat 2	2040	2040	-	-	-	-

The Stage 5 modeling selected investments that added less headroom than the Stage 1 modeling, for the reasons discussed above. The projects selected by the model at Stage 5 create 9 GW of incremental headroom by 2042 in the HCLO Scenario, 12 GW in the State Scenario, and 18 GW under the High-Transmission Need Scenario. The model selected 10 different local transmission projects in each scenario, with projects generally spread throughout the NYCA zones. (See Figure 26, below.) In addition, the model selected the West-to-East conceptual bulk solution in 2040 in all three scenarios, and the E-J conceptual bulk solution only in Scenario 3 in 2041. Neither the North-to-South nor the Zone J Extension conceptual bulk solutions were selected in any of scenarios. (See, Figure 27 below.)

Figure 26: Stage 5 Existing and Incremental Headroom Projects by NYCA Zone (2042, GW)

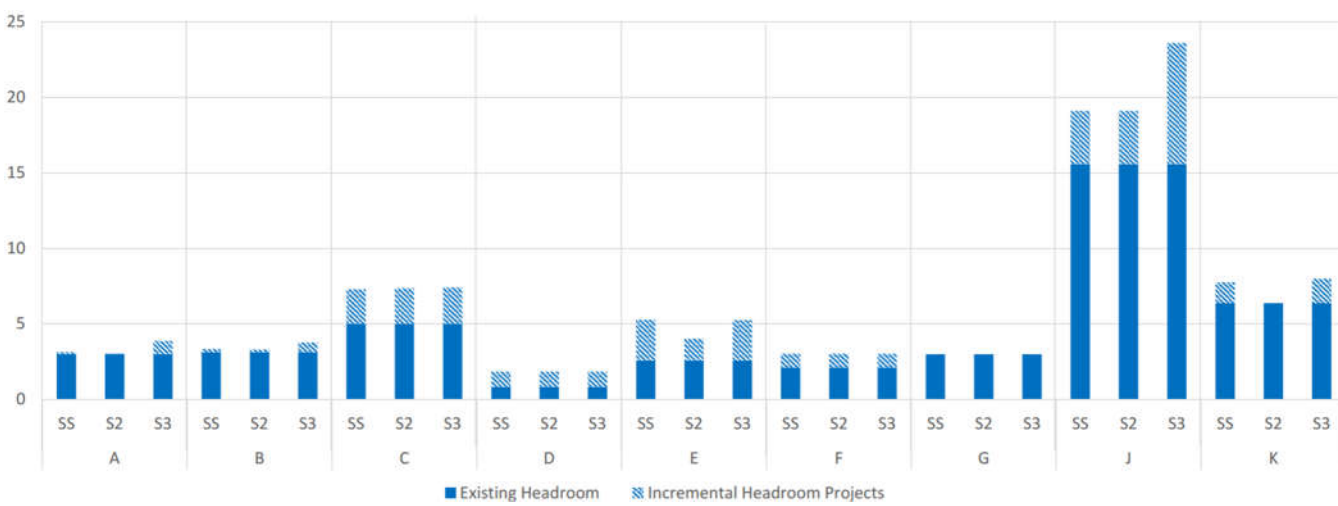


Figure 27: Stage 5 Model Selection of Conceptual Bulk Solutions

Project Name/Identifier	Project Cost ($ millions)	Scenario	Project Selection Count	Project Selected by Scenario							
				2035	2036	2037	2038	2039	2040	2041	2042
West-to-East Concept	2,400	SS	3						✓		
		S2							✓		
		S3							✓		
North-to-South Concept (Alternative B)	3,200	SS	0								
		S2									
		S3									
Extension to Zone J	12,000	SS	0								
		S2									
		S3									
E-J Option	8,000	SS	1								
		S2									
		S3								✓	

Project-by-project and summary-level results for both local transmission and conceptual bulk solutions were presented to the EPPAC on April 20, 2026.

The Joint Utilities interpreted Stage 5 outcomes and narrowed the portfolio of 25 project sets to seven. In constraining the portfolio, particular attention was paid to whether project sets were selected across multiple scenarios, the timing of project set selection, the magnitude of headroom benefits created, and any secondary system benefits.

Figure 28 presents the portfolio of transmission projects for which Con Edison, National Grid, NYSEG, and RG&E seek Commission approval in the current CGPP planning cycle. As can be seen by comparing Figure 25 with Figure 28, certain projects identified as selected in one or more modeling scenarios may not have been included in the final portfolio. Ultimately, the CGPP Portfolio includes only projects that were selected across all three CGPP scenarios—indicating the projects will be needed across a wide range of possible futures—and that were selected relatively early in the modeling horizon. Furthermore, neither the availability nor the unavailability of conceptual bulk projects in the capacity expansion model displaces any of the seven local transmission project sets in Figure 28. This reinforces the finding that the selected project sets address persistent local constraints.

Figure 28: Portfolio of CGPP projects for which utilities are seeking Commission approval in this planning cycle

Project Name/Identifier	Has Adv. Tech. Elements	NYCA Zone	Incremental Headroom (MW)	Project Cost ($ millions)[48]	Earliest Available to the Model	Earliest Need-by Date
Con Edison Project #1		I-to-J	750	$2,316	2033	2033
Con Edison Project #2		J	1500	$1,309	2033	2035
National Grid Oneida County Transmission Upgrade	Y	E	1440	$1,077	2035	2035
National Grid Mohawk Valley Transmission Upgrade	Y	F	900	$1,110	2035	2038
RG&E Rochester Cat 1		B	130	$92	2032	2038
NYSEG Hornell/Elmira/Bath Cat 1	Y	C	740	$1,884	2035	2040
NYSEG Binghampton Cat 1		C	920	$885	2034	2040

Figure 29: Con Edison Project #1 Selection Years by Scenario with and without Conceptual Bulk Solutions

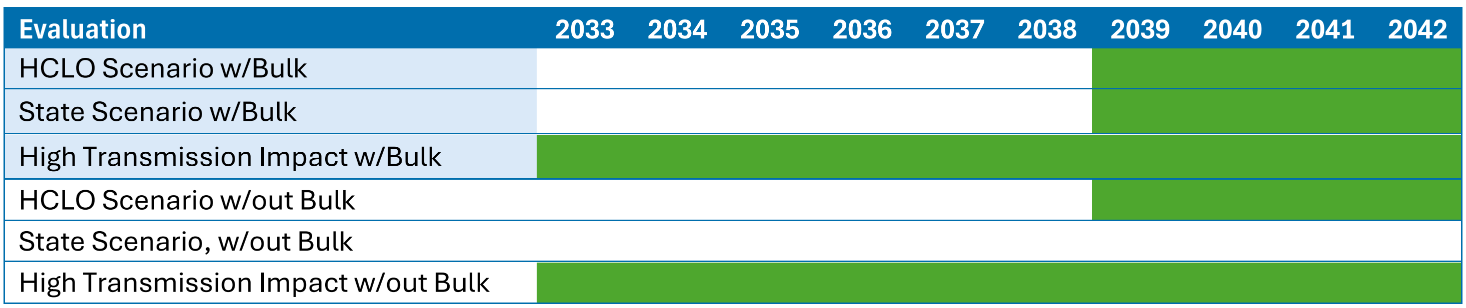
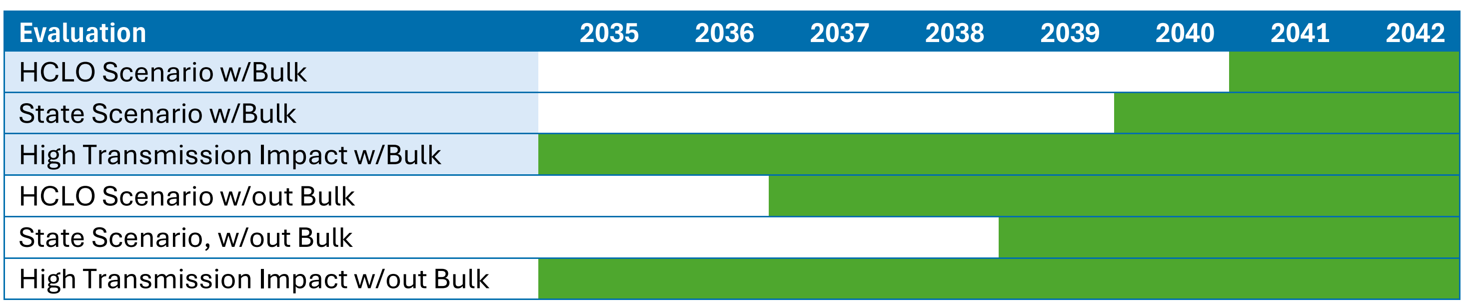


Figure 30: Con Edison Project #2 Selection Years by Scenario with and without Conceptual Bulk Solutions



48 Con Edison and National Grid project cost estimates are in $2035. NYSEG and RG&E project costs are the sum of annual cash flows (please see NYSEG/RG&E Appendix for more details).

Figure 31: National Grid Oneida County Transmission Upgrade Selection Years by Scenario with and without Conceptual Bulk Solutions

Evaluation	2035	2036	2037	2038	2039	2040	2041	2042
HCLO Scenario w/Bulk								
State Scenario w/Bulk								
High Transmission Impact w/Bulk								
HCLO Scenario w/out Bulk								
State Scenario, w/out Bulk								
High Transmission Impact w/out Bulk								

Figure 32: National Grid Mohawk Valley Transmission Upgrade Project Selection Years by Scenario with and without Conceptual Bulk Solutions

Evaluation	2035	2036	2037	2038	2039	2040	2041	2042
HCLO Scenario w/Bulk								
State Scenario w/Bulk								
High Transmission Impact w/Bulk								
HCLO Scenario w/out Bulk								
State Scenario, w/out Bulk								
High Transmission Impact w/out Bulk								

Figure 33: RG&E Rochester Cat 1 Project Selection Years by Scenario with and without Conceptual Bulk Solutions

Evaluation	2035	2036	2037	2038	2039	2040	2041	2042
HCLO Scenario w/Bulk								
State Scenario w/Bulk								
High Transmission Impact w/Bulk								
HCLO Scenario w/out Bulk								
State Scenario, w/out Bulk								
High Transmission Impact w/out Bulk								

Figure 34: NYSEG Hornell/Elmira/Bath Cat 1 Project Selection Years by Scenario with and without Conceptual Bulk Solutions

Evaluation	2035	2036	2037	2038	2039	2040	2041	2042
HCLO Scenario w/Bulk								
State Scenario w/Bulk								
High Transmission Impact w/Bulk								
HCLO Scenario w/out Bulk								
State Scenario, w/out Bulk								
High Transmission Impact w/out Bulk								

Figure 35: NYSEG Binghampton Cat 1 Project Selection Years by Scenario with and without Conceptual Bulk Solutions

Evaluation	2035	2036	2037	2038	2039	2040	2041	2042
HCLO Scenario w/Bulk								
State Scenario w/Bulk								
High Transmission Impact w/Bulk								
HCLO Scenario w/out Bulk								
State Scenario, w/out Bulk								
High Transmission Impact w/out Bulk								

Some additional local transmission projects not listed in Figure 28 may have been selected by the model in one or more scenarios in later years in the planning horizon. (Please refer to Appendix D for detailed results.) The Joint Utilities believe these projects can be initiated following a future CGPP cycle, which may confirm or bolster more near-term support in the future.

This project portfolio in Figure 28 reflects projects selected based on their ability to provide incremental transmission headroom in constrained regions of New York. These projects also support regions that are expected to attract significant clean generation interconnection interest, and they address reliability and energy deliverability needs. Certain projects with 2040 need-by dates are included at this time because they will not only create headroom early in the planning period but also provide infrastructure on which other projects selected later in the planning period rely. Deferral of these projects to a subsequent CGPP cycle could create a material risk that these and other projects would not be placed in service by 2040.

Con Edison, National Grid, NYSEG, and RG&E request Commission approval to advance development of the portfolio of projects in Figure 28, with project costs to be recovered pursuant to the Cost Sharing and Recovery Agreement (CSRA) that the Commission approved in this proceeding.[49]

[49] See, *infra*, note 19.

CONCLUSION

The first CGPP cycle has exhibited technical rigor, inter-agency coordination, and stakeholder engagement. Through five structured stages of analysis—spanning capacity expansion modeling, engineering-based system assessments, solution development, portfolio review, and least-cost planning— a defined set of local transmission projects has been identified that enhance reliability, increase system capacity, enable least cost clean energy deployment and ready for Commission consideration.

The seven projects in the CGPP Cycle 1 portfolio address near-term system needs that arise across a wide range of plausible futures. Importantly, while the broader clean energy policy and planning environment continues to evolve—reflecting changes in a range of economic conditions, the need for these projects does not depend on the realization of any single pathway to policy compliance. Instead, the project sets proposed in this report respond consistently to modeling results across multiple CGPP scenarios and were selected precisely because they perform well under uncertainty. The project portfolio represents a set of "no-regrets" investments that strengthen the grid's ability to reliably serve customers while preserving flexibility for future planning cycles. Consistent with the scale and complexity of New York's long-term transmission needs, only a limited set of projects are being proposed in this CGPP cycle and are deferring other solutions due to remaining uncertainty, longer-term need, or evolving system conditions. This project set selection reflects a judicious focus on those investments that are demonstrably necessary, timely, and well-supported by the analysis that has been completed throughout this CGPP cycle.

The Joint Utilities recognize that New York's clean energy transition is occurring amid unprecedented load growth and heightened uncertainty regarding the timing, sequencing, and composition of future resource needs. The State Energy Plan and other policy signals acknowledge that near-term targets originally contemplated under earlier planning assumptions may be achieved later or through different pathways than initially envisioned. However, this evolving policy context underscores—rather than diminishes—the importance of deploying targeted transmission investments that take years to permit and construct. This will enable utilities to address fundamental system constraints that appear across multiple system assumptions. By creating incremental headroom in constrained regions and reinforcing critical network elements, these investments reduce project delivery risk, limit the likelihood of congestion and curtailment in the next decades, and will prepare the New York grid system to accommodate a broad range of future outcomes.

The CGPP framework that produced this project portfolio is, itself, designed to be adaptive. Lessons learned during Cycle 1—including refinements to headroom cost estimations, improved coordination between bulk and local planning, and enhanced treatment of advanced technologies and disadvantaged community considerations—have already informed Commission-directed modifications for future cycles. As such, approving the Cycle 1 portfolio does not foreclose future decision-making. Rather, it establishes a durable foundation that future CGPP cycles can build on.

Con Edison, National Grid, NYSEG, and RG&E respectfully request the Commission's approval to pursue the development of the seven local transmission projects presented in this Report. These projects were selected in multiple CGPP planning scenarios, demonstrate favorable performance in the Stage 5 least-cost assessment, and are sufficiently advanced in scope definition, cost estimation, and timing to support near-term action. Deferral of these projects to a later planning cycle would materially increase the risk that these transmission resources—and the clean energy resources that will depend on them—will not be built on the timeline on which New York needs them. This would also compromise the State's ability to respond efficiently to evolving load growth, broad interconnection interests, and reliability needs.

Con Edison, National Grid, NYSEG, and RG&E further note that they intend to seek recovery of Commission-approved project costs pursuant to the CSRA previously accepted by the Commission.[50] The CSRA provides an established, transparent mechanism for allocating and recovering the costs of qualifying local transmission projects in a manner that reflects shared system benefits and advances uniform statewide planning objectives. Recovery under the CSRA is appropriate for the projects proposed in this cycle, as they were developed through the Commission-directed CGPP framework and provide demonstrable benefits beyond individual utility service territories.

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[50] See, *infra*, note 19.

CGPP Cycle 1 demonstrates that coordinated, forward-looking grid planning can identify infrastructure projects that are both responsive to current system conditions and resilient to future uncertainty. The Joint Utilities stand ready to advance the approved projects, continue collaboration with DPS Staff, NYSERDA, the NYISO, and stakeholders, and incorporate the Commission's guidance as the CGPP evolves.