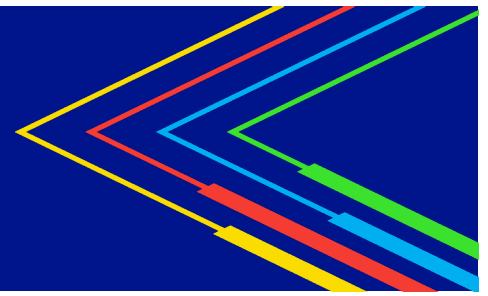


National Grid



Distributed System Implementation Plan Update of Niagara Mohawk Power Corporation d/b/a National Grid

Case 16-M-0411
DSIP Proceeding
June 30, 2025



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Acronyms

3V0:	Zero-Sequence Voltage
ACE-NY:	Alliance for Clean Energy New York
ADMS:	Advanced Distribution Management System
ADR:	Automated Demand Response
ADSS:	All Dielectric Self-Supporting
AGCC:	Avoided Generation Capacity Cost
AMEEP:	Affordable Multifamily Energy Efficiency Program
AMI:	Advanced Metering Infrastructure
ARI:	Active Resource Integration
ASHP:	Air Source Heat Pump
ATWG:	Advanced Technology Working Group
B2G:	Building-to-Grid
BCA:	Benefit-Cost Analysis
BE:	Building Electrification
BESS:	Battery Energy Storage System
BTM:	Behind-the-meter
BTUH:	British Thermal Unit per Hour
C&I:	Commercial and Industrial
CAMP:	Central Adirondack Microgrid Project
CARIS:	Congestion Assessment and Resource Integration Study
ccASHP:	Cold Climate Air Source Heat Pump
CCRP:	Climate Change Resilience Plan
CDG:	Community Distributed Generation
CEATI:	Centre for Energy Advancement through Technological Innovation Inc.
CEI:	Customer Energy Integration
CEMP:	Customer Energy Management Platform
CES:	Clean Energy Standard
CESIR:	Coordinated Electric System Interconnection Review
CFF:	Common File Format
CGPP:	Coordinated Grid Planning Process
CI:	Customer Interruptions
CIP:	Capital Investment Plan
CLCPA:	Climate Leadership and Community Protection Act
CMI:	Customer Minutes Interrupted
Commission:	New York State Public Service Commission
Company:	Niagara Mohawk Power Corporation d/b/a National Grid
CRD:	Certification Requirements Decision
CSA:	Comprehensive System Architecture
CSRP:	Commercial System Relief Program
CSS:	Customer Service System
CSV:	Comma-Separated Values
CVR:	Conservation Voltage Reduction
CY:	Calendar Year
DA:	Distribution Automation
DAC:	Disadvantaged Community

Acronyms

DAF:	Data Access Framework
DANC:	Development Authority of the North Country
DCFC:	Direct Current Fast Charger
DEC:	Department of Environmental Conservation
DER:	Distributed Energy Resource
DERA:	Distributed Energy Resource Aggregation
DERMS:	Distributed Energy Resource Management System
DG:	Distributed Generation
DHW:	Domestic Hot Water
DLC:	Direct Load Control
DLM:	Dynamic Load Management
DLR:	Dynamic Line Ratings
DLRP:	Distribution Load Relief Program
DMM:	Document and Matter Management
DMS:	Distribution Management System
DOE:	U.S. Department of Energy
DPS:	Department of Public Service
DR:	Demand Response
DRMS:	Demand Response Management System
DRIVE:	Distributed Resource Integration and Value Estimation
DRV:	Demand Reduction Value
DS0:	Digital Signal 0
DSCADA:	Distribution Supervisory Control and Data Acquisition
DSIP:	Distribution System Implementation Plan
DSO:	Distributed System Operator
DSP:	Distributed System Platform
DTT:	Direct Transfer Trip
DWDM:	Dense Wave Division Multiplexing
EAM:	Enterprise Asset Management
EAP:	Energy Affordability Program
EE:	Energy Efficiency
EE/BE:	Energy Efficiency/Building Electrification
EHP:	Electric Heat Pump
EJ:	Environmental Justice
EM&V:	Evaluation, Measurement and Verification
EMS:	Energy Management System
EPRI:	Electric Power Research Institute
EPS:	Electric Power System
ESB:	Electric System Bulletin
ESE:	Energy Service Entities
E-SFA:	Expanded Solar for All
ESR:	Energy Storage Resource
ESS:	Energy Storage System
ESSC:	Energy Storage Subcommittee
EV:	Electric Vehicle

Acronyms

EVIWG:	Electric Vehicle Infrastructure and Interconnection Working Group
EVSE:	Electric Vehicle Supply Equipment
FAN:	Field Area Network
FERC:	Federal Energy Regulatory Commission
FLISR:	Fault Location, Isolation, and Service Restoration
FTM:	Front-of-the-Meter
FY:	Fiscal Year
GBC:	Green Button Connect
GDB:	Geodatabase
GFCI:	Ground-Fault Circuit Interruption
GHG:	Greenhouse Gas
GIS:	Geographic Information System
GOTF:	Grid of the Future
GRIP:	Grid Resilience and Innovation Partnerships
GSHP:	Ground Source Heat Pump
GW:	Gigawatt
HCA:	Hosting Capacity Analysis
HMI:	Human-Machine Interface
HP:	Heat Pump
HPWH:	Heat Pump Water Heater
HVAC:	Heating, Ventilation, and Air Conditioning
ICAP:	Installed Capacity
ICE:	Interruption Cost Estimate
IEC:	International Electrotechnical Commission
IEEE:	Institute of Electrical and Electronics Engineers
IEDR:	Integrated Energy Data Resource
IJA:	Infrastructure Investment and Jobs Act
I&M:	Inspection and Maintenance
IOAP:	Interconnection Online Application Portal
IOU:	Investor-Owned Utility
IPV:	Initial Public Version
IPWG:	Interconnection Policy Working Group
IRA:	Inflation Reduction Act
ISO:	International Organization for Standardization
ISO-NE:	Independent System Operator – New England
ISS:	Intelligent Substation
ITWG:	Interconnection Technical Working Group
JMC:	Joint Management Committee
JU:	Joint Utilities
kV:	Kilovolt
kW:	Kilowatt
kWh:	Kilowatt hour
LBMP:	Locational-Based Marginal Price
LDV:	Light Duty Vehicle

Acronyms

LIPA:	Long Island Power Authority
LMI:	Low-and-Moderate Income
LMTIP:	Load Management Technology Incentive Program
LSR:	Locational System Relief
LSRV:	Locational System Relief Value
LTIP:	Long Term Integrated Planning
L2:	Level 2
M&C:	Monitoring and Control
MCOS:	Marginal Cost of Service
MDIWG:	Market Design and Integration Working Group
MDMS:	Meter Data Management Services
MHD:	Medium- and Heavy Duty
MHDV:	Medium- and Heavy-Duty Vehicle
MID:	Microgrid Interconnection Device
MM:	Multimode
MMBTU:	Metric Million British Thermal Unit
MOD:	Mobile Outage Dispatch
MOU:	Memorandum of Understanding
MPLS-TP:	Multiprotocol Label Switching – Transport Profile
MRP:	Make-Ready Program
MTC:	Market Transition Credit
MVA:	Megavolt-Amperes
MVP:	Minimum Viable Product
MW:	Megawatts
MWh:	Megawatt hours
nCAP:	New Customer Application Portal
NEEP:	Northeast Energy Efficiency Partnerships
NEM:	Net Energy Metering
NE:NY:	New Efficiency: New York
NERA:	National Economic Research Associates
NESC:	National Electric Safety Code
NESCAUM:	Northeast States for Coordinated Air Use Management
NRA:	Negative Revenue Adjustment
NREL:	National Renewable Energy Laboratory
NRTL:	Nationally Recognized Testing Laboratory
NSE:	Network State Engine
NWA:	Non-Wires Alternatives
NY:	New York
NY-BEST:	New York Battery and Energy Storage Technology Consortium, Inc.
NYISO:	New York Independent System Operator
NYPA:	New York Power Authority
NYS:	New York State
NYSDEC:	New York State Department of Environmental Conservation
NYSDOT:	New York State Department of Transportation
NYSED:	New York State Education Department

Acronyms

NYSEIA:	New York Solar Energy Industries Association
NYSERDA:	New York State Energy Research and Development Authority
NY-SIR:	New York Standardized Interconnection Requirements
O&M:	Operations and Maintenance
OMS:	Outage Management System
OpenADR:	Open Automated Demand Response
OPGW:	Optical Ground Wire
OT:	Operational Technology
PCC:	Point of Common Coupling
PFC:	Power Flow Control
PON:	Program Opportunity Notice
PPI:	Per-Plug Incentive
PSC:	Public Service Commission
PTO:	Permission to Operate
PV:	Photovoltaic
REACH:	Renewable Energy Access and Community Help
REC:	Renewable Energy Certificate
REST:	Representational State Transfer
REV:	Reforming the Energy Vision
RFP:	Request for Proposal
RMI:	Rocky Mountain Institute
RTEM:	Real Time Energy Management
RTU:	Remote Terminal Unit
SAIDI:	System Average Interruption Duration Index
SAIFI:	System Average Interruption Frequency Index
SAInt:	Scenario Analysis Interface for Energy Systems
SCADA:	Supervisory Control and Data Acquisition
SD-OM:	Smart Data for Outage Management
SD-WAN:	Software-defined wide-area network
SEEP:	System Energy Efficiency Plan
SMB:	Small-Medium Business
SME:	Subject Matter Expert
SONET:	Synchronous Optical Network
S-SFA:	Statewide Solar for All
STF:	Short Term Forecasting
STORMS:	Severn Trent Operational Resource Management System
STREAMS:	Strategic Reimagining of Enterprise Asset Management Systems
Sub-T:	Sub-transmission
Telco:	Telecommunications Companies
T&D:	Transmission and Distribution
TBTU:	Trillion British Thermal Unit
TRM:	Technical Resource Manual
UCG:	Utility Coordination Group
URL:	Uniform Resource Locator
UTO:	Unified Technology Operations Center

Acronyms

V2G:	Vehicle-to-Grid
V2H:	Vehicle-to-Home
VDER:	Value of Distributed Energy Resource
VDI:	Virtual Desktop Interface
VPP:	Virtual Power Plant
VVO:	Volt-VAR Optimization
ZEV:	Zero-Emission Vehicle

Executive Summary

Niagara Mohawk Power Corporation d/b/a National Grid (National Grid or the Company) is pleased to provide its 2025 Distributed System Implementation Plan (DSIP) Update following the framework provided by the New York State (NYS) Climate Leadership and Community Protection Act (the Climate Act or CLCPA)¹ and advancing the objectives of the New York State Public Service Commission's (Commission) Reforming the Energy Vision (REV) Proceeding.²

In 2019, NYS passed the nation-leading CLCPA to achieve 100 percent zero-emission electricity by 2040 and 85 percent emission reductions below 1990 levels by 2050 which means:

- Solar, wind, and other renewable resources, combined with energy storage and other zero-emission technologies, will deliver affordable and reliable electricity.
- New clean heating and cooling technologies, such as electric heat pumps (EHP) and smart thermostats, combined with other energy efficiency (EE) measures, will save New Yorkers energy and money.
- Zero-emission transportation options will be prevalent to improving air quality and achieving cleaner communities.
- A clean energy economy will create access to clean energy solutions and new economic opportunities.

As an energy distributor, National Grid is a key partner with NYS in enabling this future. National Grid's vision is to be at the heart of a clean, fair, resilient, and affordable energy future with a focus on optimizing performance by finding a better way and making it happen for our customers. In this 2025 DSIP Update, the Company presents its progress and plans on a host of actions it is taking in support of the clean energy goals set forth in the NYS Energy Plan³ and the Climate Act.

The Company's DSIP plans are based on the following four clarifying principles:

- **Enable the energy transition for all** by supporting the achievement of the Climate Act's targets, delivering and enabling cost-effective clean energy solutions, improving our ability to integrate a greater portfolio of Distributed Energy Resources (DERs), and delivering on the Distributed System Platform (DSP) model.
- **Deliver for our customers efficiently** by improving our processes and systems, ensuring choice and control over their energy services, enabling a high degree of situational

¹ The CLCPA is available at <https://www.nysenate.gov/legislation/bills/2019/s6599>

² Case 14-M-0101, *Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision* (REV Proceeding).

³ The current New York State Energy Plan was initially published in 2015 and amended in 2020 to align with the objectives of the Climate Act.

awareness, lowering energy costs through optimizing our network, and enabling a thriving market for new and innovative services.

- **Cultivate an efficient, reliable, and resilient grid** that can adapt to the evolving paradigms of two-way power flows, optimize system performance and network resiliency with fewer and shorter power outages, and improve reliability, responsive demand, and customer participation.
- **Maximize the effectiveness of performance incentives** in driving these important outcomes.

Figure ES-1: National Grid Commitments



To deliver on National Grid’s vision and the goals of the Climate Act, National Grid will continue to pursue foundational investments that will enable the Company to modernize the grid, improve efficiency, animate markets, and enhance the reliability and resiliency of the electric system. National Grid is well positioned to “green” the grid and progress the role of the DSP provider as directed in the Commission’s REV Track One Order.⁴ In this role, the Company continuously seeks opportunities to incorporate services that enable third-party providers of DER to deliver value to both customers and the electric system.

⁴ REV Proceeding, Order Adopting Regulatory Policy Framework and Implementation Plan (issued February 26, 2015) (REV Track One Order).

The Company's progress and plans presented in this document exemplify how National Grid has embraced its role as a DSP provider. This document depicts key progress made since the 2023 DSIP Update⁵ was filed as well as the Company's current plans through 2030. Some of the major investment areas the Company is proposing include proactive spending in increasing system hosting capacity, multi-value projects condition and reliability issues while enabling increased delivery of renewable energy, a flexible interconnection pilot to integrate distributed generation (DG) in constrained areas via further development of curtailment capabilities, an Electric Vehicle Make-Ready Program (MRP) and the continued deployment of Advanced Metering Infrastructure (AMI). In addition, the Company looks to best align with the Commission's ongoing Grid of the Future (GOTF) proceeding.⁶ This will ensure that the goals of the DSIP may be used as a roadmap for meeting the initiatives set out within the GOTF. Implementation of the activities set forth in this five-year plan is dependent on future rate case review and approval. National Grid's current Three-Year Rate Plan⁷ which was in effect through March 31, 2025, was extended with a make-whole provision through August 31, 2025, pending a Commission determination on a new National Grid rate plan for a period of three years ending March 31, 2028.⁸

National Grid's 2025 DSIP Update

This 2025 DSIP Update provides detailed information about National Grid's planned DSP implementation over the coming five-year period ending in 2030.

In this 2025 DSIP Update the Company will:

- Report on DSP actions and progress since the 2023 DSIP Update;
- Describe plans for developing and implementing necessary tools, policies, processes and resources to achieve the next five-year plan, including any relevant plans from the Coordinated Grid Planning Process (CGPP).⁹
- Identify and describe how DER developers, customers and other third parties can access available tools and information to help them understand National Grid's system needs, and potential business opportunities, including the new statewide Integrated Energy Data Resource (IEDR) platform;

⁵ Cases 16-M-0411 *et al.*, *In the Matter of Distributed System Implementation Plans* (DSIP Proceeding), Niagara Mohawk Power Corporation d/b/a National Grid – 2023 Distributed System Implementation Plan (DSIP) Update (filed June 30, 2023) (2023 DSIP Update).

⁶ Case 24-E-0165, *Proceeding on Motion of the Commission Regarding Grid of the Future* (GOTF Proceeding).

⁷ Cases 20-E-0380 *et al.*, *Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Niagara Mohawk Power Corporation d/b/a National Grid for Electric Service* (National Grid Electric and Gas 2020 Rate Case Proceeding), Order Adopting Terms of Joint Proposal and Establishing Electric and Gas Rate Plans (issued January 20, 2022) (Three-Year Rate Plan Order).

⁸ Cases 24-E-0322 and 24-G-0323, *Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Niagara Mohawk Power Corporation d/b/a National Grid for Electric Service* and *Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Niagara Mohawk Power Corporation d/b/a National Grid for Gas Service* (National Grid Electric and Gas 2024 Rate Case Proceeding).

⁹ See e.g., 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* (T&D Planning Proceeding), Order Approving a Coordinated Grid Planning Process (issued August 17, 2023) (CGPP Order).

- Provide useful links to information and live data so stakeholders have access to the latest information;
- Describe upcoming new programs, projects and procurements to enable greater levels of DER; and
- Ensure alignment with GOTF goals, where efforts laid out in this report are set to coordinate with the goals of the GOTF Proceeding.

Development of this 2025 DSIP Update has benefited from a collaborative process with the Joint Utilities,¹⁰ Department of Public Service (DPS) Staff, and numerous other stakeholders. The Joint Utilities work collaboratively to progress their respective DSPs as consistently as possible across the state while recognizing the inherent differences of each of the utility's systems.

The format of the DSIP Update has been structured to be responsive to the detailed guidance provided in the 2023 DSIP Guidance Update¹¹ and maintain consistency with the 2023 DSIP Update. Each of the topical sections represented in Table ES-1 includes a discussion on context and progress made since the 2023 DSIP Update, as well as the Company's plans for the next five years. Detailed responses to specific inquiries are provided in a Question-and-Answer format in Appendix B. Additionally, updates on DSIP Governance, Marginal Cost of Service (MCOS) studies, and the Benefit-Cost Analysis (BCA) Handbook are presented in this 2025 DSIP Update.

Table ES-1: Topical Sections

Topical Sections	1	Integrated Planning
	2	Advanced Forecasting
	3	Grid Operations
	4	Energy Storage Integration
	5	Electric Vehicle Integration
	6	Clean Heat Integration
	7	Energy Efficiency Integration and Innovation
	8	Data Sharing
	9	Hosting Capacity
	10	Billing and Compensation
	11	DER Interconnections
	12	Advanced Metering Infrastructure
	13	Beneficial Locations for DERs and Non-Wires Alternatives (NWA)

As the energy landscape evolves, so will National Grid's DSIP plans. There are multiple efforts and regulatory proceedings underway that may influence the implementation of this plan. For a

¹⁰ The Joint Utilities are Central Hudson Gas & Electric Corporation, Consolidated Edison Company of New York, Inc. (Con Edison), New York State Electric & Gas Corporation (NYSEG), Niagara Mohawk Corporation d/b/a National Grid, Orange & Rockland Utilities, Inc., and Rochester Gas and Electric Corporation (RG&E) (Joint Utilities).

¹¹ DSIP Proceeding, DPS Staff Whitepaper – Proposed Commission Guidance for the Electric Utilities' DSIP Update Filings (filed January 10, 2023).

list of regulatory proceedings that may influence the path forward, please refer to Appendix A. Throughout this evolution National Grid will stay engaged and work with stakeholders to ensure the DSP continues to provide value to customers and is sufficiently flexible to accommodate adaptive goals and paths forward that adjust to changing technology, policy, and consumer preferences in a cost-effective fashion.

1 Progressing the Distributed System Platform

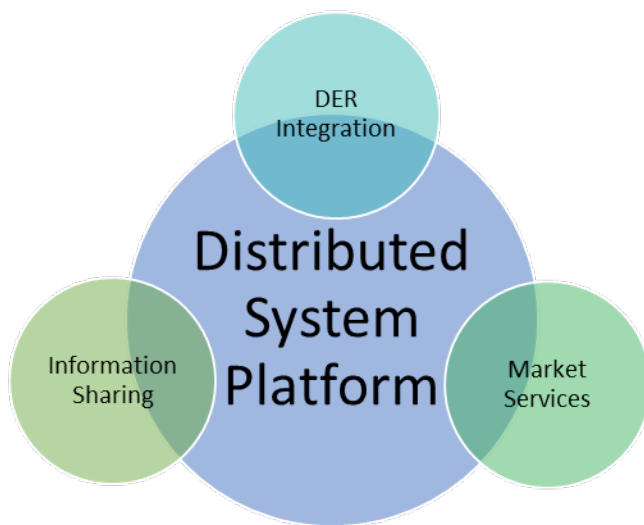
Summary: National Grid's Vision Remains Consistent as We Sharpen Focus on Flexibility

Since the outset of the REV Proceeding, National Grid's vision has been to incorporate and optimize the use of DERs into utility planning and operating practices and to facilitate the distributed energy marketplace through a DSP which empowers communities and customers, promotes affordability, and supports the state's clean energy policy goals.

National Grid's previous DSIP filings have documented both our foundational investments and advances in means and methods that have enabled considerable progress toward that vision. This 2025 DSIP Update continues that consistent vision for the future, while beginning to add focus on how those investments and advances unlock innovation to maximize the benefits of flexible resources.

The Company continues to organize its efforts through what we have long defined as the three core DSP functions: DER integration, market services, and information sharing [Fig 1.1].

Figure 1.1: Core DSP Functions



Regulatory Background

The set of regulatory initiatives and state policy goals driving the development of the DSP have evolved over the past ten years. The Commission defined the initial set of DSP-related objectives when it issued the April 25, 2014, *Order Instituting Proceeding*.¹² The six core REV goals were:

1. Enhance Customer Knowledge and Tools
2. Animate the Marketplace
3. Improve System-Wide Efficiency
4. Increase Fuel and Resource Diversity
5. Enhance System Reliability and Resiliency
6. Reduce Carbon Emissions

Subsequent laws and regulatory initiatives built upon those goals. The Clean Energy Standard (CES) established a goal of achieving 50 percent clean energy by 2030 (later revised upward to 70 percent) and was followed by the CLCPA which expanded upon state climate goals. In the case of the CLCPA, those expanded goals included an 85 percent reduction in greenhouse gas (GHG) emissions by 2050, 100 percent carbon-free electricity by 2040, and procurement of 9,000 megawatts (MW) of offshore wind, 3,000 MW of energy storage (later expanded to 6,000 MW), and 6,000 MW of solar (later expanded to 10,000 MW).

The Commission's introduction of the CGPP in 2021 supported the original REV goal of improving system-wide efficiency by increasing coordination between bulk power system planning and generation interconnection and increasing integration of local Transmission and Distribution (T&D) studies with the New York State Energy Research and Development Authority's (NYSERDA) renewable generation and storage procurements.

A number of regulatory initiatives in recent years also continued to build on the original REV goals of enhancing fuel and resource diversity and abating carbon emissions by focusing on electrification. As a result, the 2023 DSIP Updates placed a greater emphasis on electrification and identification of enabling investments and programs.

Utility Foundational DSP Investments Have Enabled Significant Progress Toward New York's Policy Goals

Utility efforts, both individual and coordinated through the Joint Utilities, have been essential in enabling DSP functions and securing significant advances toward the original six core REV goals. Working collaboratively with DPS and NYSERDA, and with robust engagement and feedback from stakeholders, we have been able to advance DSP functions and implement programs that have brought us closer to our long-term vision.

¹² REV Proceeding, Order Instituting Proceeding (issued April 25, 2014).

Through enabling actions like these detailed in DSIP filings since 2016, and as shown in Figure 4-6 of the “First Iteration of the Grid of the Future Plan” filing from NYSERDA and DPS, all of the utilities have progressed to enabling critical DSP functions in distribution planning and network development, interconnection and network reinforcement, distribution network operations, customer services and engagement, data governance, and stakeholder engagement and change management. In many cases utilities have progressed further to the next phase of integrating systems, processes, teams, and strategy or even initiating enterprise-wide deployment.

Utility actions have contributed significantly to electrification, and especially to advancing NY’s electric vehicle (EV) marketplace, such as the Direct Current Fast Charger (DCFC) Per Plug Incentive Program, EV MRP, EV Residential Managed Charging Program, Load Management Technologies Incentive Program, Demand Charge Rebate, EV Phase-in Rate, Commercial Managed Charging Program, and Medium- and Heavy-Duty (MHDV) Make-Ready Pilot Program.

In addition, the NYS Clean Heat Program, which launched on April 1, 2020, provides customers, contractors, and other heat pump solution providers with consistent experience and business environment throughout NYS. The utilities have participated in implementing a common statewide framework to advance the adoption of heat pump systems.

The results of regulatory vision progress, state incentive support, stakeholder participation, and utility DSP enablement and program implementation have been encouraging. As described by DPS:

- The solar industry has grown from 325 MW of ICAP in 2014 to 6.8 GW in March 2025. National Grid’s capacity is over 2000 MW as of June 2025.
- There have been approximately 1.0 GW of deployments, awards, and energy storage contracts as of March 2024.
- There have been nearly 59,000 heat pump installations through 2023, representing over 4.5 trillion British thermal units (TBTU) of annual energy savings.
- Nearly 210,000 EVs have been registered in NY as of March 2024, and the Commission-authorized EV MRP has supported approximately 20,000 level 2 (L2) charging stations and approximately 1,500 DCFC stations either completed or in the process of being constructed as of March 2024.
- Approximately 410 MW of demand response (DR) capability were enrolled in the Commission directed utility programs for National Grid in 2024 .

NYS has seen notable advances in all six original REV goals. The Joint Utilities have individually and collectively through the IEDR embarked on a path to enhance customer knowledge that gives customers more tools to control their bills. The profusion of DERs shows that NY has animated the market for advanced technologies and services. Enhanced planning across the T&D systems are improving system-wide efficiency. The successes of Clean Heat and EV programs are increasing fuel resource diversity. The penetration of storage and DSP-enabling grid management technologies, such as Advanced Distribution Management System (ADMS) and Distributed Energy Resource Management System (DERMS), are enhancing system reliability and resiliency.

Further, the growth of electrification and solar photovoltaic (PV) installations are reducing carbon emissions.

In summary, over the past ten years, National Grid and the Joint Utilities have made significant progress in developing and enabling the DSP, and, in tandem with our regulatory and market partners, have advanced the vision for NY's energy future.

Developments Since the 2023 DSIP Update Have Added a Focus on Flexibility

In April 2024, the Commission initiated the GOTF Proceeding. The objective of the GOTF Proceeding, as described in the Commission's *Order Instituting Proceeding*, is "to unlock innovation and investment to deploy flexible resources—such as DERs and virtual power plants (VPPs)—to achieve our clean energy goals at a manageable cost and at the highest levels of reliability."¹³

The goals of the GOTF Proceeding are clearly aligned both with the DSP enablement that National Grid has achieved so far and with its longstanding vision. They build on the original six REV goals with a particular emphasis on long-term system efficiency.

The vision for the continued development of the DSP under the GOTF Proceeding also builds directly on the longstanding core functions of the DSP. In the First Iteration of the GOTF Plan,¹⁴ NYSERDA and DPS introduced a potential DSP framework built around "five pillars" — Distribution Planning & Network Development, Interconnection & Network Reinforcement, Distribution Network Operations, Customer Services & Engagement, and Market Design & Integration [Fig1-2].¹⁵

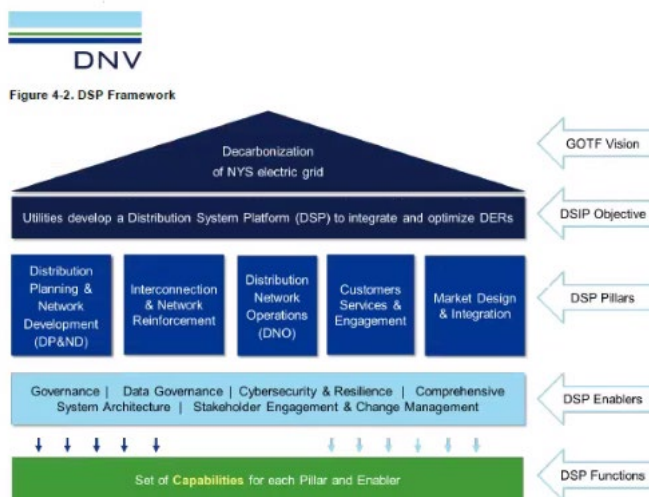
These "five pillars" are closely aligned to the "three core DSP functions" around which the Joint Utilities have been organizing, with the new "five pillars" framework parsing out interconnection and adding more focus on operations. While continuing to use the three core functions DSIP framework, National Grid looks forward to evolving the framework as needed in future DSIPs.

¹³ GOTF Proceeding, Order Instituting Proceeding (issued April 18, 2024), p. 3.

¹⁴ GOTF Proceeding, New York State Energy Research and Development Authority and Department of Public Service First Iteration of the Grid of the Future Plan (filed March 31, 2025) (First Iteration of the GOTF Plan).

¹⁵ *Id.*, p. 38.

Figure 1.2: GOTF Vision for DSP



Priorities Aligned to the 2025 DSIP Update

Looking forward, National Grid’s vision for the future remains consistent while incorporating an added focus of leveraging DSP capabilities to enable deployment of flexible resources to achieve state policy goals. As the state emphasizes increased grid flexibility, National Grid’s ongoing investments in grid technologies, advanced planning, and grid operations methods will continue to empower communities and customers to actively manage their energy needs and participate in the marketplace in support of the state’s policy goals.

To best align further progress in support of the GOTF objectives, National Grid recognizes that there will be significant barriers to overcome to achieve flexibility at scale, as identified in the GOTF Volume 1 Grid Flexibility Study.¹⁶ The Company plans to work closely with DPS and stakeholders to identify solutions for overcoming the barriers, develop metrics toward enabling greater flexibility, and consider the appropriate set of incentives for all market participants.

The GOTF Volume 1 Grid Flexibility Study identified 23 independent barriers, each accompanied by up to three corresponding solutions (58 in total). Some barriers have solutions that the Joint Utilities can consider and address directly. Addressing other barriers will require more indirect utility consultation, since they require implementation by other parties (i.e., wholesale market barriers). In all instances, the utilities are fully committed to undertaking actions and providing expertise to advance solutions. The Joint Utilities are already engaged in work with DPS Staff and stakeholders to address key priorities that we have identified for initial action that represent early steps that can deliver stakeholder and market benefits by 2030.

¹⁶ GOTF Proceeding, Department of Public Service Staff Volume 1 Grid Flexibility Study (filed January 31, 2025) (GOTF Volume 1 Grid Flexibility Study).

The First Iteration of the GOTF Plan also introduces an emphasis on future DSIP filings developing a more explicit vision for Comprehensive System Architecture (CSA), which it defines as being comprised of three interlocking elements:

- Electric Infrastructure includes the physical grid resources that meet the operational needs of grid operators, grid service providers, utility business managers, and utility customers to implement DSP capabilities (e.g., DER integration, grid control and monitoring).
- Digital Infrastructure includes both the business information systems (IT) and operational technology (OT) that enable the utility to implement and advance essential DSP capabilities (i.e., market operations, DER integration, and flexible grid operations).
- The Commercial Framework includes an integrated set of standards that are applied to design, implement, and operate the commercial mechanisms that enable the utility's business and grid operations.

While this 2025 DSIP Update does not explicitly address a long-term CSA vision, the Joint Utilities have been active participants in the Market Design and Integration Working Group where future grid architecture models, and the best potential set of solutions for NY, have been considered. As consultations with stakeholders proceed in the GOTF Proceeding, National Grid looks forward to incorporating more discussion on CSA in future DSIP Updates.

As National Grid continues to refine its vision and collaborate with stakeholders in the GOTF Proceeding, the following areas will be a particular focus:

1. The deployment of flexible resources must prioritize grid reliability, security, and affordability. Determining dependability and security of at-scale flexible resources through pilots and studies is essential.
2. The value of flexibility should capture both bulk system benefits and local grid benefits.
3. Compensation for flexibility must balance the varying costs and benefits that flexibility provides for different stakeholders and the grid.
4. Programs must be designed with agility to dynamically adjust to changing grid needs and market conditions over time.
5. Continue to advance utility capabilities and overcome barriers.

Areas of Greater Focus in Updated 2025 Vision

- Flexibility
- Architecture (electrical, digital, and commercial)
- Three core DSP functions and/or the five pillars identified in the GOTF Proceeding

DER Integration: Deliver Benefits of Technologies; Provide Safe, Reliable Electric Service; and Achieve Greater Integration with Bulk System Planning

Vision for DER Integration

National Grid’s long-term vision for the DSP is to achieve ever more seamless integration of DER into the electric system while continually evolving our planning process to preserve system safety and reliability and to maximize DER benefits for both customers and the grid. The Company is continuing to integrate DER into planning studies and advance new ways to harness DER as non-wires alternatives (NWA) to defer or address load at risk issues prior to completion of capital infrastructure projects. For example, the Company is expanding its sourcing of DER through competitive NWA procurements and utilizing existing EE and DR programs to expand access of DER to support the grid and provide beneficial integration with grid planning. National Grid expects further integration of DERs into electric operations and has prepared a Distributed System Operator (DSO) and DERMS roadmap in the National Grid Electric and Gas 2024 Rate Case Proceeding, highlighting key integrations through 2030.¹⁷ On the monitoring and control (M&C) front, the Company is advancing low-cost monitoring solutions, including software-defined wide area network (SD-WAN) (completion of proof-of-concept project for connections with third-party aggregators) and cellular direct transfer trip (DTT) (evaluation of cellular direct-transfer trip schemes for anti-islanding protection).

Through the GOTF Proceeding, National Grid is working with DPS Staff and the Joint Utilities to develop a comprehensive roadmap to “unlock grid flexibility at scale” in New York.

National Grid Accomplishments Since the Last DSIP

Table 1.1: Accomplishments Since Last DSIP

Actions	Results
Interconnection. Collaborated with members of industry to provide a 2-year waiver for UL 1741 Supplement SB in regard to certification of EV chargers with vehicle-to-grid (V2G) capability. →	Aligns certification timeline with market availability/ development of bi-directional EV chargers.
Interconnection. Collaborated with Electric Power Research Institute (EPRI) and inverter manufacturers to adopt the common file format (CFF). →	Adoption of the CFF will reduce the time required for utility engineers to review smart inverter settings for projects, which will in turn allow for faster DER interconnection times. Also, adoption of the CFF will make it easier for utilities and developers to share inverter settings with each other.
Interconnection. Provided developers with information on the Joint Utilities’ preferred charge and discharge schedules for battery storage. →	The alignment of the charge and discharge windows with the economic value streams and price signals will encourage greater adoption of battery energy storage systems (BESS) in the state.

¹⁷ *Supra* note 8.

Actions	Results
Interconnection. Adopted the UL 1741 Certification Requirements Decision (CRD) for Multimode (MM) inverter systems.	Clarifies the rules and interconnection procedures for DER systems capable of providing home backup (e.g., solar PV + storage and V2G systems). The adoption of this rule will ensure that these systems do not pose a safety and reliability risk to utility personnel when there is a system outage.
Interconnection. Collaborated with the Joint Utilities and industry members on proposed updates to the New York Standardized Interconnection Requirements (NY-SIR).	Provides stakeholders with latest guidance on UL 1741-SB certified inverters, storage schedules, and DER penetration screens, and will aid in improving the efficiency of the interconnection process.

The Joint Utilities have continued to make progress on implementing the initiatives outlined in the 2023 DSIPs. This included launching new pilot programs to test DER technologies and business models, developing new data and analytics capabilities to support DER integration, and working with stakeholders across the industry to promote the integration of DERs onto the grid. National Grid has also continued to enhance the process for interconnecting DER to allow for faster interconnection approval and making tailored requirements specific to DER types and locations. The Company has taken important steps such as collaborating with industry stakeholders on a Comprehensive Coordinated Electric System Interconnection Review (CESIR) Analysis Evaluation Initiative, that includes bulk power support and voltage support smart inverter settings and developed and proposed energy storage system (ESS) metering architectures for various technology configurations. The Company has also progressed through the planned stages of the Hosting Capacity roadmap described below to achieve ever greater functionality and insight for DER developers to help them make efficient decisions that maximize system benefits.

National Grid published the first iteration of the Hosting Capacity Storage maps in spring 2022 which provided feeder-level hosting capacity, additional system data, downloadable feeder-level summary data, and sub-transmission (Sub-T) lines available for interconnection, while reflecting existing DER in circuit load curves and allocations. In recent months, the Company updated the Storage Hosting Capacity maps to further provide sub-feeder level information, nodal constraints (criteria violations), NY-SIR Cost-Sharing 2.0 projects, and DG connected since National Grid's last Hosting Capacity map refresh. The Storage Hosting Capacity maps are refreshed annually.

The Company has also shared updated solar PV maps to provide insight into location-specific ease of solar PV integration. The analysis reflects the available sub-feeder level hosting capacity for solar PV interconnections larger than 300 kilowatts (kW). The solar PV Hosting Capacity maps are updated to reflect that the Hosting Capacity Analysis (HCA) is refreshed at least annually on all circuits, with the refresh occurring every six months for circuits that have 500 kW or more of newly connected DG.

National Grid has completed field deployment and testing of two flexible interconnection schemes with distributed solar generation sites through the ARI Pilot using a DERMS. The Company is evaluating the use of an EE incentive kicker to provide load relief to the Sawyer area (see Section 5.13 Beneficial Locations for DERs and NWAs more details).

Updates to the Approach to Achieve the Vision Since the Last DSIP

The environmental policy objectives and related requirements set forth in the CLCPA and the Accelerated Renewable Energy Growth and Community Benefit Act (Accelerated Renewables Act)¹⁸ have changed the Joint Utilities' roles in coordinated system planning and investment, and hence National Grid's vision for DER integration.

The Commission has specifically directed the Joint Utilities to undertake planning assessments and make investment proposals to facilitate cost-effective development of renewable and emissions-free resources maintaining the reliability of the State's electric grid. The fulfilment of CLCPA objectives will require the deployment of emissions-free generation capacity at an unprecedented scale, as well as BESS and other advanced technologies. To support the optimal deployment of these investments and with the goal of delivering an electric system capable of meeting NY's clean energy objectives, the Joint Utilities continue to develop and refine integrated planning processes to identify and construct local T&D infrastructure solutions, in coordination with any necessary bulk transmission infrastructure expansion. The Joint Utilities are also filing periodic analyses of headroom availability throughout their service territories.

A major focus of this 2025 DSIP Update is greater integration of distribution-level planning processes with the bulk system. The initial phases of this work were described in the CGPP Proposal filed by the Joint Utilities and the Long Island Power Authority (LIPA) (collectively, Utilities),¹⁹ which explained how the Utilities had developed an approach informed by the input of stakeholders gained through nine technical conferences, ensuring that bulk and local T&D project development opportunities are informed by the best data available and refined modeling approaches.

The Joint Utilities envision fulfilling the goals of the CGPP much in the way that the DSP and DSIP filings have been approached: as an iterative process of improvement and refinement, including through continued opportunities for stakeholder input and direction. The Joint Utilities have worked to align the CGPP and DSIP processes accordingly, with the forecast assumptions reflected in this 2025 DSIP Update mirroring those used in the CGPP process, and the CGPP forecast (once produced) feeding into future DSP planning activities.

Therefore, National Grid's vision for the DSP function now incorporates an understanding that DER will be integrated in a broader system planning context. Going forward, the Company also continues to envision a more dynamic operation of the distribution system, where local constraints can be minimized with Company assets or DER. Storage and load transfers can respond to

¹⁸ The Accelerated Renewables Act is *available at* Chapter 58 (Part JJJ) of the Laws of 2020, §2 (2) (b).

¹⁹ T&D Planning Proceeding, Utilities' CGPP Proposal (filed December 27, 2022), as corrected by the Utilities' CGPP Proposal (filed January 5, 2023) to replace Figure 5 with a higher-resolution image (Utilities' CGPP Proposal).

dispatch, operational control, or price signals for real and/or reactive needs. National Grid is taking steps to prepare for this increasingly dynamic grid by analyzing M&C and operational system requirements, developing new monitoring parameters, and coordinating with the New York Independent System Operator (NYISO) to define operational coordination processes needed to facilitate DER wholesale market participation.

The Company continues to engage with the Interconnection Technical Working Group (ITWG) and Interconnection Policy Working Group (IPWG) on the NY-SIR process and the role of flexible interconnections. The National Grid Electric and Gas 2024 Rate Case Proceeding also details the Company's DSO-DERMS investments that will support the deployment of flexible interconnections (e.g., communication pilots). On the planning side, the Company is augmenting interconnection study efforts with digital tools to reduce study cycle time and lower the resource requirement for interconnection requests.

Information Sharing: Delivering Useful, Market-Enabling Information that Enhances Customer Value, Now Through a Statewide System

Vision for Information Sharing

National Grid's vision for the information sharing function of the DSP is to provide systems that measure, collect, analyze, manage, and display granular customer and system data so that customers and other market participants can be empowered to make efficient, cost-effective market decisions. Part of the information-sharing function is protecting customer privacy and security, and that remains a core Company responsibility and an element of the vision.

Accomplishments Since the Last DSIP

In the 2020 DSIP Update, the Company emphasized the need to achieve more uniform information access across the NY utilities. The Joint Utilities have made progress in recent years toward that objective through the IEDR Proceeding. National Grid is a key stakeholder in the IEDR. The Company has worked collaboratively with stakeholders to develop and shape the overall IEDR platform, including the three use cases recently included in the Initial Public Version (IPV) of the platform: Installed DERs, Planned DERs, and Consolidated Hosting Capacity maps. The Company's contribution to the IEDR is anticipated to include information on grid performance, energy usage, and outage data to aid in informing stakeholders' decision making related to grid operations, planning, and policy development.

Updates to the Approach to Achieve the Vision Since the Last DSIP

The IEDR, initiated by the Commission in 2021 with NYSERDA in the role of program sponsor, is now a critical component of New York's REV initiative. The IEDR has the potential to be an essential tool for promoting a more transparent and data-driven energy system. The IEDR and the associated Data Access Framework (DAF), which will ensure data security and privacy as deemed appropriate by the Commission, will be a key part of National Grid's vision for information sharing. The Company recognizes that its data, insights, and collaboration with stakeholders will be critical to improving the performance and efficiency of NY's electric grid and is committed to ensuring that the IEDR achieves its full potential.

Table 1.2: Updates Since the Last DSIP

Actions	Results
Integrated Planning. PV Advanced Map Functionality & Cost Share Integration (2023–2024) • Introduced “Nodal Constraints” visualization, detailing whether hosting capacity is limited by voltage, thermal, or protection constraints. • Incorporated Cost Share 2.0 indicators, identifying where utility-driven upgrades increase hosting capacity. • Provided links to 8760-hour feeder load profiles, enabling developers to analyze detailed hourly load curves.	Improved stakeholder visibility into specific hosting capacity limitations by clearly indicating whether constraints are driven by voltage, thermal, or protection factors. Enhanced developer planning capabilities through integration of Cost Share 2.0 indicators, effectively identifying areas where utility-driven upgrades significantly improved hosting capacity. Facilitated detailed project feasibility analyses by linking 8760-hour feeder load profiles directly to the PV maps, enabling developers to access comprehensive hourly load data.
Integrated Planning. Sub-Feeder Granularity & Nodal Constraints (2023) • Added sub-feeder level hosting capacity analysis, increasing locational accuracy. • Introduced color-coded nodal views, showing variations in hosting capacity across feeder sections. • Enhanced pop-ups to show criteria violations at specific nodes (voltage, thermal, or backfeed limits). • Integrated Cost Share 2.0 project indicators for storage hosting capacity. • Enabled REpresentational State Transfer (REST) Application Program Interface (API) access for automated data retrieval.	Enhanced locational accuracy of hosting capacity analysis by transitioning from feeder-level summaries to detailed, sub-feeder (node-level) hosting capacity visualizations. Improved decision-making transparency through the introduction of color-coded nodal visualizations, clearly depicting variations in hosting capacity across individual feeder segments. Provided actionable insights via interactive pop-ups, explicitly detailing criteria violations at specific nodes, including voltage, thermal, and backfeed limits.

Actions	Results
Integrated Planning. Electrification Hosting Capacity Expansion (2023–2024) - Expanded EV Load Hosting Capacity maps into full Electrification Hosting Capacity maps per Commission directives. - Added dual seasonal hosting capacity values, allowing users to toggle between summer and winter peak conditions. - Integrated Environmental Justice (EJ) area overlays to support equitable electrification planning. - Maintained feeder-level color-coding and breakpoints, ensuring continuity with previous EV maps.	Broadened stakeholder decision-support by evolving the EV Load Hosting Capacity maps into comprehensive Electrification Hosting Capacity maps, aligning with regulatory orders and stakeholder inputs. Improved seasonal planning precision through the addition of summer and winter peak hosting capacity views, directly responding to stakeholders' needs to understand seasonal impacts on capacity availability. Advanced equitable planning processes by integrating EJ area overlays, explicitly highlighting hosting capacity status within disadvantaged communities and supporting targeted electrification investments. Ensured continuity and familiarity for stakeholders by maintaining established feeder-level color-coding and breakpoints consistent with previous EV map versions.
Information Sharing. Established processes in late 2024 (and continuing in 2025) to resolve issues related to the data transfer pipelines needed to provide multi-layered real-time energy data to the IEDR platform. Worked in bi-weekly Utility Coordination Group (UCG) meetings, one-on-one meetings with the IEDR Development Team, and ad hoc strategy sessions throughout 2023, 2024, and 2025 to further automate the process and standardize update schedules.	Consolidated state-wide hosting capacity map (via NYSERDA's Energy Infrastructure Assessment Tool) in 2024, with additional map layers also introduced in 2024 to support various Phase 2 use cases, DER asset repository, and more accessible indices of utility tariffs.
Information Sharing. Implemented protections and developed relevant User Agreements to safeguard the data quality and integrity, cybersecurity, and privacy of data delivered to the IEDR platform. Actively sought guidance from DPS Staff on status of Data Access Implementation Plan (DAIP)	NYSERDA filed Proposed IEDR User Agreements in May 2024, which address data quality and integrity standards, cybersecurity, privacy, and other requirements based on outdated filings/examples from the JU. The JU filed responses in September 2024 to the NYSERDA proposal outlining desired improvements and the need for this to be done within a larger DAF and

submitted by utilities as part of the Commission's DAF Order. ²⁰	consistent with the DAF Order and related filings.
Actions	Results
Information Sharing. Worked throughout 2023, 2024, and 2025 to enable streamlined access to standardized customer utility data, including successful transfers of customer data sets to the IEDR with appropriate mapping in place to advance implementation of Green Button Connect (GBC) functionality.	→ Provided IEDR Team with all customer energy data at varying intervals (5-, 15-, and 60-min) in 2023 and 2024, and implemented processes to deliver customer energy data usage going forward. Streamlined access to standardized customer utility data and through GBC to accelerate the deployment of clean energy in communities throughout NYS.
Information Sharing. Supported process improvements in 2023 and 2024 related to bulk data exchanges to guide the successful completion of Phase 1 Program Milestones for the IEDR Program. Phase 1 was successfully completed in March 2024.	→ Public release of IPV and Minimum Viable Product (MVP) use cases by the IEDR Team and NYSERDA's announcement, and the successful completion of Phase 1 in March 2024.
Information Sharing. Submitted quarterly IEDR reports since Q4 2021 to provide an update on the status of ongoing and planned projects and investments in support of the enablement of the IEDR. These reports support transparency in process, progress, and investments by providing actionable updates on milestone and use case development.	→ Quarterly reports, submitted in every quarter from 2023 to 2025, provide stakeholders with continued access to and transparency in progress, process, and investments.
Information Sharing. Collaborated with NYSERDA, DPS Staff, and stakeholders in bi-annual DSP webinars and meetings, and in one-on-one engagements and other forums throughout 2024 and 2025 to identify IEDR Phase 2 use cases necessary to meet stakeholder and market needs.	→ Supporting the development of 45 IEDR Phase 2 use cases which meet stakeholder and market needs as efficiently and effectively as possible. Utilities are providing significant support on GBC development, rate plan use case, and other customer-specific usages, as well as continuing to update Hosting Capacity maps, which will support future use cases designed by the IEDR team.

²⁰ Case 20-M-0082, *Proceeding on Motion of the Commission Regarding Strategic Use of Energy Related Data* (IEDR Proceeding), Order Adopting a Data Access Framework (issued April 15, 2021) (DAF Order).

Market Services: Enabling a Robust Marketplace for DER to Access Value at All Levels of the Grid, With a New Avenue at the Wholesale Level

Vision for Market Services

As in years past, National Grid's DSP vision continues to be a future energy marketplace where competitive market signals play a greater role in achieving accurate pricing and compensation for distribution system value, so that all participants can benefit from an efficient market.

Accomplishments Since the Last DSIP

As of 2020, the Company continues to offer DER compensation through broad tariff mechanisms (e.g., Value of Distributed Energy Resource (VDER) Value Stack), demand-side management programs, and direct contracting with resources (i.e., NWA). In previous years, National Grid summarized these mechanisms as the three "Ps" of incorporating and compensating DER: pricing, programs, and procurement. Each of these plays an important role in DER adoption, and the Company has seen continued or growing participation in all three in the past three years. The Company remains an active participant in proceedings at the Commission regarding the compensation of eligible DER at various sizes.

Following the Federal Energy Regulatory Commission's (FERC) approval of the NYISO's DER Market Participation Model on April 16¹, 2024, National Grid enabled Distributed Energy Resource Aggregation (DERA) Connect which is a digital product to improve the registration, enrollment, and operational coordination processes that the utility must perform. This application allows for a defined flowchart of various tasks needed to onboard DER Aggregators as well as enabling Control Center operators to view ensure granular day-ahead DER schedules align with Aggregator schedules.

The Company is actively supporting the GOTF Proceeding to discuss future market participation models (i.e., market roles and responsibilities, long-term value of locational system relief value (LSRV)).

Updates to the Approach to Achieve the Vision Since the Last DSIP

National Grid has also been able to accelerate progress toward its vision substantially by working collaboratively to help the NYISO implement its forthcoming market rules for DER participation through an aggregation. Under an initiative to implement FERC 2222 requirements, the Company worked with the NYISO to develop and support the launch of the DER Market Participation Model on April 16, 2024.

With this newly established DER participation model, National Grid will continue to work towards full FERC 2222 compliance and implementation anticipated by December 31, 2026. The fully mature role of the NYISO market in DER compensation remains a work in progress and a part of the Company's future vision. Overall, in the coming years, the DSP will be facilitating more avenues for accessing market compensation for DER either through utility tariffs, programs and procurements, or by helping to facilitate the functioning of the NYISO DER market. Maintaining the increasingly complex interplay of these avenues will require an increased ability to use grid modernization technologies, which may include further investments in AMI, ADMS, DERMS, and grid automation.

Actions	Results
Electric Vehicles. Implementation of utility programs for Light Duty Vehicle (LDV) MRP, MHDV Pilot, DCFC Per-Plug Incentive (PPI) Program, and Residential Managed Charging Implementation Plan (MCIP) throughout 2023, 2024, and 2025.	→ Removing upfront cost barriers to adoption through direct make-ready incentives and futureproofing, ongoing cost barriers to adoption through direct operating incentives, knowledge and technical barriers to adoption through fleet assessments and technical assistance, and soft cost barriers to adoption through ongoing coordination and stakeholder engagement
Electric Vehicles. Starting in 2024 and continuing in 2025, utility participation in the Commission's Proactive Planning Proceeding ²¹	→ Urgent needs for grid upgrades identified and adopted by the Commission, ²² and a longer-term upgrade planning process proposed
Electric Vehicles. Launch of utility load management technology program in 2024.	→ Redeployment of unused DCFC PPI funds, direct utility incentive of load management technology, and removal of cost barriers to encourage load management for EV charging projects
NYISO-DSP. Through 2023 and 2024, worked closely with NYISO to develop and support the launch of the DER Market Participation Model, including refining the exchange of information related to registration, enrollment, operational coordination, and data exchanges	→ Provides opportunity for DER to access value for both distribution-level services and wholesale market to potentially reduce wholesale prices through increased competition while ensuring the safety and reliability of the electric system is maintained
NYISO-DSP. Published transmission-node (T-node) information on Hosting Capacity maps in 2023	→ Enables developers/ DER aggregators to easily find the T-node upstream of the resources within a DER aggregation
NYISO-DSP. Actively worked to create utility registration portals, processes, and documentation, while constructively engaging with aggregators from 2023 through present	→ Ensures that the process of registration and enrollment of DER aggregations is easy to understand and smooth for aggregators

²¹ Case 24-E-0364, *In the Matter of Proactive Planning for Upgraded Electric Grid Infrastructure* (Proactive Planning Proceeding).

²² *Id.*, Order Addressing Urgent Upgrade Filings (issued June 12, 2025), where the Commission adopted 22 National Grid projects in support of building electrification and EV charging totaling \$126 million and 184.8 MW of new capacity, including mobile battery storage, reconductoring, substation upgrades, and projects supporting EV charging for school bus electrification and along major travel corridors (Urgent Upgrade Filings Order).

2 DSIP Update Topical Sections

2.1 Integrated Planning

Context and Background

The electricity delivery system continues to become more complex with the integration of increasing quantities of variable renewable generation. Moreover, the drive to decarbonize through electrification of heating and transportation will increase load on the system. The result is a significant increase in data, variability, and the need for new and improved ways to conduct planning to maintain safety, reliability, service quality, and affordability. Integrated planning is a cyclical process that progresses through a series of steps: system monitoring, modeling, forecasting, risk assessment, solution development, prioritization, and budgeting. Each step in the process considers all possible variables to the extent practical and possible. National Grid's Five-Year Electric Transmission and Distribution Capital Investment Plan (CIP), issued annually and filed with the Commission, is a major output of the Company's integrated planning process. The CIP presents all major capital expenditures the Company plans to conduct over the next five-year period. The CIP also identifies NWA opportunities for DER to support grid needs. The Company posts the CIP on its System Data Portal.

Implementation Plan, Schedule, and Investments

Current Progress

National Grid continues to promote a "One System – One Model" structure to integrate system data, data management, and long-term planning. A centralized data repository that is an accurate digital representation of the entire grid and all its assets is critical to effectively manage the complex GOTF. The Company has made significant progress regarding integrated planning and this section highlights some key areas of progress made to date.

Data Enhancements

The Company continues to make investments and process changes so that the Geographic Information System (GIS), which underpins the system model, is accurate and can incorporate new technologies being interconnected. Significant development has been made with respect to the Company's Network State Engine (NSE) project which involves redesigning the processes that generate the electrical connected system model, sourced from GIS and used in engineering software. These model creation processes serve as a digital representation of the electric system and form the foundation for many engineering and integrated planning studies. Despite the effort to enhance the electric system model generation process, the rapid adoption of new grid technologies and the need to incorporate a wide range of data has resulted in the development and integration of additional data sources and systems to create more robust system models that can account for grid configurations that may otherwise not be captured in a traditional GIS. Key data set enhancements include:

Table 2.1.1: Data Enhancements Related to Integrated Planning

Data Enhancement	Example Data Points	Value of Data
NSE	• Distribution devices • Lines and cables • Phase connectivity	Enables efficient and optimized generation of fully connected distribution system models to be used in engineering software.
DER Asset Data	• Interconnection location • Technology specifications • Equipment sizing • Monitoring capabilities	Allows for DER assets to be explicitly included in system models with locational precision and site-specific characteristics.
Grid Sensor Data	• Operating voltage • Device loading • Switching conditions	Enables planners to align system models with actual grid operational conditions, minimizing the need to utilize conservative assumptions.
Advanced Device Settings	• Smart inverter configuration settings • Capacitor switching routines • Voltage regulator set points	Allows for system models to account for device settings that may impact grid operations in multiple scenarios.
Forecasted EV Fleets	• Likely locations of EV fleets • Expected fleet size and electric capacity requirements	Forecasting EV fleets allow for planners to account for potential future load requests in system studies and area plans.
Feeder Level Forecast w/ DER Scenario Considerations	• Feeder-specific electric load forecasts • Contribution of load from different DERs and load sources (EV, solar PV, ESS, heat pumps, etc.) • Contribution of load from different DER scenarios (e.g., EV managed charging, high adoption of heat pumps, etc.)	Enables planners to account for different permutations of load forecast scenarios based on study needs. For example, when determining system capacity needs, planners are able to assess projects with respect to future load growth from multiple different possible scenarios and “future-proof” a project if cost effective.

In addition to the advancement of several data sets critical to integrated planning and system modeling, National Grid has invested heavily in the development of a centralized data repository, built on the Snowflake cloud computing architecture, capable of serving as a single “source of truth” for numerous business processes. Consolidating data into a centralized repository allows for ease of integration with downstream processes and systems while also enabling more robust data quality practices since previously disparate data sets are now joined together, making discrepancy identification much easier. The success of integrated planning processes at National Grid is dependent on the health and breadth of the data sets utilized and ensuring a successful implementation of a centralized data repository is a key focus.

Software Planning Tools & Studies

Although the data enhancements outlined in the section above play a critical role in the success of integrated planning processes at National Grid, numerous software tools are required to turn the vast amounts of utility data into meaningful analysis, results, and actions. The Company has continued to invest heavily in the development and implementation of different software tools that enable robust integrated planning. The Snowflake centralized data repository is at the core of the software tools unlocking efficiencies and data integrations critical to integrated planning. Having all electric system data in one centralized platform allows for easier access to the various data sets needed to conduct planning analyses and enables consistency in results since they are rooted in the same source data system. Additionally, a centralized platform enables integrated planning processes to consider data relationships that may influence analyses and solutions, such as the inclusion and consideration of climate change data with respect to equipment and asset characteristics.

Much of electric system planning relies heavily on the CYMDIST software which is used to model and run analyses on the Company's distribution system. Many of the data enhancements outlined above are integrated into the CYME models used by National Grid, via the NSE, to improve the model generation process, accuracy, and precision of analysis results. National Grid has worked to develop automated model verification and validation processes that utilize the API available within the CYME software. The CYME API has allowed the Company to develop automated processes capable of performing bulk data integrations to enhance model accuracy and precision of analysis results while requiring minimal direct user input. Automation can improve both internal and external processes. For example, National Grid operates a CYME Server which supports power flow model version control and multi-user access. Externally, consistent with the DG Interconnection Online Application Portal (IOAP) roadmap, the CYME Server helps provide an auto-analysis of Screens A-F of the NY-SIR process, which speeds up the time to complete DG interconnection studies while increasing efficiency for interconnection planning engineers and providing analysis results to external stakeholders, such as DER developers, in a timely manner.

National Grid's HCA is another example of integrated planning that relies on input from multiple data sources and requires the use of various software tools and automated processes throughout the analysis process. In producing the Hosting Capacity maps, the Company uses the CYME software to establish accurate distribution system models while leveraging historical load data to further align the model to grid conditions. Following robust system modeling, the EPRI Distribution Resource Integration and Value Estimation (DRIVE) Version 4.2.2 software tool is used to perform nodal analyses to determine the amount of hosting capacity at each node in the network. Results are then exported to support the sharing of HCA data on the Company's System Data Portal where both nodal and circuit level hosting capacity value, with respect to DER technology, are made available. Additional information regarding National Grid's HCA processes, including where analysis results can be accessed on the Company's System Data Portal, can be found in the Hosting Capacity section of this 2025 DSIP Update.

The Interruption Cost Estimate (ICE) Calculator is another example of a tool used to inform the Company's Integrated Planning activities. The ICE Calculator is an electric reliability planning tool developed by Lawrence Berkeley National Laboratory and Nexant, Inc. ICE 2.0 is a free web-based tool leveraging survey results from 45 interruption cost studies to provide region-specific

interruption cost estimates by customer class. This publicly available online tool is designed for electric reliability planners at utilities, government organizations, and other entities that are interested in estimating interruption costs and/or the benefits associated with reliability improvements. Cost estimates are generated by the tool based on user inputs such as the state, number of customers, System Average Interruption Frequency Index (SAIFI) and System Average Interruption Duration Index (SAIDI). National Grid currently uses the ICE Calculator to determine the benefits and perform BCAs for reliability and resiliency programs, such as Fault Location, Isolation, and Service Restoration (FLISR) and potential microgrid deployment. National Grid is actively engaged as a sponsoring utility in ICE 2.0, a nationwide public-private partnership to update the ICE Calculator with new survey data and improve the capabilities of the web-based tool. The Company's participation, which includes surveys of National Grid residential and commercial customers as well as the same customer groups of National Grid's Massachusetts affiliate, will provide refreshed data on the value of reliability by customer class for the Northeast region. Updates to the calculator with the new survey information, as well as upgrades to the functionality of the web-based tool, are expected in 2025 and will provide a higher level of granularity and accuracy. The ICE Calculator is available at <https://icecalculator.com/home>.

In February 2023, National Grid was awarded a \$1.2 million grant from the Department of Energy's (DOE) Vehicle Technologies Office to utilize the load forecasting methodology developed in the Company's Electric Highways Study and partner with Rocky Mountain Institute (RMI), the National Renewable Energy Laboratory (NREL), Northeast States for Coordinated Air Use Management (NESCAUM) and other organizations to forecast MHDV charging needs on 3,000 miles of corridors across a nine state region, including New Jersey, Pennsylvania, NY, Connecticut, Rhode Island, Massachusetts, Vermont, New Hampshire, and Maine. Once complete, National Grid will release a public report with findings and a list of identified priority sites across all studied corridors, which would create a minimum viable freight charging network in the region. Working collaboratively with neighboring utilities, states, and industry is key to ensuring that investments are not redundant and creating a consistent network. The report will include policy recommendations to accelerate the deployment of MHDV charging infrastructure in the region. In conjunction with capital infrastructure investments, National Grid continues to explore various flexibility solutions to address system capacity needs. The Company has acted in identifying energy storage opportunities to meet planning and operational use cases, including its joint study effort with the other utilities to produce the Joint Utilities' Study of Non-Market Transmission and Distribution Energy Storage Use Cases filed with the Commission on October 29, 2024.²³ Section 2.4 of this 2025 DSIP Update further addresses energy storage. One part of National Grid's integrated planning process is the identification of when non-wire solutions could be used to address planning needs through NWA projects or through targeted load relief programs such as the Auto-Dynamic Load Management (Auto-DLM) program. Based on the Company's NWA suitability criteria, screening for NWA opportunities occurs as part of planning studies as well as during annual review of the Company's CIP. The Company also investigates during its planning studies whether a localized area planning need could be partially addressed by an NWA (e.g., hybrid wires and NWA solution). On an annual basis and as part of its Auto-DLM program

²³ Case 18-E-0130, *In the Matter of Energy Storage Deployment Program* (Energy Storage Proceeding), Joint Utilities' Study of Non-Market Transmission and Distribution Energy Storage Use Cases and Related Process Proposals (filed October 29, 2024).

discussed in Section 2.7 of this 2025 DSIP Update, National Grid screens for highly constrained Sub-T lines and substation transformers during its Sub-T planning studies that would benefit from short-term load relief. This short-term load relief can help mitigate load at risk while the Company plans and constructs capital investment projects that will not be available in the near-term. The status of past Auto-DLM procurements is also described in Section 2.7 of this 2025 DSIP Update. To date, National Grid has not yet had any resources participate in its Auto-DLM program to support targeted loading concerns.

Another flexibility solution being explored is the concept of flexible interconnections through National Grid's Flexible Connection sites, which is also a part of the Company's overall DERMS and digitalization strategy. After success of the initial ARI Pilot at National Grid's Peterboro Substation, where the Company implemented a solution that can actively manage generation from front-of-the-meter, distribution system-connected, solar PV facilities, to defer the need for capital investment, National Grid continues to explore the potential for additional flexible interconnection opportunities. In 2024, the Company assessed the feasibility of expanding flexible connections offering, beyond the initial ARI pilot, to apply to assets such as ESS and EV charging facilities. Existing planning practices used to evaluate such facilities and analyze their impact on the bulk electric system needed to be modified to properly simulate their operation within a flexible connections program. This led to the development of new planning practices that ensure the safe and reliable operation of ESS and EV charging facilities. As part of advancing these flexible interconnection solutions, National Grid is also investigating the required DER management capabilities through its DERMS investment to operationalize planned flexibility solutions at scale to ensure the benefits are realized and system reliability is maintained. For other details regarding the Company's current and future DERMS investigation and implementation efforts, see Section 2.3 of this 2025 DSIP Update.

In 2024, National Grid sponsored and is currently participating in an EPRI-led study to review existing secondary planning and design practices and develop new guidance on how to account for electrification loads in residential secondary design. The final report and guidance is expected to be published by EPRI at the end of 2025. In December 2024, EPRI published detailed findings of current utility practices for secondary systems design with the objective to identify gaps and opportunities for improvement in the current practices. This EPRI review focused on the practices and gaps for sizing residential single-phase service transformers, secondary conductors, and service drops as well as related estimation and diversification of customer demand, and methods to account for electrification. Electrification of transportation, heating, and other end-use technologies is projected to introduce considerable new load growth at the distribution system level that existing service transformers and asset sizing practices may not fully account for. The review found that much of this service level equipment is undersized for the projected demand and will also require investments in additional capacity. Additionally, EPRI found that the existing practices of some utilities may not fully account for electrification, however, many utilities are considering changes to their practices driven by evolving customer needs and other factors. The EPRI findings also underscore the importance of appropriately accounting for the demand diversity for reliable, cost-effective, and safe secondary system design. The foundational understanding of current practices presented by the EPRI review to date sets the stage for beginning to address the gaps identified and preparing for the challenges that electrification

presents. National Grid has already taken steps to review and update its secondary transformer standards and anticipates that EPRI's final report will inform any future updates.

To support the transition to net zero, National Grid's Clean Energy Vision supports cost-effective, targeted electrification on the Company's gas network, including piloting networked geothermal solutions, as well as the pairing of EHPs with gas appliances in areas where full electrification may not be practical or cost-effective. The Company will also continue to interconnect distributed and large-scale energy resources to the electric grid. Integrated planning across the electric and gas networks and the T&D systems will be critical to effective and accurate business planning that ensures reliability, resiliency, and affordability during this transformation. National Grid's procurement of licenses and training for encoord's Scenario Analysis Interface for Energy Systems (SAInt) software tool enables electric and gas network planning engineers to engage in combined modelling of the electric and gas networks and coordinated controls between them. Since the filing of the 2023 DSIP Update, the Company has collaborated with encoord to develop processes for integrating both CYME, CYMDIST, and Siemens Power System Simulator for Engineering (PSS®E) models into SAIInt. Although the process is still being refined, National Grid and encoord have developed a case study that integrated the electric T&D system models, along with the gas system model from Synergi Gas, to assess the impact of electrification of heat in a targeted area. The learnings from this collaborative exercise served as an input to a digital initiative where the Company reviewed the integrated energy planning process and tools, identified gaps and scoped out areas for additional investigation in hopes to define a more robust and repeatable process.

National Grid's Climate Change Resilience Plan (CCRP)²⁴ was approved with minor modifications by the Commission on December 19, 2024.²⁵ The updated and approved CCRP was filed by the Company with the Commission on February 13, 2025.²⁶ The CCRP proposes measures to address the four key climate hazards (high temperature, inland flooding, high wind gusts, and ice) identified in the Company's 2023 Climate Change Vulnerability Study.²⁷ New climate resilience programs include:

- Overhead distribution and Sub-T line design upgrades to utilize larger class poles that can withstand greater wind and ice loading.
- Overhead transmission line design upgrades to build structures that can withstand up to 120 mph wind gusts.
- Distribution targeted undergrounding of 1-2 miles per year of three-phase main line in high wind and icing areas.
- Substation flood walls in high-risk areas.
- Substation transformer specification upgrades to withstand higher ambient temperatures.

²⁴ Case 22-E-0222, *Proceeding on Motion of the Commission Concerning Electric Utility Climate Vulnerability Studies and Plans* (Climate Vulnerability Proceeding), National Grid Climate Change Resilience Plan (filed November 21, 2023).

²⁵ Climate Vulnerability Proceeding, Order Regarding Electric Utility Climate Change Resilience Plans (issued December 19, 2024).

²⁶ Climate Vulnerability Proceeding, National Grid Revised Climate Change Resilience Plan (filed February 13, 2025).

²⁷ Climate Vulnerability Proceeding, National Grid Climate Change Vulnerability Study (filed September 22, 2023).

To support the Company's future climate study needs, National Grid has also been involved in the Climate Resilience and Adaptation Initiative (Climate READi) project with EPRI. Climate READi is developing a common framework to deliver a comprehensive, consistent, and collaborative approach to mitigate physical climate risk, ensure resilient energy, and enable robust planning for the years and decades ahead which has a direct impact on integrated planning practices at National Grid. Climate READi organizes its research into three areas: physical climate data and guidance, power system asset vulnerability, system modeling and investment prioritization. Over three years, a significant amount of research has been conducted to develop guidance, references, tools, and case studies to help utilities with their climate reliability efforts.

Future Implementation and Planning

Over the next five years National Grid plans to continue along its "One System – One Model" vision with increased integration and centralization of data and utilization of new software tools, analyses, and automation. As part of the Company's portfolio of digital projects and initiatives, a new project referred to as Long Term Integrated Planning (LTIP) was initiated in 2024 with the goal of transforming grid planning into a modern, data-driven, and collaborative process by implementing a robust, dynamic, and scalable grid planning framework. Some of the key goals of the LTIP project include:

- Enhance data integration and quality to support advanced analytics.
- Develop scenario-based planning tools to manage uncertainties.
- Foster stakeholder engagement to build trust and transparency.
- Improve the ability to defend and justify proactive grid upgrades.

The LTIP project efforts in much of 2024 and early 2025 were focused on performing necessary discovery work to outline the existing challenges with integrated planning processes and identifying potential opportunities for improvement with several proof-of-concept solutions under way. Throughout the rest of 2025, the LTIP project will be focusing on deploying capabilities that address the challenges with usability and accessibility of data needed for integrated planning activities such as automated cleansing of Supervisory Control and Data Acquisition (SCADA) measurement data, and grid model verification and validation. Once some of the pain points with input data are addressed, the LTIP project will focus its efforts on developing capabilities that include enabling automated studies, DER scenario planning, automated HCA, and enhanced NWA needs identification.

As National Grid progresses with the deployment of AMI across its service territory, methods for leveraging the rich data AMI has to offer is of primary importance to integrated planning among numerous other business activities as discussed in more detail in Section 2.12, Advanced Metering Infrastructure, of this 2025 DSIP Update. Granular AMI data will improve load and DER forecasts, enhancing both planning and operations. The Company is actively investigating methods of interpreting and integrating AMI data into the CYMDIST software tool. In addition to customer-based AMI data, advances in grid monitoring via SCADA systems will continue to be yet another crucial input to the Company's electric system models that will be considered as part of system

modeling data integration processes. Both accessibility and integration of SCADA and AMI measurement data is being evaluated as part of the LTIP project capability roadmap.

As renewable generation and storage capacity increases on both bulk and local systems, it is increasingly important to consider both systems simultaneously, which can occur in software and in other study processes. For example, a significant amount of DG in areas with minimal electricity load can potentially create adverse impacts on the transmission system. As described in Section 2.11, DER Interconnections, of this 2025 DSIP Update, the DSP providers are developing cross-queue coordination to account for generators interconnecting under the NY-SIR and those in NYISO-led processes. National Grid has begun an investigation into building and applying integrated T&D models and will determine the practicality and requirements of rolling out such models across its service territory.

The electric power system (EPS) is comprised of millions of assets and those assets' characteristics serve as a primary input to nearly all system models used within Integrated Planning processes and throughout the business. The Company recognizes the reliance on this fundamental dataset and has matured in the Asset Management discipline but intends to continue to advance this maturity. National Grid has developed a renewed multi-year Asset Management Maturity Roadmap which has the goal of improving the level of asset management capabilities and processes under the the Company's T&D organizations. Understanding maturity in the Asset Management space will ensure National Grid provides the best efficiencies regarding customer costs while increasing safety and improving the reliability of the grid.

Advanced Forecasting

National Grid has continued to make progress enhancing the robustness of its probabilistic electric load forecasts, but additional work must be done to utilize the newly available forecast scenarios and integrate the data into existing processes. National Grid produces electric load forecasts for the Company's entire system as well as forecasts specific to each distribution feeder. However, each forecast is comprised of several components such as base load from weather, load contribution from EV and electric heat, and load reduction from other DER sources such as solar PV, ESS, and EE. Each load component has its own individual forecast where a base, high, and low forecast is generated based on different possible technology adoption rates and policy goal accelerations. With forecasts specific to individual feeders, and multiple components of the forecast, each with several different adoption scenarios, the number of possible unique forecast scenarios is significant. Although automation methods have been used to integrate some forecast data into integrated planning practices, the Company is investigating the need for additional software tools to assist planners with visualizing and understanding the numerous forecast scenarios with respect to their probability and potential impact to the electric system. Solutions for evaluating multiple scenarios of the electric load forecast and integrating directly with engineering tools are also included as part of the LTIP project capability roadmap.

Software Planning Tools & Studies

One of the main software planning tools critical to the evolution of integrated planning processes at National Grid is SAInt, the integrated planning tool recently licensed from encoord, Inc. The Company has made much progress piloting SAInt with a limited group of users while working to develop novel data integration methods and realizing initial use cases of the software's unique

capabilities. Now that CYMDIST, PSS®E, and Synergi imports and mapping are complete, SAInt can be used to plan the evolution of coupled, fossil-free electricity and gas networks and optimize investments across T&D assets. However, initial case studies have found that the added complexity of integrating multiple different energy systems together in one tool is still a relatively novel process for the Company's planning organization. More discovery work must be done to develop a robust integrated energy planning process that leverages these new tools to their full potential.

In alignment with National Grid's "One System – One Model" vision, it is crucial to have an authoritative GIS model to serve as the single source of truth for the electronic representation of the grid. GIS underpins both the CYMDIST models used for system planning as well as the Company's ADMS used to operate the grid in real-time. Enhancements to the Company's GIS and the data it contains will continue to be explored, with the Company investigating alternative GIS solutions in use throughout the industry.

FLISR Deployment

FLISR is a centralized control scheme that is used to reduce outage impacts on National Grid's 13.2 kilovolt (kV) distribution feeders and Sub-T circuits. The Company is monitoring system performance and working through a FLISR Acceleration study which focuses on deploying FLISR across the service territory at an increased rate to reduce outage impacts on more customers on the system. Currently about 10 percent of customers are connected to distribution circuits with automated restoration schemes such as FLISR. The deployment plan would look to deploy FLISR to achieve a goal of about 60 percent of customers connected to FLISR circuits by the conclusion of Fiscal Year (FY) 2032.²⁸

Risks and Mitigations

Table 2.1.2 Risks and Mitigations for Integrated Planning

Risk	Mitigation
Potential delays in the rollout of LTIP solutions due to complexity of integrating new planning tools and capabilities into business-as-usual processes.	The LTIP project team is performing an in-depth analysis of the current and future state business activities and scoping a soft rollout of solutions with a limited user base so the product functionality can be iterative and react quickly to best integrate with business processes and user needs.
Inability to manage data enhancements and effectively integrate into system models with the addition of several highly granular data sources (i.e., AMI, device settings, probabilistic forecasts, etc.)	National Grid is investigating the potential procurement of new software solutions such as CYME Gateway which is capable of easing integration of multiple data sources with varying levels of granularity. In parallel, the Company is focusing development efforts on leveraging existing software API functionality to facilitate bulk manipulation and data integrations.

²⁸ National Grid's FY 2032 is April 1, 2031 to March 31, 2032.

Risk	Mitigation
Poor data quality and/or lack of authoritative data source	National Grid is working to implement a centralized electric data repository to function as a single “source of truth” for system data. Once previously disparate data sources are replicated into a centralized repository, data audits can be performed to identify discrepancies and build data governance practices. Upon discovery of data discrepancies, work can then be initiated to resolve the issue in the source system(s).

Alignment with CLCPA Goals

Evolving the means and methods of integrated planning are key to cost-effectively achieving CLCPA goals. The data enhancements, software planning tools, and studies described in this section will enable greater integration of DER into the system and broad decarbonization. The plans described in this 2025 DSIP Update work in concert with the statewide CGPP. The Commission’s August 17, 2023 order approved the Utilities’ Initial CGPP Framework with certain modifications and recognizes the planning and investment needed in the coming years to support achievement of the objectives of The Climate Act and related statutes.²⁹ The CGPP sets out a six-stage process aimed at optimal achievement of policy outcomes that roughly follows the typical engineering process of developing assumptions, performing a study to determine needs, developing solutions to those needs, and selecting an optimal portfolio of solutions to meet needs and provide value. While this process is most focused on unbottling renewables at a statewide level, distribution considerations are critical at the initial forecasting stage and later needs as well as the solution development stages.

During initial forecasting, following development of zonal forecasts and assumptions for load and generation, the Joint Utilities have applied DERs (primarily solar PV), and load (electrification) assumptions developed in CGPP Stage 1 to utility distribution network models according to the location, level, and timing of the additions of DER (effectively disaggregating the zonal forecast into T&D components for load and generation). Unlike locational system relief (LSR) and transmission headroom, DER is not optimized in the capacity expansion models used in CGPP Stage 1; instead, it is an input. This approach minimizes the variables that planners must consider and enables alignment among CGPP models and those utilized by integrated and distribution planners. Aligning CGPP DER assumptions with internal utility planning forecasts will ensure alignment of typical distribution planning and CGPP planning such that the later needs and solutions stages do not require ‘rework’ but instead can leverage ongoing distribution planning processes. In this first cycle of CGPP, several DER forecasts were utilized across the various scenarios, informed by integrated planning. These forecasts ranged from minimal compliance

²⁹ T&D Planning Proceeding, Order Approving a Coordinated Grid Planning Process (issued August 17, 2023).

(e.g., reaching DER goals but not exceeding them) to far exceeding CLCPA DER targets (e.g., over 12GW of DER modeled for 2042).

During the needs development stage, local system studies identify the grid needs resulting from connecting DERs and electrification load to local distribution networks over time. The location, level, and timing of DER and electrification load additions are determined by local system forecasts. A vital outcome of the local distribution planning process within the CGPP is identifying locations where hosting capacity constrains the ability to add solar PV. Distribution is also considered at the solution stage. Local solutions contemplated as part of the CGPP include modifications to the local T&D system that enable greater hosting capacity and integrate more renewable energy while maintaining system reliability for electricity customers. Local solutions can include traditional T&D upgrades, NWAs, and the use of advanced technologies that can help increase the capability of T&D infrastructure or otherwise enhance the ability of the system to support the objectives of the CGPP and CLCPA. If early forecast assumptions between CGPP and utility planning forecasts are well aligned, this stage becomes a simple matter of leveraging and documenting existing distribution solutions. For example, if there is a station in the CGPP that shows potential for reverse power flow in excess of the distribution transformer bank rating, there should already be an existing plan for upsizing the substation bank through NY-SIR Cost Sharing 2.0, as the planners identifying Cost Sharing 2.0 opportunities would be leveraging the same DER forecast as used in the CGPP.

Stakeholder Interface

As indicated in the title of this section, integration is a key component of the planning process, which continues to increase in importance. Integration of additional data sources and planning scenarios coupled with enhancement of existing data yields more robust study results and enables more holistic planning. The ability to integrate greater levels of information and more accurate data into the planning function allows National Grid to better plan, leverage DER, and maintain a safe and reliable grid for the benefit of customers. National Grid's integrated planning initiatives will continue to be influenced significantly by interactions with stakeholders through various Joint Utilities' working groups such as Information Sharing, Integrated Planning, NWAs, Smart Inverter Strategy, ITWG, and IPWG. The Company will continue to facilitate a feedback loop between stakeholders and the appropriate Joint Utilities' working groups to ensure enhancements and changes to planning practices effectively support stakeholder needs. This will be accomplished through an iterative cycle of gathering stakeholder needs and input, developing implementation plans, and deploying utility solutions, with a return to soliciting stakeholder feedback to further expand and/or refine the deliverable.

There are many stakeholders of National Grid's integrated planning activities comprised of both internal and external parties. Internal stakeholders of integrated planning include the numerous engineering, planning, and clean energy organizations within National Grid that influence the types of integrated planning studies performed and the technical details of those studies. Challenges with existing planning processes, the evolution of new technologies, and the advent of ambitious clean energy policies influence the Company's integrated planning activities and approaches needed to plan for the energy system of the future. External stakeholders such as DG

developers, load customers, and industry professionals also inform integrated planning processes at National Grid by means of shaping what type of analyses the Company performs, the solutions developed, and the data the Company shares externally to help inform our customers. The Company engages in regular cross-organizational workshops for internal stakeholders in addition to webinars and dedicated customer training sessions to facilitate feedback to ultimately inform and help National Grid refine integrated planning practices.

2.2 Advanced Forecasting

Context and Background

Electric load forecasts are a fundamental component of utility operations and planning activities. The increasing penetrations of demand-side management technologies, DG, and new load from electrification necessitate utilities evolve their forecasting methodologies and processes to account for these impacts on the power system. This section focuses on long-term load forecasting, which involves predicting electricity demand for years ahead. For discussion of short-term forecasting, please refer to Section 2.3, Grid Operations, of this 2025 DSIP Update.

Currently, National Grid performs long-term load forecasting that considers the baseload³⁰ growth and impacts from DERs, including EE, solar PV, EV, EHP, ESS, and DR. The forecasts are provided at both the system and distribution feeder levels. Detailed discussions on the forecasting methodology and process are provided in the Niagara Mohawk Power Corporation Electric Peak Report.³¹

Since the 2023 DSIP Update filing, the Company has continued to refine its methods and practices on load and DER forecast and scenario assessment. These include:

1. Introducing a probabilistic baseload model

A probabilistic method was introduced to forecast the baseload, where weather, customer behavior, and underlying economic and demographic changes were considered. With this new methodology, the forecast can consider a more comprehensive framework for peak-creating scenarios. For detailed discussion, please refer to Section 3.1 of the Peak Report.

2. Refining feeder-level baseload profiles

The feeder-level baseload forecasting method has been refined to use regional-specific information including zonal-specific weather adjustment factors, growth projection, and feeder-specific load profiles that are based on typical customer profiles by customer class and the specific customer class mix at the feeder level. For detailed discussion, please refer to Section 3.1 of the Peak Report.

³⁰ Baseload is defined as load before DER impacts.

³¹ See Niagara Mohawk Power Corporation 2025 to 2034 Electric Peak (MW) Forecast and Load Assessment through 2050 (March 2025) (Peak Report), *available at* https://systemdataportal.nationalgrid.com/NY/documents/Peak_Load_Forecast.pdf

3. Updating DER Scenarios

National Grid continued to reflect up-to-date adoption trends, program plan, NYS policy and climate targets, and outlooks from market studies in its DER forecast and scenario development. Recent new information includes, but is not limited to, vehicle-in-operations data, proposed Energy Efficiency and Building Electrification Plan, Energy Storage Roadmap,³² CGPP, and Moody's demographic projections. For detailed discussion on the latest DER scenarios, please refer to Section 3.2 and Appendix C of the Peak Report.

4. Refining Feeder-level DER Adoption Methodologies

Medium- and Heavy-Duty EVs and Electric Buses

National Grid continued its enhancement for MHDV EVs and electric school and transit buses at the system and feeder levels using an in-house fleet depot and public charging site database to inform the geographical allocation of fleet electrification and charging load impacts across the Company's service territory. For detailed discussion on the latest DER scenarios, please refer to Section 3.2 of the Peak Report.

Light-Duty EVs and Electric Heat Pumps

National Grid refined its light-duty and heating electrification propensity models by leveraging high granularity US Census Data (i.e., at census tract level). For detailed discussion on the latest DER scenarios, please refer to Section 3.2 of the Peak Report.

Solar

National Grid developed a rooftop PV propensity model for residential rooftop PV and a financial model for commercial rooftop PV to inform relative rankings for allocation. The solar generation model was updated to leverage granular irradiance values across the territory for ground-mounted PV allocation. For detailed discussion on the latest DER scenarios, please refer to Section 3.2 of the Peak Report.

5. Refining DER Load Impact Profiles

Cooling Demand

National Grid started modeling the impact of heat pump usage on cooling demand by analyzing building-level end-use load profiles from the NREL ResStock and ComStock database. The cooling demand is estimated by considering a building's potential increase in air-conditioning load net of any efficiency gains from heat-pump adoption. For detailed discussions, please refer to Section 3.2 of the Peak Report.

Heating Demand

National Grid refined its residential EHP heating profile by incorporating Company service territory-specific energy consumption information from the NREL ResStock and ComStock database. The updated methodology accounts for the impact of weather, calendar effects, building

³² Energy Storage Proceeding, New York State Department of Public Service and New York State Energy Research and Development Authority New York's 6 GW Energy Storage Roadmap: Policy Options for Continued Growth in Energy Storage (filed March 15, 2024) (Energy Storage Roadmap), *available at* <https://www.nyserda.ny.gov/-/media/Project/Nyserda/Files/Programs/Energy-Storage/Energy-Storage-Roadmap.pdf>

envelopes and efficiency improvements over time, as well as EHP performance assumptions. For detailed discussions, please refer to Section 3.2 and Appendix C of the Peak Report.

Solar

National Grid introduced a probabilistic approach for modeling solar PV load impact profiles for different configurations including fixed-axis and single-axis tracking system. For detailed discussions, please refer to Section 3.2 of the Peak Report.

Energy Storage

National Grid refined the energy storage charging and discharging profiles that consider various battery configurations in each season and for different customer classes. For detailed discussions, please refer to Section 3.2 of the Peak Report.

Energy Efficiency

National Grid refined EE profiles using NREL ResStock and ComStock data specific to the Company's electric service territory for various end uses and estimated hourly distribution of savings based on the shares of the different end uses in the Company's EE portfolio. For detailed discussions, please refer to Section 3.2 of the Peak Report.

Electric Vehicles

National Grid refined its EV load profile methodology to directly incorporate assumptions around battery-temperature efficiency, daily average dry-bulb temperatures, annual vehicle miles traveled as well as daily miles traveled, and to account for day-type effects (i.e., weekend versus weekday travel behavior). These updates enable more accurate estimation of average daily energy needs per vehicle and by type and in turn inform the charging load profiles necessary to meet that demand. The Company also models load impacts between depot and public-specific charging load shapes for major types and subtypes of MHDV EVs, including school and transit buses. The Company also investigated a managed charging scenario for MHDV EVs, building upon their existing scenario for light-duty EVs. For detailed discussions, please refer to Section 3.2 and Appendix C of the Peak Report.

Demand Response

National Grid developed separate DR profiles for residential and commercial and industrial (C&I) sectors. The Company enhanced the profiles for commercial customer segments by using actual performance data from DR programs in the electric business. For the residential sector, where actual performance data could not be obtained, the profiles were inferred from historical performance of customers from the residential DR program in the NY gas business. For detailed discussions, please refer to Section 3.2 and Appendix C of the Peak Report.

6. Improving Analytical and Computational Capabilities

National Grid enhanced its analytical database and computational environment with utilization of version control, cloud computing, and storage.

Implementation Plan, Schedule, and Investments

Current Progress

The forecasts continue to be provided at the system level, by NYISO load zones, and at feeder levels. A probabilistic method that considers weather and customer behavior, as well as economic and demographic outlooks from Moody's, is being used to provide baseload growth projections. Impacts of DERs (EE, solar PV, EV, EHP, ESS, and DR) are individually modeled for load impacts and adoption.

The forecasts continue to be provided for multiple weather and DER scenarios at both the system and feeder levels, providing system planners and DER developers with information on uncertainties. The various weather and DER scenarios are discussed in the Company's Peak Report. The forecasts include seasonal peaks and peak day hourly profiles for baseload and each DER component, giving system planners and DER developers granular insights. These forecast insights provide the system planners with valuable information to anticipate future infrastructure needs and capacity constraints. For example, feeders with substantial forecasted solar or EVs can be used to assess future hosting capacity and load requirements.

Future Implementation and Planning

National Grid is committed to continually improving its load and DER forecasting methodologies and practices. For example, the Company plans to continue research on probabilistic methods for forecasting.

The Company plans to continually refine its DER scenarios to align with current state policies, market studies, and recent historical trends, and to account for uncertainties about the future.

National Grid plans to refine forecasting methods with the utilization of empirical data sources, including but not limited to AMI data, as such data becomes available and is deemed reliable. Such data may provide the Company with a better understanding of adoption and load impact behavior of novel DER technologies to better inform the forecast.

The Company plans to continue improvements of its in-house EV fleet database, which was built using the best-available public and internal data, studies, and analyses. These improvements include expanding coverage to additional fleet depot locations, conducting further validation and refinement on the existing pool of identified fleets, and expanding the universe of fleet-specific information that is available for future modeling initiatives. Until an alternative single data source is identified and vetted for quality, reliability, and comprehensiveness, this database remains the most comprehensive source of fleet depot and public charging site information for EV fleets operating in National Grid's service territory, especially for larger EV fleets which are expected to be bigger drivers of long-term MHDV-related load growth.

The Company plans to continue promoting communication with other utilities by sharing forecasting methods and best practices.

The incorporation of empirical and more granular data will require migration and processing of current data into the cloud as well as a substantial increase in cloud storage and computing to process and analyze the data. National Grid plans to enhance data process, integration, and analysis capability utilizing cloud computing and storage, and is seeking approval of resources to enable the implementation of this plan in the National Grid Electric and Gas 2024 Rate Case Proceeding.

Risks and Mitigations

Table 2.2.1: Risks and Mitigations for Advanced Forecasting

Risk	Mitigation
Availability and quality of data at a more granular level	The Company will continue to expend efforts to explore alternative and additional data sources.
Cost of managing and accessing more granular data	The Company is pursuing additional resources to enhance data processing, storage, and integration.
The increasing size and variety of data being used for forecasting require a more powerful computational environment and centralized control system.	The Company plans to invest in its analytical environment, including cloud storage, cloud computing, and version control system and is pursuing additional resources to enable the implementation of this plan.
With scenarios and probabilistic forecasting methods being introduced into the forecast to help quantify and inform the uncertainties in DERs, weather, and the economy, the forecast outputs grow exponentially. This creates challenges in presenting the results to stakeholders and in stakeholders properly interpreting the results and smoothly incorporating the forecasts in their analyses.	The Company will continue forming the discussions and feedback loops between the forecasting team and stakeholders to ensure forecasts are delivered in a transparent and effective way for stakeholders' uses.
Greater uncertainties introduced by increasing penetrations of DER and electrifications, climate change, economic uncertainties, and policy changes.	The Company will continue exploring and evaluating policies and studies to ensure the forecasts provide up-to-date views on uncertainties.
Workforce for enhancements and expanded scopes	The Company will need to invest in acquiring additional workforce to support enhancements and expanded scopes.

Alignment with CLCPA Goals

National Grid developed base and alternative DER scenarios to inform uncertainties in the rate at which CLCPA goals are met. Below are summaries of how the base DER scenario aligns with CLCPA goals. Detailed discussions on scenario development and forecasted numbers are provided in Section 3.2 and Appendix C of the Peak Report.

- EE: the forecast incorporates the EE goals established in the Commission’s January 16, 2020 Order Authorizing Utility Energy Efficiency and Building Electrification Portfolios Through 2025³³ and the Company’s proposed plan in the Energy Efficiency and Building Electrification filing made with the Commission.³⁴
- Solar PV: for the near-term, the forecasts are based on historical trend, subject matter expert’s (SME) outlook, and projects in the interconnection queue. The forecast is aligned with the Company’s estimated share of the NY-Sun Solar Program target of 10,000 MW installed nameplate capacity by 2030. In the long term, the forecast is aligned with the Company’s share of the statewide CLCPA solar PV capacity.
- Electric Heat Pumps: the forecast’s various scenarios capture growth projections towards meeting CLCPA Scenario 3 targets.
- Electric Vehicles: the forecast for EV sales share is based on California’s Advanced Clean Car II and Advanced Clean Trucks regulations and are encapsulated in the forecast’s various scenarios which also aligns with CLCPA targets.
- Energy Storage: the forecast adopted NYS goals outlined in the CGPP and the Energy Storage Roadmap, which aligns with CLCPA targets.

These forecasts and forecasting tools have also proven invaluable in developing CGPP models. As further discussed in the Integrated Planning section of this 2025 DSIP Update, the strategy was taken in CGPP to align as much as possible with distribution planning and forecasting to ensure consistent application of needs and solutions from high-level zonal forecasts utilized for CGPP maps down to distribution forecasts. While most CGPP forecast sub-components were determined on a state-wide, CLCPA policy-compliant basis, the disaggregation of those forecasts into nodal elements in CGPP Stage 2 aligns with the levels developed for distribution forecasts described throughout this section. In practice, this first CGPP cycle utilized the New York State Climate Action Council Integration Analysis as a starting point for most forecast components, including DERs and EVs. This ensures statewide consistency (as opposed to developing unique territory specific bottom-up forecasts) and compliance with the CLCPA. In CGPP Stage 2 and beyond, however, nodal models required the zonal forecasts to be disaggregated, in some cases down to nodes nearly at the distribution level. Planners utilized distribution forecasts and the methods described above to disaggregate the statewide forecasts, balancing the consistency value of statewide forecasts with the accuracy and precision improvement reaped by utilizing local forecasts for each utility’s service territory.

³³ Case 18-M-0084, *In the Matter of a Comprehensive Energy Efficiency Initiative* (NE:NY Proceeding), Order Authorizing Utility Energy Efficiency and Building Electrification Portfolios Through 2025 (issued January 16, 2020) (January 2020 NE:NY Order).

³⁴ NE-NY Proceeding, Proposal of Niagara Mohawk Power Corporation d/b/a National Grid for Market-Rate Energy Efficiency and Building Electrification Programs (filed November 1, 2023).

Stakeholder Interface

Forecasting is an essential step in the distribution system planning process. Load forecasts are inputs for regular engineering processes such as base scenario development, summer preparedness, annual planning, area studies, minimum loads, operations studies, risk evaluation, sensitivity studies, new customer studies, and electrification studies. Furthermore, the work of procuring NWA solutions uses the forecast to identify the type, timing, and size of a system needed or the studies which underpin the beneficial locations of DERs. These detailed forecasts allow planners to understand forecasted load growth with locational granularity while accounting for multiple possible loading scenarios and decompartmentalizing the peak impact of each DER to better inform planned upgrades and accommodate future DER projects.

National Grid provides forecasts at several geographical and temporal granularity levels in addition to multiple weather and DER scenarios, which provide DER developers insights on system capacity and opportunities, to aid in the risk assessment of developing DER projects. Furthermore, the forecast report details methodology and source data used in the forecast to help developers understand the incorporation of new technological trends or economics of DER development. The forecast reports and forecasted load profiles are published on National Grid's System Data Portal.

The Company's forecast report was cited multiple times as a prime example of electric load forecasting and information sharing in a recent study published by the Lawrence Berkeley National Laboratory for the DOE in helping "regulators and stakeholders understand how the forecast aligns with state policies and expected technology and market changes."³⁵

³⁵ See Sean Murphy et al., *Bridging the Gap on Data and Analysis for Distribution System Planning: Information That Utilities Can Provide Regulators, State Energy Offices and Other Stakeholders* (January 2025), prepared for the U.S. Department of Energy's Office of Energy Efficiency and Renewable Energy under Lawrence Berkeley National Laboratory, pp. 14-15, available at https://eta-publications.lbl.gov/sites/default/files/2025-01/bridging_the_gap_between_utilities_and_regulators_20250106.pdf

2.3 Grid Operations

Context and Background

The Grid Operations update includes multiple platform deployments and grid modernization workstreams designed to support implementation of distribution-connected wholesale and retail markets, and progress federal orders and state goals including FERC 2222, the Climate Act, and GOTF Proceeding.

Grid modernization refers to the hardware and software associated with managing the grid, as well as the supporting communication and cybersecurity frameworks. Grid modernization programs covered in this section are described below.

Distribution Automation (DA)

DA refers broadly to equipment and control schemes deployed to digitalize National Grid's electric distribution networks and build a more reliable and resilient system through improved visibility, automation, and control at the grid edge. DA includes deployment of distributed control algorithms for FLISR and VoltVAR Optimization (VVO). The hardware installed as part of the DA program enables the analysis and automation tools in centralized systems such as ADMS and DERMS.

Advanced Distribution Management System

ADMS is a control room-based hardware and software solution that allows for greater visibility, situational awareness, and optimization of the electric distribution grid. The ADMS combines analysis tools, outage management, and SCADA control to establish a centralized grid control platform.

Distributed Energy Resource Management System

DERMS is a suite of digital products (technology and platforms) that will enable National Grid to create and operate a smart, flexible, and dynamic grid through its DSP that can manage future supply mix and energy needs using both utility-scale (community solar facilities, standalone ESS, large fuel cell plants) and behind-the-meter (BTM) DERs (e.g., rooftop solar PV panels, EVs, EHPs) with real-time communications while solving grid problems and providing resiliency.

Short Term Forecasting (STF)

STF establishes a platform to supply visualizations and predictive analytics to downstream grid modernization programs, including ADMS and DERMS. The use of robust forecasts in short-term operational planning improves efficiency and enables proactive grid management under complex and varying system conditions.

Flexible Interconnections

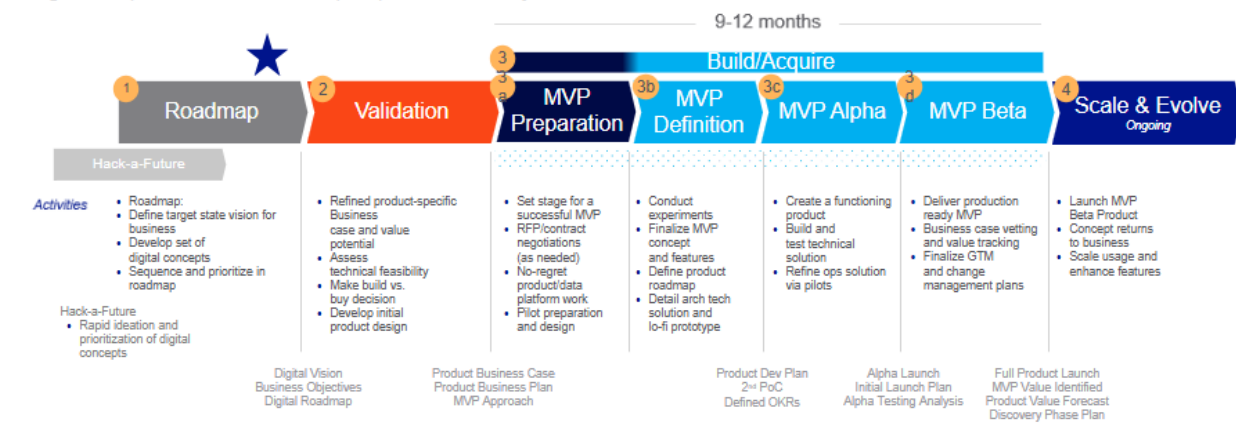
Flexible interconnections are development opportunities that aim to improve DER interconnection customer experience, connect more DERs to the grid, and increase DER application productivity by deploying technology that allows National Grid to actively manage DERs to mitigate distribution system constraints. Capabilities developed through the ARI Pilot enable the deployment of a full-scale, centralized DERMS platform.

The Company has adopted an Agile project management framework to employ multidisciplinary best practices for delivering digital products. The Agile delivery methodology is focused on aligning programs to organizational strategy, managing dependencies and risks between them, and delivering more value faster. Dedicated change management resources are in place to understand change impacts and develop and deliver the right stakeholder communication, engagement, and education across business units. Training staff is engaged throughout the process, and training curriculums are regularly evaluated and expanded to include upcoming implementations and ensure business readiness.

Figure 2.3.1: Product Roadmap Implementation

Digital Product Delivery and Phases

High-level process from roadmap to product delivery



Implementation Plan, Schedule, and Investments

Current Progress

FLISR

FLISR coverage has been expanded to 45 distribution schemes and 3 Sub-T schemes, encompassing 184,082 customers. FLISR schemes have saved 5,806,439 Customer Minutes Interrupted and avoided 28,890 Customer Interruptions (CI) in FY25. FLISR scheme locations are selected based on historical SAIDI and SAIFI, availability of feeder ties and communication, existing protection capability, and other factors. Expansion of FLISR coverage is planned through calendar year (CY) 2033 and is estimated to impact approximately 60 percent of National Grid's customers by the deployment conclusion.

VVO/CVR

Measurement and Verification (M&V) of previously deployed VVO/Conservation Voltage Reduction (CVR) schemes has been completed. The Company does not plan to pursue centralized VVO/CVR deployment further through programmatic capacitor and voltage regulator installations utilizing third-party control algorithms. The Company instead will be focusing on using coordinated switched capacitors and voltage regulators with local volt/var controls as part of the normal business approach to build upon techniques learned through the VVO/CVR programmatic deployment.

Monitoring and Control/Intelligent Substation (ISS)

The Feeder Monitor Program has been completed, deploying over 400 line sensors across the Company's service territory.

Energy Management System-Remote Terminal Unit (EMS-RTU) Program

The EMS-RTU program is still ongoing and delivering new M&C capabilities to existing substations. These upgrades and new installations will be utilized to integrate substation assets into ADMS and provide new remote capabilities and scheme controls that will support system reliability and power quality for customers. National Grid looks to continue upgrading and installing new RTUs into substations for further M&C as well as value for internal and external stakeholders.

Digital Substation

The Digital Substation program continues to leverage modern digital technology and incorporate new ways of working to improve delivery and operation of electric substation projects. The program consists of two primary components, International Electrotechnical Commission (IEC) 61850 and substation online monitoring. The digital substation program is building on the success of the first-fully digital, network-connected active IEC 61850 system in North America installed outside of Utica, NY. In the next five years, eight full digital substations will be deployed by National Grid.

IEC 61850 leverages internationally accepted industry standards to digitalize substation protection and control systems as well as engineering and construction processes. Intelligent and network connected IEC 61850 systems will provide the following benefits:

- Reduce substation physical infrastructure: Packet-based communications networks require far less cabling and raceways than conventional protection and control systems.
- Digitalize protection and control systems: Touch-screen Human-Machine Interface (HMI) replaces physical control switches reducing the size of control houses and enabling greater functionalities.
- Standardize design and construction processes: Standard data models and engineering processes will eventually facilitate re-use and design efficiencies.
- Greater system visibility: The digitality connected system will allow engineers and technicians to diagnose issues remotely to quickly troubleshoot and resolve potential system interruptions.
- Lower operating costs: Network-based systems enable easy and quick expandability without added infrastructure.

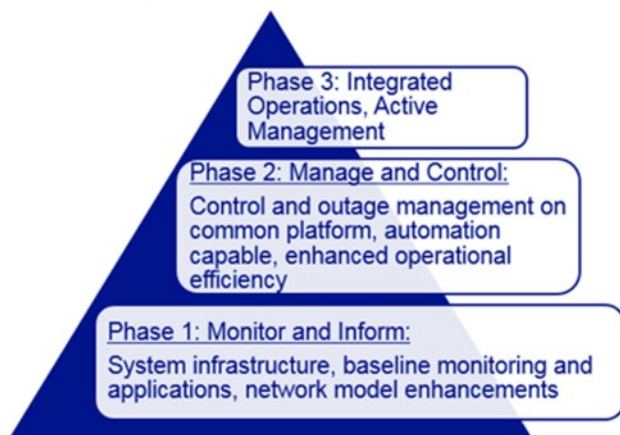
Intelligent Substations

Grid edge computing is in the early stages of deployment through the ISS Project. The Company was awarded federal funding to develop three substations compliant with the ISS specification. A hardware-in-the-loop test facility has been established at National Grid's Clay Substation to enable vendor evaluation and testing for the grid-edge computing solution and eventually serve as a test bed for cloud-based validation during deployment and maintenance.

ADMS

As initially noted in the 2020 DSIP Update, National Grid developed a phased approach for rolling out its ADMS, including implementing Distribution Management System (DMS) advanced applications in Phase 1 and upgrading the existing Outage Management System (OMS) as a module of the ADMS in Phase 2. The ADMS project will implement a distribution-specific SCADA system, DSCADA, dedicated to the management and control of distribution equipment. The resulting DSCADA system will be integrated with the DMS applications and OMS while data quality, model fidelity, and integrations with external systems continue to be improved and expanded to create common operations platform in Phase 3, enabling the centralization of DA technology.

Figure 2.3.2: ADMS Phased Approach



ADMS Phase 2 was completed in March 2024, bringing the OMS functionality into the ADMS.

Mobile Outage Dispatch (MOD), an application that enables field crews to receive, manage, and complete trouble and outage reports through their mobile devices, has been integrated with the ADMS to improve efficiency and accuracy in managing emergent and emergency work.

The AMI network is integrated with the ADMS, and the ability to manually ping individual or groups of AMI meters from the ADMS user interface is enabled. Detailed progress on the Company's AMI deployment can be found in Section 2.12 of this 2025 DSIP Update.

ADMS Phase 3 is progressing, with 3,473 devices configured and connected to the ADMS DSCADA system. Real-time analog data for devices on distribution feeders is available for analysis and outage modeling. Throughout FY26,³⁶ FLISR schemes will be enabled in advisory mode and the ADMS will propose a solution but will not execute the restoration steps so as to allow National Grid operators and engineers to evaluate and familiarize themselves with the tool.

GIS data supplied to the ADMS has been expanded. Asset data from GIS designs that are scheduled for construction can be made available in the ADMS to enable immediate consumption by the analysis tools once the equipment is in service. Substation operating diagrams are being translated to a connected network model to improve the accuracy and scope of ADMS solutions. To date, two substation models are available in the ADMS, with several more designs complete in GIS.

DERMS

The Company has identified early use cases for DERMS that focus on providing customer and grid value, particularly where there are system capacity constraints on the distribution system to interconnect and accommodate new electric demand accelerated by demand electrification, or new DG and ESS projects. DERMS will serve as the underlying operational system to support new and evolving utility DER programs that are focused on grid support such as NWA solutions and targeted DR as well as more active management of interconnected facilities such as through flexible interconnection solutions where participating facilities would be required to operate within dynamic operating limits based on grid conditions. National Grid also anticipates DERMS will emerge as a key system to support operational coordination of DER and DER aggregations participating in wholesale market services within the Company's service area. Figure 2.3.3 Shows Grid DERMS Use Cases for both BTM and front-of-the-meter (FTM) DER.

Figure 2.3.3: Grid DERMS Use Case Summary



³⁶ National Grid's FY 2026 is April 1, 2025 to March 31, 2026.

The Company is currently in the process of procuring a centralized, network-aware DERMS (i.e., Grid DERMS). The Grid DERMS is planned to have capabilities including DER configuration, monitoring, scheduling, dispatch control and optimization, and M&V. Integration with other enterprise operational systems such as the ADMS and short-term forecasting platform will enable Grid DERMS to be network-aware and both predictive (through use of forecast models) and corrective (through use of real-time system monitoring). National Grid is also in the process of conducting change impact and business readiness efforts to better understand the necessary staff who will be primary and secondary users of Grid DERMS such as distribution security operators, DERMS engineers, and DER program managers, and their associated roles. This system is anticipated to centralize the operational management of new and existing utility DER programs targeted at localized distribution system needs that may be currently supported by legacy systems or manual processes. Grid DERMS will allow operators and program managers to more efficiently, manage the DER programs safely, reliably, and efficiently and in support of wider system operations.

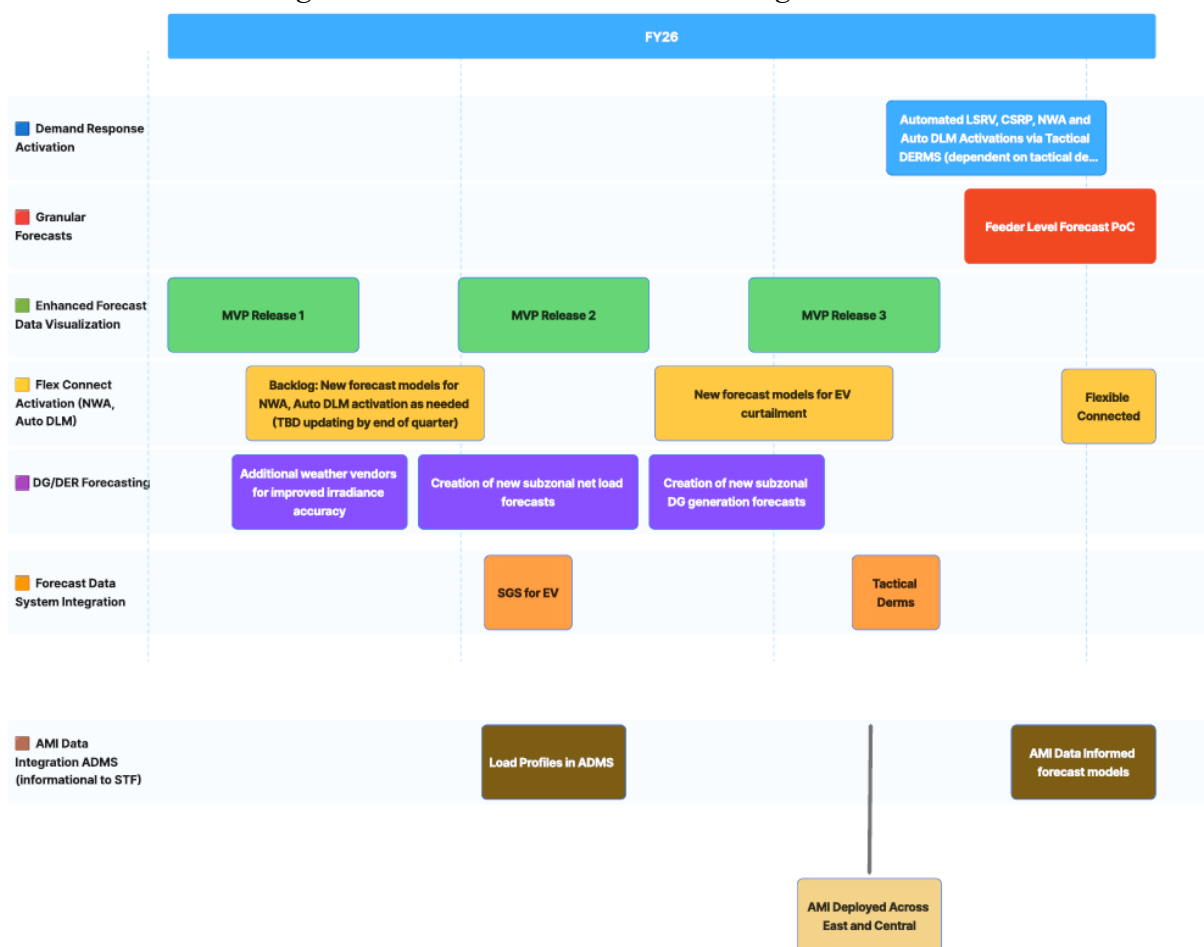
Grid DERMS is intended to maximize accessibility to existing capacity in existing assets without risking the safety/reliability of the grid, overcome the current planning challenges of needing to statically plan to a worst-case scenario by transitioning to an approach of dynamically adjusting to system needs, and increase potential for customers to make DER projects economically viable. Details and status of existing or planned DER participation programs can be found in DSIP Section 2.13, Beneficial Locations for DER and Non-Wires Alternatives.

Short-Term Forecasting

Short-term load forecasts produced through 14 days into the future have been developed at the regional (West, Central, and East) and substation level at three National Grid facilities. All of these forecasts have been made available to the Company's Control Centers through an interim visualization dashboard for use in planning and real-time operations.

Direct pipelines triggered from forecast results have been deployed to support NWA, DLM, and LSRV activations by notifying operators and developers of various threshold exceedances requiring generation support or load relief to ensure a reliable and secure electric system.

Figure 2.3.4: FY 2026 Load Forecasting Timeline



Flexible Interconnections

National Grid continues to advance its operational capabilities to improve utilization of the distribution system by leveraging DER flexibility while maintaining safety and system reliability. As of January 2025, the Company has completed the deployment and operational testing of two flexible interconnection schemes integrated with a centralized constraint management software (i.e., DERMS) at MW-scale distributed solar generation facilities as part of its ARI Pilot. For both schemes, the Company has successfully demonstrated that DERMS can automatically calculate dynamic export limits based on real-time system measurements and with a shared curtailment (i.e., pro-rata) methodology to mitigate backfeed overload concerns at a 115/13.2 kV substation with a dual transformer bank configuration with a normally open low-side bus tie. The ARI Pilot established control center operator real-time visibility and override capabilities of the flexible interconnection schemes through secure communications between EMS and DERMS. The DERMS also was implemented with site-level compliance monitoring capabilities so as to verify that sites with a flexible interconnection scheme adhered to operating limits communicated by the Company. This functionality was tested to disconnect the facility through the Company's point of common coupling (PCC) recloser if it did not respond based on terms agreed upon by the utility and DER operator, ensuring safety and reliability of the electric power system (EPS) is maintained.

Through the deployment of the Company's Watertown NWA project and the ARI Pilot, National Grid developed and gained experience in deploying telemetry to FTM DG and ESS facilities to exchange real-time status and control signals (e.g., dispatch base points and export limits) primarily through the Company's private wireless network and using utility-grade RTUs that serve as DER communication gateways between utility equipment and third-party equipment. National Grid has also implemented additional cybersecurity solutions in these instances where utility equipment is communicating directly with third-party equipment. The Company has also started to explore other networking solutions (e.g., SD-WAN) and communication protocol options with DER (e.g., open automated demand response (OpenADR) and Institute of Electrical and Electronic Engineers (IEEE) 2030.5) for future consideration.

In 2024, National Grid's Distributed Communications and IT departments partnered to complete a proof-of-concept project to evaluate SD-WAN. The pilot specifically looked at aggregators that participate in the wholesale market in support of the launch of FERC 2222. The pilot sought to leverage software-defined network management to quickly provision and manage network devices for DER-related communications. Recognizing an increased need for external third-party communications over a secure and scalable network, the design uses an open standard internet medium for high scalability. Future implementation will support stakeholders by offering a lower-cost and scalable communications solution to meet telemetry requirements between developer aggregation points, the transmission operator control centers, and the NYISO. The ability to offer such a solution is being encouraged by the NYISO, as the existing leased telecommunications companies (Telco) circuits used today are expensive and slow to install. As the pilot was successfully completed, SD-WAN can now be considered for other DER applications in need, such as flexible interconnections and DER to DERMS communications.

DERAConnect

Shortly after NYISO received approval for their DER Participation Model, established to comply with FERC 2222. In April 2024, National Grid enabled DERAConnect as a tool to aid in the enrollment process and operational coordination between aggregators and the Company's Regional Control Centers. This tool allows operators to upload granular DER dispatch schedules of individual aggregators participating in NYISO wholesale markets for comparison with the aggregated schedules. This in turn allows for better identification of discrepancies and potential impacts to distribution system reliability in a day-ahead scenario.

Communications

Essential to M&C of the conventional power grid as well as grid modernization technology, communication needs are expanding as the industry becomes more intelligent and interconnected. Since the 2020 DSIP Update filing, National Grid has deployed operational telecom projects to support and expand connectivity across the power system.

The Unified Technology Operations Center (UTOC) has been operationalized, monitoring 2,500 primary devices across the Company's service territory. As new AMI communication channels are deployed, those channels are also included in monitoring.

To support increased bandwidth needs of operational systems and the upgrade of National Grid's existing networks, Dense Wave Division Multiplexing (DWDM) technology has been deployed to 13 Company substations and other major facilities.

The legacy Synchronous Optical Network (SONET) technology, which runs National Grid's fiber optic network, is approaching end-of-life and in the process of being replaced with Multiprotocol Label Switching – Transport Profile (MPLS-TP) technology. Deployment of the MPLS-TP network has started with core nodes installed and operational at 13 facilities. Testing and initial circuit cutovers have also commenced.

Across the state, telecommunication companies are discontinuing analog circuits (i.e., Digital Signal 0 (DS0)) and converting from copper to fiber. So far, over 409 substations and dozens of other operational circuits have been migrated from DS0 services.

Dark fiber (i.e., unlit fiber optic strands that have been secured for exclusive Company use) is being utilized to expand National Grid's fiber optic network to new substations and other major facilities. This work supports the Company's migration from DS0 circuits and the implementation of DWDM and SONET upgrade plans.

To enhance coverage and reliability, the Company has completed the implementation of an AT&T FirstNet cellular gateway for SCADA and field device connectivity. This secondary option to the Verizon Private internet protocol network is in place at over 20 National Grid substations so far.

To help manage the Company's communications networks, National Grid has deployed the Telecom Operations Management System which is a telecom asset management and design tool. It is currently being populated with telecom asset data through surveys and other investigative work.

Cybersecurity

National Grid continues to implement risk-focused and customer-centric cybersecurity approaches for all grid modernization initiatives. All grid modernization projects are proactively supported by security SMEs dedicated to identifying appropriate secure-by-design requirements to ensure each solution goes into production with a robust security architecture, adapted to National Grid in accordance with industry standards and regulatory obligations.

Security-by-design ensures that security is an integral part of all phases of a grid modernization project, from conceptualization and solution design to the selection of equipment, systems, and third-party service providers. Cybersecurity's organizational operating model has been adapted such that security SMEs are embedded in all solution teams to identify and implement the relevant security requirements and architectures and help to bake security into the solution by design. Security SMEs have been involved in the ARI Pilot project, ADMS Project, AMI Project, Divisional Multiplexing Project, and more.

Operational Technology (OT) Intrusion Detection Systems: Intrusion Detection Systems have been placed in over a dozen substations for FY25³⁷ and logging from the Substation Core Bus and HMIs is being sent to the Critical Infrastructure Protection (NERC-CIP)-certified Cyber Security Operation Center. OT privileged access workstations are still being issued with an increase in support personnel for users.

Continuous remediation of risks and emergent vulnerabilities: As new solutions are implemented, there will be continuous security engagement to identify application and system risks and vulnerabilities and remediate findings. All grid modernization initiatives will be integrated from their inception to the appropriate security systems to provide this visibility, and to the relevant processes for periodic penetration testing and remediation to ensure they remain in a secure posture. All OT-based engagements are penetration tested (pen tested), remediated, and retested where the requirements are applicable.

Future Implementation and Planning

FLISR

The Company will continue to expand FLISR coverage across the service territory. FLISR control algorithms are expected to be established in the ADMS starting in FY2027

Table 2.3.1: FLISR Deployment Roadmap

		Proposed				Future		
	End of FY25	FY26	FY27	FY28	FY29	FY30	FY31	FY32
Distribution FLISR Schemes	43	47	54	60	53	53	53	53
SubT FLISR Schemes	3	8	22	24	18	TBD	TBD	TBD
Projected Customers Connected	184,082	105,750	121,500	135,000	119,250	119,250	119,250	119,250

UTO

AMI communication lines will be added for supervision as they are installed, and supervision of private networks will be expanded through FY2026. Opportunities to improve efficiency and coverage of critical communication lines will be continuously explored.

Monitoring and Control/Intelligent Substations

The Company has explored emerging and beneficial solutions for DER monitoring and control communications with the desire to achieve more scalable options that can support anticipated greater interaction with DER for the purpose of grid management. National Grid plans to continue its exploration of emerging industry standard protocols, such as OpenADR and IEEE 2030.5 – Standard for Smart Energy Profile Application Protocol, in anticipation that use of these standards

³⁷ National Grid's FY 2025 is April 1, 2024 to March 31, 2025.

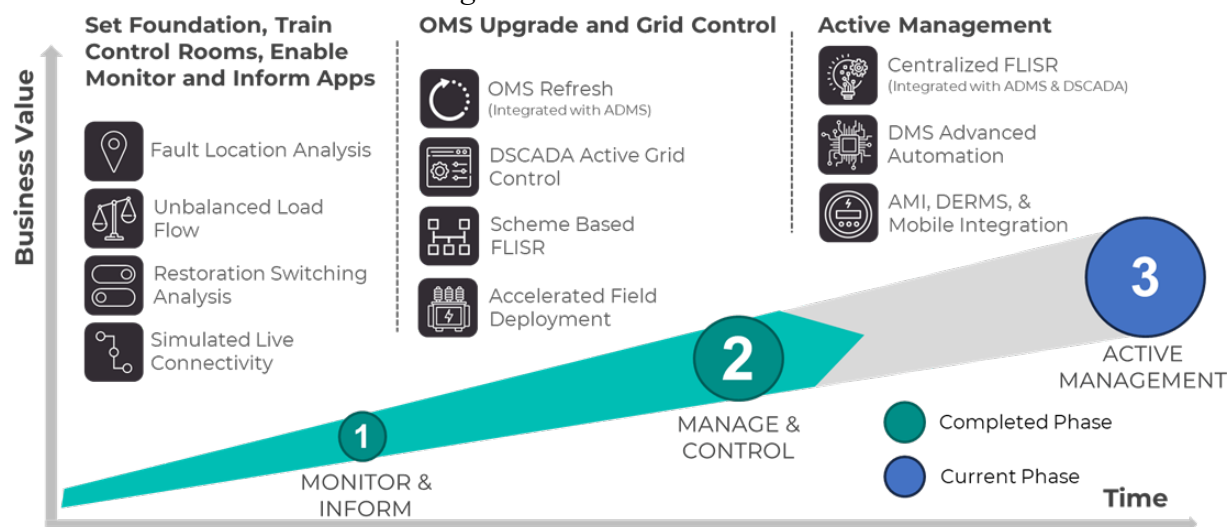
will streamline efforts to integrate DER into grid management. The Company successfully completed a proof-of-concept project utilizing SD-WAN for connections with third-party aggregators to support FERC 2222 for general monitoring and control of DER for grid management and provide potentially lower upfront and ongoing operating costs for deploying communications with DER.

ADMS

ADMS Phase 3 will continue to extend ADMS functionality with additional automation targeted on active grid management. Some of the proposed integrations include centralized control of VVO and FLISR, AMI, short-term forecasting, DERMS integrations, and expansion of the mobile dispatch capability. The Company will develop the ability to more broadly share ADMS model and data supporting digital product concepts. In addition, National Grid will evaluate other integrations with this foundational application for the DSO Platform.

Unsolicited last-gasp power outage notifications from AMI will be enabled to improve outage analysis. Additional use cases will be explored and piloted to improve model and data quality, outage management processes, and customer satisfaction.

Figure 2.3.5: ADMS Timeline



DERMS

As part of National Grid's plan for Grid DERMS platform development and deployment, DER management use cases can start to be consolidated into more of a unified platform approach along with close integration with ADMS and/or EMS and the Company's Demand Response Management System (DRMS) where appropriate. A more comprehensive platform for DERMS will provide greater capabilities of dispatch optimization across multiple DER management use cases, improve system operator visibility, and provide additional analytic capabilities to support system operations and operational planning decisions. Although most of the Company's current NWA projects and DER management pilots, such as the ARI Pilot, have focused on managing distribution capacity constraints on substation transformer loading, National Grid anticipates investigating if DERMS can support constraint management using DER flexibility for feeder

capacity constraints as well, considering the complexity of feeder reconfiguration and less availability of granular real-time feeder measurements.

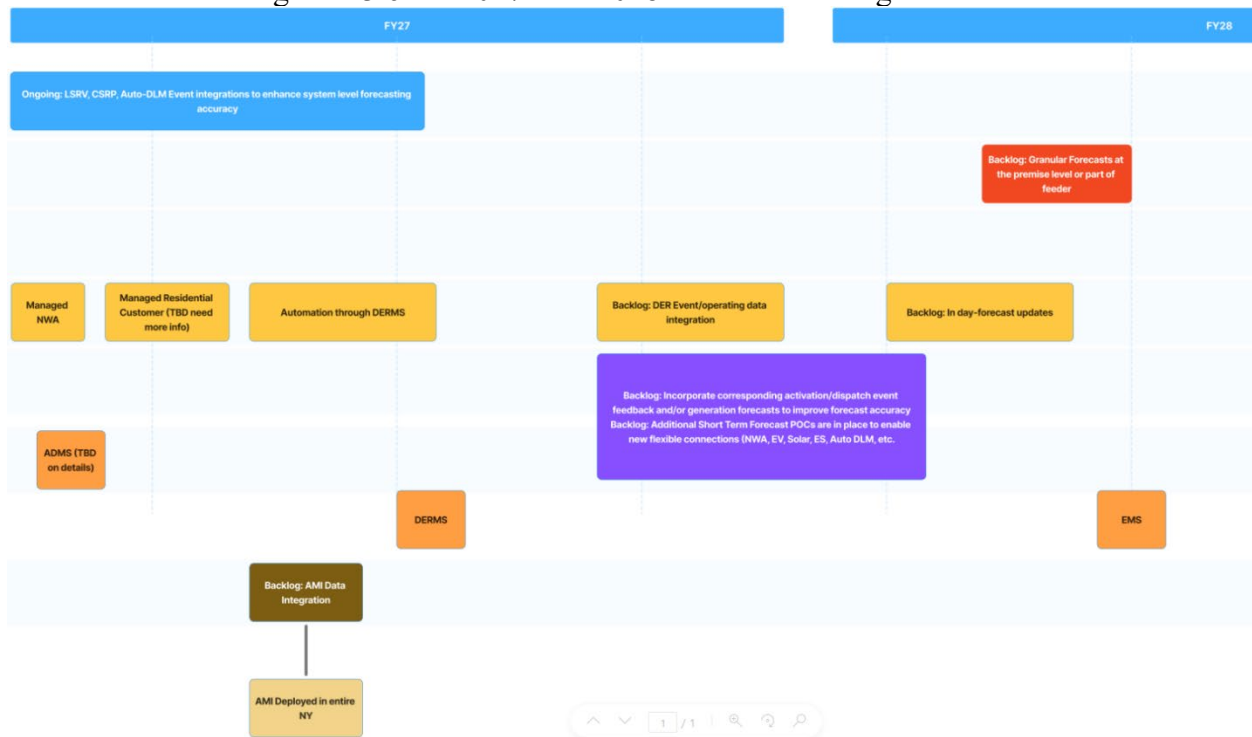
Short-Term Forecasting

The Short-Term Forecasting program will focus on continued improvement in National Grid's short-term forecasting capabilities to raise model output accuracy to predict load shapes and scale model development, maintenance, and training to drive greater efficiency in how DERs are dispatched. This has the added potential to reduce other operational costs for both the Company and DER operators.

Upcoming STF efforts also include:

- Feeder-level STF proof of concept(s) and integration with ADMS to be deployed in collaboration with ADMS vendor and project teams
- Additional substation short-term forecasts will be developed for AutoDLM sites and to facilitate an EV Flexible Connection site as necessary
- Improved operator awareness through a redesigned and improved visualization dashboard

Figure 2.3.6: FY2027 – FY2028 Load Forecasting Timeline



Communications

Continued expansion and privatization of Tier 1, 2, and 3 networks to support core electric and gas operational needs such as SCADA, teleprotection, and security services, as well as the increased deployment of intelligent network-connected systems such as VVO, FLISR, and NWA, are some of the planned improvements to National Grid's communications systems.

- The SONET to MPLS-TP upgrade work will continue for the next several years. National Grid will increase the number of nodes, complete initial testing, and cut over multiple operational circuits to the new system. The Company plans to transition ADMS leased circuits between data centers to the MPLS-TP network to save significant leased Telco operating expenditures. Further plans include installation of MPLS-TP nodes at over 100 substations and other facilities in the next three years.
- To relieve fiber constraints between facilities and support the further expansion of the MPLS-TP network, National Grid will continue to deploy DWDM with plans for installations and upgrades to 10 more nodes in the next two years.
- The Company will continue to migrate phased-out Telco circuits which currently provide SCADA, teleprotection, and other critical services. National Grid also plans to replace over 500 existing circuits in the next few years by using a combination of new leased services and circuits provisioned on the Company's private network.
- The Company will continue to expand its fiber infrastructure and private network using Optical Ground Wire (OPGW) and All Dielectric Self-Supporting (ADSS) fiber cable as well as increased use of dark fiber.
- National Grid will also expand its fiber optic build-out to rural areas by partnering with open-access broadband providers. Working together, community broadband projects leverage shared fiber optic cables to provide underserved, disadvantaged communities (DACs) with broadband access while also connecting unconnected substations, grid automation devices, customer and DER RTUs, BESS, and other electrical assets which require communication at a lower cost. As part of the Infrastructure Investment and Jobs Act (IIJA) initiative with the Development Authority of the North Country (DANC) and Northland Communications, the Company anticipates adding fiber connectivity to over 50 substations in the next three years.
- The Company's Telecom Operations Management System will continue to be populated with new and existing asset data to support the growing and even more critical telecom network. National Grid will develop new processes for the use of this important asset management and design tool.

Cybersecurity

- Expanding security monitoring and incident response: Security will continue to deploy the OT Intrusion Detection System and OT privileged access workstation solutions to new environments, in addition to building stronger Computer Security Incident Response Team visibility for all systems and applications deployed as part of the Company's various grid modernization projects. Current reporting processes will be further enhanced to ensure National Grid adheres to the highest standards for detection, response, and communication with all relevant stakeholders.

- Building security capabilities for new technologies: Many grid modernization initiatives involve technologies new to the OT space, such as unmanned aerial vehicles, robots, smart/Internet of Things devices, and cloud hosted services. Security will build a risk-ranked stack of capabilities needed to prevent, detect, and correct security threats and risks across the relevant technologies, and will adopt industry recognized standards to ensure consistency.
- Cybersecurity is engaged with future projects such as the Energy Management System (EMS) RFP, NY Geothermal proof-of-concept, DSO/DERMS, and ADMS Rapid Rebuild.

STREAMS

Program Summary

Strategic Reimagining of Enterprise Asset Management Systems (STREAMS) is a National Grid effort to implement a holistic asset and work management process and business transformation. The initiative focuses on reengineering Company processes to establish customer-centric, modern, digital asset management and work implementation practices. This effort will be supported by replacement of legacy systems with best-in-class technology. This will empower our workforce to deliver an expanding capital plan while enhancing employee experience, driving operational efficiency, and ensuring long-term customer affordability.

Background

National Grid and National Grid's Massachusetts affiliate currently utilize a minimum of six applications, many of which are legacy systems, to manage end-to-end asset management and work execution processes. These solutions are approaching the end of their lifecycle and are becoming unsupported. The Company's current work management system (Severn Trent Operational Resource Management System (STORMS)) and GIS are both approaching their end-of-life where the technologies cannot be upgraded or appropriately maintained. In addition, the current environments are no longer fit for purpose to allow National Grid to meet its strategic priority of transforming our capabilities. The existing strategy of using piecemeal solutions to address isolated issues and serve siloed operational functions is no longer adequate. Enterprise-level investments in asset and work management are essential to standardizing operations and realizing the Company's Future of Electric vision for our customers, especially given the anticipated, significant growth in capital investment and electrification within the US Electric Business Units. Excellence in asset and work management and data integrity are critical and foundational.

High Level Scope

- Enterprise Asset Management (EAM) System Deployment is comprised of:
 - o Implementing a robust EAM system to optimize asset lifecycle management, preventive maintenance, and work order processes
 - o Integrating the EAM system with existing National Grid enterprise systems for seamless data exchange and workflow coordination
 - o Implementing robust security measures to safeguard sensitive asset and spatial data to ensure compliance with data privacy regulations

- o End-to-end testing and quality assurance for each deployment and release, including functionality, performance, and security testing, to identify and address any issues
 - o Enabling a post-implementation support model and skilled resources within the IT support model
- GIS Deployment
 - o Implementing a state-of-the-art GIS to enhance spatial data visualization, mapping, and analysis capabilities for the Company's electrical network
 - o Ensuring integration between GIS and the EAM system to facilitate spatially-informed decision making and asset management
 - o Implementing robust security measures to safeguard sensitive asset and spatial data, ensuring compliance with data privacy regulations
 - o End-to-end testing and quality assurance for each deployment and release, including functionality, performance, and security testing, to identify and address any issues
 - o Enabling a post-implementation support model and skilled resources within the IT support model
- Asset Data Migration
 - o Migrating existing asset data from legacy systems to the new GIS and the EAM system, ensuring data accuracy and completeness during the transition
- User Training and Change Management
 - o Developing and delivering comprehensive training programs for end-users to ensure a smooth transition to new systems
 - o Implementing change management strategies to address potential resistance and facilitate user adoption of the GIS and the EAM system
- Regulatory Compliance
 - o Ensuring that the GIS and the EAM system comply with relevant industry regulations and standards governing electrical utility operations
- Retirement and Decommissioning of National Grid Technical Debt
 - o Upon successful GIS and the EAM system deployments and cutovers, the delivery team will remove legacy infrastructure and software and desktop clients, along with the termination of non-applicable vendor/supplier contracts
 - o Content archiving and retention of any data identified as needed to be preserved for a period of time

Table 2.3.1: STREAMS High Level Milestones

Milestone	CY Targets
Startup	Nov 2023
Program Planning	Dec 2024
Mobilization	Dec 2025
Requirements & Design	June 2026
Development & Deployment*	Jan 2032
Project Closure	Mar 2032

*Iterative development and release periods

Alignment with CLCPA Goals

CLCPA goals are supported by the renewable energy development that occurs in response to compensation provided through wholesale and retail markets. As resource development continues, the DSP will evolve to manage grid and market operations to provide safe, reliable service while optimizing system usage. Many of the foundational investments discussed in this section will continue to support all stakeholders in meeting these goals.

These tools and processes will directly enable the CGPP planning / alignment strategy described in the Integrated Planning Section of this 2025 DSIP Update (i.e., align with distribution planning assumptions so that modeling and solution development may seamlessly integrate distribution considerations as an input, rather than an output). These tools will enable DER integration into wholesale markets through operational schemes and rules, ultimately leading to a more renewable power supply, supporting CGPP and CLCPA goals.

Risks and Mitigations

As DER penetration increases there is higher variability in resource outputs which produce risks on the T&D system. The development of tools and resources to provide the appropriate level of operator situational awareness is paramount. Continued investment in energy management applications provides the proper awareness and automation to maintain safety and reliability.

The speed of the market and thus grid operational changes on both the wholesale and retail markets also pose a risk. The implementation of FERC 2222, additional retail tariffs, and new market participation models, if introduced too rapidly, risk exceeding the utility's ability to develop, implement, and learn new operational technologies. National Grid has deployed its Agile Project Management Framework as a strategy to quickly respond to industry drivers by streamlining development and deployment cycles, breaking down organizational silos, and facilitating change management and training.

As part of the Company's Agile Project Management Framework, the team, program, and portfolio risks are assessed with the objective to Resolve, Own, Accept and Mitigate such risks on a quarterly or more frequent basis, assigning accountability to individuals to take the appropriate

action to manage the risk. Risks are identified and documented continuously in planning and development phases.

Integrated & Associated Stakeholder Value

National Grid and the other Joint Utilities continue to participate in several forums, including NYISO working groups, that engage developers, customers, market participants, and regulatory agencies to create a holistic view of select activities. Some examples include NYISO working groups and governance meetings, and forums.

The Grid Operations section of this 2025 DSIP Update principally addresses preparing the grid to handle DER integration consistent with the timelines of the Climate Act and FERC 2222. The section also describes the many investments in grid modernization the Company considers to be good utility practices to maintain system safety and reliability, with appropriate stakeholder input. National Grid has found stakeholder interaction valuable in soliciting feedback and guidance on processes, programs, and applications under development.

National Grid performs BCA assessments for all projects, and each noted creates significant customer value through avoided outages, capacity and energy savings for customers, and avoided/deferred capital system upgrades. Some projects are also required to meet regulatory requirements.

The Company's goals are to maintain a safe and reliable system that optimizes the use of assets and creates value for all stakeholders. To that end stakeholder information regarding capabilities and needs are used to shape plans for future changes supporting NYS and federal goals and requirements.

National Grid as well as the Joint Utilities will continue to engage stakeholders, when logical and feasible, to ensure processes, procedures, and applications do not cause unintended problems.

2.4 Energy Storage Integration

Context and Background

The following items are having a significant impact in driving the increased deployment and integration of energy storage in NY:

- *Anticipated Commission orders in Case 18-E-0130 – In the Matter of Energy Storage Deployment Program*
- *National Grid Electric and Gas 2024 Rate Case Proceeding*
- *NYISO Energy Storage Resource (ESR) Model and FERC 2222 Order Compliance*
- *The Climate Act*
- *Utility Bulk Storage Dispatch Rights Procurement*
- *Climate Action Council Draft Scoping Plan*
- *Inflation Reduction Act (IRA) and Investment Tax Credits for Energy Storage*

Implementation Plan, Schedule, and Investments

Current Progress

Energy Storage Demonstration Projects

In accordance with the Commission’s March 9, 2017 *Order on Distributed System Implementation Plan Filings*,³⁸ National Grid deployed two (2) 2 MW / 3 megawatt hours (MWh) energy storage units, both of which have provided substantial learning in various project phases such as planning, development, deployment, and operation of ESS. These projects have, and will continue to, inform plans for future ESS projects being considered by the Company.

East Pulaski

The East Pulaski ESS Project (East Pulaski Project) has encountered technical difficulties, including network connectivity problems and limited storage capacity on its system servers. These issues have led to operational challenges and, at times, necessitated taking the East Pulaski Project offline, which unfortunately resulted in a halt in bidding into the NYISO wholesale market while the problems were resolved.³⁹ The Company subsequently

³⁸ DSIP Proceeding, Order on Distributed System Implementation Plan Filings (issued March 9, 2017).

³⁹ See Energy Storage Proceeding, Order Approving Utility-Owned Asset Participation in Wholesale Markets (issued September 9, 2021), p. 2, where the Commission authorized National Grid to bid the energy, capacity, and/or ancillary services available from the East Pulaski ESS Project into the NYISO-administered wholesale markets when not needed for local reliability support, and where financial gains from any such market transactions shall accrue entirely to the benefit of National Grid’s customers.

transitioned its operating network to a new circuit under its IT management system, which caused connectivity issues between the Virtual Desktop Interface Project. This situation required the ESS units to be temporarily offline as the Company worked to incorporate the previously excluded devices, ultimately restoring full operational capabilities. The East Pulaski Project continued to struggle with maximum storage capacity on its servers, leading to frequent crashes and outages. Since its inception in 2018, the original servers had remained in use, and although the Operations and Maintenance (O&M) vendor has provided temporary maintenance, a long-term solution involving server replacement was essential. Following the resolution of these technical challenges, National Grid successfully resumed bidding into the NYISO. The East Pulaski Project has experienced approximately 1,130 MWh of throughput since 2023 that includes energy to charge the ESS units, discharge the ESS units, and provide auxiliary power requirements as part of balance of plant for control and safety systems.

North Troy

The North Troy ESS Project (North Troy Project) is currently operational. The ESS units encountered technical issues related to the heating, ventilation, and air conditioning (HVAC) equipment, as well as a ground-fault circuit interruption (GFCI), which led to one of the five ESS units being taken offline. The O&M vendor successfully completed repairs to the HVAC system and is scheduled to address the GFCI fault in early spring of 2024. The North Troy Project is currently operated at a 75 percent State of Charge, as recommended by the manufacturer, LG Chem, following a BESS fire in California in early 2025. Currently, the North Troy Project is being used under a scheduled dispatch to provide peak load reduction. Due to technical challenges and limited operation recommendations, the North Troy Project has experienced approximately 114 MWh of throughput since 2023 that includes energy to charge the ESS units, discharge the ESS units, and provide auxiliary power requirements as part of balance of plant for control and safety systems.

Energy Storage Order Implementation

National Grid has continued to progress its efforts in the deployment of energy storage and, as directed by the Commission's December 13, 2018 *Order Establishing Energy Storage Goal and Deployment Policy*,⁴⁰ in securing dispatch rights to 10 MW of bulk energy storage projects and expanding the Company's DLM procurement to provide new opportunities for ESS. Specific project and program progress are noted in the Central Adirondack Microgrid Project (CAMP) and Auto-DLM updates described below.

CAMP, formerly known as the Old Forge Project

In May 2022, National Grid contracted with a developer to design, install, own, and operate a 20 MW and 40 MWh ESS in the hamlet of Raquette Lake, NY. The Company and developer conducted community outreach consisting of community conversations and town hall discussions regarding the proposed ESS. However, due to increasing community concerns and a moratorium on energy storage enacted within the town of Long Lake, both the Company and the developer deemed the project unfeasible and mutually agreed to

⁴⁰ Energy Storage Proceeding, Order Establishing Energy Storage Goal and Deployment Policy (issued December 13, 2018) (2018 Energy Storage Order).

terminate CAMP. National Grid continues to explore alternative sites to achieve the goals of the 2018 Energy Storage Order and secure 10 MW of bulk energy storage.

Energy Storage as NWA

National Grid continues to pursue NWA opportunities through a competitive procurement process which is detailed in Section 2.13 of this 2025 DSIP Update. Fourteen competitive procurements have been conducted to solicit proposals for specific locations. A total of 45 bids have been received, each with ESS as part, or all, of the proposed solution.

Pine Grove

Pine Grove is a third-party owned NWA solution that is operational. The completed NWA solution deploys two grid-tied 5 MW solar arrays, each paired with a 5 MW / 20 MWh lithium-ion BESS. The Pine Grove NWA solution provides delivery infrastructure avoidance value as well as reliability and operational benefits. Currently, the site has been successful in meeting summer peak load constraints via a load-following dispatch schedule. However, some technical challenges were experienced by the developer and were resolved in the later months of 2024 and beginning of 2025. Please see the DER and NWA Locations section for further details.

Watertown

Watertown is a third-party owned NWA solution that is operational. The completed NWA solution deploys two grid-tied systems solar arrays with each paired lithium-ion BESS meeting a 5.7 MW/ 29 MWh need. The Watertown NWA solution provides delivery infrastructure avoidance value as well as reliability and operational benefits. Please see the DER and NWA Locations section of this 2025 DSIP Update for further details.

Gilmantown

Gilmantown is a potential NWA solution that is currently in the early planning stage. The Company anticipates that an NWA solution may deploy an ESS to support the area fed by the radial Gilmantown substation. The combined energy storage capacity is expected to be 5 MW and 15 MWh. Implementation of this NWA solution would ensure service to customers more regularly during outages experienced on the radial network. Please see the DER and NWA Locations section of this 2025 DSIP Update for further details.

Ticonderoga

Radial transmission supply and rugged terrain puts the Ticonderoga area at a higher risk of outages due to storms and other environmental factors while also making restoration more challenging and time consuming. National Grid has evaluated ESS solutions to improve reliability and resiliency for this area which would diminish the number of outages experienced by customers. Residential, customer-sited BTM storage was evaluated and deemed not to be preferable. In 2023 and 2024, the Company studied and began planning for a complex microgrid solution at multiple sites with the help of external consultants. This work suggested such a project could significantly reduce customer minutes interrupted while providing secondary benefits such as avoided impacts to the local environment. See next steps regarding the Ticonderoga area below under *Potential Energy Storage Projects Under Consideration*.

The Company has done extensive work within BTM energy storage projects within its ongoing programs and updates consistent with the Commission’s June 20, 2024 *Order Establishing Updated Energy Storage Goal and Deployment Policy*.⁴¹ These programs and pilot programs look to incentivize and integrate BTM storage to meet the State’s energy storage implantation goals and meet grid planning needs.

Auto-DLM

Since the issue of the 2018 Energy Storage Order, National Grid has successfully launched three Auto-DLM procurement events in 2020 through 2024 with an aggregate load relief opportunity of more than 45 MW across all events. The Company’s Auto-DLM program requirements are well suited to be met by the flexible dispatchability of ESS. National Grid has continued to design procurement opportunities so that resources can provide short-term load relief in areas with forecasted load growth prior to needing a more formal long-term solution. This could include an NWA solution where Auto-DLM resources could transition to being part of a potential NWA portfolio solution if the need persists without a cost-effective system infrastructure solution. For more details regarding National Grid’s plans and design of its Auto-DLM procurements, see Section 2.7, Energy Efficiency Integration and Innovation, of this 2025 DSIP Update.

Residential/Small-Medium Business Bring Your Own Battery Program

In the Company’s November 2023 Annual Report on DLM Programs, the Company proposed expanding the existing Direct Load Control (DLC) Program to include residential and small-medium business (SMB) ESS. In its March 15, 2024 *Order Directing Dynamic Load Management Program Changes*,⁴² the Commission directed the Company to provide additional detail regarding this proposed expansion, and the Company subsequently provided these additional details in the November 2024 Annual Report on DLM Programs. The Commission approved National Grid’s proposal to implement a DLC energy storage program in its April 25, 2025 *Order Addressing Dynamic Load Management Program Modifications*.⁴³ The Company has begun the process of developing and implementing this “Bring Your Own Battery” (BYOB) Program and anticipates launching the program before the end of summer 2025.

NYSERDA Storage Incentive Program

In the Updated Energy Storage Goal and Deployment Policy Order, the Commission approved a region-specific declining block retail storage incentive proposed in the Energy Storage Roadmap and directed NYSERDA to implement the program to procure 1,500 MWs of retail energy storage. The Commission also adopted the Energy Storage Roadmap recommendations to launch a statewide residential energy storage program with funding until 2030 to support the buildout of 200 MWs of residential energy storage across NY, with a minimum of 35 percent of funding dedicated to projects in DACs.

⁴¹ Energy Storage Proceeding, Order Establishing Updated Energy Storage Goal and Deployment Policy (issued June 20, 2024) (Updated Energy Storage Goal and Deployment Policy Order).

⁴² Case 14-E-0423, *Proceeding on Motion of the Commission to Develop Dynamic Load Management Programs* (DLM Proceeding), Order Directing Dynamic Load Management Program Changes (issued March 15, 2024).

⁴³ DLM Proceeding, Order Addressing Dynamic Load Management Program Modifications (issued April 25, 2025).

On August 19, 2024, NYSERDA filed its draft Residential and Retail Energy Storage Market Acceleration Incentives, 2024-2030 Implementation Plan (Implementation Plan)⁴⁴ which set forth the program goals and implementation strategies. The Implementation Plan includes program budget details, performance metrics, incentive structures, application requirements, DAC considerations, and the incorporation of recommendations from the Inter-Agency Fire Safety Working Group.

On February 14, 2025, the Commission approved the Implementation Plan with modifications.⁴⁵ The residential and retail MWh blocks offer fixed-rate incentives per kilowatt hour (kWh) of system energy capacity for grid-connected residential energy storage projects installed behind a residential meter. For retail customers, the approved plan designated the first block of incentives for a current incentive of \$175/kWh, decreasing to \$150/kWh in the next block, for service territories outside of New York City.⁴⁶

Incentives provided by the State are expected to drive additional investment in BTM energy storage in the National Grid's service territory, both among commercial and residential customers. To maximize impact, the Company aims to allow customers to stack the value of state incentives, utility programs, and wholesale market opportunities, where possible.

Building-to-Grid

The Three-Year Rate Plan Order in the National Grid Electric and Gas 2020 Rate Case Proceeding proposed a Building-to-Grid (B2G) project to develop B2G software, communications, and integration between grid management software, Building Automation Systems (BAS), and DER to actively manage the expected increased electrical load from electrification trends across the Company's customer base. The Company has conducted a demonstration project at a multifamily development in Rotterdam, NY, that involved manually coordinating dispatch of multiple DER types at the site. This project aimed to identify best practices to integrate buildings with BAS and DER to the grid in a way that serves building residents' needs, aligns with grid needs, and provides compensation to the building owner and tenants. The demonstration customer accessed benefits from participating in the B2G project including reduced demand charges through demand management protocols and revenue for providing distribution grid services.

Expanding from the B2G demonstration project above, a B2G pilot proposed in the National Grid Electric and Gas 2024 Rate Case Proceeding will engage additional all-electric multi-family and commercial new construction building owners with greater utility control of flexible BTM DER, including battery and thermal energy storage. This proposed B2G pilot would support more localized peak demand and hosting capacity constraints on the distribution network with minimal impact on tenant comfort or convenience. Signals sent from National Grid's DERMS would be

⁴⁴ Energy Storage Deployment Proceeding, New York State Energy Research and Development Authority Residential and Retail Energy Storage Market Acceleration Incentives 2024-2030 Implementation Plan (filed August 19, 2024).

⁴⁵ Energy Storage Deployment Proceeding, Order Approving Implementation Plan with Modifications (issued February 14, 2025).

⁴⁶ See <https://www.nyscda.ny.gov/All-Programs/Energy-Storage-Program/Developers-and-Contractors/Residential-and-Retail-Storage-Incentives/Retail-Incentive-Dashboard>

received by customer thermostats and ventilation controlled by BAS, as well as domestic hot water, battery energy storage, and EV chargers. Signals sent from edge-DERMS would automatically apply operational modes to groupings of on-site DER through telecom network hardware integrated with BAS and cloud-based internet-connected controllers. Customers would receive incentives for reserved flexible capacity and compensation for performing localized grid services. Future benefits to be tested in the B2G pilot include opportunities to earn wholesale market revenue from building-integrated solar and storage via the VDER value stack and reduced risk of outages from a more reliable grid.

In October 2024, National Grid partnered with NYSEERDA on a joint Electric Power Transmission and Distribution Future Grid Challenge (Program Opportunity Notice (PON) 4393) to support technical solution development for B2G. Two vendors will help the Company deploy gateway devices at a variety of commercial building types across the Company's service territory, with different metering configurations, BAS, and cloud-connected DER technologies. Contracting with awardees is expected to be completed in June 2025, resulting in automated dispatches of portfolios of DER at up to five geographically diverse sites.

Since the filing of the 2020 DSIP Update, the Company has developed and published its energy storage Hosting Capacity maps, available under the ESS Hosting Capacity tab,⁴⁷ to assist energy storage developers in identifying potential locations for energy storage investment and deployment.

As of December 31, 2024, the cumulative amount of energy storage capacity interconnected in National Grid's service territory is greater than 119 MW with a majority (greater than 95 percent) being energy storage projects co-located with generation (e.g., solar PV) compared to those that are standalone energy storage projects.

Interconnection Technical Working Group:

In collaboration with industry and DPS Staff, National Grid and the other Joint Utilities have formed an energy storage sub-group of the ITWG to facilitate energy storage interconnections for multiple use cases. The Company is a key participant in the energy storage subgroup which proposed interconnection process and study improvements including:

1. Proposed amendments to Appendix K (Energy Storage System Application Requirements) of the NY-SIR. The proposed edits included, among other changes, the ability for developers to specify the type of storage system being installed (Stand-alone, AC Coupled, DC Coupled), provide details on ancillary equipment and loads, and specify proposed charge and discharge schedules.
2. Consideration of operational windows for energy storage via specific time for charge and discharge capabilities, which will help developers maximize the economic value that BESS assets can accrue.

⁴⁷ Available at <https://systemdataportal.nationalgrid.com/NY/>

Additionally, National Grid, in conjunction with the other Joint Utilities, developed and proposed energy storage metering architectures for various system configurations such as DC coupled ESS paired with solar PV. The goal of the proposal was to guide developers on potential metering configurations based on their system characteristics.

On June 23, 2025, the Commission issued *Order Modifying Standardized Interconnection Requirements*⁴⁸ adopting the proposed changes to Appendix K of the NY-SIR.

Flexible Interconnections:

Leveraging learnings from National Grid's ARI Pilot that has deployed and operationalized flexible interconnection schemes for DG projects, the Company is also looking to carry over the concept and general approach to interconnection projects utilizing energy storage that can charge from the grid. Given that utility-scale energy storage projects that charge from the grid can greatly impact both generation hosting capacity and peak load, a flexible interconnection option could offer a more cost-effective, and timely interconnection.

Through the DOE Grid Resilience and Innovation Partnerships (GRIP) Program grant award, specifically for the Company's Future Grid Project and the funds that were awarded to National Grid by the DOE, National Grid plans to demonstrate flexible interconnection technology on energy storage projects that can charge from the grid and the ability of the Company to actively manage discharge and charge capabilities of such projects based on real-time system conditions.⁴⁹ The Company plans to investigate this concept at least with one project starting in FY26 before considering if the technology is ready to further offer beyond the initial demonstration. Additionally, the Company will evaluate how this offering would affect or coordinate with the ability for energy storage developers to opt for the Company's ESS scheduled discharge and charge windows that are also described in the DER Interconnection DSIP Section of this 2025 DSIP Update.

The Company also remains active in the discussions within IPWG and ITWG to consider flexible interconnection more broadly in New York and propose a framework that could be used to scale this application efficiently and beneficially. See Section 2.11, DER Interconnections, of this 2025 DSIP Update for more details.

External Collaboration

National Grid continues to prioritize external collaboration to accelerate deployment of energy storage and share learnings. Highlights since 2023 include efforts by and among the Joint Utilities, New York Battery and Energy Storage Technology Consortium, Inc. (NY-BEST), Alliance for Clean Energy New York (ACE-NY), and NYSERDA to contribute to advancing the recommendation in the Energy Storage Roadmap. Further, the Company collaborated with the

⁴⁸ Case 24-E-0621, *In the Matter of Modifications to the New York State Standardized Interconnection Requirements and Application Process for New Distributed Generators and/or Energy Storage Systems 5 MW or Less Connected in Parallel with Utility Distribution Systems* (In the Matter of NY-SIR Modifications), Order Modifying Standardized Interconnection Requirements (issued June 23, 2025) (June 2025 Order Modifying NY-SIR).

⁴⁹ See <https://www.energy.gov/gdo/grid-resilience-and-innovation-partnerships-grip-program-projects>

Joint Utilities and NYSERDA to advance the mission of the Advanced Technology Working Group (ATWG) task force, which had created draft reports such as the Unified Planning Guidelines to assist planning engineers in conducting T&D planning analysis of energy storage as part of the CGPP and the ongoing *Energy Storage Potential Study for Electric Transmission and Distribution Applications* (“Potential Study”). These efforts will continue through 2025, and National Grid is looking forward to working with stakeholders to shift from policy proposals to implementation.

NY Inter-Agency Fire Safety Working Group

In July 2023, Governor Kathy Hochul announced the establishment of an Inter-Agency Fire Safety Working Group (“Working Group”) to enhance the safety and security of ESS throughout the state, in response to fire incidents at facilities in NYS. National Grid participated in the NYS Fire Safety inspections for its two Company-owned BESS facilities at the North Troy and East Pulaski Substations, and addressed the findings noted during these inspections. The Working Group produced a Fire Code Recommendations Report that includes proposed fire code language reflecting their recommendations. The Company has reviewed the draft fire code updates and plans to monitor these updates and potential effects on future projects. In line with the Working Group's recommendations, the Company hosted BESS Fire Safety training sessions for local and mutual fire departments that would respond to emergencies regarding the BESS facilities at National Grid’s North Troy and East Pulaski Substations.

Software and Studies

In the past, the Company has utilized various tools to plan the use of energy storage supporting distribution needs. These tools include CYMDIST, EPRI’s Storage Value Estimation Tool (StorageVET® renamed DER-VET™), Quanta Technology’s Energy Storage Planning Tool, Siemens’ PSS®E software application, PSCAD’s software application, and internal evaluation methods and tools. National Grid is currently investigating tools to expand its ability to plan the use of ESS on the T&D system, including factors such as siting, cost estimating, economic analysis, and performance modeling, for both T&D use cases.

Information relevant to the siting of potential locations for ESS is also shared publicly on the Company’s System Data Portal. The ESS Hosting Capacity map provides developers with a locational representation of the grid’s ability to support potential ESS sites with respect to current grid constraints. This information can be helpful to developers who want to find locations where the grid can support interconnection with minimal system upgrade costs. More information about the ESS Hosting Capacity map, the data currently available on the map, as well as future plans for HCA, can be found in the Hosting Capacity section of this 2025 DSIP Update.

In 2023 and 2024, National Grid, with the help of consultants, conducted detailed studies on applications of energy storage as a transmission asset to provide non-market T&D services, specifically to deliver flexible transmission capacity and large-scale renewable enablement applications. One such study evaluated parts of the Company’s northern New York service territory and showed that storage as a transmission asset could enable the siting of large-scale renewables and mitigate renewable energy curtailment. The Company presented the study results to NYISO’s Installed Capacity / Market Issues Working Groups and other state and federal

stakeholders. This is one example of how energy storage could be integrated into state planning processes seeking to achieve CLCPA goals, such as CGPP.

Additionally, National Grid has engaged consultants to study specific use cases to better understand the potential for energy storage projects to provide non-market T&D services, identify discrete projects, and quantify benefits and costs of such projects. Potential applications include delivering reliability and resiliency benefits and supporting New York's CLCPA goals.

The Company, and a consultant engaged by National Grid, completed studies that evaluated the uses of mobile storage, and, importantly, design considerations that provide optionality and consider the affordability of future redeployment in support of the mobile storage units included in National Grid's Urgent Upgrade Projects filing with the Commission.⁵⁰ The Commission's June 12, 2025 *Order Addressing Urgent Upgrade Filings*⁵¹ approved 22 projects proposed by the Company supporting building electrification and EV charging, including mobile battery storage.

Forecasting Energy Storage

To capture the growing impact of energy storage deployments connecting to the distribution system over the next several years, the Company understands the importance of modeling the impact of energy storage as an input to many business processes including how it conducts integrated system planning. Currently, National Grid's internal forecast assumptions include the implementation of energy storage across the Company's distribution network. This same forecast is used to study and plan for NWA or utility-owned energy storage assumptions. Please refer to Section 2.2 of this 2025 DSIP Update for more details regarding the Company's forecasting progress and next steps.

Currently, National Grid's long-term forecast is aligned with the Energy Storage Roadmap. Assumptions derived from this forecast and the Energy Storage Roadmap (e.g., marginal costs, utilization factor, round trip efficiency, etc.) have been utilized to inform capacity expansion modeling through the CGPP, resulting in a robust and scenario-dependent energy storage buildout. Load impacts at the local level from energy storage were developed that considers peak reducing and solar PV-paired schedules. Please refer to the Peak Report for detailed discussions.

Future Implementation and Planning

National Grid has significant plans to continue the exploration, integration, and use of energy storage on the distribution system.

Potential Study for Energy Storage to Support T&D

The Company is an active member of the ATWG and is collaborating with NYSERDA and the other Joint Utilities to study the potential for energy storage to be integrated with and support the needs of utility T&D systems, as recommended within the Energy Storage Roadmap. The study offers information regarding potential energy storage applications and context for techno-

⁵⁰ Proactive Planning Proceeding, National Grid Urgent Upgrade Projects (filed November 13, 2024) (National Grid Urgent Upgrade Projects Filing).

⁵¹ Proactive Planning Proceeding, Urgent Upgrade Filings Order.

economic evaluation. Building on the findings of this study, National Grid will conduct an in-depth analysis for individual projects. Not only is energy storage anticipated to experience significant growth in deployment over the next few years and beyond 2030, but additionally utility T&D systems are expected to see substantial load growth from greater demands for electrification. The will further support the Energy Storage Potential Study and the goals of the CGPP. National Grid also anticipates further investigation of the capabilities and potential uses of long-duration energy storage through both the ATWG and through this potential study, including how long-duration energy storage can be incorporated into integrated T&D planning.

Energy Storage Study Supporting Fleet Electrification

National Grid has worked with stakeholders and consultants to directionally forecast charging demand for transportation electrification in its service territory, including the Company's Electric Highways Study. In 2023, the Company led a DOE funded effort to study and write a regional plan for MHDV highway charging in NY, NJ, PA and NE and intends to, in a NY-focused effort, evaluate the ability of the transmission grid in specific locations to support charging needs over the next twenty years and identify potential solutions, including energy storage. Additionally, leveraging recent study efforts, National Grid has developed bridge to wires solutions to procure and interconnect mobile storage units for use of load relief until long-term, conventional upgrades can be built to support increased loading and interconnections. These bridge-to-wire solutions were included within the National Grid Electric and Gas 2024 Rate Case Proceeding and incorporating feedback from DPS Staff, within the National Grid Urgent Upgrade Projects Filing. Locations are still being finalized, along with specific points of interconnection. After mobile battery units are no longer needed for the initial use case, the units will be transferred to another planning location. Duration of the initial use is tied to the completion of long-term solutions. Although the next set of locations and planning use cases have not yet been determined, the Company expects there will continue to be a need for additional bridge to wires solutions at other locations in National Grid's service territory. Additionally, the response to the NYSERDA Vehicle Grid Integration Program (PON 5354) solicitation that the Company and its partners developed in September 2024 is currently being evaluated. If the response is selected and early milestones are met, the partnership would provide the Company an opportunity to enhance capabilities to support transportation electrification with mobile energy storage. There will be further continuing evaluation of energy storage for the support of transportation electrification under specified studies and the Proactive Planning Long-Term Framework.

Proactive Planning Proceeding

The National Grid Urgent Upgrade Projects Filing in the Proactive Planning Proceeding was followed by the Joint Utilities' Long-term Proactive Planning Framework.⁵² In both filings, energy storage was identified as an option to meet interim and long-term planning needs, including support for fleet electrification. The Commission approved 22 National Grid projects supporting building electrification and EV charging, including a mobile energy storage program, in its June 12, 2025 *Order Addressing Urgent Upgrade Filings*.⁵³ Further evaluation will continue to proceed with further development of the long-term planning framework in alignment with the CGPP. The

⁵² Proactive Planning Proceeding, Joint Utilities' Long-Term Proactive Planning Framework (filed December 13, 2024) (Long-Term Proactive Planning Framework).

⁵³ Proactive Planning Proceeding, Urgent Upgrade Filings Order.

Company will continue to evaluate the use of energy storage projects in future project filings under the Proactive Planning Proceeding.

Potential Energy Storage Projects Under Consideration

Ticonderoga

In 2023 and 2024, National Grid evaluated the potential of DOE cost sharing for a complex multi-site microgrid through the GRIP program to enhance grid flexibility and improve the resilience of the power system against extreme weather by accelerating the deployment of transformative projects. After much consideration, the Company elected not to submit a funding application. However, as the challenge still exists in the area under consideration, National Grid has begun to evaluate microgrid solutions on a more simplified scale.

Rate Case Projects

The National Grid Electric and Gas 2024 Rate Case Proceeding proposed five energy storage projects for a total of 43 MW to support planning constraints within the Company's service territory that it seeks to progress in the future. These proposed projects look to integrate energy storage into the existing distribution architecture and support real-time power quality and thermal constraints. These proposed energy storage projects are located at the Akwesasne, North Lakeville, Sherman, Gilmantown, and Kenmore Stations. These five energy storage projects are still in the scope development and planning phases. The Company will continue to develop these projects through initial design, procurement, and construction over the next five-year horizon. Although the Company initially included three mobile battery units in the National Grid Electric and Gas 2024 Rate Case Proceeding, these projects were subsequently transitioned into the National Grid Urgent Upgrade Projects Filing and were approved by the Commission in the June 12, 2025 *Order Addressing Urgent Upgrade Filings*.

Future NWA Procurements

National Grid looks to continue reviewing and soliciting procurement opportunities for siting energy storage on local distribution networks where beneficial and feasible. Procurement opportunities would include developer-owned storage opportunities, agnostic to FTM or BTM, that may be utilized for flexibility opportunities. The Company continues to update its approach for procurement options so as to increase the number of procurements to better incentivize the market while achieving a higher penetration of energy storage interconnections within its service territory. National Grid seeks to continue increasing the number of bids received for energy storage annually over the next five years. The Company has recently released its updated NWA products Request for Proposals comprised of NWA Secure Service and NWA Sustain Service procurements to provide additional opportunities for developers to participate in NWA markets with less barriers to entry. For additional future implementation plans, please see Section 2.13 regarding Beneficial Locations for DER and NWA of this 2025 DSIP Update.

Auto-DLM

In the Commission's November 19, 2024 *Order Adopting Modifications to Dynamic Load Management Program Procurements*,⁵⁴ National Grid's proposal to expand Term-DLM and Auto-DLM procurement methodologies to include a fixed, published price model was approved. For the 2026 Auto-DLM Vintage Year, the Company implemented this fixed, published price methodology. As a result of the shift to the published price methodology, the Company saw an increased level of interest and participation in the Auto-DLM program, including a significant increase in the level of interest from FTM energy storage developers, rather than the traditional BTM DER aggregators. National Grid will continue to evaluate the results achieved in the Auto-DLM program, continue to offer procurement opportunities, and solicit stakeholder feedback to drive improvements in the Auto-DLM program to increase participation. Annual solicitations for procurements and assessment of new opportunities will continue to be included.

Building-to-Grid Pilot

The Company's incentives offered in the B2G pilot for reservation of flexible capacity at constrained locations on the grid are anticipated to encourage customers and developers to consider installation of energy storage at their grid-interactive building sites. New incentives will be available for reserving flexible capacity and performing localized peak shaving grid services when dispatched based on short-term forecast constraints. National Grid aims to learn about overcoming barriers to adoption and facilitate economic operation of BTM energy storage through grid DERMS. One multifamily gut renovation pilot site in the City of Buffalo plans to electrify all HVAC loads and add new Electric Vehicle Supply Equipment (EVSE), and has received NYSERDA Future Grid Challenge funding to install a 750 kW BTM BESS. Dispatch of combined site flexible capacity will be enabled through automated grid-responsive controls to signals from DERMS by 2027.

Low-and-Moderate Income Battery Virtual Power Plant Pilot

In its testimony in the National Grid Electric and Gas 2024 Rate Case Proceeding, the Company proposed a pilot consisting of third-party owned battery systems for low- and moderate-income (LMI) residential customers on constrained feeders with poor outage metrics. The aggregated storage capacity would be utilized as a VPP to meet a deferral NWA planning need for up to 10 years. DPS Staff raised several concerns via Information Requests which the Company responded to with pilot design clarifications. Ultimately, DPS Staff's rebuttal testimony argued for moving the proposal to the GOTF Proceeding. The Company is actively considering options for pilots to formally propose in the GOTF Proceeding, including the LMI Battery VPP Pilot.

⁵⁴ Energy Storage Proceeding, Order Approving Modifications to Dynamic Load Management Program Procurements (issued November 19, 2024) (November 2024 Order Approving DLM Program Procurement Modifications).

Battery Health Management Pilot

National Grid is executing a pilot on the ESS at the East Pulaski distribution substation to support battery health management so as to unlock the full potential of its energy storage assets by deploying monitoring algorithms. This pilot will use these algorithms to maximize uptime, reducing unplanned downtime, and deliver rack-level insights to correct imbalances before they cause problems. This pilot aims to then start live monitoring of the ESS while it conducts market operations through FY27, delivering insights and recommendations to improve performance for primary peak-shaving operations and secondary market operations. Following an evaluation period, this battery health management solution may be recommended for deployment on BESS installations at North Troy, Watertown, and Pine Grove, and other future sites where a BESS may be subsequently installed.

Expanding Capabilities in Developing and Operating Energy Storage Projects

The Company is evaluating appropriate steps to take this year to accelerate internal readiness and expand capabilities in developing, procuring, operating, and maintaining energy storage projects to deliver benefits to customers and support New York's energy storage goals. National Grid is learning from utility best practices in this space and actively engaging with customers, developers, manufacturers, and other industry experts to expand the Company's capabilities and develop opportunities for collaboration.

Guidelines for both planning and operations look to be further developed to integrate energy storage into the Company's business practices. Such guidelines and documentation look to ensure both industry and state code requirements are appropriately implemented over the lifespan of an ESS to provide safe and reliable service to customers. Further development of such guidelines seek to achieve alignment with standards currently shared externally, such as National Grid's Electric System Bulletin No. 756 (ESB-756), which is the standard requirement for parallel generation interconnection on the Company's distribution network.

External Collaboration

In response to the Updated Energy Storage Goal and Deployment Policy Order, the Company has collaborated with the Joint Utilities to study non-market use cases for T&D storage. The study included an in-depth engineering analysis and economic framework, a description of how planning and operating procedures would be modified to incorporate storage, and a proposal for a review, approval, and cost recovery mechanism. The resulting Joint Utilities' study was filed with the Commission in October 2024⁵⁵ with parties' initial comments filed in February 2025 and parties' reply comments filed in April 2025.

Collaboration among the Joint Utilities and other parties across various working groups, such as the ATWG and ITWG, will be ongoing to develop implementation plans to assist the ES industry in delivering the 2030 energy storage goals. Collaboration with the energy storage developers, equipment manufacturers, and outreach to utility communities that host energy storage assets,

⁵⁵ Energy Storage Proceeding, Joint Utilities' Study of Non-Market Transmission and Distribution Energy Storage Energy Storage Use Cases and Related Process Proposals (filed October 29, 2024).

while already important today, will become increasingly vital to ensure safe and reliable operation as more and larger scale energy storage is deployed. Additionally, National Grid plans to enhance its standard operating procedures training program for local and county level first responders to ensure access to training to safely identify and respond to incidents related to energy storage.

Collaboration with the ATWG's Energy Storage Subcommittee (ESSC), which includes members from DPS Staff, NYSERDA, NY-BEST, and the Joint Utilities, is ongoing. The ESSC has developed a draft of Unified Planning Guidelines for energy storage resources supporting electric T&D in New York to explore issues such as representing energy storage in power flow models, characterizing grid needs and the applicability of T&D energy storage, and considerations for economic and cost assumptions. The ESSC is also supporting the Energy Storage Potential Study for Electric Transmission and Distribution Applications in NYS offering information regarding storage applications and context for techno-economic evaluation. National Grid and the other utility members will require in-depth analyses for individual projects based on their respective service territories and applications. The ESSC has also proposed a study focused on qualifying and quantifying the potential for energy storage and clean generation technologies at the regional level, considering factors such as land availability, permitting requirements, constructability, and other relevant factors.

Collaboration with NY-BEST and its members is ongoing. The collaboration is intended to provide a mutual understanding of the priorities of the parties and to address areas of opportunities to work together, remove barriers, and foster understanding of topics related to the growth of energy storage in NY.

Collaboration with NYSERDA is ongoing and is intended to discuss energy storage topics that are of relevance to both parties such as ATWG, CGPP, and Proactive Planning.

Forecasting Energy Storage

National Grid plans to continue refining energy storage scenarios for forecasting by keeping up to date with state policies and market studies. The Company will also continue monitoring further information such as metered data and regulations on storage operation as it becomes available and useful in studying load impact profiles. Further information on future implementation regarding forecasting strategy may be found in Section 2.2 of this 2025 DSIP Update.

Energy Storage Integration into Energy Efficiency and Demand Response

National Grid is supportive of the proposed retail and residential storage targets and recognizes BTM storage deployment will need to scale up in order to meet these targets. The Company supports utility involvement that can spur market development. In the implementation process for the most recent Storage Order, the utilities will support NYSERDA's Residential and Retail Energy Storage Market Acceleration for BTM and FTM deployment, including through NWA opportunities and ease of interconnection process.

National Grid recognizes that the expanded IRA investment tax credit for standalone storage in addition to potential retail and residential incentives may change the value proposition for BTM storage for customers and developers and drive increased adoption of storage assets in NY. The Company sees an opportunity to maximize the value of residential storage systems, whether

through existing DLM program offerings or through a new DLM participation model designed for residential storage systems.

National Grid began its 4-year deployment of AMI in 2023 (see AMI Section 2.12 of this 2025 DSIP Update for more detail). When AMI meters have been deployed, customers will have access to more granular, disaggregated energy usage data that will allow them greater visibility, choice, and control in how they respond to load-reducing or load-shifting signals from existing DR programs, future DR programs, and/or future time-varying rates. Those opportunities will further drive the customer value case for energy storage. The Company is exploring potential pilot and program designs to utilize storage and other BTM DERs to address more targeted, dynamic grid needs.

National Grid is also looking at the potential impact smaller-scale storage will have when able to participate in wholesale markets through FERC 2222. One way the Company is encouraging more storage through aggregator participation is by posting NWA and DLM opportunities on Piclo Flex, a global marketplace provider for flexibility services. National Grid entered into a pilot agreement with Piclo Flex in 2022 to deliver an independent marketplace that widens and streamlines participation for all types of DERs capable of providing flexibility services.

Risks and Mitigation

Table 2.4.1 Risks and Mitigations

Risk	Mitigation
Delay in returning East Pulaski and North Troy BESS projects back to service	Improve asset monitoring, IT, and maintenance plans working closely with BESS vendors and O&M providers.
Supply chain challenges impacting ESS procurement and delaying project timelines	Work closely with project vendors in monitoring supply chain issues and project schedules, and negotiating liquidated damages for shipment delays.
Public pushback due to safety concerns provided by community residents and municipalities	Actively work with community residents and local leaders to ensure concerns are addressed in siting, design, construction, interconnection, operation, and maintenance of any energy storage unit.
Studies focused on energy storage use cases do not result in new or feasible use cases	Refocus efforts on improving existing use cases for energy storage and interconnection of energy storage to help bolster energy storage deployment to achieve closer to the 6 GW goal by 2030.

Alignment with CLCPA Goals

National Grid's implementation plans for advancing energy storage align with the goals of the CLCPA in two ways: advancing the method to interconnect energy storage onto the system and progressing how energy storage can be integrated into serving the needs of the grid. These two implementation categories will facilitate growing the deployment of energy storage and driving the benefits that those ESS can provide to offset other system needs while delivering value to customers.

The CGPP aims to identify the transmission upgrades needed to support the CLCPA goal of achieving a zero-emissions electricity system by 2040. In support of the CGPP, National Grid has coordinated with the ATWG ESSC to develop the Unified Planning Guidelines for Energy Storage Resources Supporting Electric Transmission and Distribution in New York to explore issues such as representing energy storage in power flow models, characterizing grid needs and the applicability of T&D energy storage, and considerations for economic and cost assumptions. The ESSC has also proposed a study focused on qualifying and quantifying the potential for energy storage and clean generation technologies at the regional level, considering factors such as land availability, permitting requirements, constructability, and other relevant factors to serve as an input to the CGPP. This will ensure that not only is energy storage included in CGPP models at levels commensurate with policy achievement (i.e., Net Zero by 2040), but also that planners have the information needed to consider energy storage as tool for enabling renewable deliverability throughout this study.

As discussed above, numerous efforts are underway to improve the interconnection experience and feasibility of energy storage through efforts in the IPWG, ITWG and ATWG. National Grid's Energy Storage Hosting Capacity maps drive further data transparency that can aid energy storage developers to efficiently site energy storage facilities in areas that have available system capacity. The Company's interconnection process for energy storage continues to improve the data used for interconnection studies as well as investigate steps to better study energy storage effectively. More flexible interconnection options, such as incorporating flexible operating limits to mitigate exacerbating system constraints, can lead to lower interconnection costs, rather than assuming that energy storage can charge and discharge at its maximum nameplate capability during all hours of the day and year. All of these efforts must be carefully planned and incorporated in order to ensure they do not compromise system reliability or safety or result in unduly increasing customer costs.

Increased deployment of energy storage can aid in furthering CLCPA goals if utilized effectively to support system needs. Energy storage can be an extremely flexible and dispatchable energy resource and therefore can be used to optimize system capacity utilization, provide reliability services, and bolster system resiliency as NWA assets or energy storage integrated as T&D assets. Pine Grove, Watertown, and proposed energy storage projects are early examples of how the Company has explored effective use of energy storage to support grid needs. The Company continues to exercise its integrated planning process to identify additional opportunities where energy storage could be utilized cost effectively as a grid asset. These uses of energy storage to support transmission needs are especially being investigated through the Company's CLCPA efforts and through the energy storage task force supported under the ATWG. The Company

anticipates the outcome of the ATWG Energy Storage Potential Study to inform CGPP in how to effectively utilize energy storage as a solution to address T&D needs, similar to other technological solutions such as dynamic line ratings (DLR) and power flow control (PFC), which are also being reviewed by the ATWG. National Grid is also considering what ongoing resources (e.g., contract management, O&M) will be needed to support these energy storage assets, whether they are Company-owned or third party-owned, through the duration it is being used to support grid needs.

National Grid continues to collaborate with the other Joint Utilities, as well as NYSERDA and DPS Staff, particularly in support of state policy goals and programs such as the Energy Storage Roadmap targeting 6 GW of energy storage deployment. The Joint Utilities recently filed the Joint Utilities' Study of Non-Market Transmission and Distribution Energy Storage Energy Storage Use Cases and Related Process Proposals with the Commission. The Company also engages the energy storage developer stakeholder community through various forums such as ITWG and IPWG, program opportunities facilitated by NYSERDA, engagement with NY-BEST, and other industry associations including EPRI and Centre for Energy Advancement through Technological Innovation Inc. (CEATI). Recently, ESSC has been established to continue the work under the Energy Storage Task Force, which was a sub-group under the ATWG in supporting efforts required for informing the CGPP. Information regarding energy storage hosting capacity and NWA opportunities for energy storage are also available on National Grid's System Data Portal for stakeholders.

The aforementioned stakeholder working groups also have individual goals and timelines to best develop and implement energy storage for residential and commercial customers. However, each of these goals are looking to be in support, either directly or indirectly, of NYS's goals of net zero decarbonization by 2040. In addition, National Grid looks to further incentivize the market and allow customers and developers to participate further in meeting the planning needs of their local network. Stakeholder engagement ensures that the Company can continually expand its opportunities to customers to participate and lower the barrier to entry into participation into energy storage programs and market opportunities. Through the rollout of new opportunities as mentioned previously, National Grid can further engage with stakeholders to best meet the needs of the DER developers as well as residential, and commercial customer groups.

2.5 Electric Vehicle Integration

Context and Background

The goal of the utility transportation electrification programs is to deploy an EV charging network across NYS that could support 850,000 light-duty zero emissions vehicles (ZEVs), consistent with the 2013 ZEV Memorandum of Understanding (MOU).⁵⁶ In July 2020, New York was a signatory to the Multi-State MHD ZEV MOU which set a mutual goal for all signatories to ensure that 100 percent of all new MHD vehicle sales will be ZEVs by 2050, with an interim target of 30 percent MHD ZEV sales by 2030.⁵⁷

In September 2021, NYS signed into law NYS Senate Bill 2758/Assembly Bill 4302 that targets 100 percent of new LDV sales to be ZEV by 2035.⁵⁸ Additionally, this legislation amended the NYS environmental conservation law to include a goal that 100 percent of in-state sales of MHD vehicles be ZEVs by 2045.

In April 2022, Governor Hochul passed a statewide zero-emission school bus mandate, requiring all new school bus purchases starting in 2027 to be zero-emission, with 100 percent electric school buses by 2035.

On September 29, 2022, Governor Hochul announced that NYS would promulgate a regulatory process to adopt California's Advanced Clean Cars II regulations, which sets goals for ZEV adoption as a share of new vehicle sales starting at 35 percent for model years 2025 and scaling to 100 percent by 2035. Over the longer term, this will help accelerate activity beyond the already ambitious 2025 targets from the 2013 ZEV MOU and require greater investment in EV charging infrastructure.

In April 2023, Governor Hochul announced the NYS proceeding to implement policies and develop programs related to MHDV charging infrastructure. This proceeding supports New York's existing electrification efforts by addressing the electrification needs of the State's MHDV sector. Included in this proceeding is the MHD Grid Impact and Investment Study, focusing on barriers to electrification, including vehicle availability, tradeoffs between fuel cell and plug-in vehicles, and infrastructure costs and available incentives.

⁵⁶ The ZEV MOU was signed by California, Connecticut, Maine, Maryland, Massachusetts, New Jersey, New York, Oregon, Rhode Island, and Vermont to work together through a multi-state ZEV Program Implementation Task Force to develop an action plan with priority actions for deployment of ZEVs.

⁵⁷ Fifteen other states and the District of Columbia are signatories to the Multi-State MHD ZEV MOU.

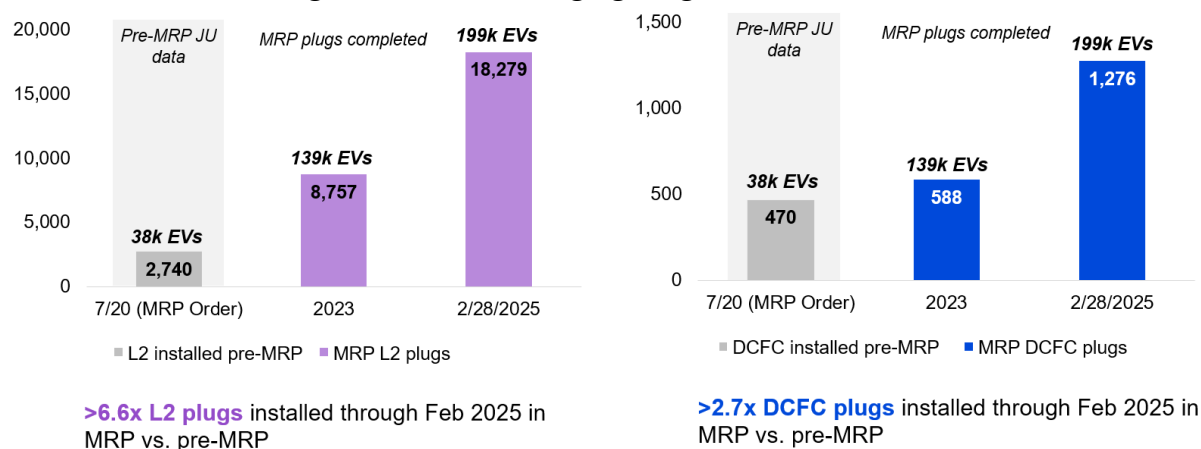
⁵⁸ Zero-Emissions Cars and Trucks Act, N.Y. Env'tl. Conserv. Law § 19-0306-B (added by L. 2021, ch. 66, § 1).

In August 2024, the Commission commenced the Proactive Planning Proceeding, directing the Joint Utilities to develop a framework for planning for future infrastructure needs driven by transportation and building electrification. The Commission directed the Joint Utilities to file a proposal for a long-term coordinated planning process that will address increased expected electrification loads. In response to this Commission directive, the Long-Term Proactive Planning Framework was filed by the Joint Utilities on December 13, 2024.

High-level Market Overview of NY EV Landscape

As of February 2025, more than 275,000 registered EVs are on the road in New York.⁵⁹ The investment from the Joint Utilities in the MRP has contributed to more than 667 percent growth of Level 2 (L2) plugs and more than 271 percent growth of DCFC ports in NYS since the Commission issued the MRP Order on July 16, 2020.⁶⁰ Since 2023, MRP investments have increased L2 plugs by 9,522 and DCFC plugs by 688. The Joint Utilities presented the following graphics, in a MRP Review Webinar held on March 25, 2025, illustrating the growth in EV charging plugs throughout the state:⁶¹

Figure 2.5.1: EV Charging Plug Growth in New York



Federal Policies

Federal policies have also dramatically shaped the EV sector in New York, with many initiatives supporting LDV and MHDV market adoption. The Federal Highway Administration's National Electric Vehicle Infrastructure Formula Program supports DCFC highway corridors across the country. The IRA includes a set of provisions for the supply chains for clean vehicles, including LDV tax credits, used EV tax credits, commercial EV tax credits, EVSE tax credits, and support for replacing heavy-duty vehicles. In addition, the U.S. Environmental Protection Agency's Clean

⁵⁹ See Atlas Public Policy, available at <https://www.atlasevhub.com/market-data/state-ev-registration-data/>

⁶⁰ Case 18-E-0138, *Proceeding on Motion of the Commission Regarding Electric Vehicle Supply Equipment and Infrastructure* (EVSE Proceeding), Order Establishing Electric Vehicle Infrastructure Make-Ready Program and Other Programs (issued July 16, 2020) (MRP Order).

⁶¹ See EVSE Proceeding, 2025 Make-Ready Program & Load Management Technology Incentive Program Review Kickoff Presentation (dated March 25, 2025), Slide 11.

School Bus Program supports the procurement of electric school buses and associated charging equipment.

Implementation Plan, Schedule, and Investments

Current Progress

Infrastructure Programs

Make-Ready Program

The MRP supports stakeholders' needs for EV charging in public, workplace, and multi-unit dwellings to accommodate an increased deployment of EVs within NYS by reducing the up-front costs of building EV charging stations. The Make-Ready incentive offsets a large portion of, or in some cases, all, of the infrastructure costs associated with preparing a site for EV charger installation.

The Commission's November 16, 2023 *Order Approving Midpoint Review Whitepaper's Recommendations with Modifications* (Midpoint Order)⁶² marked the conclusion of a year-long midpoint review of the MRP, throughout which extensive stakeholder engagement, comment periods, and technical conferences were held to inform the Midpoint Order. The Midpoint Order adjusted the plug targets, baseline incentives, and reporting requirements for all the utilities from their original values to the ones that would apply through the remainder of the programs through 2025. The Midpoint Order also established required communication standards for chargers to improve interoperability and communication capabilities. These requirements aim to ensure a positive charging experience for EV drivers and minimize the risk of stranded assets.

Current utility program stats:

- As of the end of April 2025, National has supported 5,263 L2 plugs and 543 DCFC plugs through the MRP. Throughout the state, the implementation of the program has increased L2 plugs in the state by 18,928 and DCFC plugs in the state by 1,328, outpacing the demand for charging based on EV registrations. Being ahead of the market in this way ensures that the current implementation will continue to support stakeholders' future needs.

MHDV Make-Ready Pilot

The Midpoint Order also authorized updates to other charging infrastructure pilot programs. The MHDV Make-Ready Pilot was revised to offer an incentive of 50 percent of customer-side costs in addition to the incentive for 90 percent of utility-side costs for certain eligible projects. This additional incentive makes the MHDV Make-Ready Pilot more accessible to more customers.

The MHDV Make-Ready Pilot, and other future full-scale successor programs, will be important factors in stakeholders' ability to meet the aggressive policy mandates for MHDV and school bus electrification before 2035. The MHDV Make-Ready Pilot's primary objective is to reduce diesel

⁶² EVSE Proceeding, Order Approving Midpoint Review Whitepaper's Recommendations with Modifications (issued November 16, 2023) (Midpoint Order).

emissions within DACs, so decreasing barriers to electrification for entities that serve DACs not only supports the needs of the stakeholders owning and operating MHDV fleets, but also the communities throughout the state that are impacted by air quality issues.

In addition, the Fleet Assessment offering included in the MHDV Make-Ready Pilot will continue to support fleets in their electrification journey by evaluating current fleets and recommending vehicles and transition timelines.

As of March 2025, National Grid's MHDV Pilot has activated 26 plugs at 3 make-ready projects and completed 292 fleet assessments for a variety of fleets throughout the state, assessing more than 10,000 vehicles for electrification.

Transit Authority Pilot

National Grid has supported electrification projects for the two transit authorities in its jurisdiction – Niagara Frontier Transit Authority in Buffalo, and the Capital District Transit Authority in Albany. These two projects have enabled 14 electric buses, as well as infrastructure for an additional 138 buses.

Micromobility Pilot

As part of the MRP, NYSERDA is responsible for administering the Micromobility Pilot for upstate New York. In March of 2025, NYSERDA released a status report of that program,⁶³ which summarized their first year of implementation. The first year included the results of the NYSERDA Clean Mobility Program (PON 5739) in 2024, which awarded 29 planning awards, 12 of which are upstate communities planning for micromobility. Of the 12 projects awarded for micromobility in upstate New York, 8 were in the National Grid service territory. Plans should be completed in the summer of 2025 and NYSERDA expects that many of these awardees may apply for demonstration funds via Round 2 of the program in the fall of 2025.

Load Management Technology Incentive Program

The Commission's August 19, 2024 *Order Establishing Load Management Technology Incentive Programs*⁶⁴ approved the Joint Utilities' proposal to repurpose the unused funds from the subset DCFC PPI program to offer incentives for load management technology for EV charging projects that are funded through other utility programs. The requirement for the development of a Load Management Technology Implementation Plan (LMTIP) by utility, which launched in November 2024, encourages installation of load management equipment, including on-site energy storage equipment, energy storage-integrated EVSE, load management software, and load management hardware.

Load management helps customers manage the costs of providing EV charging and eases strain on the grid. The increased grid resilience provided by load management activities is crucial for meeting the increased energy demands of a growing number of EVs on the road in the future.

⁶³ EVSE Proceeding, New York State Energy Research and Development Authority, Upstate Micromobility Implementation Plan Status Report (filed March 31, 2025).

⁶⁴ Case 22-E-0236, *Proceeding to Establish Alternatives to Traditional Demand-Based Rate Structures for Commercial Electric Vehicle Charging* (EV Solution Proceeding), Order Establishing Load Management Technology Incentive Programs (issued August 19, 2024).

As of March 2025, National Grid's LMTIP has committed to support 35 projects.

Operating Cost Relief Programs

DCFC PPI Program

As of March 2023, the DCFC PPI program stopped accepting applications in accordance with the Commission's January 19, 2023 *Order Establishing Framework for Alternatives to Traditional Demand-Based Rate Structures*.⁶⁵ Participants were given the option to stay enrolled for the remainder of the program or to switch to the Demand Charge Rebate. Most utilities had all PPI participants switch programs. As of March 2025, National Grid had paid \$807,674 in rebates, with 110 plugs enrolled.

Demand Charge Rebate

The Demand Charge Rebate was approved in the Commission's November 20, 2023 *Order Implementing Immediate Solutions Programs*.⁶⁶ With this approval, utilities launched commercial managed charging programs to provide a tiered, load factor-based discount on demand charges, meeting stakeholders needs by significantly reducing the operating costs for owners of EV charging stations, thereby reducing a significant barrier to EV charging operation. As of March 2025, National Grid has 50 sites enrolled or pending review in the Demand Charge Rebate program.

Time of Use Rates

As described in the Commission's October 17, 2024 *Order Implementing Electric Vehicle Charging Rates for Commercial Vehicles*,⁶⁷ National Grid is currently developing the processes and billing system changes necessary to launch the EV Phase-In-Rate in the fall of 2025. This EV Phase-In-Rate will benefit EV sites with customers, particularly those with low utilization (load factor), by offering a tiered demand charge. The rate reduces demand charges while offsetting with an additional energy charge in order to reduce electricity bills for EV charging station site hosts.

Commercial Managed Charging Program

The Commercial Managed Charging Program is designed to incentivize customers to shift EV charging load from on-peak hours to off-peak hours with a peak avoidance incentive. This program is awaiting a Commission order, with an anticipated launch date in late 2025 or 2026.

Residential Managed Charging Program

The Residential Managed Charging Programs authorized by the Commission's July 2022 *Order Authorizing Managed Charging Programs with Modifications*⁶⁸ offer participating customers

⁶⁵ EV Solution Proceeding, Order Establishing Framework for Alternatives to Traditional Demand-Based Rate Structures (issued January 19, 2023).

⁶⁶ EV Solution Proceeding, Order Implementing Immediate Solutions Programs (issued November 20, 2023).

⁶⁷ EV Solution Proceeding, Order Implementing Electric Vehicle Charging Rates for Commercial Vehicles (issued October 17, 2024).

⁶⁸ EVSE Proceeding, Order Approving Managed Charging Programs with Modifications (issued July 14, 2022).

incentives for charging at off-peak hours. The managed charging programs support stakeholders by incentivizing grid-beneficial behavior. In the future, as electrical demand related to EV charging increases, grid resilience will become more important. In addition, these programs lay the groundwork for possible future programs for active load control to further support grid flexibility. As of March 2025, National Grid has 1,789 enrolled customers and 1,949 vehicle integrations participating in its Residential Managed Charging Program.

Future Implementation and Planning

With many program milestones occurring in 2025, the utilities are looking forward by planning for successors to the existing programs and taking all necessary regulatory steps (informed by stakeholder feedback and program learnings) to ensure continued and improved support for EV charging.

Infrastructure Programs

Make-Ready Program

The MRP ends in 2025. The end-of-program review commenced in March with a stakeholder webinar, and over the course of the review period, feedback from the Joint Utilities, industry stakeholders, interest groups, and government entities will inform the next steps for a future of funding EV charging in New York through 2030 and beyond.

The Joint Utilities' experiences in the first five years of the MRP, and especially since the Midpoint Order, indicates that utility support and investment remain necessary for the industry to progress.

To address short-term continuity and progress, the Joint Utilities have filed a petition to continue to fund Make-Ready projects with unspent funds should the program review not conclude until after the program end date of December 31, 2025.⁶⁹ If this request is granted by the Commission, the utilities will be able to temporarily avoid a funding gap in the market if a successor program is not authorized immediately upon the conclusion of the MRP. At the conclusion of any interim funding period, further investment will be needed from the utilities to continue the market momentum.

Load Management Technology Incentive Program

The MRP review will also assess the LMTIPs, evaluating the implementation to date and determining whether they should be re-authorized with additional funds.

Medium- and Heavy-Duty Program

A forthcoming Commission order in Case 23-E-0070⁷⁰ is expected to authorize a full-scale medium- and heavy-duty (MHD) program to replace the MHD Pilot and continue to meet MHDV stakeholders' needs beyond 2030. Significantly increased investment is needed to advance to a

⁶⁹ EVSE Proceeding, Joint Utilities' Petition to Continue Make-Ready Program Funding During the Program Review Period (filed February 24, 2025) (Joint Utilities' Petition to Continue MRP Funding).

⁷⁰ Case 23-E-0070, *Proceeding on Motion of the Commission to Address Barriers to Medium- and Heavy-Duty Electric Vehicle Charging Infrastructure* (MHD Proceeding).

full-scale deployment of MHD charging infrastructure, and the program that will replace the MHD Pilot should use the learnings from that Pilot to offer incentives with fewer restrictions to use.

The work needed to progress from the current MHD Pilot to the full-scale program should include significant input from the Joint Utilities and stakeholders to ensure the program design is as inclusive as possible. The Joint Utilities anticipate a Commission order authorizing a full-scale program before the end of 2026 and will continue to operate the MHD Pilot until that time.

Operating Cost Relief Programs

Residential Managed Charging Program

The Residential Managed Charging Program authorized in the EVSE Proceeding have seen success since launching. Although this program is set to end in 2025, each of the Joint utilities have sufficient funding to continue operating for an additional year without further investment. The Joint Utilities have filed a petition with the Commission requesting authorization to continue the Residential Managed Charging Program until the end of 2026, with the opportunity to evaluate the programs in a program review.⁷¹ This review would determine future iterations of the program.

Demand Charge Rebate

The Demand Charge Rebate authorized in the EVSE Solution Proceeding will be replaced once the EV Phase-In Rates become available. The Joint Utilities will make the Phase-In Rates effective by or before October 2025.

Commercial Managed Charging Program

The Commercial Managed Charging Program proposed by the Joint Utilities in the EVSE Solution Proceeding is designed to incentivize customers to shift EV charging load from on-peak hours to off-peak hours, with a peak avoidance incentive. This program is awaiting a Commission order to proceed with an anticipated launch date in late 2025 or 2026.

The operating cost relief programs above will also benefit from National Grid's implementation of AMI as discussed in other sections of this 2025 DSIP Update. The Company's expansion of AMI will enable better visibility into EV charging behavior, more flexible load management, and streamlined interaction with both commercial and residential EV customers. The operating cost relief programs will continue to evolve through the proceedings listed above as the Company achieves its AMI goals, lowering the impact of EVs to the grid while lowering the costs of EV charging.

Other Proceedings

Proactive Planning Proceeding

On August 15, 2024, the Commission established the Proactive Planning Proceeding⁷² building upon work done in the MHD Proceeding. A first-of-its-kind, the Proactive Planning Proceeding's

⁷¹ EVSE Proceeding, Joint Utilities' Petition to Continue MRP Funding.

⁷² Proactive Planning Proceeding, Order Establishing Proactive Planning Proceeding (issued August 15, 2024) (Proactive Planning Order).

purpose is to allow for grid investments and upgrades to enable growing electricity demand primarily driven by vehicle and building electrification. The Proactive Planning Order allows utilities to plan for and construct these grid upgrades proactively, rather than the traditional and reactive approach of waiting for an interconnection request to proceed with upgrades.

The Proactive Planning Order is divided into two parts: the first allowed utilities to submit a portfolio of ‘Urgent Projects,’ and the second asked for utilities to propose a long-term framework to more granularly forecast growing load, develop methodologies to prioritize projects, and develop projects to address those growing needs. The ‘Urgent Projects’ portfolio of over \$450 million in the National Grid Urgent Upgrade Projects Filing includes projects developed to address both vehicle and building electrification. The vehicle electrification portfolio includes the construction of five greenfield substations to create 100+MW of capacity along the New York Thruway; three mobile energy storage units to serve as bridge-to-wires solutions to provide near-term capacity until more permanent solutions come online; and four off I-90 projects to provide additional capacity to travel plazas and fleet depots. The Long-Term Proactive Planning Framework filed by the Joint Utilities lays out how utilities will conduct future load studies, develop projects, and allocate costs. Additionally, the Long-Term Proactive Planning Framework details how the process will interact with other statewide proceedings like the CGPP.

On June 12, 2025, the Commission authorized National Grid to proceed with 22 projects totaling \$126 million and providing 184.8 MW of new capacity.⁷³ This portfolio of projects includes new and upgraded interconnections to support building and transportation electrification, and mobile battery storage.

Integrated Implementation Timeline

The Joint Utilities have developed the following implementation timeline that combines the key milestones for all topic-related work and investments planned over the five-year period ending in 2030. This view shows the milestones and dependencies for the work and investments related to the topics discussed in this section.

⁷³ Proactive Planning Proceeding, Urgent Upgrade Filings Order.

Risk	Mitigation
Automaker development and production schedules	National Grid and the other Joint Utilities have various insights from automakers through industry working groups, including the Corporate Electric Vehicle Alliance, Edison Electric Institute, Alliance for Transportation Electrification, and EPRI. These working groups provide clarity and updates on automaker production schedules, which in turn inform National Grid's communications with customers and developers about the progress of the EV programs.
Federal and local policy (and cost-share implications)	The Joint Utilities routinely discuss any changes to federal or local policy and address any impacts on the implementation of their respective EV programs.

Stakeholder Engagement

Utility program customers are direct supporters of the various EV program offerings as program participants who are eligible to receive incentives from the utilities and are most directly responsible for implementing EV integration through the adoption of EVs and EV charging technologies. Stakeholders in this category include direct residential and commercial utility account customers, EV drivers, and fleets.

Industry support of the various EV program offerings is accomplished by providing hardware, software, engineering, and planning services to help utility program customers adopt and integrate EVs and EV charging. Stakeholders in this category include automakers, EVSE original equipment manufacturers, managed charging aggregators, network service providers, consultants, developers, electricians, and installers.

Government entities support the various EV program offerings by providing policy, regulatory, and public investment aligned with the deployment of EVs and EV charging infrastructure. Stakeholders include the Commission, DPS Staff, NYSERDA, New York State Department of Transportation (NYSDOT), New York State Education Department (NYSED), New York State Department of Environmental Conservation (NYSDEC), New York State Division of Housing and Community Renewal, New York Power Authority (NYPA), Port Authority of New York and New Jersey, state-level elected officials, and municipalities and regional governments across the state.

Interest Groups support the various EV program offerings by providing technical expertise, community representation, and advocacy for policy objectives such as equity, decarbonization, and advancements of technology. Stakeholders in this category include environmental groups, industry associations, and sector coalitions (i.e., bus fleet operators).

The Joint Utilities engage with their stakeholders through a variety of different forums to ensure that their program implementation successfully addresses the needs of the utilities, EV drivers, automakers, and state policy goals.

Stakeholder Meetings and Workshops: The Joint Utilities have held regular stakeholder meetings and public workshops to discuss EV integration, gather feedback, and address technical issues. These forums include participation from government agencies, industry representatives, and community organizations and provide ample opportunity for transparency and stakeholder comments to be considered by the utilities and the Commission.

- The Midpoint Review of the MRP included a robust series of technical conferences to gather feedback from industry stakeholders on topics such as incentive baselines, data reporting, V2G integration, serving DACs, and MHDV charging.

Technical Working Groups: The Joint Utilities have established technical working groups that focus on specific aspects of EV integration, such as grid impact and charging station deployment. These groups consist of experts who collaborate to develop solutions and best practices. Examples include:

- EV Infrastructure and Interconnection Working Group (EVIWG), which has been meeting since early 2024, created an improved process to efficiently manage MRP application queues and improve program transparency.
- Technical Standards Working Group engaged industry experts to research the accuracy of telematics data collected by EVs participating in the Residential Managed Charging Programs.

Education and Outreach: The Joint Utilities have implemented education and outreach plans to inform stakeholders about EV programs and incentives. This includes providing resources and information on their respective websites, as well as conducting public awareness campaigns.

- The Joint Utilities EV webpages are kept up to date with program progress tracking, updates to program rules (such as those resulting from the MRP Midpoint Review), and resources for stakeholders.
- The EVIWG also participates in semi-annual stakeholder webinars to share updates alongside the other Joint Utilities' working groups and contributes to quarterly stakeholder newsletters from the Joint Utilities.

Collaborative Partnerships: The Joint Utilities have partnered with local governments, private companies, and non-profit organizations to advance EV initiatives. These partnerships help leverage resources and coordinate efforts to promote EV adoption.

Regular Updates and Documentation: The Joint Utilities continuously update technical documentation and program guidelines to ensure stakeholders have access to the latest information. This includes posting meeting agendas and supporting materials and program implementation plan updates online and publicly filing annual and semi-annual program reports with the Commission.

These methods of continuous customer engagement, often in multi-session series focused on related topics, ensure that stakeholders' needs will continue to be met over time. By staying involved with stakeholders in the forums of ongoing working groups and collaborative partnerships, the utilities will continue to gain valuable insights into the evolving needs of their stakeholders, and how best to promote program progress and updates to meet their needs. This continued engagement will ensure that stakeholder needs influence the creation and evolution of the Joint Utilities' EV programs.

Through these efforts, the Joint Utilities have engaged with various stakeholders to develop EV programs that meet the needs of the community and support the state's policy goals for a sustainable and efficient transition to electric transportation. Examples of stakeholder feedback gathered by the Joint Utilities through engagement efforts related to EV programs include:

- **MRP:** During the stakeholder feedback sessions for the EV MRP, stakeholders highlighted the need for more accessible and strategically located charging stations. They emphasized the importance of placing chargers in underserved areas to ensure equitable access to EV infrastructure and greater incentive level baselines to reflect actual costs in the market.
- **Technical Working Groups:** In technical working group meetings, stakeholders, including technical consultants and equipment manufacturers, provided feedback on the technical specifications for EVSE proposed by the Commission including International Organization for Standardization (ISO) 15118-2 and 15118-20, Open Charge Point Protocol, and SAE International J3400 (also known as the North American Charging System). Stakeholders suggested improvements to streamline the queue management and interconnection process.
- **Public Workshops:** The Joint Utilities partner with stakeholders, such as DPS and NYSERDA, to host numerous webinars and workshops to educate customers. One example is workshops targeting school districts on the benefits of electric school buses, available incentives, and best practices for fleet electrification. Webinars and workshops generally cover topics such as charging infrastructure, fleet management, and funding opportunities.
- **Customer Surveys:** Through online surveys, stakeholders are asked to provide feedback on the effectiveness of existing EV programs and suggested areas for improvement. For example, some respondents requested additional financial incentives for purchasing EVs and installing home charging stations.
- **Regular Meetings with DPS Staff and Other Agencies:** In regular meetings with DPS Staff, the Joint Utilities share insights into market trends, program progress, and emerging technologies and discuss the challenges faced by project developers and proposed solutions to address issues. The Joint Utilities also participate in frequent meetings with state agencies such as NYSERDA, NYSDOT, NYPA, and NYSED to ensure coordination between utility and state incentive programs and state EV adoption mandates and policy goals.

These examples illustrate how the Joint Utilities have actively sought and incorporated stakeholder feedback to refine and enhance their respective EV programs, ensuring the needs of the community are being met and align with the state's policy goals.

Before delivering a new tool, resource, or program offering, utilities use best practices, such as consulting with stakeholders, to effectively deliver the intended support and avoid unintended problems. Examples include:

- Using customer satisfaction survey data to inform new or modified program designs such as participation requirements, incentive structure, or eligibility rules such as in the Residential Managed Charging Program.
- When a public comment period is open in an EV proceeding such as the review of the SAE International J3400 standards in the MRP, the utilities may conduct informal outreach to a range of stakeholders to encourage their participation.
- When tools or processes are being created, the utilities may gauge suitability and solicit informal feedback from stakeholders to improve the solution prior to a full-scale launch, such as in the case of the School Bus Capacity Assessment in coordination with NYSED, NYSEDA, and school district customers.
- When stakeholders raise certain questions or issues that are applicable to all utility companies, the Joint Utilities first explore how each utility approaches the situation before further discussion with stakeholders or offering support.

2.6 Clean Heat

Context and Background

The NYS Clean Heat Program, which launched on April 1, 2020, provides customers, installation contractors, and other heat pump solution providers with a consistent experience, programmatic support, and financial incentives statewide. The NYS Clean Heat Program contributes to achievement of the State's ambitious climate goals under the CLCPA by supporting customer adoption of heat pumps and other efficient, heat electrification technologies.

The NYS Clean Heat Program provides incentives for efficient EHP systems for space heating and water heating applications, including cold climate air source heat pump (ccASHP) systems, ground source heat pump (GSHP) systems, variable refrigerant flow systems, larger scale heat pump systems in commercial and multifamily buildings, and heat pump water heaters (HPWHs).⁷⁴ The NYS Clean Heat Program also provides promotion and pricing by contractors and other heat pump solution providers. The Implementation Plan⁷⁵ and Program Manual filings⁷⁶ provide detail about the NYS Clean Heat Program, including incentive structures and levels, eligible technologies, program rules and processes, and information for participating contractors.⁷⁷

Since 2023, in response to the Commission's July 20, 2023 *Order Directing Energy Efficiency and Building Electrification Proposals*,⁷⁸ National Grid, in conjunction with the Joint Utilities, developed a proposal for the Clean Heat portfolio for the 2026-2030 period. This proposal recommended budgets and targets for this period that would continue the program's role in supporting utility customer adoption of efficient heat electrification technologies. Several questions were posed to the utilities to gain stakeholder feedback on how to accomplish this task, including the potential to continue the statewide Clean Heat Program for residential customers and embed heat electrification offerings for larger, more complex projects into each utility's sector-

⁷⁴ See NE:NY Proceeding et al., NYS Clean Heat: Statewide Heat Pump Program Implementation Plan (Implementation Plan) (initially filed on March 16, 2020, and most recently refiled on July 1, 2021), Appendix 3: NYS Clean Heat Program Glossary of Terms, pp. 54-57. This Glossary provides definitions of ccASHP, GSHP, HPWH, Participating Contractor, and other key terms used in this 2025 DSIP Update.

⁷⁵ NE:NY Proceeding, Implementation Plan. The Joint Efficiency Providers' work in coordinating development of the NYS Clean Heat Program began in 2019. See NE: NY Proceeding, Order Authorizing Accelerated Energy Efficiency Targets (issued December 13, 2018) (2018 NE:NY Order).

⁷⁶ See NE:NY Proceeding, NYS Clean Heat: Statewide Heat Pump Program Manual (Program Manual), (initially filed on March 16, 2020 and most recently refiled on April 1, 2024); see also NYS Clean Heat Con Edison Heat Pump Program Manual, (initially filed on January 12, 2023 and most recently refiled April 1, 2024).

⁷⁷ Both the Implementation Plan and Program Manual are revisited, as necessary and with prior notice, on a separate schedule from Annual Report filings in the NE-NY Proceeding.

⁷⁸ NE:NY Proceeding, Order Directing Energy Efficiency and Building Electrification Proposals (issued July 20, 2023) (Order Directing EE/BE Proposals).

based programs for commercial and multifamily customers. The Commission’s May 15, 2025 *Order Authorizing Non-Low- to Moderate-Income Energy Efficiency and Building Electrification Portfolios for 2026-2030* and *Order Authorizing Low- to Moderate-Income Energy Efficiency and Building Electrification Portfolios for 2026-2030*⁷⁹ establishes future budgets and targets for the Clean Heat Program.

The NYS Clean Heat Program is overseen by the Joint Management Committee (JMC). The JMC has implemented, and is working to improve upon, a common statewide framework to advance the adoption of heat pump systems that are designed and used for heating, integrated under the umbrella of NYS Clean Heat. The NYS Clean Heat Program supports the installation of heat pump technologies that are best suited to heat efficiently in cold climates. It requires participating contractors to follow best practices related to sizing, selecting, and installing heat pumps in cold climates. It also promotes consumer education, including requiring that guidance be provided by participating contractors to customers on how to operate and maintain their systems. As part of program delivery, the JMC monitors the extent to which NYS Clean Heat-incentivized heat pump systems displace or replace other heating fuels. The JMC continues to review the program’s progress and adjust improve performance as appropriate.

Implementation Plan, Schedule, and Investments

A list of the Company’s Clean Heat programs’ incentives as of this 2025 DSIP Update is provided in Table 2.6.1 below. A more complete description of National Grid’s programs can be found in the links below Table 2.6.1 or within the New York State Clean Heat Program Manual for Central Hudson Gas & Electric Corporation, National Grid, New York State Electric & Gas Corporation, Orange and Rockland Utilities, Inc., and Rochester Gas and Electric Corporation.⁸⁰

Table 2.6.1: National Grid Clean Heat Incentives

Category	Description	Incentive	Contractor Reward (from Incentive)
2	ccASHP: Full Load Heating	\$1,200 / 10,000 BTUH of maximum heating capacity at Northeast Energy Efficiency Partnerships (NEEP) 5° F	\$300 / project

⁷⁹ NE-NY Proceeding et al., Order Authorizing Non-Low- to Moderate-Income Energy Efficiency and Building Electrification Portfolios for 2026-2030 (issued May 15, 2025) and Order Authorizing Low- to Moderate-Income Energy Efficiency and Building Electrification Portfolios for 2026-2030 (issued May 15, 2025) (collectively, May 2025 EE/BE Orders).

⁸⁰ NE-NY Proceeding, New York State Clean Heat Program Manual for Central Hudson Gas & Electric Corporation, National Grid, New York State Electric & Gas Corporation, Orange and Rockland Utilities, Inc., and Rochester Gas and Electric Corporation, Version 13 (filed April 1, 2025).

2a	ccASHP: Full Load Heating with Integrated Controls	\$1,400 / 10,000 BTUH of maximum heating capacity at NEEP 5° F	\$500 / project
Category	Description	Incentive	Contractor Reward (from Incentive)
2b	ccASHP: Full Load Heating with Decommissioning	\$1,600 / 10,000 BTUH of maximum heating capacity at NEEP 5° F	\$500 / project
2e	Full Load Air-to-Water Heat Pump, for Space Conditioning	\$1,600 / 10,000 BTUH of heating capacity at the condition of 5°F ambient and 110°F leaving water temperature (A5W110), as documented by the New York State Clean Heat Program's Air-to-Water Heat Pump Qualified Product List (NYS Clean Heat AWHP QPL)	\$300 / project
3	GSHP: Full Load Heating	\$2,500 / 10,000 BTUH of full load heating capacity as certified by Air-Conditioning, Heating, and Refrigeration Institute	\$500 / project
4	Custom Space Heating Applications	\$80 / Metric Million British Thermal Unit (MMBTU) of annual energy savings	\$500 / project
4a	Heat Pump Plus Envelope	Tier 1: \$80 / MMBTU of annual energy savings Tier 2: \$100 / MMBTU of annual energy savings	\$500 / project
4b	Custom Full Load Multifamily Space Heating Applications (5-100 dwelling units)	\$2,000 / Dwelling unit	\$500 / project
5	Residential Rated HPWH: Retail	\$1000 / unit	N/A
5	Residential Rated HPWH: Midstream	\$1,000 / unit	\$50 contractor reward, \$50 distributor reward
6	Custom Centralized Hot Water Heating Applications	\$80 / MMBTU of annual energy savings	N/A
6a	Custom Centralized Multifamily Hot Water Heating Applications (5-100 dwelling units)	\$500 / Dwelling unit	\$500 / project

7	GSHP Desuperheater in Category 3 GSHP Systems	\$100 / unit	N/A
Category	Description	Incentive	Contractor Reward (from Incentive)
8	Water-to-Water Heat Pump used to meet Domestic Hot Water (DHW) Load in Category 3 GSHP Systems	\$900 / unit	N/A
10	Custom Partial Load Space Heating Applications	\$80 / MMBtu of annual energy savings	\$500 / project

Note: More Clean Heat Program information is available via the following links:

- <https://cleanheat.ny.gov/contractors/>
- <https://ngrid.com/nys-cleanheat>

Current Progress

The Clean Heat Program is implemented in coordination with a portfolio of NYSERDA-led market development initiatives which aim to build market capacity for delivery of building electrification solutions. Some of National Grid's highlights since the launch of the Company's Clean Heat programs are summarized below:

- Updated and improved the heat pump measures in the NY Technical Resource Manual (TRM).
- Improved application process cycle times through increased program staffing, improved communication with participants, and increased training opportunities for industry partners.
- Agreed to add HPWH midstream incentives to the Program Manual and began to deploy these incentives.
- Added Category 2a - ccASHP full load heating with integrated controls and Category 2b - ccASHP with decommissioning.
- Introduced Category 2e Full Load Air-to-Water Heat Pump, for Space Conditioning.
- Introduced a bonus for priority electrification zip codes.
- Realized sustained growth in custom Commercial, Industrial, and Multifamily projects with a 72 percent increase in savings from 2023.
- Added 97 new participating contractors for a total of 425 active enrolled industry partners in 2024.

- Installed and provided incentives for 3,242 Clean Heat projects in 2024.
- Updated performance and eligibility criteria for commercial unitary systems and large commercial air source heat pumps (ASHP).
- Introduced Category 4b for space heating projects in multifamily buildings between 5-99 units, while providing an incentive value per dwelling unit.
- Introduced Category 6a for custom DHW projects in multifamily buildings with 5-99 units.

Table 2.6.2 below shows the current implementation of National Grid's most recent Clean Heat program targets resulting from the cumulative NE:NY savings targets.

*Table 2.6.2: National Grid's Electric Clean Heat Savings Target to 2025**

	2020	2021	2022	2023	2024	2025
Gross Savings Actuals and Target (MWh)	38,993	63,163	136,017	217,862	216,944	280,647

*2020-2024 values are actuals from the Company's 2019-2024 Electric Clean Energy Dashboard Scorecard whereas the 2025 value is a target from the Commission's January 2020 NE:NY Order.⁸¹ Targets for 2026-2030 are provided in the Commission's May 2025 EE/BE Orders.⁸²

Future Implementation and Planning

National Grid continues to advance energy affordability by developing initiatives focused on energy solutions for the Company's market-rate customers, driving deeper energy savings in building retrofits and construction, and supporting cost-effective heat pump adoption and beneficial electrification projects. As commercial technology to displace fossil-fuel driven heating and cooling evolves, the Clean Heat program will consider and implement appropriate incentive structures to support adoption of electrification more deeply into the C&I sector. The Company will continue to focus on scaling up the Clean Heat program and identifying ways to simplify rebate structure and incentive processing.

The Company strives to develop programmatic approaches to encourage customers to weatherize their homes and strengthen the emphasis on full-load heating where appropriate as this aligns with the State's goals. In the May 2025 EE/BE Orders, the Commission directed DPS Staff, in consultation with NYSEDA and the Joint Utilities, to undertake an analysis on various hybrid heating scenarios, drawing upon previous and ongoing programs and pending utility proposals, that can inform future programming within the EE/BE portfolios and other proceedings. Hybrid heating may be part of the solution to address future issues of electric load flexibility and potential electric network constraints to full electrification. National Grid also plans to determine appropriate program structure during this time, as well as opportunities where the Company can potentially tie into community and utility-owned thermal energy networks.

⁸¹ See NE:NY Proceeding, January 2020 NE:NY Order, Appendix C - Table C1.

⁸² NE:NY Proceeding et al., May 2025 EE/BE Orders.

Risks and Mitigation

Table 2.6.3: Risks and Mitigations for Clean Heat Integration

Risk	Mitigation
Fundability – Do we have enough funding secured to deliver the outcomes	May 2025 EE/BE Orders provide guidance on future funding
Uncertainty for EE program administration and targeted policy incentives for EHP adoption e.g., regulatory approval of EE program administration jurisdiction and targeted EHP incentives with customer segment priority	Early engagement/outreach to clarify program administration and advocate for targeted incentives Engage w/ stakeholders early and often Co-create regulatory solutions (Joint advocacy)
Data gap exists for electric-only customer EHP forecasting.	Understand data issues Resource data clean up and management Assign owner to coordinate forecasting needs and work
Coordination with external stakeholders and communities required for EHP and EE development plan.	Early proactive outreach Target and coordinate different stakeholders for different projects/needs Improve data management to streamline sharing
Coordination with Joint Utilities to maintain a statewide framework for Clean Heat Program	Conduct analysis on potential incentive structure and incentive level changes

Continued discussion between utilities, government agencies, and other stakeholders will help maximize the savings attained in NY and the value attributed to those savings, while minimizing the financial impact to consumers.

Alignment with CLCPA Goals

National Grid is fully committed to a clean energy future and helping NY achieve its energy and environmental goals under the CLCPA and has designed the Company's EE programs under NE:NY in a manner that is consistent with net zero efforts. As part of its commitment to a clean energy future, National Grid announced in October of 2020 our "Net Zero by 2050" plan and updated Responsible Business Charter.⁸³ In 2022, National Grid issued its "Clean Energy Vision,"⁸⁴ which outlines a path forward for a fossil-free future for cleanly heating homes and

⁸³ National Grid's "Net Zero by 2050" plan and updated Responsible Business Charter affirm the Company's commitment to: i) reduce Scope 1 and 2 GHG emissions 60 percent by 2030; ii) reduce Scope 3 GHG emissions (excluding electricity sold), which includes the gas National Grid's customers use, by 37.5 percent by 2034; and iii) achieve net zero by 2050 for Scope 1, Scope 2, and Scope 3 GHG emissions, and further reduce these emissions beyond 2030 consistent with New York's targets as laid out in the CLCPA. (Scope 1 consists of direct emissions, Scope 2 is comprised of indirect emissions that come from energy purchases and production, and Scope 3 encompasses all other indirect emissions created by a company's value chain.)

⁸⁴ Available at <https://www.nationalgrid.com/us/fossilfree>

businesses through four pillars: first, aggressively accelerating insulation and EE improvements to buildings; second, supporting cost-effective, targeted electrification on the Company's gas network, including piloting networked geothermal solutions; third, in areas where full electrification may not be practical or cost-effective, providing customers with the tools to pair EHPs with their gas appliances; and, finally, eliminating fossil fuels from our existing gas network no later than 2050 by delivering renewable natural gas and green hydrogen to customers.

Across every community we serve, National Grid is deeply committed to the goal of net zero and has a long track record supporting the reduction of GHG emissions.

The Company also has established internal processes to track and report on clean energy investments in DACs in furtherance of the goals of the Climate Act. Serving DACs will require consideration of community needs in the development of our customer products and services, from inception through delivery and in all market sectors, including residential and small business programs. Internal procedures to address serving DACs will enable the Company to help all customers benefit from EE and electrification.

Lastly, Clean Heat is well considered in CGPP. Work described in this section directly helped inform CGPP inputs, namely the load forecast. Clean Heat represents a major component of load growth driving the need for increased renewables in CGPP models. By 2040, models are solving for a winter peaking system, primarily driven by heat electrification. This gives the Company an excellent opportunity to continue the discussion around flexible heating load, as National Grid recognizes the need to leverage flexibility during the energy transition to cleaner, more sustainable sources.

Stakeholder Interface

As a statewide program, Clean Heat has pre-established stakeholder interfaces to ensure consistency across NY. National Grid will continue to work with interested internal and external stakeholders to increase participation and engagement through the Clean Heat Participating Contractor and Industry Partner Network. Further collaborative efforts are planned and executed through the Company's participation in the Clean Heat JMC.

The JMC oversees all residential and small commercial applications through implementation vendors for the Clean Heat program, assisting large C&I customers directly to meet each customer's specific needs. The Clean Heat program must balance the needs of the customers with the overarching requirements of the state's ambitious climate and building electrification goals. The JMC uses stakeholder-provided feedback to inform program decisions which are then reflected in the Clean Heat program's annual updates to the Clean Heat Implementation Plan.

2.7 Energy Efficiency Integration and Innovation

Context and Background

National Grid recognizes that EE is the lowest-cost option to help customers reduce their energy usage, energy costs, and GHG emissions. Clean energy pathways start with EE and comprehensive energy savings solutions. As such, the Company is committed to EE efforts that optimize its electric (and gas) networks to reduce system costs and provide enhanced customer savings. EE is one of the four pillars of the Company's vision of a fossil-gas free future, as it plays a critical role in ensuring a fair and equitable energy transition for all. The Company's EE programs, including DR Programs, continue to align with, and contribute to, achievement of the statewide EE target of 185 TBTU of energy usage reductions at the customer level per the CLCPA.

In November of 2023, the Company submitted a proposal in response to the Commission's mid-cycle Interim Review in the January 2020 NE:NY Order.⁸⁵ Several questions were posed to the Joint Utilities to gain stakeholder feedback on how the State should go about meeting its aggressive EE/BE goals. Since 2020, there has been an increased focus on encouraging more weatherization to facilitate building electrification for residents and occupants. On May 15, 2025, the Commission issued two orders which established budgets and targets for the EE/BE portfolios during the period of 2026-2030.⁸⁶ The new EE/BE targets continue to address energy savings in residential, multifamily, and C&I sectors across National Grid's service territory.

Due to several long-standing national initiatives to improve the efficiency of lighting choices, the federal government adopted new lighting standards effective January 2023. The Energy Independence and Security Act set a new baseline efficiency standard for most of the lighting that people use in everyday lamps in their homes and offices. Now all general service lamps must meet a requirement of forty-five lumens per watt as per Energy Independence and Security Act guidelines. This effectively made high-efficiency light-emitting diode (LED) bulbs the baseline standard in all major retail stores, with the gradual phase out of incandescent lamp production nationwide. As a result of this, lighting incentive programs were dramatically reduced since 2023 because of the marginal improvements in bulb efficiency available to incentivize.

During this time, National Grid continued to adjust where needed to the robust portfolio of EE offerings in the annually filed System Energy Efficiency Plan (SEEP).⁸⁷ The SEEP is designed to support the progression of market-based solutions and the penetration of emerging and

⁸⁵ NE:NY Proceeding, January 2020 NE:NY Order.

⁸⁶ NE:NY Proceeding et al., May 2025 EE/BE Orders.

⁸⁷ NE-NY Proceeding, Niagara Mohawk Power Corporation d/b/a National Grid 2019-2020 Electric and Gas System Energy Efficiency Plan (filed February 19, 2019) (SEEP). National Grid filed an updated SEEP with the Commission on September 15, 2020, October 1, 2021, September 30, 2022, October 2, 2023, and October 1, 2024.

transformative technologies within the Company's service territory in support of the Commission's REV Proceeding, NE:NY orders, and the CLCPA. The SEEP provides detailed information on National Grid's EE programs,⁸⁸ budgets, targets, and Evaluation, Measurement, and Verification (EM&V) strategies. The overall goal is to meet energy savings targets while continuously improving and making programs more efficient so as to reduce implementation and administration costs, thereby directing more EE funding to customer incentives. The Company continues to expand its EE program offerings, taking a more holistic approach to delivering customer solutions and focusing on providing enhanced value to both the customer and National Grid.

In addition to EE programs, National Grid currently operates DLM programs which were initiated in accordance with directives provided by the Commission in Case 14-E-0423.⁸⁹ The current DLM programs are comprised of the Distribution Load Relief Program (DLRP), Term-Dynamic Load Management Program (Term-DLM), Auto-Dynamic Load Management Program (Auto-DLM), Commercial System Relief Program (CSRP), and the Direct Load Control (DLC) Program. The DLC Program includes the **Connected**Solutions Program. CSRP, Term- and Auto-DLM, and DLRP are primarily considered to be C&I customer-focused programs, while the DLC Program targets residential and small business customers. National Grid filed its most recent DLM Annual Report on November 15, 2024 which includes an assessment of its DLM programs for the 2024 capability period and identifies changes planned for the 2025 capability period.⁹⁰

Table 2.7.1 below shows the current implementation of National Grid's most recent SEEP in verified gross savings targets resulting from the cumulative NE:NY goals. The Company recovers all EE program costs through base rates, including those in its electric and gas SEEP.

*Table 2.7.1: National Grid's Electric EE Savings Goal to 2025**

	2020	2021	2022	2023	2024	2025
Verified Gross Savings Target (MWh)	534,738	487,325	444,976	348,436	374,940	319,383

*2020-2024 values are actuals from the Company's 2019-2024 Electric Clean Energy Dashboard Scorecard whereas the 2025 value is a target from the Commission's January 2020 NE:NY Order.⁹¹

⁸⁸ See, e.g., <https://www.nationalgridus.com/Upstate-NY-Home/Energy-Saving-Programs/>

⁸⁹ DLM Programs Proceeding, Order Adopting Dynamic Load Management Filings with Modifications (issued June 18, 2015).

⁹⁰ DLM Programs Proceeding, Niagara Mohawk Power Corporation d/b/a National Grid Dynamic Load Management Programs Annual Report for 2024 Capability Period (filed November 15, 2024).

⁹¹ NE:NY Proceeding, January 2020 NE:NY Order, Appendix A – Table A3.

Implementation Plan, Schedule, and Investments

A list of the Company's current electric EE and DR programs is provided below. A more complete description of National Grid's programs can be found in the links below the table or within National Grid's annually filed SEEP.

Table 2.7.2: National Grid's Electric EE Programs

Program	Sector
Electric Demand Response	C&I
Electric Demand Response	Residential
Multifamily Direct Install	Multifamily
Electric Commercial & Industrial	C&I
Electric Real Time Energy Management (RTEM)	C&I
Electric Non-Residential Weatherization	C&I/Multifamily
LED Streetlighting	C&I
Electric Residential Consumer Products	Residential
Electric Residential Engagement	Residential
EmPower+ Referrals	Residential

Note: More information is available via the below links:

- 1) <https://www.nationalgridus.com/Upstate-NY-Business/Energy-Saving-Programs/>
- 2) <https://www.nationalgridus.com/Upstate-NY-Home/Bill-Help/Energy-Affordability-Program>
- 3) <https://www.nationalgridus.com/Services-Rebates?r=10&page=1&customerType=For+Businesses&locations=Upstate+New+York>
- 4) <https://www.nationalgridus.com/Upstate-NY-Business/Energy-Saving-Programs/Multifamily>

Current Progress

National Grid's current EE program portfolio focuses on cost effectiveness by managing programs at the portfolio level and investing in successful, highly efficient offerings while assessing and sunsetting less efficient programs. The Company evaluates and explores new delivery methods, such as shifting from downstream offerings to midstream/upstream offerings, to increase market penetration and customer ease while also lowering costs.

To align with the Strategic Framework established in the Commission's Order Directing EE/BE Proposals, the Company began modifying program structure to facilitate the transition to a stronger focus on measures that benefit future electrification for our customers. In addition to this, initiatives are under development to support the CLCPA's mandate that a percentage of all EE funding be directed towards the direct benefit of DACs. National Grid applauds this effort as it aligns with the Company's goals for a fair and equitable energy transition for all.

In addition to the Company's offerings for market rate (non-LMI) customers, National Grid continues to advance energy affordability by developing initiatives focused on energy solutions for LMI/DAC customers, driving deeper energy savings in building retrofits and construction, and supporting cost-effective heat pump adoption and BE projects. In 2022, the Company began an initiative to provide LED light bulbs with brochures outlining further EE program offerings and bill assistance programs to food banks across the Company's service territory. In 2023 and 2024, the initiative branched out beyond food banks to attend other local events to provide LED light bulbs and outreach brochures, such as events held by National Grid consumer advocates or NYSERDA's Clean Energy Hubs. This initiative is expected to close by the end of 2025.

Also in 2022, the Company began providing funding to NYSERDA to support EmPower+ projects in the National Grid electric service territory and began serving multifamily housing through the Affordable Multifamily Energy Efficiency Program (AMEEP). The funding the Company provides to the EmPower+ program is not tied to projects that come from the Company's monthly referrals; however, the Company is dedicated to ensuring an increased number of customers referred to EmPower+ apply and proceed with an EE work scope where applicable. Therefore, in 2023 the Company enhanced the referral process by reaching out to customers before and after an application is mailed by NYSERDA to inform them of the program and encourage them to apply.

EM&V continues to be an integral part of the EE portfolios. Throughout the 2023-2025 period, National Grid's EM&V team has continued conducting EE potential studies as well as impact evaluations of multifamily, residential, and small business programs. The Company incorporates, as applicable, "real-time EM&V" to provide timely feedback to the program implementation team as the evaluation is proceeding.

Within the January 2020 NE:NY Order, the utilities were directed to perform BCAs for the EE portfolio of programs including all market-rate and LMI statewide initiatives. The application of study-based verified gross savings realization rates as per NE:NY guidance has aided in developing more precise savings metrics. The EM&V plan also looks at the market to maximize feedback to the EE programs. The Company continues to explore new evaluation methods that utilize automation, smart devices, and/or software solutions.

In the DR space, National Grid's relatively new DLM Programs, Term- and Auto-DLM, as well as the more established DLRP, CSRP, and DLC Program, have continued to progress steadily. The CSRP and DLC Program have generally experienced growth over the last three years, with the DLC Program, including the **ConnectedSolutions** Program, growing most rapidly. The DLRP is a contingency program activated for system critical situations (*i.e.*, unforeseen distribution system emergencies wherein stressed electrical equipment may exceed established limits), as defined in the Company's Electricity Tariff.⁹² The Auto-DLM program has experienced challenges in securing bids in response to requests for proposal (RFPs), but the Company continues to modify the program to make it more appealing. Please refer to Section 2.4 on energy storage of this 2025 DSIP Update for additional information on the Auto-DLM program.

⁹² PSC No. 220 Electricity, Niagara Mohawk Power Corporation d/b/a National Grid Schedule for Electric Service (Electricity Tariff).

The CSRP is activated for peak-shaving needs when National Grid’s electrical system exceeds 92 percent of the system-wide 95/5 peak forecast, as defined in the Electricity Tariff. This program also includes Reservation and Voluntary options for participants. CSRP is a territory-wide program available to customers served from all voltages.

Table 2.7.3: National Grid’s CSRP Annual Results

Year	Participants	Contracted Curtailment (MWs)	Average Curtailment (MWs)	Events	Aggregators	Individual Participants
2020	295	241.72	219.46	5	5	4
2021	279	220.55	195.04	8	6	4
2022	227	206.44	157.57	8	7	4
2023	216	159.04	164.53	5	6	4
2024	267	249.79	257.87	11	6	3

*The increase in participants count and average curtailment increase in 2024 are not directly related. Two existing customers made larger commitments in 2024 concurrently with an influx of smaller customers to the CSRP.

Term- and Auto-DLM are activated similarly to CSRP and are likewise focused on C&I customers. Whereas CSRP and Term-DLM are system-wide programs, Auto-DLM is intended to provide load relief in pre-defined constrained locations identified by the Company through the system planning process. Unlike CSRP participants who must enroll annually at a tariff-defined rate, Term- and Auto-DLM participants are contracted through annual procurements in which they submit bids and are potentially awarded contract-defined participation rates on a three-to-five-year basis.

Table 2.7.4: National Grid’s Term-DLM Annual Results

Year	Participants	Contracted Curtailment (MWs)	Average Curtailment (MWs)	Events	Active Vintage Year Contracts
2022	41	55	47.94	6	1
2023	49	82.6	83.93	5	4
2024	46	97.6	95.85	10	5

The Auto-DLM Program has unfortunately been less successful, as over the five years of procurement solicitations National Grid has only received a single Auto-DLM bid. National Grid has been active in attempting to connect with stakeholders to understand how the Company can improve the program and make it more attractive to bidders. In response to feedback, National Grid extended the procurement timeline to five years (up from three years), added value tiers to the Auto-DLM locations to help bidders better understand the program, and successfully petitioned the Commission for flexibility in Term- and Auto-DLM procurement methodologies,⁹³ which was

⁹³ See Energy Storage Proceeding, November 2024 Order Approving DLM Program Procurement Modifications.

ultimately implemented in the Vintage Year 2026 Term- and Auto-DLM RFP, which resulted in the first Auto-DLM bid received by the Company.

The DLC Program is activated for system-critical situations or for peak shaving purposes. Through this program, National Grid can remotely adjust thermostat settings of participating customers with Wi-Fi communicating thermostats. The ConnectedSolutions Program connects existing Honeywell, Ecobee, Lux, Emerson Sensi,TM Alarm.com, Vivint, and Google Nest Wi-Fi connected thermostats to National Grid's DRMS. ConnectedSolutions is available to all residential and small commercial customers served at primary and secondary voltage levels. For thermostats participating in ConnectedSolutions there is a one-time sign-up payment of \$50 and a \$20 yearly incentive that is payable in the second year of participation for the reduction of load during at least 80 percent of called event-hours. The Company's request to expand the DLC Program to include battery storage was recently approved by the Commission in its April 25, 2025 *Order Addressing DLM Program Modifications*.⁹⁴

At the end of the 2024 capability period, there were 26,315 thermostats enrolled in National Grid's ConnectedSolutions Program, now nearly 40 percent larger than reported for the 2023 capability period. Thermostat enrollment increased by 3,225 in 2023, and 1,267 in 2024. Enrollment is expected to grow in 2025 and beyond. For the 2023 and 2024 Capability Periods, ConnectedSolutions events were scheduled coincidentally with CSRP events. Average participation has increased to around 85 percent throughout each summer, regardless of the relative frequency of back-to-back event days. In 2023 and 2024, National Grid continued to see three or more consecutive event days. On the device level, despite the program growth and increasing frequency of events, the average demand shed per device has also managed to increase to 0.96 kW.

Demand Response Management System

In 2023, National Grid finalized the procurement of a C&I DRMS vendor for a period of three years. The responsibilities and capabilities of the vendor include the overall management of administrative aspects of the DLM programs, the dispatch of DR events, and curtailment calculations, all through a single, integrated system. This also includes support for the newly proposed Term-DLM resources, including standard and premium auto-DLM resources as described in the following section.

Future Implementation and Planning

In the near term, customers' interest in EE remains strong, especially in the residential sector as technologies advance and more consumers become aware of the benefits of EE. In addition to EE, the recent focus on Building Electrification through state and federal legislation has put a renewed focus on emerging technologies to help secure an equitable energy future. To keep pace, National Grid continues to explore creative, new opportunities such as focused DR efforts, community initiatives and partnerships, future based non-infrastructure initiatives such as NWA projects,

⁹⁴ DLM Proceeding, Order Addressing Dynamic Load Management Program Modifications (issued April 25, 2025).

improved customer segmentation efforts, rate designs, and a continued focus on demonstration initiatives to test new and advanced technologies, all in the pursuit of deeper savings.

Investment in technologies like AMI and data sharing capabilities such as GBC will give National Grid and our customers a greater understanding of energy usage and more options to identify and deliver savings. The Company is exploring ways of analyzing customer energy usage and system data to deliver greater benefits from our programs. These activities will be undertaken consistently with the principles and goals of NE:NY and the CLCPA, and are supported by the Company's SEEP, which seeks more flexibility in program delivery and management.

For the LMI/DAC customer segment, AMEEP provides in-unit electric measures which are a direct benefit to the tenants of the property. In 2025, additional incentives are being offered for AMEEP projects that are also located within DACs. Contributions made by National Grid to the EmPower+ program and AMEEP will end in 2025 as the current funding period closes. The Company will continue to make monthly referrals of customers to the EmPower+ program beyond 2025 and affordable multifamily customers will be directed to NYSERDA's program offerings for EE incentive support.

The Company continues to focus on ways to coordinate EE, DR, and NWA procurement to develop programs that lower system needs and costs. National Grid currently delivers EE programs on a system-wide basis based on customer demand. The Company's EE team works closely with the National Grid Forecasting and Distribution Planning team to identify areas of system improvement. A more coordinated effort creates closer collaboration among the Company's Planning groups to communicate localized system needs in designing targeted programs and adding locations to existing targeted load relief programs such as Auto-DLM.

National Grid continues to focus on positioning EE as a least-cost system resource. The Company's load forecast will continue to account for EE in assessing future peak demand impacts. EE is also a suitable means to achieve carbon reduction goals. The Company anticipates building on its foundation of successful EE efforts to expand its role in meeting customer energy needs and supporting state and national energy policy over time. These expanded efforts are likely to include pay-for-performance programs, energy as a service, and non-financial incentive programs. National Grid will continue to work with stakeholders to deliver higher levels of cost-effective savings.

Considering the successful delivery of EE programs, as well as an increasing societal value in mitigating GHG emissions, the Company expects customer interest in EE offerings to continue to increase beyond 2025. The next generation of National Grid's EE programs will require transformative thinking and significant improvement in the capacity to provide independent, high value, and trusted support to customers. Specifically, the drivers of program design will be the delivery of holistic customer solutions that use a single touch point to influence deep and sustained energy cost savings. These changes will only serve to enhance the Company's focus in identifying and meeting customer energy needs while maintaining National Grid's ability to operate reliably.

Risks and Mitigation

Table 2.7.5: Risks and Mitigations

Risk	Mitigation
Strategic framework limitations that restrict the development of new offerings	Drive innovation through advanced technologies and future-proofing strategies where possible by staying ahead of current offerings.
Capacity constraints may develop due to increased electricity use by consumers as a result of beneficial electrification projects.	Regular involvement in large-scale infrastructure conversations to maximize available funding for projects that address capacity constraints that may result from increased electrification.
The May 2025 EE/BE Orders approve funding that creates challenges with reaching energy savings targets.	Seek incremental changes to budgets while streamlining offerings to offset gaps if needed.

Continued discussion between utilities, government agencies, and other stakeholders will help maximize the savings attained in NY and the value attributed to those savings, while minimizing the financial impact to consumers.

Alignment with CLCPA Goals

National Grid is fully committed to a clean energy future by helping NY achieve its energy and environmental goals under the CLCPA and has designed the Company's EE programs under NE:NY in a manner that is consistent with the Climate Act's net zero goals. As part of its commitment to a clean energy future, National Grid announced in October of 2020 our "Net Zero by 2050" plan and updated Responsible Business Charter.⁹⁵ In 2022, National Grid issued "Our Clean Energy Vision,"¹⁰ which outlines a path forward for a fossil-free future for cleanly heating homes and businesses. Within that proposal, the Company outlines EE work as one of the key pillars of that vision.

Across every community we serve, National Grid is deeply committed to the goal of net zero and has a long track record supporting the reduction of GHG emissions. The Company has helped NY achieve ranking in the top five of the most energy efficient states in the nation through our existing EE and DR programs several years in a row, and these programs continue to grow.

⁹⁵ National Grid's "Net Zero by 2050" plan and updated Responsible Business Charter affirm our commitment to: (i) reduce GHG emissions from our direct operations by 80 percent by 2030, 90 percent by 2040, and to net zero by 2050; (ii) reduce GHG emissions from the gas we sell to customers by 20 percent by 2030, and further reduce these emissions beyond 2030 consistent with New York's targets as laid out in the CLCPA; and (iii) prioritize ten major focus areas to achieve Net Zero for our US operations and the energy we deliver to customers.

The Company also has established internal processes to track and report on our clean energy investments in DACs in furtherance of the goals of the Climate Act. Serving DACs will require consideration of community needs in the development of customer products and services, from inception through delivery and in all market sectors, including residential and small business programs. Internal procedures to address serving DACs will enable National Grid to help all customers benefit from EE and building electrification.

Stakeholder Interface

National Grid will continue to work with interested internal and external stakeholders to increase participation and engagement in the Company's DLM Programs. National Grid currently interacts with several third-party vendors for administrative and technological enhancement of DLM Programs which includes both the commercial and residential DRMS. In addition to existing thermostat manufacturers in the **ConnectedSolutions** Program, the Company is exploring the opportunity to add more thermostat vendors and other smart device types using the residential DRMS. With additional vendors, there will be an increased need for coordination and compatibility. Additionally, the success of DLM Programs is directly related to efforts of the distribution planning, NWA, and EE teams internally. As the DLM Programs expand, additional internal coordination will be paramount.

For the Company's portfolio of market-rate programs, National Grid plans to engage directly with stakeholders through marketing and advertising of our offerings in each sector as well as quarterly reporting to demonstrate progress towards EE goals. The upcoming annual Non-LMI EE/BE implementation plan as well as DAC reporting will both provide meaningful insights into the steps that National Grid is taking towards a fair, affordable, and sustainable energy future.

2.8 Data Sharing

Context and Background

Data sharing services are a primary function of the DSP and involve the management and sharing of multiple segments of utility data relevant to stakeholder needs, including both system data and customer data. System Data describes the physical state, size, or operating parameters of the grid such as voltage levels, thermal capacity, and geographical location of assets. Customer Data includes information the Company collects and maintains to serve its customers such as utility service information, billing data, and DER installation records. National Grid adheres to enterprise-wide data management standards that enable effective data management strategies and sharing controls that apply to both system data and customer data. As the need for data sharing grows, along with technological advancements and interest from third parties, the Company continues to collaborate with all stakeholders.

National Grid has developed and maintained its NY System Data Portal which serves as a public centralized online platform that transparently displays relevant Company reports in addition to utility system capabilities, needs, limitations, and opportunities for DERs. Data on the System Data Portal is refreshed on a periodic basis with some data sets being refreshed monthly while others are refreshed annually. Additionally, on February 11, 2021, the Commission issued an order approving the design and implementation of a statewide IEDR platform to centralize data access, including utility data (customer and system data) and other energy-related data (e.g., EV registration, building characteristics, DER operations) in support of NY's clean energy goals.⁹⁶ The Company has continued to enhance its own System Data Portal to meet stakeholder needs such as increased data granularity to understand local electric system capacity in addition to meeting regulatory requirements including the creation of a new Electrification Capacity map. In parallel with enhancing the System Data Portal, National Grid has coordinated with the IEDR Development Team to provide extracts of system data from the portal for use within the centralized IEDR platform.

⁹⁶ IEDR Proceeding, Order Implementing an Integrated Energy Data Resource (issued February 11, 2021) (IEDR Order).

Implementation Plan, Schedule, and Investments

Current Progress

System Data Portal

Since filing the 2023 DSIP Update, National Grid has made significant improvements to system data and portal functionality. Improvements have been made with respect to process, automation, quality control, and analysis required to develop the data, along with increasing the breadth of data available and enhanced presentation of that data in the Company's System Data Portal. Although an account was previously required to access the NY System Data Portal, the account functionality was disabled to remove unnecessary data access barriers for users of the portal.

Recent enhancements to the System Data Portal have focused on expanding the types of system data made available to now include nodal hosting capacity for both solar PV and ESS maps, cost share projects increasing hosting capacity, substation accepting flexible interconnections, and seasonal electrification capacity at the feeder and substation level. A description of the information currently available on the System Data Portal and its intended uses by third parties is provided in Table 2.8.1 below.

Table 2.8.1: Information Available on National Grid's New York System Data Portal

Portal Tab	Description / Data Provided	Stakeholder Utilization
Introduction	Provides a link to National Grid's IOAP (referred to by the Company as a new customer application portal (nCAP)), plus FAQs, links for further help, and a contact email. This also provides a link to the DPS website hosting each of the utility's NY-SIR Monthly Inventory Reports showing certain DG interconnection queue information.	Assists with access to interconnection application portal and how to use the portal. Provides helpful links to the Joint Utilities' sites and the NY-SIR Monthly Inventory Reports on the DPS website.
Company Reports	Provides National Grid reports including Five-Year CIP, Fifteen-Year Plan, Condition Assessment Report, Peak Load Forecast, Peak Feeder Level Load Forecast, Reliability Report, Summer Preparedness, Power Quality, DSIP Update, and BCA Handbook.	Consolidated location for providing transparency to pertinent Company documents.
Distribution Assets Overview	Provides planning information for feeders including feeder number, substation name, primary voltage, thermal ratings, past and forecasted loading, and historic feeder load curves. Since the 2018 DSIP Update, 8,760-hour forecasted feeder loading has been added.	The data provides information that helps DER developers understand potential system constraints that may impact future interconnections.

Portal Tab	Description / Data Provided	Stakeholder Utilization
PV Hosting Capacity	Provides overall hosting capacity on a zoomed-out view. A zoomed-in localized view provides data down to nodal level as to the amount of solar PV DG capacity that each feeder could accommodate at that node without requiring significant infrastructure upgrades.	Hosting capacity gives the developer a relative indication of where interconnection costs may be higher or lower.
Electrification Capacity	Provides seasonal load-serving capacity on a per feeder basis.	The data provides information that helps customers understand how much seasonal capacity each feeder has for electrification technologies such as EV charging infrastructure and/or building electric heating equipment.
ESS Hosting Capacity	Provides overall hosting capacity, for both a charging and discharging operational scenario, on a zoomed-out view. A zoomed-in localized view provides data down to the nodal level as to the amount of ES DG capacity and load-serving capacity that each feeder could accommodate at that node without requiring significant infrastructure upgrades	Hosting capacity gives the developer a relative indication of where interconnection costs may be higher or lower.
LSRV / VDER	Indicates the substations on which LSRV compensation is available as part of the VDER Value Stack compensation.	Enables DER developers to target beneficial locations and enhance the value of eligible DER interconnections.
DG Cost-Sharing	Provides a list of cost-sharing projects.	Enables developers to view a list of cost-sharing eligible capacity projects with existing cost contribution and related incremental capacity improvements.
CESIR Pass Fail	Provides an anonymized report indicating the historical pass/fail results of completed DG or ESS project CESIRs with respect to each evaluation criteria assessed in the CESIR.	Developers can utilize this report to understand the CESIR results of other projects and get an idea of which evaluation criteria are most likely to pass/fail.

Portal Tab	Description / Data Provided	Stakeholder Utilization
REST API	Provides a submission form where portal users can request access to the underlying ArcGIS platform's RESTful API services where the data on National Grid's System Data Portal is accessible programmatically via REST URL.	Enables more advanced users of the portal to utilize the ArcGIS map service REST URL to integrate National Grid's map services with their own maps.
NWA	Provides a link to National Grid's NWA page which defines NWAs and the associated Planning Process and Opportunities.	Developers are provided an advanced view as to where future DER opportunities may exist in advance of formal RFP solicitations for NWAs.

Integrated Energy Data Resource

Of particular importance to data sharing to benefit Energy Service Entities (ESE) statewide is NYSERDA's development of a new IEDR platform. The IEDR platform will house energy data from all gas, electric, and steam investor-owned utilities (IOUs) in NYS. The Commission selected NYSERDA as the project sponsor for the IEDR platform and NYSERDA has contracted with a third-party consortium led by E Source Companies, LLC (E Source) where E Source is serving as the solution architect and development team (IEDR Development Team) for the IEDR platform in addition to providing ongoing operation and maintenance services for the platform.

National Grid is providing sourcing data for the IEDR and collaborating with the IEDR Development Team throughout the five-year time horizon for this 2025 DSIP Update. The IEDR Program Team implemented the following use cases for the IEDR IPV which was released in Q1 2023.

Table 2.8.2: Information Currently Available on IEDR Platform

Initial Public Version Use Cases	Use Case Summaries	Completion Timeframe
Large Installed DERs	This use case enables access to, and the ability to manipulate, data that shows all installed DERs that utilities have data on (e.g., over 300 kW), so that users can plan for siting of new DERs and monitor the overall state of DER development in NY.	3/31/2023
Large Planned DERs (Interconnection Queue)	This use case enables utilities, DER aggregators, DER providers, and government agencies to view the most important queued DER attributes in a table (e.g., DER Type, DER Status, DER Status Rationale, etc.) and graphically display the types and statuses of DERs, so users can accurately forecast future projects and easily retrieve key information.	3/31/2023

Initial Public Version Use Cases	Use Case Summaries	Completion Timeframe
Consolidated Hosting Capacity Maps	This use case supports the ability of DER developers, DER owners, and/or utilities to view all Hosting Capacity maps for the entire state in a single map view with consistent data so that end users can site new DERs and monitor the state of DER development in NYS more accurately.	3/31/2023

Table 2.8.3: MVP Use Cases

Use Case	Description
DER Siting	This use case will support local governments and community solar developers who would want to accelerate the process for identifying, selecting, and negotiating site agreements for community solar projects so as to deploy available capital more quickly and increase the amount of clean energy available to NY electricity customers. The IEDR will serve as a one-stop shop for standardized DER data and will operationalize the flexible demand market.
Hosting Capacity and DER Map Enhancements	This use case will support DER developers, DER owners, and/or utilities to better understand and accelerate the interconnection approval process for planned/installed DER systems, so that DER projects can deliver clean energy to customers as soon as possible. Accelerating the interconnection process also includes enabling a clearer understanding and evaluation of the process of siting the location of a DER installation. These goals could be achieved by enhancing existing Hosting Capacity maps through standardization, the addition of interconnection approval time and interconnection cost information, and corresponding forecasts of hosting capacity updates.
Efficient and Effective Access to Existing Customer Billing Data	Current access to bill data is problematic as the only way to access bill image PDFs is through a customer online account where separate actions are required for each customer account at the time of the authorization request. Ideally, customer consent can be granted both in advance and at the moment of the request, and it should be possible to grant access via mobile phone. This use case could help to improve the timeliness of bill payment and reduce late fees, as well as facilitate verification of satellite customer savings.

Use Case	Description
Access to Basic Rate Data and Tariff Book for Individual Rate Find and Filter Rate Options Across NYS IOUs	This use case is comprised of features that enable those estimating energy customer bills to access the data they need to do so more easily and precisely than currently available. 1. Make rate parameters that change slowly available in a structured format: rate periods, holidays, seasons, minimum and other fixed charges, and baseline allowances (a/k/a tiered block rates). 2. Facilitate easier navigation to the sections of the Electricity Tariff (i.e., tariff book) where rate parameters for a given rate class can be found, which includes easier navigation to both the most recent version of the tariff book itself and historical versions of the tariff book.

The IEDR MPV is available at <https://iedr.nyserda.ny.gov>.

Data Management

In line with National Grid’s “One System, One Model” data strategy, the Company and its affiliates are investing in data management tools to enable a wide variety of data use cases for grid modernization and electric business needs. This will also be used to support data sourcing and compilation requirements for the IEDR. Within National Grid, this is currently being referred to as the Data Management Platform (electric) and DataHub Platform (gas). Much discovery in this space has occurred since the 2023 DSIP Update, by means of outlining source systems and their dependencies, development of data pipelines and governance strategies, and defining proof-of-concept work for targeted data products.

Future Implementation and Planning

National Grid will continue to enhance the system data it directly makes publicly available with specific improvements to HCA. National Grid has refreshed the analysis on the entire system and released an update to the PV Hosting Capacity, ESS Hosting Capacity, and Electrification Capacity maps on April 1, 2025. A detailed plan for enhancing HCA is discussed in the Hosting Capacity section of this 2025 DSIP Update.

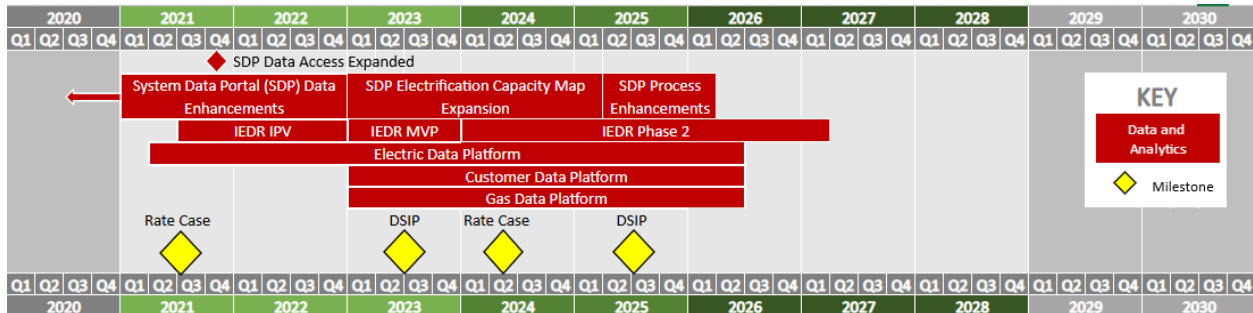
Additional information regarding the future implementation of IEDR can be found in Appendix B., Section 5.8, entitled “Data Sharing”, of this 2025 DSIP Update.

IEDR Phase 2 use cases are in draft format and may change as Phase 2 discovery and development progresses. IEDR Phase 2 consists of approximately 31 use cases to be developed over a 30-to 36-month schedule that commenced in April 2024. IEDR Project status is available on NYSERDA’s website at <https://www.nyserda.ny.gov/All-Programs/Integrated-Energy-Data-Resource-Program>. The IEDR platform is available at <https://iedr.nyserda.ny.gov>.

In the future, the gas and electric data platforms will be combined into a single National Grid platform named Grid Lake. The work to deploy the current platform is included in the creation of a cloud-based data platform, the use of data cataloging and quality tools, and additional capture of metadata across a variety of the business processes and use cases of the Company and its affiliates. This approach will be used to more efficiently, consistently, and effectively source data across

processes and systems to enable more meaningful, data-driven decision making. Future work phases will build out the Grid Lake platform and will include any remaining key datasets. The Grid Lake platform will reduce the effort and cost to source and integrate data for several other related efforts. These include ADMS, Telecom Operations Management, and digital projects such as FutureNow and On My Way. The data management capabilities of the Company and its affiliates will be enhanced through these additional tools that enable easier data integration and master data management.

Figure 2.8.1 Data Sharing Integrated Implementation Timeline



Risks and Mitigations

Table 2.8.4: Risks and Mitigations for Data Sharing

Risk	Mitigation
Performance	National Grid will investigate any reports of performance degradation of data sharing portals and assess the need to upgrade and/or migrate services to another platform.
Data discrepancies	National Grid is working to improve data management capabilities, identify discrepancies, and treat data as an asset by developing data governance strategies and targeted data products with quality assurance/control assessed throughout the data lifecycle.
Data privacy/data sensitivity	National Grid is collaborating with the IEDR Development Team and other stakeholders to gain the required approvals before sharing any data deemed sensitive with specific attention being given to customer data.

Alignment with CLCPA Goals

The System Data Portal plays a valuable role in meeting NYS's clean energy goals under the CLCPA. The data shared on the portal is of particular value to DER developers looking for potential locations where the grid is best suited to support a specific DER such as solar PV, ESS, and EV infrastructure. By enhancing the granularity of data provided on the System Data Portal while maintaining data quality, DER developers can apply for interconnection, with greater confidence, at locations where the likelihood of grid-side upgrades is low and any potential infrastructure upgrade costs are minimal. This enables more applications that lead to a successful interconnection which is critical to meet the state's clean energy goals.

Additional information made available through the System Data Portal, such as LSRV locations, allows DER developers to target beneficial locations for siting DERs. National Grid's NWA website also provides information for third parties that may be capable of using DERs to solve grid constraints.

Stakeholder Interface

National Grid conducts periodic stakeholder sessions for various data sets made available on the Company's System Data Portal including hosting capacity and NWA information. Stakeholder sessions are conducted as a collective of Joint Utilities' members, such as when a new enhancement is released to the Hosting Capacity maps in parallel across all member utilities. However, National Grid also conducts more individualized stakeholder sessions where SMEs engage in workshops and training sessions with interested stakeholders such as the hosting capacity map demonstration conducted for NY-BEST and the Company's DG customer engagement seminar. As a result of these stakeholder sessions, additional training material and help guide documentation have been devised to improve the usability and transparency of the variety of data National Grid shares externally. Suggestions for improvements from stakeholders are regularly incorporated into the Joint Utilities' roadmaps that outline a path for implementing future enhancements as part of a regular update cycle.

National Grid's active engagement in the development of the IEDR also supports stakeholders as the primary use cases of the IEDR were developed collaboratively with stakeholder input. IEDR stakeholders include:

- Developers
- Policy advocates
- State government
- Regulators
- Technology providers
- Energy consultants
- Utilities
- Federal government
- State agencies
- Local community organizations
- Local governments or municipalities
- Advocacy groups (environmental, data sharing)

2.9 Hosting Capacity

Context and Background

Hosting capacity is defined as the amount of DER that can be accommodated without adversely impacting power quality or reliability under existing control configurations and without requiring infrastructure upgrades to the primary and/or secondary network system.⁹⁷

To encourage efficient DER integration, National Grid provides estimates of its system's hosting capacity for each radial distribution circuit within the Company's service territory, as it relates to different types of DERs (e.g., solar PV, ESS). Different types of DERs have unique operational characteristics and therefore require the use of a specific HCA methodology. The results of HCA provide valuable system data that has been requested by DER providers. The hosting capacity information supports a "DER Planning" use case and benefits stakeholders as it helps prospective interconnection customers to make more informed business decisions with respect to marketing activities and relative interconnection costs, prior to committing resources to an interconnection application.

Stakeholders can access the most up-to-date Hosting Capacity maps through National Grid's System Data Portal available at <https://systemdataportal.nationalgrid.com/NY/>.

Implementation Plan, Schedule, and Investments

Current Progress

National Grid, in coordination with the Joint Utilities, has continuously developed and refined the Company's hosting capacity maps to improve transparency, support grid planning, and enable better decision-making for DERs, ESS, and electrification-related load growth. Over the past decade, these maps have evolved from high-level circuit indicators to detailed, data-rich tools with sub-feeder granularity, nodal constraint visibility, and expanded data accessibility via APIs and integration of hosting capacity data with the IEDR. This evolution has been guided by stakeholder input, regulatory directives, and technological advancements in power system modeling and distribution planning.

Using an Esri-based mapping platform, National Grid displays a geographical representation of each feeder and associated topology as well as pertinent tabular information about each line segment, feeder, and associated substation via data popups on the various maps hosted on its System Data Portal. The System Data Portal is publicly accessible and provides users with an

⁹⁷ Electric Power Research Institute (EPRI), *Defining a Roadmap for Successful Implementation of a Hosting Capacity Method for New York State*, Report Number 3002008848 (EPRI Roadmap) (June 2016), p. 2, available at <https://www.epri.com/research/products/3002008848>

interactive representation of National Grid’s distribution system that includes distribution feeders at both the 5 kV and 15 kV voltage class as well as substation and Sub-T lines operating under 69 kV.

The following sections provide a detailed, chronological breakdown of the major updates and enhancements made to the PV, ESS, and Electrification Hosting Capacity maps.

PV Hosting Capacity Map Updates

- Initial Feeder-Level Hosting Capacity (2016–2017)
 - Launched the first Stage 1 Hosting Capacity maps, providing basic feeder-level indicators showing general circuit availability for DER interconnections.
 - Maps displayed high-level traffic light indicators (red/yellow/green ratings) to show where DERs could likely interconnect without major system upgrades.
- Feeder-Level Hosting Capacity & Standardized Methodology (2017–2018)
 - Released the first feeder-level hosting capacity values using EPRI’s DRIVE tool.
 - Provided standardized methodologies across all utilities, ensuring consistency.
 - Introduced additional system data fields based on stakeholder input.
 - Began updating maps annually through utility DSP portals.
- Sub-Feeder Granularity & Existing DER Integration (2019)
 - Introduced sub-feeder (nodal) granularity, allowing hosting capacity to be displayed at different points along a circuit rather than a single feeder-wide value.
 - Existing DER capacity included in calculations to reflect remaining capacity more accurately.
 - New “Local Hosting Capacity for PV” pop-up tab added, showing minimum and maximum hosting capacity per section.
 - Included a field tracking “DG Installed Since Last Refresh” giving stakeholders insight into circuit changes over time.
- Data Transparency & Enhanced Pop-ups (2020)
 - Provided downloadable feeder summary tables (Comma Separated Values (CSV)/XLS format) with all map details.
 - Added substation equipment information, including substation transformer bank thermal capacity (Megawatt-Amperes (MVA) rating) and zero-sequence voltage (3V0) protection limits.
 - Enabled annotated notes on circuit-specific situations.
- Increased Update Frequency, API Access & Additional Data (2021-2022)
 - Implemented a targeted 6-month refresh cycle for circuits experiencing rapid DER growth (defined as >500 kW of new DG added in 6 months).
 - Launched REST API access for third-party developers to programmatically retrieve hosting capacity data.
 - Included Sub-T lines to highlight additional interconnection opportunities beyond feeders.

- Advanced Map Functionality & Cost Share Integration (2023–2024)
 - Introduced “Nodal Constraints” visualization, detailing whether hosting capacity is limited by voltage, thermal, or protection constraints.
 - Incorporated Cost Sharing 2.0 indicators, identifying where utility-driven upgrades increase hosting capacity.
 - Provided links to 8760-hour feeder load profiles, enabling developers to analyze detailed hourly load curves.

ESS Hosting Capacity Map Updates

- Initial Storage Hosting Capacity Map (2022)
 - First storage-specific Hosting Capacity maps released, modeled after PV hosting capacity methodology.
 - Displayed feeder-level hosting capacity for both charging (load) and discharging (generation).
 - Toggle feature implemented to switch between storage as generation versus storage as load.
 - Included Sub-T lines to highlight additional interconnection opportunities beyond feeders.
- Sub-Feeder Granularity & Nodal Constraints (2023)
 - Added sub-feeder level HCA, increasing locational accuracy.
 - Introduced color-coded nodal views, showing variations in hosting capacity across feeder sections.
 - Pop-ups enhanced to show criteria violations at specific nodes (voltage, thermal, or backfeed limits).
 - Integrated Cost Share 2.0 project indicators for storage hosting capacity.
 - Enabled REST API access for automated data retrieval.

Electrification Map Updates

- EV Load Hosting Capacity Map Development (2020)
 - First EV Load Hosting Capacity maps released in response to the MRP Order.
 - Provided feeder-level hosting capacity values for EV charging loads, mirroring the PV hosting capacity approach.
 - Incorporated color-coded circuit indicators to display remaining capacity for new electric load.
- Electrification Hosting Capacity Expansion (2023–2024)
 - Expanded EV Load Hosting Capacity maps into full Electrification Hosting Capacity maps in compliance with Commission directives.
 - Added dual seasonal hosting capacity values, allowing users to toggle between summer and winter peak conditions.
 - Integrated EJ area overlays to support equitable electrification planning.
 - Maintained feeder-level color-coding and breakpoints, ensuring continuity with previous EV maps.

Updates Related to Hosting Capacity Data Sharing with IEDR

The integration of hosting capacity data into the IEDR has evolved significantly since the platform's launch. Early 2023 marked the IEDR's IPV, which included the first statewide Hosting Capacity map consolidation. At that stage, the IEDR essentially mirrored each utility's published Hosting Capacity maps in a single viewer, displaying key attributes like available capacity per circuit section. The focus was on consistency so that “users can view all hosting capacity maps for the entire state in one map view with consistent data.” However, the granularity and features of the Hosting Capacity data have expanded through 2023 and 2024, driven by the Joint Utilities’ Hosting Capacity roadmap.

In April 2023, the Joint Utilities collectively rolled out a suite of enhancements to their hosting capacity analyses which were subsequently fed into the IEDR. These included: sub-feeder level hosting capacity for energy storage (providing node-level granularity on storage interconnections), identification of nodal constraints (violation criteria) on the PV and storage maps, an indication of how much DER has been connected since the last Hosting Capacity refresh, and integration of data from the Commission’s Cost Sharing 2.0 Order⁹⁸ (i.e., planned upgrade projects to increase hosting capacity, with details on the affected substation, the expected capacity increase, anticipated in-service date, and upgrade cost). All of the Joint Utilities implemented these updates around the same time, meaning the IEDR received a richer dataset for hosting capacity by mid-2023. The IEDR's “Electric Infrastructure/Hosting Capacity” module was updated to display these new fields so that developers could see, for example, if a section of the grid is slated for an upgrade that will boost its hosting capacity and when that is expected to occur.

From a procedural standpoint, one notable change since 2023 is the move toward more frequent incremental updates. As noted, the Joint Utilities agreed to issue interim six-month updates for rapidly changing circuits (which is a new practice starting in 2023). Procedurally, this means the utilities must re-run hosting capacity calculations for certain feeders out-of-cycle and push those updates to IEDR without waiting for the next full system refresh.

Since integrating the Hosting Capacity data, the Joint Utilities have continuously refined data quality controls. In late 2022, the Joint Utilities worked on consistency of data element nomenclature across all utilities so that fields like circuit ID, voltage, available MW, etc., mean the same thing for Con Edison, for example, as for National Grid. By 2023, this standardization paid off – the IEDR's consolidated map presents uniform column headings and units for all service territories. During IEDR Phase 1, the Joint Utilities also sent test data and engaged in iterative feedback with the IEDR Development Team to iron out any mismatches. This collaborative debugging continued into IEDR Phase 2: in 2024 the Joint Utilities participated in working sessions on data defects and used an online portal to report any Hosting Capacity dataset issues in IEDR for prompt resolution.

⁹⁸ Cases 20-E-0543 et al., *Petition of Interconnection Policy Working Group Seeking a Cost-Sharing Amendment to the New York State Standardized Interconnection Requirements* (IPWG Petition for SIR Cost-Sharing Amendment), Order Approving Cost-Sharing Mechanism and Making Other Findings (issued July 16, 2021) (Cost-Sharing 2.0 Order).

Future Implementation and Planning

Planned Future Enhancements to Hosting Capacity Maps

The Joint Utilities' Integrated Planning Working Group continues to be informed by active Joint Utilities' engagement in the ITWG, Energy Storage Working Group, EV Working Group and more recent efforts including the GOTF Proceeding. The Joint Utilities expect future updates to align with needs identified in these forums.

In the meantime, updates to the electrification, PV and ESS HC maps were published by April 2025. Key enhancements were made to electrification maps including the addition of voltage information for each circuit. This enables stakeholders to better assess grid capacity. The maps also now include notes identifying upstream constraints that could potentially impact hosting capacity at the substation.

The Joint Utilities are also considering expanding the use cases for the Electrification maps to better support the strategic siting of electrification projects. This potential enhancement could focus on identifying suitable locations for school bus charging infrastructure and public EV charging stations. By incorporating these specific use cases, the Electrification maps could provide insights for fleet operators, municipalities, and charging providers, helping them align electrification efforts with grid readiness. While still under discussion, this expansion would improve the Electrification maps' ability to guide infrastructure investments and facilitate the transition to electric transportation.

Concurrently, efforts continue within the IPWG and the ITWG to potentially enhance the ESS Hosting Capacity maps. These improvements may incorporate ESS operational schedules, providing increased detail and practicality while considering alignment with the established NY-SIR and the CESIR process therein, and related processes. Such enhancements aim to assist developers by offering clearer insights and streamlining navigation through the interconnection process.

As part of this effort, each utility has published tentative ESS schedules through the ITWG. These schedules provide insight into how storage systems may operate at different times and could help improve interconnection planning, CESIR evaluations, and system impact assessments. However, the utilities and industry stakeholders are still determining how these schedules should be used and whether they should be reflected in the ESS Hosting Capacity maps.

The Integrated Planning Working Group intends to update the ESS Hosting Capacity maps where appropriate, but first, the ITWG must align on how to utilize ESS schedules in the interconnection process. Once this alignment is reached, the Integrated Planning Working Group will evaluate next steps for integrating this information into the HC maps. This ongoing collaboration ensures that any updates made to the ESS maps improve transparency, provide value to interconnection stakeholders, and support the continued deployment of energy storage in NY's energy transition.

To enhance stakeholder understanding and ensure broad accessibility of the Hosting Capacity maps, the Joint Utilities will offer targeted training sessions in fall 2025. Recognizing the critical role of stakeholder feedback in developing effective training content, the utilities are actively

gathering input through a stakeholder survey. This feedback will directly inform the curriculum, covering map content, navigation techniques, and practical applications of the data. This initiative emphasizes the Joint Utilities' commitment to meaningful stakeholder collaboration, supporting both experienced and new stakeholders in effectively utilizing these critical resources for electrification and interconnection projects.

To advance from the current Hosting Capacity maps to the envisioned enhancements, the Joint Utilities will continue investing in stakeholder engagement and feedback processes, data analysis, and ongoing collaboration across working groups. This collaborative approach ensures that future updates remain responsive to stakeholder needs and effectively support strategic electrification and interconnection planning.

Stakeholder Training and Support

Recognizing the importance of clear guidance and effective use of Hosting Capacity maps, the Joint Utilities are preparing targeted training sessions scheduled for fall 2025. To ensure these sessions genuinely meet stakeholder needs, the Joint Utilities have proactively distributed a survey to gather direct user input. The survey seeks feedback on stakeholders' familiarity with hosting capacity concepts, map navigation preferences, desired technical depth (ranging from introductory overviews to advanced analysis), and the practical applications of data most relevant to their planning activities. Respondents are invited to identify specific knowledge gaps or operational challenges they have encountered, suggest priority topics (such as interpreting constraint data or effectively using map APIs), and express preferences regarding session formats (e.g., interactive demonstrations, recorded webinars, or technical Q&A sessions). By collecting and acting upon this detailed feedback, the Joint Utilities aim to create training that directly addresses real user challenges, empowering both new and experienced stakeholders to effectively leverage the Hosting Capacity maps in their interconnection and electrification projects.

IEDR Collaboration

Phase 2 of the IEDR (2024–2026) is anticipated to explore numerous new potential use cases, several of which may involve hosting capacity data in more advanced or detailed ways. It is important to note that these use cases are currently under discussion, preliminary in nature, and not finalized. The following examples from recent stakeholder proposals and exploratory conversations illustrate how hosting capacity data might potentially be leveraged in future developments:

- One notable use case being considered involves providing detailed hosting capacity insights directly at the customer-premise level. Often referred to in stakeholder discussions as “Determine Customer Site Hosting Capacity,” this concept, as outlined in proposals such as the one from NYPA, would enable users—such as state agencies, large customers, or developers—to assess how much integration or load capacity exists on the local distribution system for an existing or potential DER interconnection or increased load at a specific address. Implementing this scenario would require combining existing substation-level and feeder-level hosting capacity information with specific details of a service connection, including data not currently shown explicitly on existing Hosting Capacity maps, such as transformer ratings and phase connectivity.

- Another potential future-oriented use case involves enhancing the DER interconnection portal to better integrate hosting capacity data. While Phase 1 introduced some contextual information on interconnection (i.e., and timing), Phase 2 proposals envision a more comprehensive approach, termed "Accessible DER Interconnection (Hosting Capacity) Information." Official discussions suggest this might include standardized hosting capacity data across utilities (a process already underway), augmented with additional details such as interconnection queue statuses, advanced filtering options, and possibly streamlined application processing steps.

Hosting capacity data is also being considered for wider planning contexts within the IEDR, such as the "Accelerated DER Siting" concept. This potential use case, included in IEDR Phase 2 preliminary proposals, would utilize hosting capacity data as one of multiple factors to help identify optimal locations for community solar or other DER projects. This approach would potentially integrate historical and forecasted hosting capacity data with additional datasets, such as land use or anticipated load growth, to highlight areas where new DER investments could be most effectively accommodated.

Risks and Mitigations

Table 2.9.1: Hosting Capacity Risks and Mitigations Strategies

Risk	Mitigation
Cybersecurity	National Grid is ensuring that the System Data Portal used to share the Hosting Capacity maps remains up to date with security patches and protocols.
Performance	National Grid will investigate any reports of performance degradation of data sharing portals, Hosting Capacity maps, and assess the need to upgrade and/or migrate services to another platform.
Data discrepancies	National Grid is working to improve data management capabilities, identify discrepancies, and continue to refine quality assurance/quality control steps into the processes.
Data privacy/data sensitivity	National Grid is collaborating with stakeholders including regulatory and cybersecurity experts to ensure the data made publicly available on the Company's System Data Portal and Hosting Capacity maps does not disclose any data deemed sensitive or put the Company, its customers, and its assets at unnecessary risk.
Software limitations	The expanded granularity of data made available on the Hosting Capacity maps and the drive to further increase the frequency of HCA updates requires a nuanced assessment of the software and processes currently used to update and maintain the Hosting Capacity maps. National Grid will investigate methods to improve process efficiencies through task automation and continue to work with EPRI on the development of its DRIVE tool and the integration with the CYMDIST distribution power flow software.

As a cautionary note, data provided in the Hosting Capacity maps is for informational purposes only and is not a substitute for the established interconnection application process. DER, EVSE, and system data used for HCA must be accurate and current to provide accurate results.

Alignment with CLCPA Goals

Hosting Capacity maps help developers find locations that are likely lower cost and easier for interconnection and will help to support the CLCPA goals of 10 GW of solar and 6 GW of ESS by 2030. Future planned developments to facilitate CLCPA goals include the incorporation of additional hosting capacity data for different DER operation scenarios. Additionally, Hosting Capacity maps for other load resources such as EV chargers will further support economy-wide GHG emission reduction goals. These efforts indirectly support CGPP, by enabling DER integration planning at the distribution level commensurate with the CLCPA goals. CGPP is well aligned, using the same assumptions, supported in part by an understanding of local HCA granting additional confidence in the pathways to CLCPA achievement envisioned in CGPP models.

Stakeholder Interface

The Joint Utilities place stakeholder engagement at the core of developing and improving Hosting Capacity and Electrification maps. These maps are intended to serve a broad user community – from renewable developers and EV charging companies to municipal planners and customers – so their value depends on meeting stakeholder needs. By actively involving stakeholders, the Joint Utilities ensure the maps remain useful, transparent, and aligned with real-world requirements, ultimately streamlining DER interconnections and guiding efficient grid investments. In practice, this engagement builds trust in the data and tools provided, empowers users to make informed decisions, and helps NY achieve its clean energy and electrification goals through collaborative planning.

Stakeholder needs are continuously through formal sessions, surveys, and other feedback channels. The evolution of map features is driven by user priorities. For example, the Joint Utilities convene dedicated Hosting Capacity Stakeholder Sessions (open webinars and technical conferences) where developers, industry groups, and community representatives can voice their needs, ask questions, and suggest enhancements. These sessions are a cornerstone of the planning process – the Joint Utilities present current map capabilities and solicit input on what to improve next. In these forums, stakeholders' priorities emerge (e.g., desire for more granular data, easier data access, or new map types), and the Joint Utilities actively record and consider this input. Crucially, stakeholder feedback is not only heard but systematically incorporated into map enhancements.

As the Joint Utilities have noted, third-party input directly influences the prioritization of both near-term and long-term Hosting Capacity map upgrades. A clear example is how stakeholder requests for greater detail led to the addition of sub-feeder level data and nodal constraint indicators on the maps. Similarly, stakeholders advocated for more frequent data refreshes to keep the maps current; in response, the Joint Utilities moved from purely annual updates to also providing mid-

cycle updates for rapidly changing circuits (e.g., six-month refreshes on PV maps where greater than 500kW of new DG was connected since the last annual update). The introduction of Electrification Capacity Maps in 2024 was driven by the growing electrification efforts of customers and policymakers – stakeholders signaled the need to understand where the grid can accommodate new electric vehicle chargers and building electrification loads, prompting the Joint Utilities to include these maps as the latest stage of the Hosting Capacity roadmap. By identifying needs through constant engagement and acting on them in each iteration of the maps, the Joint Utilities demonstrate a highly responsive approach to stakeholders.

The content and functionality of Hosting Capacity and Electrification maps today reflect extensive stakeholder-provided input, data, and feedback. Many enhancements are traceable to stakeholder contributions. For instance:

- **Map Features and Data Fields:** Developers and other users often request specific information to aid their project planning. In response to such feedback, the Joint Utilities have progressively enriched the maps. Substation-level and feeder-level granularity, existing DER visibility, and nodal voltage constraint data were all added following stakeholder discussions about what information would help them screen interconnection locations. The Joint Utilities explicitly credit stakeholder sessions for shaping these upgrades, confirming that stakeholders helped guide which features to implement next on the roadmap.
- **User Capabilities and Data Access:** Some stakeholders (e.g., consultants and large developers) have advanced analytical tools and requested direct access to underlying data to integrate with their own planning models. The Joint Utilities addressed this request by enabling data downloads and APIs for the Hosting Capacity maps. For example, storage hosting capacity data is now available via an API, and 8760-hour load profile data links are provided. These are features that make the maps more useful for those who wish to perform custom analysis. These capabilities were added to support sophisticated users based on feedback about how stakeholders wanted to use the information.
- **Feedback Loop for Ongoing Improvements:** The Joint Utilities treat stakeholder feedback as an invaluable resource for continuous improvement. They catalog suggestions from meetings, support tickets, and surveys, then feed them into the design cycle for future map versions. For example, stakeholders have consistently highlighted the value of regular data updates. In stakeholder forums, there have been requests for more frequent updates to Hosting Capacity maps beyond the standard annual refresh. The Joint Utilities have acknowledged these concerns by implementing interim updates and exploring additional frequency improvements as HCA processes become more automated.

The Joint Utilities employ a multi-faceted engagement strategy to involve stakeholders. Key means and methods include:

- **Dedicated Stakeholder Sessions and Webinars:** The Joint Utilities host regular stakeholder meetings specifically focused on DSP initiatives, with Hosting Capacity maps as a frequent agenda item. For instance, the utilities have made it a practice to hold an annual stakeholder webinar each spring (typically around May) devoted to hosting capacity updates. In these

sessions, the Joint Utilities present recent map updates or new features, then open the floor for questions and discussion. This format allows real-time stakeholder input on what is or is not working. In the past, the Joint Utilities have also arranged thematic webinars (e.g., a Storage Hosting Capacity map deep-dive in May 2022) to walk through new map tools and gather stakeholder reactions in detail. Meeting materials underscore these goals. All webinars are open to the public and broadly announced, ensuring any interested party (developers, trade organizations, community representatives, etc.) can participate.

- **Surveys, Feedback Forms, and Direct Outreach:** To supplement meetings and inform new initiatives, the Joint Utilities employ targeted feedback mechanisms to understand stakeholder needs. A practical example is their approach to the upcoming Fall 2025 Hosting Capacity maps' training. Rather than designing the training based on assumptions, the Joint Utilities first distributed a user survey to identify specific knowledge gaps and challenges. This proactive step ensures the training will address actual stakeholder needs rather than presumed ones. The survey collects input on preferred training topics, format preferences, and specific questions users have about the maps. By gathering this feedback before finalizing the training agenda, the Joint Utilities demonstrate their commitment to creating truly useful resources that respond to real user challenges.
- **Transparent Information Resources:** As part of engagement, the Joint Utilities make extensive information readily available to stakeholders, empowering them to self-educate and provide informed input. The Joint Utilities' website hosts a dedicated section for hosting capacity, complete with user guides, FAQs, definitions of criteria, and downloadable data. By equipping stakeholders with knowledge (e.g., criteria and assumptions used in the HCA are published for transparency), the Joint Utilities facilitate more productive stakeholder interactions – users can understand the context and limitations of the maps and thus give more pointed feedback or requests. Additionally, the Joint Utilities publish quarterly DSP newsletters and timely announcements (e.g., via email lists) so stakeholders are kept up-to-date on new map features or upcoming engagement opportunities. This ongoing communication keeps stakeholders engaged throughout the cycle, not just at formal events.

Throughout their engagement efforts, the Joint Utilities remain vigilant that the information and tools provided are clear, effective, and do not inadvertently mislead or burden stakeholders. Through these efforts, the Joint Utilities work to ensure that stakeholder engagement is not only frequent but effective – meaning the provided information is understood as intended and genuinely useful. Several practices underscore this commitment:

- **Standardization Across Utilities:** A major focus has been making the Hosting Capacity maps consistent in format and quality statewide, despite each utility maintaining its own map. Stakeholders voiced that it is confusing if each utility's map has different scales or conventions. The Joint Utilities responded by closely coordinating on map design so that a developer or customer can cross a utility's boundary and see the same exact Hosting Capacity maps on the same exact scales, enabling users to get up to speed quickly anywhere in NY. This standardization minimizes the learning curve and prevents errors that could

arise from inconsistent data presentations. It reflects a unified approach to meeting stakeholder needs uniformly, which industry observers have noted is a key part of the Joint Utilities' strategy.

- **User Guidance and Training:** The Joint Utilities recognize that providing complex grid data without context can cause misinterpretation – an unintended challenge they work to avoid. To that end, every map release is accompanied by clear documentation and user guidance (definitions of fields, caveats on data usage, etc.). Utilities often include pop-up explanations or legends on the maps themselves to guide users. Moreover, as described above, the Joint Utilities are initiating formal training sessions to ensure stakeholders fully understand how to navigate the maps and apply the data. By educating users, the Joint Utilities mitigate the risk of misuse.
- **Stakeholder Training and Support:** To further enhance stakeholder familiarity with, and effective use of, Hosting Capacity maps, the Joint Utilities will deliver focused training sessions in fall 2025. Planning for these sessions incorporates direct input from stakeholders, gathered through a recent survey designed to better understand users' specific challenges, priorities, and preferences. Survey topics cover stakeholders' experience levels, specific questions about interpreting and applying map data, and desired training formats—such as interactive tutorials, live demonstrations, or dedicated Q&A discussions. Stakeholders were also encouraged to highlight particular map functionalities or data layers where additional clarification or instruction would be most beneficial. By tailoring training sessions based on this detailed stakeholder input, the Joint Utilities aim to ensure stakeholders across varying levels of experience can confidently use the maps to support their electrification, interconnection, and planning objectives.
- **Phased Implementation and Testing:** The staged roadmap approach for Hosting Capacity map enhancements was intentionally designed to gradually introduce complexity – this gave both the Joint Utilities and stakeholders time to adapt. At each stage, the Joint Utilities gathered feedback on the last set of features before proceeding to the next, ensuring that new data layers or functions were adding value and not confusion. This iterative rollout, guided by stakeholder input, prevented the maps from becoming overwhelming or unwieldy. It also allowed the Joint Utilities to refine features in response to any early challenges. For example, when the first sub-feeder data was launched, the Joint Utilities closely watched how developers used it and solicited feedback; any clarity issues could then be addressed (through improved tooltips or FAQ explanations) before expanding further. This careful, stepwise implementation helped avoid unintended negative consequences and built stakeholder confidence in each new feature.
- **Quality and Usefulness of Data:** Stakeholders rely on the maps for important decisions, so the Joint Utilities prioritize making the information useful and up-to-date. Regular procedures are in place to maintain and refresh the data. Additionally, the Joint Utilities have made efforts to update Hosting Capacity and Electrification maps at least annually, including interim updates for areas experiencing rapid change. Updates are coordinated across all member utilities so stakeholders statewide receive refreshed information

simultaneously. These efforts help stakeholders effectively utilize the tools and make informed decisions.

Across planning, development, and implementation of Hosting Capacity and Electrification maps, the Joint Utilities have established a thorough, collaborative process that keeps stakeholders at the forefront. Stakeholder engagement is not treated as a checkbox exercise but as an integral part of the maps' life cycle – from the initial roadmap crafted with stakeholder input to each incremental update influenced by user feedback. The Joint Utilities actively seek out stakeholder needs through diverse means (workshops, working groups, surveys, and direct communications) and then demonstrate real responsiveness by translating those needs into map enhancements, support tools, and policy adjustments. This continuous dialogue has led to maps that are ever more useful, detailed, and user-friendly, while also ensuring stakeholders fully understand and trust the information provided. The ongoing training and survey initiative is the latest testament to this philosophy of engagement, showing the Joint Utilities' commitment to not just deliver data, but to cultivate an informed user community around that data.

Separately from the collective Joint Utilities' efforts, National Grid will continue industry engagement in the EPRI DRIVE users' group to have the opportunity to propose enhancements and improvements. National Grid has held webinars for developers explaining and demonstrating the hosting capacity capabilities on the Company's System Data Portal. The webinars have proved to be a useful tool for providing a live demonstration on how the portal is intended to be used and how to get the most useful information out of it. Additionally, the webinars have provided useful discussion forums for fielding developers' ideas on how to improve the functionality and the information on the portal.

2.10 Billing and Compensation

Context and Background

National Grid, along with the other Joint Utilities, has significantly adapted the Company's approach to the various DER-related billing and compensation programs that are maintained or have begun in the past ten years. The Company currently maintains the following compensation programs:

- Volumetric Net Energy Metering (NEM)
- Monetary NEM
- Remote Net Metering
- Remote Crediting
- CDG Net Crediting -both with single anchor/discount rate and multiple anchors/discount rates
- VDER Phase 1 NEM
- VDER Phase 1 NEM with Customer Benefit Contribution
- Phase 1 VDER Value Stack
- Phase 2 VDER Value Stack
- Wholesale Value Stack
- Expanded Solar for All (E-SFA)
- Statewide Solar for All (S-SFA)
- Renewable Energy Access and Community Help (REACH)

Implementation Plan, Schedule, and Investments

Current Progress

Since the 2023 DSIP Update filing National Grid has completed the billing automation of Community Distributed Generation (CDG), Net Crediting, and all VDER billing and crediting mechanisms, as well as implemented three new compensation programs: E-SFA, S-SFA, and REACH.

On September 30, 2024, the Company filed its final quarterly report detailing its progress toward automation of crediting and billing of CDG pursuant to Ordering Clause No. 2 of the Commission's September 15, 2022 *Order Establishing Process Regarding Community Distributed Generation Billing*.⁹⁹ The report detailed the billing system constraints, the changes necessary to effectuate automated CDG billing, and the steps and timeline for National Grid to achieve full

⁹⁹ Cases 15-E-0082 et al., *Proceeding on Motion of the Commission as to the Policies, Requirements and Conditions for Implementing a Community Net Metering Program*, Order Establishing Process Regarding Community Distributed Generation Billing (issued September 15, 2022),

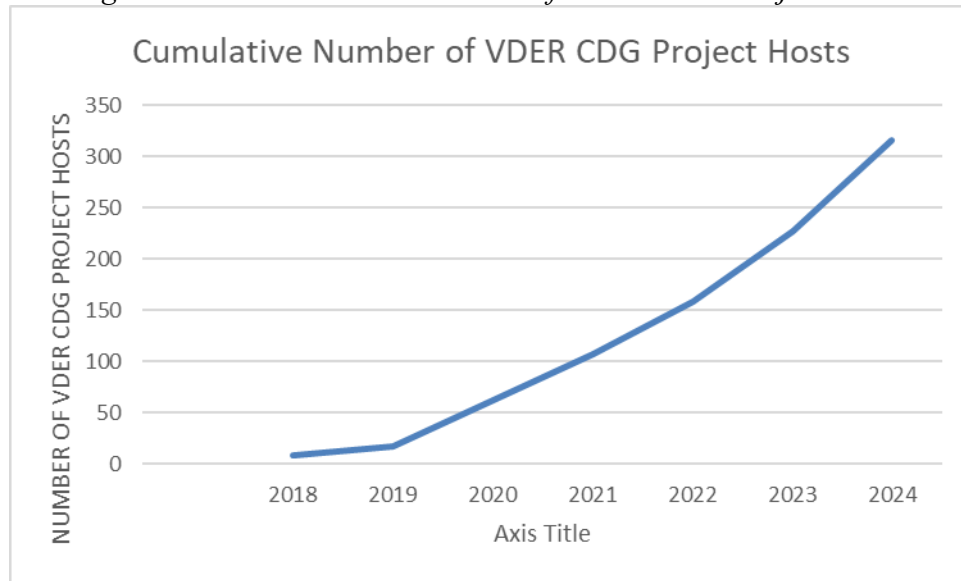
automation of CDG billing. The final phase of programming, the host cancel/rebill programming, was implemented in May 2024 with additional testing taking place through the summer 2024. In addition to all host accounts billing and crediting to their respective subscribers automatically through the Company's Customer Service System (CSS), the interchange between CSS and My Business Account now enables customers to receive monthly reports in a timely manner.

During 2022 and 2023, NYSERDA and National Grid collaborated on the E-SFA program, successfully procuring approximately 190 MW of CDG solar projects. Currently, 13 of these projects are interconnected and generating credits, while an additional 30 projects are in various stages of permitting and construction. Since December 2023, over 150,000 Energy Affordability Program (EAP) customers have been receiving bill credits each month. Following the successful implementation of E-SFA, DPS Staff filed a proposal to adopt S-SFA based on the E-SFA model, and the Commission adopted this model in May 2024. The S-SFA program offers low-income utility customers participating in the Company's EAP bill credits from a pool of participating community solar and storage projects in National Grid's utility territory on an opt-out basis. Credit recipients must reside in a DAC. S-SFA provides a streamlined opportunity for project developers to eliminate customer acquisition/management costs, while receiving a single monthly payment directly from the utility. The utility then automatically distributes these pooled credits equally among customers enrolled in the utility's EAP.

REACH authorizes NYPA to establish the REACH program to enable LMI end-use electricity consumers in a DAC to receive bill credits derived from a portion of the net revenues generated through the production of renewable energy by a system planned, designed, developed, financed, constructed, owned, operated, maintained or improved, or contracted for by NYPA as a renewable energy project. The REACH program is designed to align with the S-SFA program.

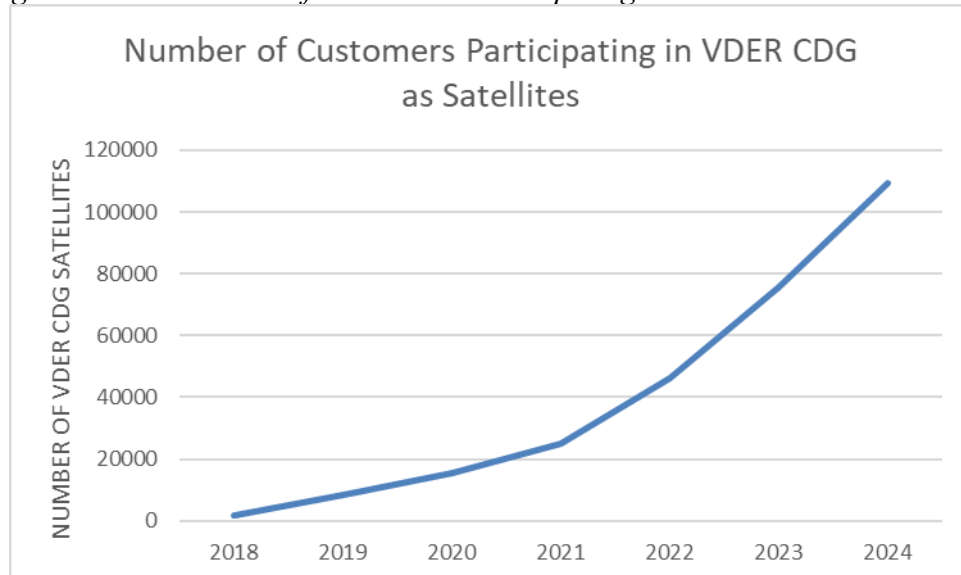
The CDG host/cancel rebill process is an enhancement under the Value Stack automation project completed in September 2024. This functionality allows National Grid to cancel and rebill hosts and satellites directly in the billing system when billing remediation warrants such an approach.

Figure 2.10.1 shows a steady increase in the number of VDER CDG project hosts from 2018 to 2024 with an upward trend year-over-year.

Figure 2.10.1: Cumulative Number of VDER CDG Project Hosts

This chart below illustrates a significant growth in the number of customers participating as satellites in the VDER CDG program over the same period. Reaching close to 110,000 by the end of 2024.

Figure 2.10.2 indicates a strong upward trend in satellite participation within the VDER CDG program over the years.

Figure 2.10.2: Number of Customers Participating in VDER CDG as Satellites

Future Implementation and Planning

Several projects are currently in the pipeline for future implementation. Starting June 1, 2025, CDG Net Crediting offers hosts the ability to exempt multiple subscribers (i.e., anchor tenants) from net crediting and to utilize multiple discount rates for subscribers. Pursuant to the Commission's May 16, 2024 Order Approving Multiple Savings Rates for Community Distributed Generation Subscribers, National Grid will allow up to three CDG savings rates per project and allow for the exclusion of multiple anchor tenants from net crediting. This policy change aims to give CDG developers the flexibility to adapt to market changes and improve project financial viability. Additionally, a new CDG portal for hosts to manage subscriber allocations is in the scoping phase. Volumetric Net Crediting for CDG is also anticipated to be deployed, with further details provided below.

National Grid is currently in the scoping and IT sanctioning phase for a CDG billing portal that will allow hosts to self-manage allocation list validations for billing credits. To ensure the portal meets user needs, multiple users experience interviews have been conducted with CDG credit allocation managers to gather their input on desired functionalities. The implementation of this portal will depend on securing the necessary funding sources.

The Joint Utilities began offering net crediting for monetary Value Stack CDG customers in October 2020, providing an alternate payment and crediting methodology for CDG Hosts and CDG Satellites that eliminated the need for a separate participation payment from the CDG Satellite to the CDG Host. The Net Crediting program requires the utility to credit the CDG Satellite's bills directly for the net credit and then pay the CDG Host the remaining value of the credit, less a utility administrative fee. However, the same program rules do not apply to grandfathered volumetric projects that currently allocate kWh to CDG satellites. Per the Commission's December 20, 2024 *Order Approving Net Crediting for Volumetric Community Distributed Generation Projects*,¹⁰⁰ a Volumetric Net Crediting program for volumetric CDG projects with fully automated billing is to be made available by the Joint Utilities by January 1, 2026.

The Host Community Benefit Program will provide an annual bill credit to residential electric utility customers with premises located in a renewable Host Community for each of the first ten years that a Major Renewable Energy Facility (greater or equal to 25 MW) operates in that community. The owner of the renewable facility will fund the credits by paying an annual fee of \$500 per MW of nameplate capacity for solar facilities and \$1,000 per MW of nameplate capacity for wind facilities. This annual fee will be paid directly to the electric utility or utilities operating in a Host Community, where the electric utility would then distribute the fees paid by the renewable facility owner, less utility administrative fees, equally among the residential utility customers within the Host Community. Each of the utilities filed Implementation Plans with draft tariff leaves with the Commission on September 30, 2021, as directed by the Commission's February 11, 2021 *Order Adopting a Host Community Benefit Program*.¹⁰¹ The Joint Utilities await

¹⁰⁰ Advancement of Distributed Solar Proceeding, Order Approving Net Crediting for Volumetric Community Distributed Generation Projects (issued December 20, 2024).

¹⁰¹ Case 20-E-0249, *In the Matter of a Renewable Energy Facility Host Community Benefit Program*, Order Adopting a Host Community Benefit Program (issued February 11, 2021).

approval by the Commission of the Implementation Plans and tariff leaves. National Grid currently has 13 major renewable energy facilities in its service territory totaling 2.9 GW of nameplate capacity. The earliest that any of these projects are expected to achieve commercial operation is November 2025 where bill credits would then be due to eligible residential customers in January 2026.

Risk and Mitigations

The main risk associated with DER-related billing and compensation programs remains consistent with the 2023 DSIP Update filing: timely implementation is hindered by the significant challenge of making the necessary complex changes to National Grid's billing system. An attendant challenge to timely implementation is having sufficient lead time from the date of a Commission order to the expected go-live date for a new program. New programs or program requirements involve changes to the billing system. The Company's legacy billing system is designed for comparatively simple and straightforward billing based on customer usage and often requires significant changes or upgrades to accommodate new regulatory requirements. Changes layered on top of other recent changes can add significant complexity due to interactions. Furthermore, custom programming requires multiple iterations of testing – each of which needs adequate time to complete – and subsequent changes to billing can require restarting the testing process.

Another consideration is that throughout the implementation process, manual shadow billing is required until new systems are verified to work as intended. Integrating large numbers of customers and being able to scale quickly for increased rates of adoption prior to the automation process presents additional challenges.

National Grid mitigates the risk of delay by engaging additional employees to complete the work and communicating with stakeholders and regulators about the process to establish full understanding of the steps and timeline involved.

Table 2.10.1: Billing and Compensation Risk and Mitigation Strategies

Risk	Mitigation
Billing program implementation delays due to complex changes requiring upgrades to legacy systems, comprehensive testing, and manual processes in early stages of new programs	- Engaging additional employees to complete the work - Communicating with stakeholders and regulators about the process to establish full understanding of the steps and timeline involved

Alignment with CLCPA Goals

National Grid is fully committed to a clean energy future and helping NY achieve its energy and environmental goals under the CLCPA. The CLCPA goals supported by DG Billing and Compensation include:

- 6,000 MW of distributed solar by 2025
- 10,000 MW of distributed solar by 2030
- 1,500 MW of ESS by 2025
- 6,000 MW of ESS by 2030
- At least 35 percent of benefits directed to underserved communities

By conceptualizing and advocating for programs such as E-SFA, S-SFA, and REACH, the Company is contributing towards bringing the economic benefits of the clean energy transition to low-income customers in DACs. Offering credible, accurate and timely billing and crediting enables the DG market to function efficiently and to grow.

Stakeholder Interface

National Grid recognizes that stakeholder engagement is an important part of customer satisfaction and developing inclusive regulatory policy to achieve desired policy outcomes. Since the 2023 DSIP Update filing, the Company has hosted or participated in many stakeholder engagement sessions to continually provide information to customers and industry participants and will continue to do so. These stakeholder engagement efforts include presentations, webinars, and workshops centered on various utility program topics. Additionally, collaboration between the Joint Utilities, NYISO, and stakeholders has been on-going for the FERC 2222 implementation effort.

The Joint Utilities continue to participate in meetings with the CDG Billing and Crediting Working Group which are predominantly attended by DER developers and other industry trade associations (e.g., New York Solar Energy Industries Association and Coalition for Community Solar Access). These meetings are facilitated by NYSERDA with DPS Staff typically in attendance. Topics covered to date or going forward include customer education and experience, bill presentation, and reporting improvements.

In late 2022 and early 2023, the Joint Utilities also participated in multiple stakeholder conferences on CDG billing and crediting issues where industry stakeholders proposed performance metrics and negative revenue adjustments (NRAs) to be tied directly to the utilities' CDG crediting and billing performance. DPS Staff also proposed performance metrics, and the Joint Utilities countered with more achievable metrics. DPS Staff is expected to issue a refined proposal for CDG billing and crediting performance metrics and associated NRAs.

Starting in 2023, National Grid began hosting an annual customer outreach seminar to engage with developers and third-party billing companies. These seminars provide a platform to discuss current

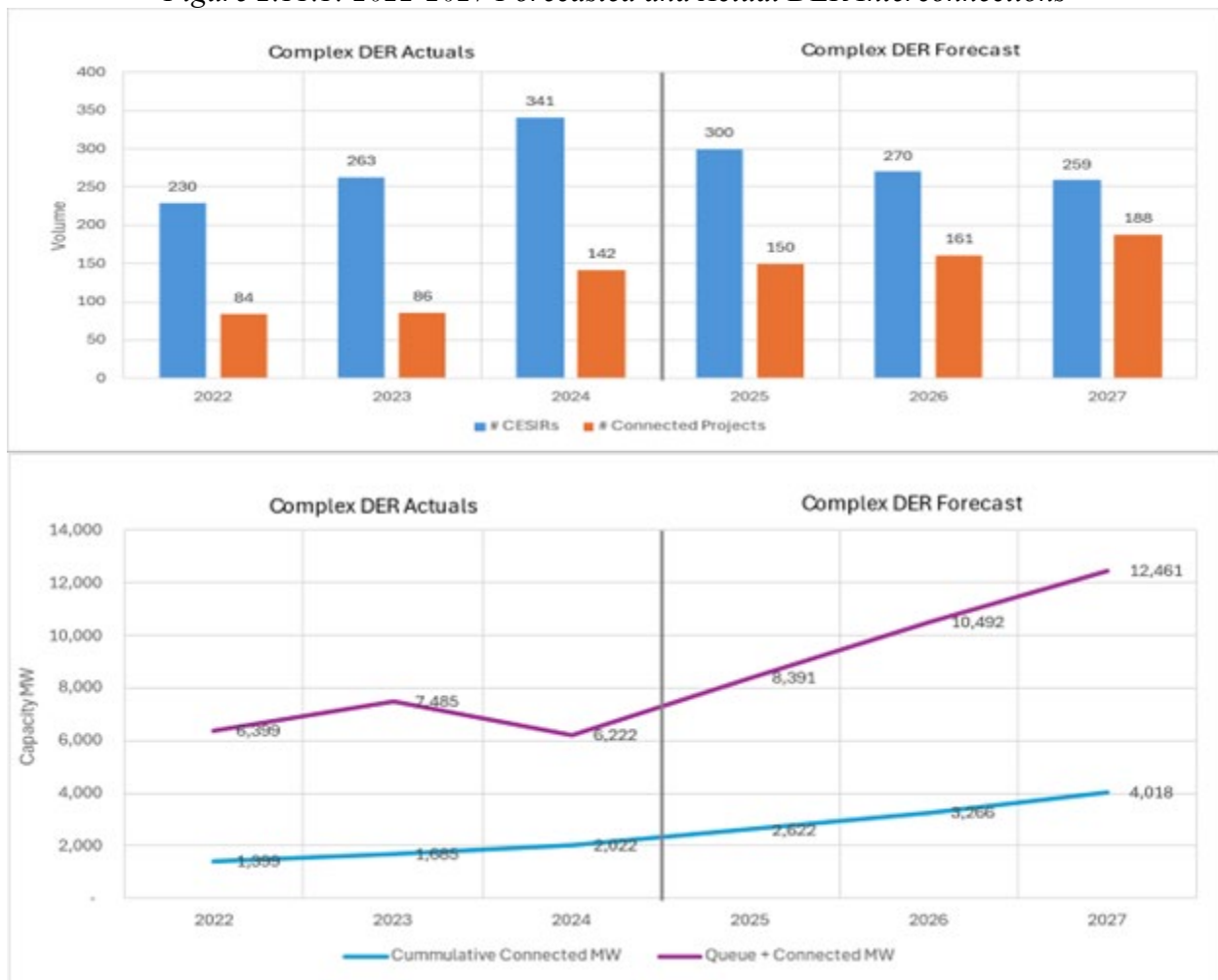
processes, future projects, and any changes the Company plans to implement. They also offer an opportunity for developers to ask questions and gain clarity on various topics. The 2025 outreach seminar was held on May 7 and featured a dedicated DG billing breakout session.

2.11 DER Interconnections

Context and Background

National Grid continues to be a leader in not only the number of DER interconnections but also in championing policy changes and implementing technical improvements to integrate DG and ESS more efficiently in support of the state's goals. The number of DG applications continues to rise along with the number of completed DER interconnections of solar PV and ESS projects. The graphic below depicts the continuing expansion of complex DER interconnections (projects greater than 50 kW in capacity) within National Grid's service territory. While the dominant DER continues to be solar PV, the volume of ESS applications and interconnections is growing.

Figure 2.11.1: 2022-2027 Forecasted and Actual DER Interconnections



To drive consistent practices across the state, National Grid participates in the IPWG, ITWG, and Smart Inverter Working Group to coordinate and collaborate with the other Joint Utilities, DPS Staff, and industry stakeholders on interconnection issues. The ITWG promotes consistent standards across the utilities to address technical concerns and interconnection procedures affecting the DG community. Key topics the ITWG has focused on include technical cost matrix, UL 1741 CRD for MM systems, NY-SIR updates on preliminary and supplemental screens, cost estimate methodologies, cost reconciliation, flexible interconnection, and smart inverter settings. The IPWG explores non-technical issues related to the processes and policies relevant to the interconnection of DER in NY. The IPWG has focused on cost share payment milestones, letters of credit in lieu of cash for some milestone payments, queue management, construction milestones, and data collection to support the Renewable Action Through Project Interconnection and Deployment (RAPID) Act.¹⁰² Workshops and collaboration efforts have also been underway to support flexible interconnection enablement.

Cost-Sharing 2.0

National Grid initiated discussions at IPWG between DPS Staff, NYSEERDA, the other Joint Utilities, and industry to negotiate a proposal for cost-sharing mechanisms that embraced the pro rata methodology. This included controls around utility customer risk, safeguards depending on the level of the upgrade, and new mechanisms for line work. The proposal was adopted by the Commission in the Cost Sharing 2.0 Order¹⁰³ and made part of the NY-SIR in April 2022. The Company posts monthly updates on qualifying upgrade project estimates and payments on the System Data Portal.¹⁰⁴ National Grid will evaluate the effectiveness of the Cost-Sharing 2.0 mechanisms and continue to discuss improvements to cost allocation methodologies at the IPWG.

Since cost-sharing mechanisms were adopted, 24 3V0 and 9 relay substation cost sharing payments reaching the 25 percent threshold have been received by the Company. No transformer cost share payments reaching the 75 percent threshold have been received. National Grid-funded contributions total just under \$8.5 million.

Table 2.11.1 Cost Share 2.0 Active Qualifying Upgrades

W/ 25% Payment	Number	MW enabled
3V0	65 Substations	579
Relay	20 applications	148
Line Relays	1 application	9
Substation Breaker	1 application	10
Payments but Threshold not met	Number	MW enabled
3V0	2 Substations	n/a
Relays	4 Applicants	n/a

¹⁰² The RAPID Act was passed in April 2024 to streamline permitting for major renewable energy and electric transmission projects and replaces Executive Law § 94-c with Public Service Law Article VIII, giving the Office of Renewable Energy Siting and Electric Transmission (ORES) responsibility for project approvals.

¹⁰³ IPWG Petition for SIR Cost-Sharing Amendment, Cost-Sharing 2.0 Order.

¹⁰⁴ Available at <https://systemdataportal.nationalgrid.com/NY/>

As of March 31, 2025, sixty-five (65) interconnection applicants requiring 3V0 solutions have met the 25% threshold payments to continue work on the upgrades, accounting for approximately 579 MW of enabled hosting capacity, while two (2) additional interconnection applicants requiring 3V0 solutions have provided partial payments but have not yet met the 25% threshold.

Twenty (20) interconnection applicants requiring substation transformer relays have met the 25% payment threshold to continue work, representing approximately 248 MW of enabled hosting capacity, while four (4) additional interconnection applicants requiring substation transformer relays have made partial payments but have not yet met the 25% threshold.

One (1) interconnection applicant requiring line relays has met the 25% payment threshold to continue work, representing approximately 9 MW of enabled hosting capacity, while no additional interconnection applicants requiring line relays have made partial payments to meet the 25% threshold.

One (1) interconnection applicant requiring substation breaker replacements has met the 25% payment threshold to continue work, representing approximately 10 MW of enabled hosting capacity, while no additional interconnection applicants requiring station breakers have made partial payments to meet the 25% threshold.

Twenty-four (24) interconnection applicants requiring substation transformer Qualifying Upgrades were identified but no payments have yet been received, while ten (10) interconnection applicants previously requiring substation transformer Qualifying Upgrades, including four (4) who have made partial payments, have opted for downsized solutions not requiring substation transformer Qualifying Upgrades.

No line upgrades are subject to cost sharing at this time.

Implementation Plan, Schedule, and Investments

Current Progress

Cost Matrix Revision

Along with the other Joint Utilities, National Grid updated the DER technical cost matrix to provide up-to-date cost information for system upgrades to developers. The matrix provides indicative estimates of various scopes of work and the relevant costs associated with the interconnection of DER. Each utility, including National Grid, has agreed to updating the technical cost matrix on an annual basis.

Preliminary and Supplemental Screen Update

National Grid actively collaborated with other utilities to enhance the effectiveness of the “Preliminary Screening” and “Supplemental Screening” sections of the NY-SIR. Feedback from the industry indicated that adjustments were necessary to accommodate high DER penetrations. As a result of a collaborative process, the Joint Utilities and industry stakeholders identified the need for changes specifically to Screens E (Simplified Penetration Test) and G (Supplemental Penetration Test). The Joint Utilities worked closely with industry representatives to refine these screens which provided greater clarity to developers regarding the necessary upgrades to circuits for accommodating reverse power flow. The petition was filed with the Commission on

November 27, 2024¹⁰⁵ and the Commission adopted the proposed NY-SIR revisions in its June 23, 2025 *Order Modifying SIR*.¹⁰⁶

Billing and Crediting

National Grid is implementing several new Commission directives related to billing and crediting for DG and storage projects. These include the addition of multiple discount rates for CDG projects, net crediting for CDG projects compensated under net metering, and two new programs designed to provide DG bill credits to low-income customers. Details can be found in Section 2.10, entitled Billing & Compensation, of this 2025 DSIP Update.

Developer Engagement

National Grid hosted one-day workshops for DG developers in 2023 and 2024 providing process overviews and technical training. In 2025, this summit was expanded to include projects connecting through the NYISO process. Additionally, through the course of the year, the Company hosts ways of working workshops directly with project developers as well as topical workshops addressing, for example, flexible interconnection and property rights practices, so as to improve the customer experience as well as to obtain feedback to improve National Grid policies and practices.

The Company has developed a comprehensive set of requirements for the interconnection construction stage of DER projects to facilitate a smooth construction review process, highlighting all necessary requirements as per National Grid's ESBs and other technical specifications. In February 2024, National Grid revised the standardized construction review checklist and streamlined incoming construction reviews to support decreased construction review timelines and expedite final commissioning of DER projects. The revision of the construction review checklist reduced the iterations of detailed engineering reviews by the Company.

National Grid has developed a Facility Audit Checklist, also known as Acceptance Survey Checklist. The purpose of the Acceptance Survey Checklist for Customer-Owned Sites interconnected under the NY-SIR is to ensure compliance with the National Electric Safety Code (NESC) and relevant National Grid standards (ESB 750, ESB 753, and ESB 756 Appendix B). This checklist facilitates the assessment of safety measures, equipment integrity, and regulatory compliance for parallel generation systems. The outcome of the Facility Audit Checklist is to ensure DER facility readiness to proceed to witness testing activities and receive final permission to operate (PTO). This checklist serves as an opportunity for both the customer and National Grid to highlight areas of concern and need for corrective action. Inclusion of this checklist will continue to aid DER customers in assessing site readiness and identify facility issues that can be addressed prior to National Grid's inspection.

¹⁰⁵ In the Matter of NY-SIR Modifications, *Petition of the IPWG/ITWG Members Seeking Certain Minor Amendments to the New York State Standardized Requirements (SIR) for New Distributed Generators and/or Energy Storage Systems 5 MW or Less Connected in Parallel with Utility Distribution Systems* (filed November 27, 2024) (November 27, 2024 Petition).

¹⁰⁶ In the Matter of NY-SIR Modifications, *Order Modifying Standardized Interconnection Requirements* (issued June 23, 2025) (June 2025 Order Modifying SIR).

Enhanced Customer Coordination

National Grid's Customer Energy Integration (CEI) team has updated its organizational structure to better serve customers. The CEI organization includes: (i) teams to shepherd applications through preliminary studies and more detailed CESIRs; (ii) the complex project management team to support applicants once the decision is made to proceed to construction; and (iii) a team of billing and crediting specialists to support interconnected customers. This updated structure is designed to ensure skilled representatives are aligned based on the nuances of each customer's project. For projects that have entered the construction phase, the project management teams have weekly or biweekly calls with the DG applicants. In addition, an account management approach to larger accounts is now in place supporting eight (8) key accounts in longer term strategy and planning needs.

Flexible Interconnections/Active Resource Integration

As part of the Company's Clean Innovation Pilots, National Grid implemented its ARI Pilot, demonstrating the use of flexible interconnections to interconnect DG projects on a thermally constrained 115/13.2 kV substation without the need to increase substation transformer capacity but instead managing the generation output of the interconnected DG projects under a flexible interconnection scheme. The ARI Pilot demonstrates the application of a pro-rata curtailment scheme across participating DG projects and the development of a curtailment study methodology and a pilot agreement in order to define contractual obligations for the parties to maintain the flexible interconnection scheme. The Company successfully completed full active curtailment testing of two flexible interconnection projects that were interconnected to National Grid's Peterboro Substation in February 2025.

The Company has initiated a search of candidate substations to further explore scalability of flexible interconnections and to inform its collaboration with other utilities, such as NYSEG and RG&E, on variations of flexible interconnection concepts.

National Grid is planning to expand efforts through an awarded DOE IIJA funding grant to carry over its learnings and technology development from the ARI Pilot to a further pilot that will demonstrate a flexible interconnection concept for energy storage and EV charging equipment.

Energy Storage Operating Schedules

National Grid, in collaboration with the other Joint Utilities, has provided DER developers with information regarding static charge and discharge schedules for BESS projects. These schedules have been developed to provide an opportunistic interconnection for BESS developers to capture revenue streams such as VDER Value Stack compensation or participation in NYISO wholesale markets. Additionally, the implementation of static charge/discharge schedules can provide a feasible path to interconnection with reduced costs as compared to BESS that operate with unrestricted charging/discharging characteristics. It is anticipated that aligning the charge and discharge windows with economic value streams and price signals will encourage greater adoption of BESS throughout the state.

SIR Revisions

In addition, National Grid and the other Joint Utilities, in concert with the IPWG/ITWG, petitioned the Commission for amendments to Appendix K (ESS Application Requirements) of the NY-SIR. The proposed changes included a number of requirements to be imposed on developers including specifying the type of storage system being installed (stand-alone, AC coupled, or DC coupled), provision of details on ancillary equipment and loads, and outlining proposed charge and discharge schedules. These edits aimed to present BESS application information in a more coherent manner, ultimately improving the speed of the interconnection study process. The relief sought in the November 27, 2024 Petition was adopted by the Commission in the June 23, 2025 Order Modifying SIR.

Future Implementation and Planning*ConnectNow*

ConnectNow is a portfolio of digital products that will expand upon the existing capabilities in the IOAP that was built under previous orders from the Commission nearly a decade ago. National Grid intends to start building out the incremental functionality for ConnectNow pending a Commission order in the 2024 National Grid Electric and Gas Rate Case Proceeding.

The core digital products, Connection Explorer and Connection Workplace, will expand the baseline IOAP functionality. Connection Explorer is a self-serve application portal for trade partners (e.g., solar installers, EV charging station installers, electricians, building developers) to submit and manage their portfolio of applications to connect electric load and DERs in a single platform. Connection Workplace will provide one-stop visibility for National Grid employees managing connection requests from application submission to connection completed to final financial reconciliation.

Layered on top of the core digital products, ConnectNow will include three additional features: Pre-Application Research Assistant, Connection Finance, and Connection Schedule. The Pre-Application Research Assistant will incorporate the foundational information already provided in National Grid's System Data Portal and provide a guided (and artificial intelligence (AI)-assisted) approach for potential applicants to assess the preliminary feasibility of installing their preferred load and/or DERs at a site before submitting an application. The Connection Finance feature will expand upon the existing online payment capabilities for DG IOAP and provide a portfolio view of all payments related to application, study, or construction fees (including Contributions In Aid of Construction and cost sharing as applicable); enabling users to see outstanding invoices, amounts paid, and the status of any pending financial reconciliations. The Connection Schedule feature will provide users with a portfolio view of the project status (including customer and National Grid deliverables) after the CESIR is complete and up until National Grid's construction is completed.

Self-Build Solutions of Required Utility Upgrades

The Joint Utilities were involved in discussions with DPS Staff and industry regarding the option of allowing developers to build some interconnection work for DG projects through contractors they hired directly, rather than having the utility perform this work with its own workforce or alternatively hire utility contractors to perform this work. The Joint Utilities anticipate that these conversations will continue. Among other stipulations, the Joint Utilities have already stated that

developers would only be allowed to install equipment at the point of interconnection. However, National Grid is considering a possible expansion of this scope to upgrades for deenergized lines or line extensions. Additionally, interconnection applicants must utilize equipment vendors and contractors that are utility-approved. Any new contractors will be required to undergo an onboarding and approval process. Further, all contractor work will be overseen on-site by qualified utility personnel, at the interconnection applicant's expense, to ensure compliance and safety.

Letter of Credit

The Commission's February 14, 2025 *Order Granting Petition with Modifications*¹⁰⁷ adopted revisions to the NY-SIR allowing interconnection applicants to use Standby Letters of Credit (SLOCs) in lieu of cash for specific payments. National Grid is refining its internal processes to accept, record, and track SLOCs.

Flexible Interconnections

National Grid continues to collaborate with NYSEG and RG&E on flexible interconnection options, given the Company's initial experiences deploying the ARI Pilot. There is a need to explore possible interconnection process changes, unique approaches to principles of access, contractual arrangements, and other topics to effectively enable scaling of flexible interconnection in NY.

As part of its scope within an awarded DOE IIJA grant, National Grid plans to expand flexible interconnection schemes to at least one energy storage project and at least one EV charging site over the next few years as technology demonstrations. The experiences gained will inform whether flexible interconnection options can be expanded to other types of DER more broadly.

Cellular DTT

National Grid evaluated the feasibility of using cellular communications, with multiple carriers, as the medium for a DTT or anti-islanding protection as an alternative to de-energizing customer DERs. IEEE 1547-2018, Standard for Interconnection and Interoperability of Distributed Energy Resources with Associated Electric Power Systems Interfaces, specifies that DERs shall trip within 2 seconds of the formation of an island. The results with cellular communications indicated trip times were well under this threshold. Laboratory testing between publisher and subscriber devices demonstrated latencies on average of 63.7 milliseconds (ms), while extended field testing demonstrated latencies of 79-170 ms in addition to 99.853-99.997 percent availability between both cellular service providers. As a result, Cellular DTT can now be evaluated against other traditional alternatives for new interconnection projects that require anti-islanding protection.

¹⁰⁷ Case 24-E-0414, *Petition of New York Solar Energy Industries Association Seeking Modifications to the New York State Standardized Interconnection Requirements to Allow Use of Alternative Forms of Financial Security for Distribution Upgrades in Excess of \$500,000 for New Distributed Generators and/or Energy Storage Systems 5 MW or Less Connected in Parallel with Utility Distribution Systems*, Order Granting Petition with Modifications (issued February 14, 2025).

UL1741 Bi-directional V2G-CRD for MM Systems

National Grid, in collaboration with the Joint Utilities, has adopted the UL 1741 CRD for MM systems after extensive discussions with Underwriters Laboratories. This decision ensures that combined inverter and microgrid interconnection device (MID) assemblies will prevent DERs from backfeeding into a downed EPS, while still powering local premises. The Joint Utilities have noted an increase in inverter and MID configurations in solar PV + storage and EV applications and are anticipating further growth due to decreasing costs and supportive policies. The risk of backfeed from DERs into a downed EPS poses safety hazards for utility workers and affects distribution system reliability. The UL 1741 CRD for MM provides assurance against such risks. Based on the UL 1741 CRD for MM certification status, the Joint Utilities have extended the date for CRD compliance to no later than June 30, 2025, with no further extensions permitted. After this date, a certificate of compliance from a Nationally Recognized Testing Laboratory (NRTL) demonstrating adherence to the CRD will be mandatory.

N-1 Contingency Hosting Capacity

In the National Grid Electric and Gas 2024 Rate Case Proceeding, industry stakeholders within the DER sector urged the Company to focus on a key bottleneck in increasing DER deployment in NY. More specifically, industry participants placed emphasis on addressing a common constraint related to the Company's impact assessments of DER during an N-1 contingency resulting from the loss of a parallel transformer bank. Industry asked the Company to immediately investigate solutions using available DTT technologies or advanced schemes that would allow DERs to utilize the maximum transformer bank hosting capacity by leveraging direct tripping of impacted DERs. National Grid has committed to investigating this approach and will work to drive solution developments and the Company's criteria for tripping technologies schemes. Solution investigation is expected to continue through CY 2025 with the Company's initial recommendations and requirements to be established by Q3 2025.

Risk and Mitigation*Table 2.11.2: Risk and Mitigation for DER Interconnections*

Risk	Mitigation
Longer interconnection times and higher upgrade costs will delay DER interconnections.	The Company will champion policies and methods to facilitate more interconnections such as self-build solutions, flexible interconnection pilots, and Cost-Sharing 2.0. Decreasing process cycle time has been a key internal initiative for National Grid. The Commission established Case 24-E-0415 in response to the RAPID Act.¹⁰⁸ The Company will engage cooperatively and collaboratively with IPWG, ITGW, and other stakeholder forums to

¹⁰⁸ Case 24-E-0415, *In the Matter of Timely Interconnection of Distributed Energy Resources*. The RAPID Act required the Commission to commence a proceeding to review the cause and extent of any delays to interconnecting DERs, metrics related to timely interconnection, and potential revenue adjustments associated with such metrics.

	address issues related to timeliness and program improvements with increased transparency and in support of delivering DER interconnections in a more expeditious manner. National Grid is leading discussions with industry to develop methods to improve queue management and construction timeline transparency.
Risk	Mitigation
Interconnection applicants and industry have been seeking additional transparency in cost estimates and actual costs incurred to interconnect DER.	National Grid has implemented a process to update cost estimates on an annual basis. The Company is leading efforts within ITGW and IPWG to coordinate and update cost matrices for the Joint Utilities and identify NY-SIR revisions needed to support further transparency.
There is a lack of implementation for DER applications combined with microgrid interconnection devices (MID), such as V2G and V2H applications, due to technical and technology limitations, as well as the inability to meet utility interconnection compliance requirements.	National Grid is working closely with other utilities, regulatory bodies, manufacturers, and other stakeholders to ensure that DER with MID (V2G/V2H) systems meet essential safety requirements. There are few manufacturers that have been certified to CRD for MM systems. Based on the UL 1741 CRD for MM certification status, the Joint Utilities have extended the compliance date for the CRD to no later than June 30, 2025, with no further extensions to be permitted. After this date, a certificate of compliance from a NRTL demonstrating adherence to the CRD will be mandatory.

Alignment with CLCPA Goals

DER integration directly supports the CLCPA goals to reduce the carbon footprint by displacing fossil fuel generator production and excess capacity with renewable generation sources while flattening peak loads. National Grid seeks to remove interconnection barriers in order to expedite DER interconnections so as to stay on pace with supporting the CLCPA goals. DER interconnection growth has also created additional benefits for the Company's customers such as providing load relief in areas of high load. These efforts indirectly support CGPP by enabling DER integration planning at the distribution level commensurate with the CLCPA goals. CGPP is well aligned, using the same assumptions, supported in part by robust DER interconnection methods granting additional confidence in the pathways to CLCPA achievement envisioned in CGPP models.

Stakeholder Interface

Stakeholders for DER interconnections include both internal and external parties. National Grid works closely with external parties including DPS Staff, NYSERDA, and developers to continuously review best practices and remove barriers to interconnections. Much of this section reflects initiatives developed within the various NY working groups such as the IPWG and ITWG.

External concerns are primarily identified at IPWG and ITWG meetings, and via concerns that developers bring directly to National Grid's DG Ombudsperson. Internal goals and needs are identified via process workshops and in the normal course of business.

Each stakeholder in the DER interconnection process is supporting the overall goal of meeting and exceeding CLCPA goals in support of reducing GHG emissions and mitigating the impacts of climate change. Internal and external working groups provide forums for stakeholders to ensure their needs are met to advance their portion of the interconnection process.

The DER interconnection process is a particularly collaborative process. National Grid needs to ensure that interconnections do not adversely impact other customers already connected to the EPS, necessitating the iterative process of engineering study and review of each interconnection. The Company works with developers to ensure that projects are interconnected safely and reliably while supporting developer timelines.

The IPWG and ITWG are the primary forums for informing stakeholders of process improvements. This allows stakeholders to provide input and propose modifications to the NY-SIR as necessary.

National Grid has an escalation process where developers can raise concerns to the Company's Customer organization and the DG Ombudsperson if processes in place are not adequately supporting stakeholders or leading to unintended consequences. The DER interconnection process within National Grid is continuously being improved to adapt to the needs of all stakeholders in the process.

National Grid assigns SMEs to support interconnection customers through the life of the projects. The Company has teams dedicated to guiding the application through the preliminary studies and the CESIR issue, project management of the interconnection construction phase, and billing/crediting experts for operational projects.

National Grid hosts an annual renewable connections Summit to facilitate discussions and gather insights from the developers. The Company also conducts one-on-one meetings with developers to address specific concerns and foster relationships. The Company's representatives take on the liaison role for the ITWG/IPWG with industry and DPS Staff to streamline information sharing and decision-making processes. Additionally, the key account manager role within the Company helps to maintain ongoing relationships with developers, ensuring their needs are met, and aligning project objectives and expectations. Through these efforts, National Grid aims to create a cohesive environment that promotes transparency, trust, and mutual benefit among all stakeholders.

2.12 Advanced Metering Infrastructure

Context and Background

In July 2016, National Grid filed its initial DSIP, which set forth a plan for investments needed to modernize its system and enhance its DSP capabilities. In the DSIP, the Company identified AMI as a foundational component of its grid modernization effort. The Company included an AMI business case that described and compared alternative AMI deployment options and based on the results of a BCA, proposed territory-wide implementation as the cost-effective, fit-for-purpose solution.

In April 2017, the Company filed a more detailed and updated AMI business case supporting full-scale AMI deployment as part of its general rate case.¹⁰⁹ The Company initiated an AMI collaborative process in April 2018 in accordance with the Joint Proposal approved by order of the Commission in the rate case. The collaborative process culminated in the November 15, 2018 filing of the Report on the Proposed Implementation of Advanced Metering Infrastructure (AMI Report). After filing the AMI Report, the Company supplemented its AMI proposal with additional benefit opportunities identified in peer utility filings, as well as reduced costs, which enhanced the case for AMI in NY. The enhancements were outlined in five supplemental filings.¹¹⁰

On November 20, 2020, the Commission issued the AMI Order, approving the Company's AMI proposal with modifications.¹¹¹ Overall, the Commission authorized the Company to proceed with deploying approximately 1.7 million electric AMI meters and 640,000 AMI-enabled gas modules, and the associated communications network, across its service territory on an opt-out basis. As part of its findings, the Commission described how the AMI investment can provide benefits to customers and the system, while also advancing clean energy goals:

¹⁰⁹ See Cases 17-E-0238 and 17-E-0239, *Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Niagara Mohawk Power Corporation d/b/a National Grid for Electric and Gas Service* (National Grid Electric and Gas 2017 Rate Case Proceeding), Direct Testimony of the AMI Panel (April 28, 2017).

¹¹⁰ See National Grid Electric and Gas 2017 Rate Case Proceeding, 2017 Rate Case Company filings dated February 22, 2019; September 4, 2019; January 22, 2020; September 18, 2020; and October 28, 2020; *see also* National Grid Electric and Gas 2020 Rate Case Proceeding, Direct Testimony of the AMI Panel (July 31, 2020).

¹¹¹ National Grid Electric and Gas 2017 Rate Case Proceeding, Order Authorizing Implementation of Advanced Metering Infrastructure with Modifications (issued November 20, 2020) (AMI Order).

- **Customer Benefits:** “[T]he deployment and use of AMI can be harnessed to transform the relationship between National Grid and its electric and gas customers. With AMI, National Grid can improve its response to power outages, as the Company will have more accurate and granular information regarding the voltage and current status of customers’ services. AMI can empower customers by providing them with information about their energy usage and allowing them to take action to manage their electric and gas costs.”¹¹²
- **Operational/System:** “National Grid will likely need to invest funds in its metering infrastructure in the near future, whether to replace AMR [Automated Meter Reading] meters and gas modules in kind, or to upgrade to AMI. This presents an opportune time to upgrade to AMI while avoiding the costs of replacing the existing AMR meters in kind.”
- **Clean Energy:** “AMI is an important and valuable contribution to enabling the Company to assume the role of the [DSP provider], to increasing use of DERs to support system operation, to increasing the use of measures such as VVO to reduce energy use and emissions, and to facilitating customer access to products and services provided by third-parties.”

Implementation Plan, Schedule, and Investments

Current Progress

The AMI roadmap has continued to guide the program in delivering functionality and capabilities to enable full-scale electric meter installation. The program has also been focused on the functionality and capabilities enabling the initial deployment of gas modules.

In April of 2023, the program initiated an electric-only “soft launch” in advance of scaled deployment. Throughout 2023, the Company ramped up AMI meter deployment in the Central Division and focused on deployment of the Field Area Network (FAN) installations in National Grid’s Central division.

In February of 2024, deployment operations of FAN expanded into the Eastern Division. Initial focus was to obtain a healthy FAN to provide saturation of the network in the Central and Eastern Divisions. This enabled the expansion of resources to be able to deploy AMI electric meters in those areas. The year 2024 also saw expanding FAN into the Western Division. Throughout 2024, the Company continued to make progress toward its ability to significantly scale deployment.

In October 2024, the Company received conditional Commission approval to install gas modules as part of an initial trial and ramp-up period.¹¹³ The Company installed its first gas modules in

¹¹² *Id.*, pp. 26-27.

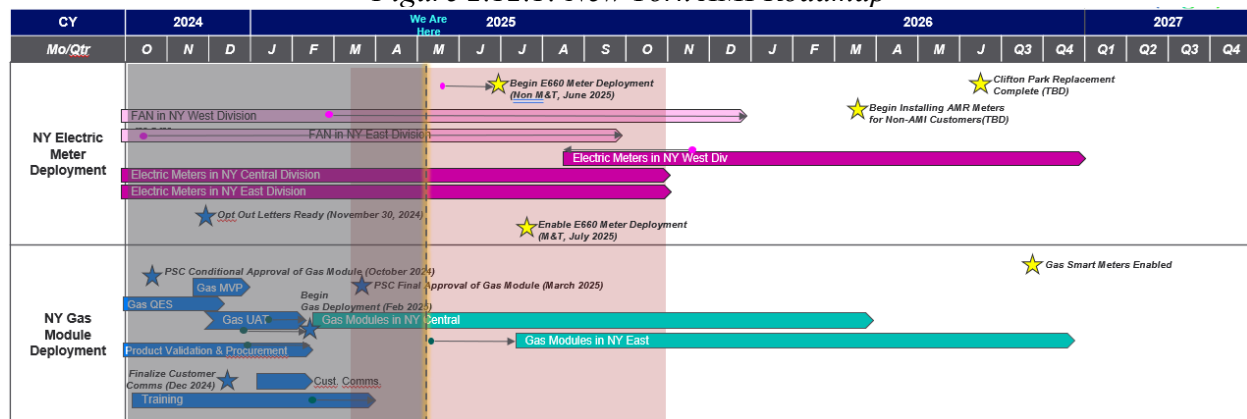
¹¹³ Case 22-G-0679, *Petition of Niagara Mohawk Power Corporation d/b/a National Grid for Approval of Landis+Gyr AMI Gas Devices* (National Grid Petition Seeking Approval of AMI Gas Devices), Order Granting Conditional Approval of Gas Metering Equipment (issued October 23, 2024).

November 2024. The Commission's March 2025 order¹¹⁴ fully approved the program's most common gas modules, allowing the program to scale to full deployment.

AMI Roadmap

The AMI program roadmap projects continued deployment of electric meters and gas modules to more customers, including scaled electric meter deployment expanding into the Western Division and the installation of commercial E660 meters. Additionally, the AMI program projects the release of capabilities and functionality to enable outage management, limited remote-connect-disconnect capabilities related to emergency work and Sense load disaggregation. Reaching these milestones will enable the NY AMI program to maximize its deployment rates and optimize customers' experience.

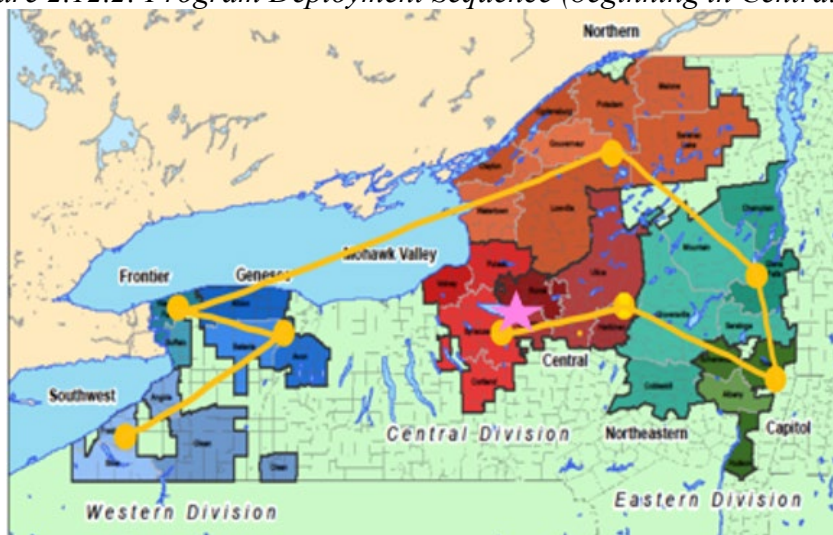
Figure 2.12.1: New York AMI Roadmap



The Company continues to make good progress with the implementation of back office technical systems, introduction of processes and tools, and development of requisite capabilities. Deployment continues to afford opportunities to test end-to-end system integrations and make refinements based on lessons learned, while mitigating potential risk.

¹¹⁴ National Grid Petition Seeking Approval of AMI Gas Devices, Order Approving Gas Metering Equipment (issued March 26, 2025).

Figure 2.12.2: Program Deployment Sequence (beginning in Central NY)



National Grid continues to monitor all AMI deployments for safety, performance, customer interaction, customer engagement, and opt-out intents throughout the deployment process. The Company monitors safety compliance through field visits, compliance assessments, independent inspections and self-audits performed by the installation contractor. The Company monitors overall technician efficiency, total quantity of technicians actively installing meters daily, return to utility, and meter installations against plans on a weekly basis. Additionally, the Company is collecting and monitoring customer interaction and engagement feedback to provide full context of the installation contractors performance. The protocols instituted to monitor and correct contractor safety and installation performance has resulted in increased technician efficiency, increased installations, and reduced safety incidents.

In parallel with its deployment activities, National Grid and L+G continue to work with DPS Staff to obtain regulatory approval for the additional electric meter forms and gas modules needed to accommodate the upstate NY deployment plan.

FAN Deployment

The Company has successfully deployed 5,693 FAN devices through May 2025, representing approximately 90 percent of the current network design. Based on evolving field and geographic constraints, as well as the strategic addition of network equipment to enhance system reliability and redundancy, the total projected FAN deployment has been revised to 6,307 devices. FAN deployment is largely complete in the Central Division with remaining construction progressing in both the Eastern Division and Western Division. The AMI Program will complete the bulk deployment of the FAN infrastructure by 2025 with network optimization continuing through 2027. Network optimization refers to the process of evaluating and enhancing network performance and efficiency through targeted adjustments, typically initiated following the completion of meter deployment in a defined geographic area. The Company has also successfully deployed 132 battery backup systems for extended reliability, anticipating full deployment by June 2026.

Figure 2.12.3 Pole Mounted extended battery backup solution and mobile connecting grid router

The AMI Deployment Plan targets are based on the combined endpoints of electric AMI meters and gas modules across the Company's service territory within the three divisions of Central, Eastern and Western. A total of 2,334,000 endpoints will be installed, which includes approximately 1,692,000 electric meters and 642,000 gas modules. As of May 31, 2025, the Company has deployed over 869,319 AMI endpoints (electric meters and gas modules) across the three divisions, representing 37 percent of the total endpoint goal.

While delivery to the original forecast of total endpoints is still the goal, the impacts associated with gas module availability, premise access, and challenges related to installation contractor resources, such as retention and attrition have affected the deployment of forecasted endpoints in each program year. The Company will continue to communicate these impacts, if realized, in subsequent updates to Staff.

AMI Electric Meter Deployment

As of May 31, 2025, the Company has deployed 848,690 electric meters across the three divisions of Central, Eastern and Western, representing nearly 50 percent of the total AMI electric meters to be installed.

National Grid is planning to complete the majority of electric meter installations in the Central Division by first quarter of 2026, in the Eastern Division by second quarter of 2026, and in the Western Division by the close of 2026. In the case of meters requiring specialized installation skills (including some C&I meters), the completion may extend into 2027. To date, the residential electric installations have utilized the E360 electric meter variant for all installations. The C&I meter variant (i.e., E660) installations will begin in the summer of 2025 and scale up through the subsequent months. Self-contained meter forms will be installed by Utility Partners of America and internal operations, with transformer rated meters being installed by the Company's internal operations team only.

AMI Gas Module Deployment

On March 26, 2025, the Commission approved the Company's Petition for the approval of Landis+Gyr AMI gas devices, enabling bulk deployment of AMI gas modules. Through May 31,

2025, a total of 20,69 gas modules have been deployed in the Central Division, representing about 3.21 percent of the total AMI gas modules to be installed.

An MVP solution was initiated to install gas modules to a small population of employee-customers in the Central Division. The objective of the effort was to test the functioning of the modules, establishing network communications, and billing operations prior to the beginning of any scaled installations. As a result of the lessons learned from the MVP, National Grid established a process to verify the health of the existing mesh network in the vicinity of intended gas module deployment routes to maximize network connectivity.

Opt-Out Intent

To date, the AMI opt-out intent rate is 0.76 percent, below the targeted final opt-out threshold of <1 percent.

Since AMI deployment started, the Company has received AMI meter opt-out intent requests from 13,385 customers through May 31, 2025. This represents 13,346 electric meters and 5,582 gas modules, noting that some customers have electric or gas-only service, and some have both electric and gas services. Based on the number of endpoints, the rate of opt-out intent stands at 0.76 percent. Once customers submit their intent to opt out, they are provided with additional information outlining the loss of benefits, additional fees, next steps, links to additional information, and instructions on how to opt back into the AMI meter installation pool. An additional letter is sent to these customers to address safety, health and privacy concerns customers may have. No non-communicating meters have been installed for opt-outs, nor have associated fees been implemented for customer meter opt-outs at this time.

Business Design and Integration

The Business Design and Integration effort continues to make progress with functionalities that will add value for customers above AMI meter core functionality. AMI Technology and Software continues to progress in the following ways:

- The billing systems are proving to be highly accurate and efficient.
- The number of customers using Customer Energy Management Portal (CEMP) has been increasing month over month as more AMI meters are deployed.
- Specifically for engagement, the Company has begun testing the Sense app with select customers, giving them real-time energy insights at no cost. Customer feedback will be captured and integrated into the Customer Engagement Plan going forward.
- Open integrations enable flexibility across AMI, "futureproofing" the system to handle new systems, apps, APIs, dataflow, and more.
- Over the air updates are enabling the Company to add features on a regular basis to endpoints without needing to physically update them.
- Agile build methods have allowed the Company to pivot multiple times, including data storage to optimize pricing and APIs with the App Center integration.

AMI Billing

From November 20024 through April 2025, 3,587,324 AMI electric bills were produced, of which 20,689 were estimated. This resulted in an estimated bill rate of 0.58 percent for AMI electric meters, significantly below the target rate of 1.5 percent.

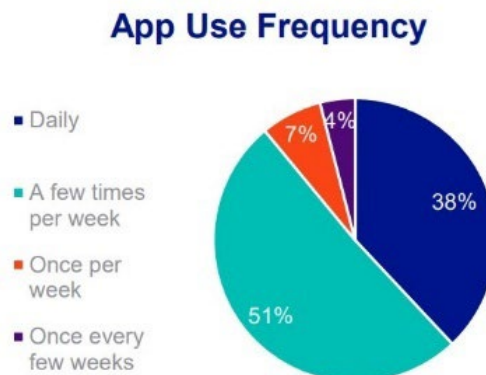
During this same period, 1,158 AMI gas bills were produced, of which 92 were estimated. This resulted in an estimated bill rate of 7.94 percent for AMI gas modules. This is largely the result of an issue with the Company's meter management system which has since been addressed. With the exception of a small subset of accounts requiring manual reads, most accounts now properly communicate with the network, allowing AMI to obtain accurate reads and send them to the billing system.

Grid Edge Computing – Real-Time Load Disaggregation

National Grid anticipates a controlled roll-out of the Sense technology in late 2025. Approximately 30,000 non-employee customers in ten zip codes will be first targeted during the controlled roll-out. Previously the Company ran small pilots with employees and a small group of non-employee customers.

The Company has continued its effort to ensure that appliance-level usage data is available to customers through a third-party vendor, Sense. National Grid contacted and facilitated non-employee customers to participate in the pilot to gain feedback from their participation. After concluding the pilot phase, 78 percent of customers who onboarded the Sense App were satisfied with their overall experience, and 100 percent of customers reported they would continue using the Sense App beyond the testing period. While the pilot phase was a success, a few issues were identified and are actively being worked on with the third-party vendor to fix before making the Sense App available to other customers. With over 80 percent of pilot customers stating they will use the Sense App daily to a few times a week, the Company believes changes in energy usage behaviours from customers will be observed.

Figure 2.12.4: Customer Sense App Participation Frequency



The Company is working with our third-party vendors Sense and Landis+Gyr, to ensure a positive customer experience is ready before communicating the availability of the Sense App to customers. The availability of the Sense App will be communicated to customers in phases starting Q3 of 2025. The Company will leverage current communication channels to ensure customers

know about this new experience and are able to drive better decision-making regarding energy utilization in their homes.

Remote Connect/Disconnect

Remote Connect/Disconnect capabilities will be rolled out in three phases: Move In/Move Out (December 2025), Emergency (February 2026, with manual work around summer 2025), and Collections (April 2026).

Phase 1 Move In / Move Out (December 2025): Upstate New York National Grid (UNY) operations will be able to issue remote connect and disconnect command(s) from the CSS. CSS will be able to issue commands from CSS to the meter data management system (MDMS) that will instruct the MDMS to connect or disconnect a meter remotely. This command remotely opens or closes an internal service switch to turn on or off service to a customer.

Remote Connect or Disconnect batch command(s) originate with CSS that will send a request to the MDMS to Connect or Disconnect the customer. The MDMS then sends the request to the command center (Head End system), which then communicates to the meter via the mesh network to open or close the switch. Once the switch status has been changed, the meter communicates back to the command center, which communicates back to the MDMS. Finally, the MDMS communicates back to CSS, confirming that the Connect/Disconnect was successful or unsuccessful.

Phase 2 Emergency (February 2026) with Manual work around (June 2025): Emergency remote disconnect allows National Grid to remotely disconnect electricity service at the premise level at the request of first responder and field crews. Full integration of emergency remote disconnect into backend systems is anticipated to be completed by February 2026. However, emergency remote disconnect functionality for fire calls is going live with a manual account update mid-2025 in order to accelerate the delivery of this safety feature for customers.

In addition, in instances when a meter cannot be reconnected post-emergency due to site conditions, National Grid has improved the process of the remove-meter-order by assuring customers are contacted regarding their re-connect and billing options after emergencies have been resolved.

Phase 3: Collections (April 2026): Design work has started.

Outage Management

The Company is building integrations to automatically pass electric meter power loss notifications (aka “Last Gasps”) from AMI-enabled meters to initiate outage restoration actions in the field. Smart Data for Outage Management (SD-OM) is a L+G application module within MDMS that serves as an intelligent intermediary between the command center and OMS and performs necessary filtering of outage notifications from the meters before forwarding them to the OMS/ADMS. In the initial phase, the SD-OM setup and integrations will enable key outage data availability to OMSs. As the systems and processes are enhanced, the Company will be able to report on operational metrics.

- As of October 2024, Ping capability is enabled in OMS/ADMS that allows operators to validate the meter status for all types of outages reported before rolling trucks/dispatching crew to field. This results in the reduction of truck roll due to false, non-reportable outages such as customer side outages, in turn reducing fuel consumption and vehicle emissions.
- December 2024 - Technical implementation of AMI ADMS integration to maximize outage awareness was adopted. AMI is now sending PowerOFFNotifications to ADMS.
- February 2025 – In Monitoring mode to validate accuracy of PowerOFFNotifications before turning it on in ADMS, an issue was identified that momentary outages are sent to ADMS in some cases due to delayed PowerOFFNotifications and Power Restore Notification (PRN). L+G is working in conjunction with National Grid to resolve the network connectivity issues.
- Capability to consume PowerOFFNotifications is NOT turned on in ADMS. Pending issue resolution and hence pending business enablement.

Voltage Variance Optimization (VVO)

VVO deployment is not expected until later in the project and therefore metrics are not available currently. VVO benefits are not anticipated until Year 7 of the AMI Program. The AMI program will continue to work with Electric Operations and in coordination with the Company's overall long-term VVO strategy.

Green Button Connect

Prior to AMI deployment, National Grid enabled GBC My Data for all UNY residential and small commercial customers on March 31, 2021. Once authorized by the customer, GBC shares relevant customer data with certified third-party companies. To qualify, third-party companies must enter into a Data Security Agreement and execute a Self-Attestation.

As of April 30, 2025, seventy-six (76) third-party companies have registered with the Company's GBC platform. A list of authorized third parties is updated on a quarterly basis and can be found on the Company's website.

The Company continues to evaluate ways to leverage this program to improve customer experience. The Company is currently expanding this program to include MV-90 and AMI meter data for the National Grid service territory. The Company is scheduled to have this available starting in Q2 of 2026.

Community Engagement

AMI Community engagement events follow the AMI deployment path. The Company participated in nearly 81 community events, most recently focusing on multi-day home shows across the service territory.

Customer Engagement

The Company continues to roll out AMI meters in its UNY territory to ensure all customers are aware of the installation process and benefits of the AMI meter through the 60/30/10-day notification to customers ahead of installation. From program inception to April 30, 2025, the Company sent over 1.7 million pieces of communications to customers. The Company's Market Intelligence team continues to monitor customer awareness and experience with AMI meters.

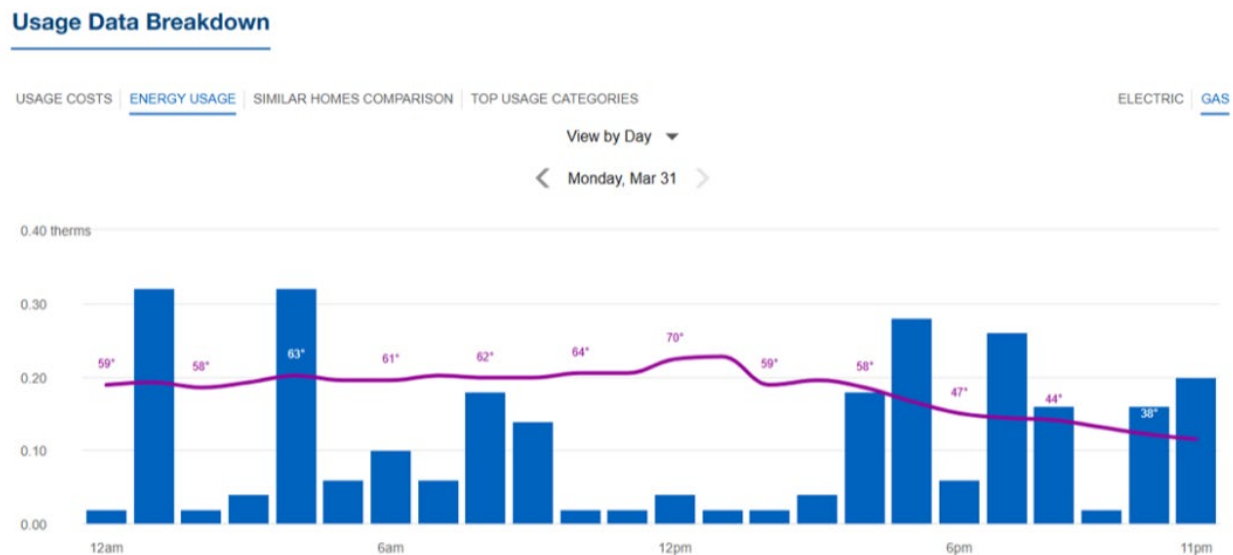
Insights from customers have remained generally positive, with over 87 percent satisfaction and more than the target 80 percent awareness of AMI meters six months post-installation.

CEMP

The Company's MyAccount portal has been upgraded to include two new widgets for displaying customers' usage data. The Near-Real-Time widget (updated every 15 minutes) and the Day View widget are now available for residential electric and gas customers, respectively. Electric residential customers can also access their Highest Day of Use widget, highlighting the five days each month when they consume the most energy. This feature will assist customers in understanding their peak energy usage times and recognizing the activities that contribute to their consumption. Furthermore, electric customers are automatically enrolled to receive two proactive alerts – Weekly Energy Updates and High Usage Alerts, with the option to opt out if they choose. More functionalities are being worked on to enable gas residential customers and commercial customers.

The Company's website has been enhanced to display customers' usage data through views (day view, bill view, etc.) for electric and gas residential customers. Electric customers can also retrieve their unverified usage data in near-real-time to see their usage in 15-minute intervals for the past 24 hours, while gas customers can now view their daily usage in one-hour intervals on their day-view widget (Note: This data has a 1-day lag). Electric customers can also examine their five highest usage days within a calendar month and drill down into any of those days to understand their detailed usage. These features will educate customers on usage patterns and provide insights for better energy management.

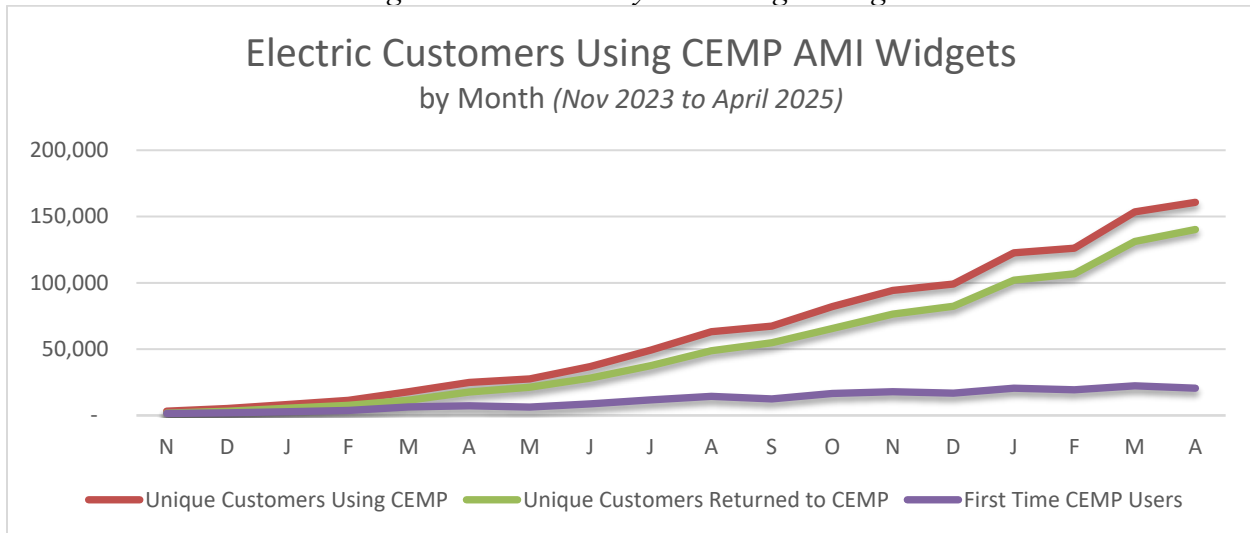
Figure 2.12.5: Day view widget for gas customers



Call Center representatives can guide customers to these widgets to understand their usage patterns and address concerns regarding high bills. Customers have expressed appreciation for the availability of these widgets, as they can validate days when they used more energy due to family and friends visiting.

The number of customers using the widgets and returning to check the widgets has been increasing month over month as more AMI meters are deployed. In the past six months (November 2024 – April 2025) there have been an average of nearly 20,000 new users each month. With an increase in new and returning customers to the portal during the past six months, the Company anticipates that customers will leverage the data on the widgets to make more informed decisions that could impact their respective energy usage.

Figure 2.12.6 Monthly AMI Widget Usage



The Company has also enabled proactive alerts that are triggered when the average energy usage for the current billing period is trending to exceed 25 percent or more than the same billing period in the previous year. The alert is sent in the middle of the billing period, allowing customers to make behavioural changes with enough time to influence their next bill. This alert is currently available only to electric residential customers and will be made available to gas residential customers over the next reporting period. Customers are automatically enrolled in receiving the proactive alerts, and very few customers have indicated intent to opt out of receiving the high bill and proactive alerts (0.04 percent and 0.1 percent, respectively). To be automatically enrolled in proactive alerts, customers must have previously provided a valid email address to the billing system and given their consent to be contacted.

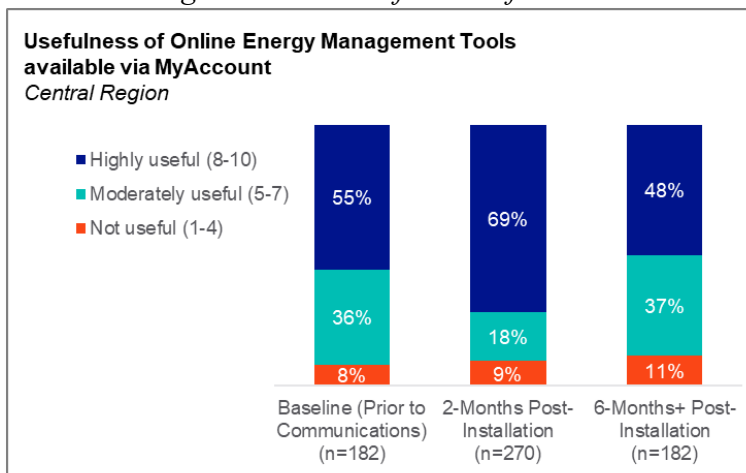
Table 2.12.1 Number of Customers Enrolled in High Usage Alerts and Weekly AMI Reports

Reporting Period Ending	Customers Enrolled in High Usage Alerts	Customers Enrolled in Weekly AMI Reports
April 2024	34,800	34,696
October 2024	126,589	125,714
April 2025	264,563	261,060

According to the post-deployment survey, nearly half of the customers in the Central region who received an AMI meter are aware of CEMP at 2 months (44 percent) and 6 months+ (45 percent) post-installation. Among those engaging with CEMP and its features, the perceived usefulness of CEMP is higher at 2 months post-AMI meter installation (69 percent) compared to baseline (55

percent). Within the Central region, while more customers have used the online management tools at 6-months+ post-installation, the perceived ‘usefulness’ of the online tools drops off at 6-months+ post-installation (48 percent). The Company’s post-installation campaign will target building customers' perception around the usefulness of these widgets as they leverage the data to make informed decisions.

Figure 2.12.7: Usefulness of CEMP



Change Management

To support successful adoption of AMI across the organization, the Company continues to engage employees with the information, tools, and resources necessary to confidently embrace new ways of working. The AMI Change Management effort is delivering targeted engagements and internal communications tailored to key stakeholder groups and focused on delivering defined business outcomes.

Alignment with CLCPA Goals

AMI supports state CLCPA clean energy targets by enabling more efficient, data-driven, and flexible energy systems.

- **Improved Demand Response and Load Management:** Real-time and near-real time data will enable National Grid to better understand and manage customer energy usage patterns. It will also support DR programs, in tune, that will help integrate intermittent renewables like solar and wind
- **Improved Integration of DERs:** AMI enables two-way communication, allowing utilities to monitor and manage energy (e.g., rooftop solar, battery storage, and EVs).
- **Grid Optimization and Reliability:** More granular data allows for more accurate load forecasting, fault detection, and outage management. AMI can also reduce the need for fossil-fuel-based spinning reserves by making the grid more responsive and resilient.

- **Empowering Customers:** AMI provides customers access to detailed energy usage data, enabling EE and conservation. Through transparency of available energy data, AMI supports behavioral change and participation in clean energy programs.
- **Enhanced Renewable Forecasting and Planning:** National Grid will be able to use AMI data to improve forecasting of renewable generation and adjust grid operations accordingly. This will support long-term planning for grid modernization aligned with clean energy targets.
- **Reduced Emissions:** Through optimization of system performance and reducing peak demand, AMI can indirectly reduce the reliance on fossil fuel peaking plants, and thereby reduce emissions.

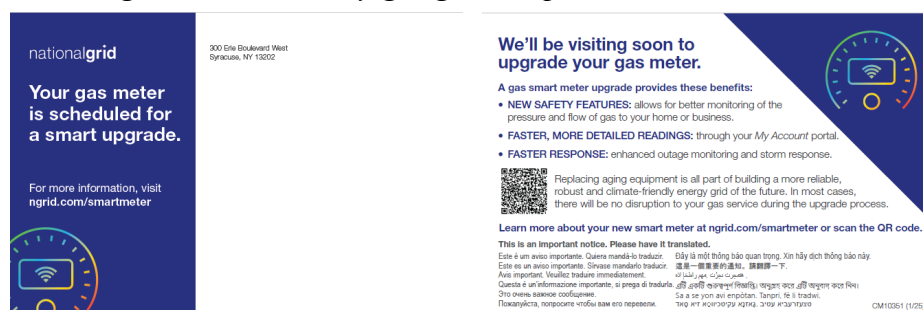
Stakeholder Interface

Customers remain the primary focus for the Company as it deploys more AMI meters. Communications to customers continue to follow a comprehensive campaign for AMI meter awareness. The Company is engaging its customers, starting with awareness (90 days prior to meter installation), empowerment (60 days prior to meter installation), and enablement, which conveys meter installation messaging and AMI meter education to customers (30 days prior to meter installation).

The 90-day communication focuses on mass media communications such as radio advertisements, social media posts, online banner ads, billboards, bus wraps, Spotify ads, and newspaper ads. The 60-day communication is a personalized letter sent via mail or email, focusing on the message that an AMI meter is coming. The 30-day communication provides more details about the benefits of the soon-to-arrive AMI meter. This is sent as a welcome brochure, bill insert, and letter through email or mail. As the Company approaches the installation date, a 10-day communication is issued through text, email, or robocall to inform the customer that the Company is nearing the AMI meter installation. After the installation, a door hanger is left with the next steps for the customer. Communication materials were updated to reflect the fuel and customer types.

The Company developed a new 30-day “gas go-back” communication piece for dual fuel customers who will be receiving their gas modules more than thirty days after their electric meter was installed. This new piece reminds customers that the Company is now ready to install gas modules. The 60/30-day communication pieces highlight that the Company may install both electric meter and gas module at the same time or will come back at a later date to install the gas modules.

Figure 2.12.8: 30-day gas go-back postcard



The Company has sent customers over 1.7 million communication pieces (60 and 30-day communication initiatives) from program inception through April 30, 2025.

The Company leverages feedback from surveys, field employees, customer service representatives or office staff, customers inquiries and concerns to enhance communication pieces and frequently asked questions on its website.

The Company will commence developing post-install campaign tactics with the release of functionalities that customers can use to drive decision-making around their energy. The campaign will drive customers to their MyAccount portal to monitor their usage through the new widgets, allow them to view appliance-level data if eligible, and cross-promote customer programs like EE and clean energy alternatives.

Market Intelligence

As the Company rolls out AMI meters in its UNY territory, the Market Intelligence team monitors customer awareness and experience with AMI meters at three touchpoints along the customer's journey (pre-installation, 1-2 months post-installation, and 6 months+ post-installation).

The Pre-Deployment Baseline Survey is fielded to customers prior to the start of 90-day communications in a given geographic area and is designed to establish a baseline measure of awareness, interest, and attitudes towards AMI meter offerings prior to formal communications launch. This is valuable information for the Company to understand the “starting point” of where customers are at in terms of AMI meter knowledge.

The Post-Installation Survey is fielded monthly to customers approximately 2 months after receipt of their AMI meter. This survey is designed to monitor changes in AMI meter awareness and provide insights into the installation experience.

The Long-Term Tracking Survey is fielded at 6-month intervals to customers who have had a meter for 6-months or longer. This survey continues to monitor changes in AMI meter awareness, satisfaction, and attitudes.

The findings that follow present a combination of results from the three surveys conducted between July 2023 and March 2025. The findings encompass insights from customers in the Central, Capital, Northeast, Northern, Mohawk Valley, Southwest and Genesee regions prior to the installation of their meter; customers who received their AMI meter between September 2023-

January 2025 at 2-months post-installation; and insights from a portion of customers who received their AMI meter between August 2023 and June 2024 at 6-months or longer post-installation. Results are among residential customers only.

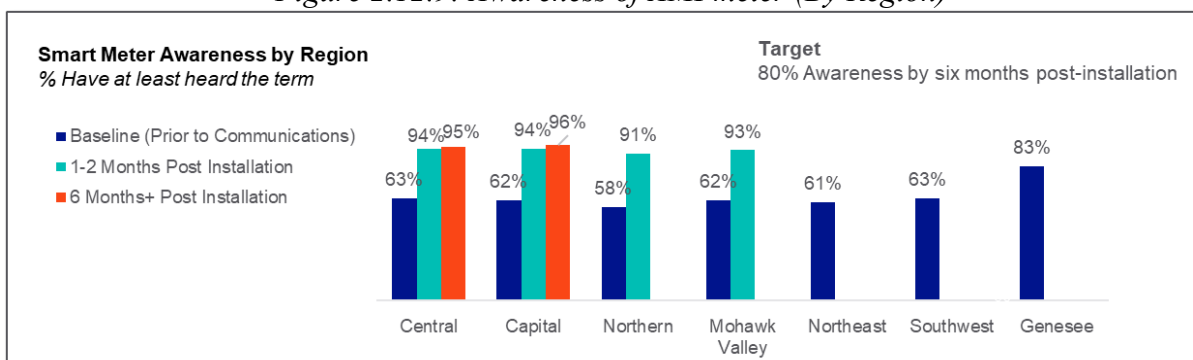
Table 2.12.2: Survey Respondents to Date by Region

National Grid Region	Baseline Survey	Post-Installation Survey	Long-Term Tracking Survey
Central	622	1,212	679
Capital	499	513	68
Northern	476	197	33
Mohawk Valley	270	234	21
Northeast	449	385	-
Southwest	385	435	-
Genesee	435	-	-
Frontier	-	-	-
TOTAL	3,136	2,976	801

The Company's marketing communications are designed to educate customers, and the data indicates they are effective.

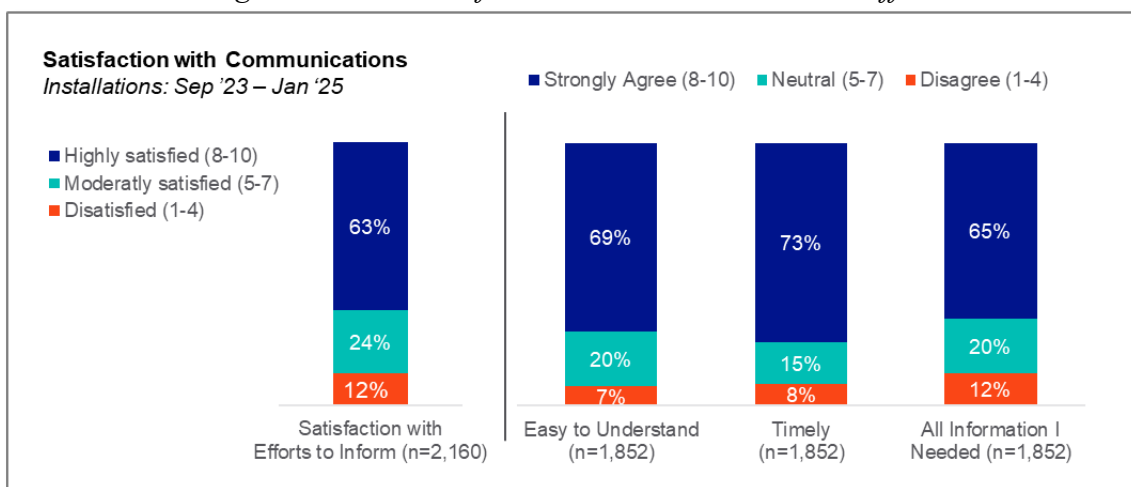
The Company is targeting 80 percent awareness of "AMI meters" at 6 months post-installation. In all regions measured to date, AMI meter awareness at 6-months+ post-installation exceeds the target, surpassing pre-deployment levels (by a significant 32 to 34 points).

Figure 2.12.9: Awareness of AMI meter (By Region)



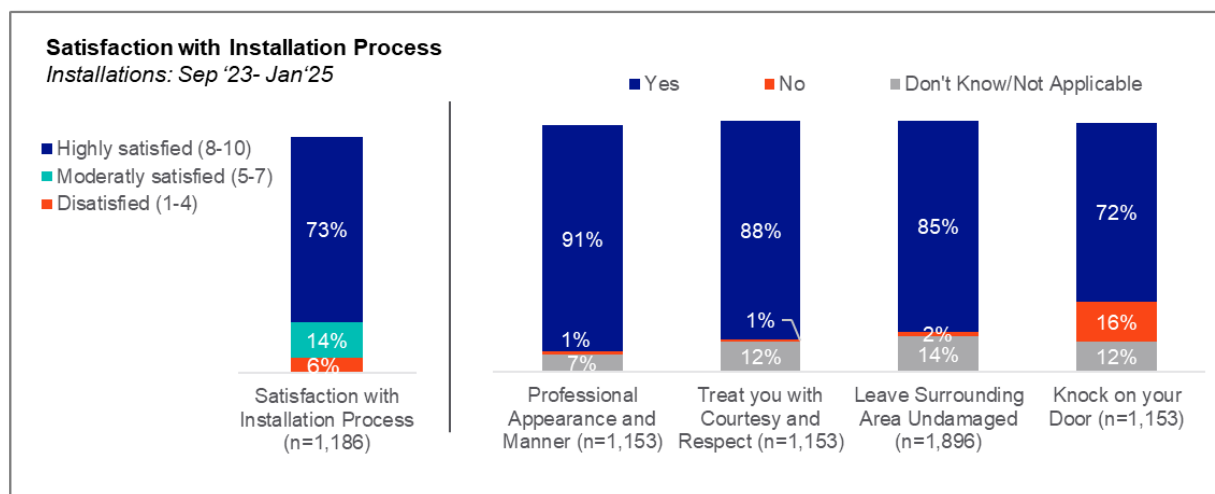
In addition to increased awareness, a large majority of customers are highly satisfied with the Company's efforts to inform them about the AMI meter installation (63 percent); and strongly agree that communications were timely (73 percent), easy to understand (69 percent) and provided all the information they needed (65 percent).

Figure 2.12.10: Satisfaction with Communications Efforts



Customers are largely satisfied (87 percent) with the installation process as well, with around three quarters highly satisfied (73 percent). A moderate proportion (61 percent) of customers either spoke to or saw an installer during their meter installation. Most who did interact with or see the installer feel the installers were courteous/respectful (88 percent), had a professional appearance/manner (91 percent), and left the surrounding area undamaged (85 percent).

Figure 2.12.11: Satisfaction with the Installation Process



Community Engagement

The Company has participated in multiple outreach events and community forums to enable discussions with customers and to answer questions regarding the Company's AMI meter program. Conversations typically revolve around deployment schedules, the installation process, and online data presentment.

Table 2.12.3: AMI meter Community Engagement Events

Community Event Type *At April 30, 2025	Ramp Up Period	Program Year 1 7/23-6/24	Program Year 2 7/24-6/25	Program Year 3 7/25-6/26	Program Year 4 7/27-6/26
Consumer Advocate Expo		8	4		
Senior Organizations		6	2		
Farmers Markets		4	1		
Youth Education		5	3		
Libraries	4	7	1		
Municipalities	2	4	4		
Community/Bus Orgs		6	7		
Regional Home Shows			6		
Internal		2	2		
Total Community Events	6	42	30*		

Table 2.12.3 shows the types of events attended and how many. Consumer advocate expos and senior events help target low to moderate-income customers.

In general, customers have responded positively to the AMI meter rollout. They like having access to a visual representation of their energy use to make more informed decisions, are positive about the automatic power outage detection, and understand that the current metering infrastructure has nearly reached the end of its useful life. Frequently asked questions include whether they need to be home during installation, especially if they are ‘snowbirds’, if it’s safe for the workers because they have a backup generator, what happens if they have an inside meter, and if there are changes to how they can pay their bills. As new concerns are identified, they are typically addressed in the FAQ section of the Company website. The Company has additionally supplied the jurisdictional customer and community teams with AMI meter-focused tear pads to assist with general questions they receive as they interact with customers and community members.

The Company has engaged members of the various communities in the Mohawk, Capital, Central, Northern, and Western regions at thirty events since July 2024. Throughout the community effort, the Company has targeted events to attend alongside the Company’s consumer advocates to ensure an equitable approach to meeting the needs of each community we serve. Events have included senior fairs, community expos, and neighbourhood and youth group events. The Company has attended several large-scale events (Home Shows) across the Albany, Utica, Syracuse, and Buffalo areas, engaging with thousands of customers. As meter deployment expands, the Company is identifying opportunities to attend community events in those specific areas.

Community Leader Letters

Community leaders across the UNY service territory are slated to receive a semi-annual AMI meter program update. The next community leader letter will be mailed by year-end. This letter series provides community leaders with updates on where deployment has occurred, how it's going, and where deployment can be expected over the next several months.

Figure 2.12.12: 30-day gas go-back postcard



2.13 Beneficial Locations for DERs and Non-Wires Alternatives

Context and Background

The impacts of DER vary greatly depending on where they are placed on the distribution system. National Grid endeavors to identify where DER may provide benefits to the electric delivery system through its integrated planning process and shares that information on the System Data Portal.¹¹⁵ National Grid defines a beneficial location as a location where DER integration can reduce, delay, or eliminate the need for electric system upgrades or enhance reliability and/or efficiency of the electric system. There are multiple procurement and compensation mechanisms that rely on accurate assessment of beneficial locations. To date, the Company has identified potential beneficial locations in support of NWAs, LSRV, and the programs initiated by the 2018 Energy Storage Order (*i.e.*, competitive procurement for energy storage dispatch rights and novel, targeted DLM programs). For more information regarding Energy Storage Order programs, please refer to the Energy Storage and Energy Efficiency Integration and Innovation topical section in this 2025 DSIP Update. The beneficial locations associated with NWAs, LSRV, and bulk power energy storage procurement represent areas in which appropriate DER will be compensated for the value they provide in support of the grid.

NWAs are an important mechanism for bringing DER onto National Grid's electric system. NWA assessments are a natural outgrowth of National Grid's planning processes. The Company performs planning studies over both short- and longer-term horizons, summarized in the annual CIPs. In concert with the other Joint Utilities, National Grid has developed NWA suitability criteria to identify projects which are reasonable candidates for NWA consideration. The Company applies the suitability criteria early in the planning process. National Grid's planning groups document the amount and location of load relief needed to mitigate system capacity or reliability needs, while working to scope a traditional solution. Once the Company has defined the system needs that could be addressed by an NWA solution, it will communicate the need to the market via an RFP. RFPs include a project overview with a description of the specific need and relevant high-level customer information, which may include customer count and demographic, and other system characteristics in the detail necessary for respondents to develop solutions and submit a proposal. RFPs also include links to other National Grid resources including the NWA Website and the System Data Portal, which contains information regarding NWA areas and the Company's BCA Handbook for an explanation of the Company's BCA process. RFPs also contain an order-of-magnitude cost estimate for the National Grid to implement a traditional solution. The Company's NWA solicitation process aims to balance the timing of the system need against a reasonable timeline for DER providers to develop responses to the RFP. The RFP is filed with the Commission and posted on the public Commission website, in addition to being available on

¹¹⁵ Available at <https://ngrid.portal.esri.com/SystemDataPortal/NY/index.html>

National Grid’s procurement system. DPS Staff and other stakeholders are regularly apprised of the status of potential NWA projects.

National Grid evaluates RFP responses to proposed NWA opportunities considering both economic and technical dimensions. The Commission’s BCA Framework Order,¹¹⁶ explained in more depth in National Grid’s BCA Handbook¹¹⁷, guides the economic assessment of a project. The technical assessment of a proposed NWA solution evaluates whether the proposed solution will provide a safe, reliable, and operationally sound solution. NWA projects that satisfy the technical requirements and have a positive BCA may progress.

Suitability Criteria

The Company’s NWA suitability criteria matrix is presented in Table 2.13.1:

Table 2.13.1: National Grid’s NWA Suitability Criteria Matrix

Criteria	Potential Elements Addressed
Project Type Suitability	Project types include Load Relief and Reliability. Other types have minimal suitability and will be reviewed as suitability changes due to State or Federal policy or technological changes.
Timeline Suitability	Eighteen months minimum prior to the date of the system need
Cost Suitability	Greater than or equal to <u>\$1M</u>

By applying the suitability criteria earlier in the planning process, the Company creates more time to refine the NWA solution(s), providing bidders more time to develop proposals and meet the need date.

Implementation Plan, Schedule, and Investments

Current Progress

The Company continues to identify beneficial locations for its evolving portfolio of programs, procurements, and DER tariffs, as each is expected to continue to evolve as market mechanisms and analytic capabilities mature. National Grid performs long-term, feeder-level forecasts that feed into an integrated planning process that subsequently informs the Company’s identification of beneficial locations. The Forecasting section discusses National Grid’s current capabilities and multi-year roadmap. Beneficial locations are increasingly driving DER deployment as National Grid has completed twelve evaluations and a current active evaluation for NWA opportunities. The Company has taken many steps to implement and refine its NWA RFP process. To date,

¹¹⁶ REV Proceeding, Order Establishing the BCA Framework (issued January 21, 2016) (BCA Framework Order).

¹¹⁷ REV Proceeding, Niagara Mohawk Power Corporation d/b/a National Grid – Version 3.0 BCA Handbook (filed June 30, 2020).

National Grid has issued thirteen RFPs. The following table summarizes the RFPs released through the end of May 2025.

Table 2.13.2: Status of National Grid's 2023-2025 NWA RFPs through Competitive Solicitation

Project Name	Status	Voltage Type	Estimated RFP Timing (CY)
Pine Grove (New Cicero) Substation DSUB & D-LINE	Operational	Distribution	RFP Closed
Sawyer 11H Sub-T Line <i>Former Buffalo 23KV</i>	EE Kicker Implemented	Sub-T	RFP Closed
Watertown 115/13.2 KV Substation	Operational	Distribution	RFP Closed
New Krumkill	Under Evaluation	Distribution	RFP Closed

For the projects undergoing planner review, the load forecast will be revised to determine the area needs. For the projects under construction or operational, the Company will continue to file the quarterly reports, and implementation plans for updates as these projects have had contracts executed.

Pine Grove

On November 26, 2018, National Grid filed with the Commission an RFP that was issued for an NWA solution to meet certain needs of the Company's electric system served by the Pine Grove Substation located in the Town of Cicero. The loading at the Pine Grove Substation serving the Town of Cicero area has increased to a level at which it is projected to be overloaded to 100 percent (or higher) of its emergency rating (upon an outage of one of the two station transformer banks). The Company evaluated alternatives to reduce the area load to maintain or improve reliability performance. National Grid sought NWA solutions that could provide delivery infrastructure avoidance value as well as reliability and operational benefits. National Grid's evaluation process results indicated that a developer's bid proposal for a ten-year solution consisting of a solar PV system coupled with a BESS to be the most efficient, economical, and feasible NWA solution. The completed NWA solution deploys two grid-tied 5 MW solar arrays, each paired with 5 MW / 20 MWh lithium-ion BESS. The Pine Grove NWA solution is operational and was successfully dispatched for summer 2024.

Watertown

On November 8, 2019, National Grid filed with the Commission an RFP that was issued for an NWA solution to meet certain needs of the Company's electric system served by the Coffeen Substation located in the Town of Watertown. The loading at the Coffeen Substation serving the Town of Watertown area has increased to a level at which it is projected to be overloaded to 100 percent (or higher) of its emergency rating (upon an outage of one of the two station transformer banks). The Company evaluated alternatives similar to in Pine Grove and a contract was executed with a third party. The NWA solution is a solar and battery installation that will meet the 5.7 MW / 40 MWh need, is now operational. The NWA solution was commissioned by March 2025 and is expected to dispatch for its first season in summer 2025.

Sawyer

On December 18, 2018, National Grid filed with the Commission an RFP that was issued for an NWA solution to meet certain needs of the Company's electric system served by the Sawyer 11H Sub-T Line in the City of Buffalo. The loading on the Company's 11H Sub-T Line serving the Buffalo area has increased to a level at which it is projected to be overloaded to 100 percent (or higher) of its emergency rating (given an outage on the parallel Sub-T line). The Company evaluated bids proposing to reduce the area load in order to maintain reliability performance in response to the RFP. However, none of the proposals were deemed to be viable solutions. The Company is now pursuing an NWA solution that leverages existing National Grid EE programs to provide an alternative NWA solution to local distribution system needs through the use of an EE kicker. An EE kicker is a targeted EE offering that complements an NWA area, such as the one served by the Sawyer 11H Sub-T Line, by offering locational incentives to those customers implementing EE projects that provide demand reduction results. Updates to the NWA EE kicker program will be detailed in NWA quarterly reports.

RFP Process Improvement and Lessons Learned

Throughout 2023 to 2025, RFPs were further improved by:

- Updates to the NWA service definition to include secure and sustain definitions to expand NWA solutions
- Optimizations in the procurement methodology and interface to expand to more NWA solution providers and increase participation in NWA RFPs
- Continued improvements to the BCA tool to ensure NWA benefits are appropriately considered and explored
- Incorporating checklists of the items needed for the Company to thoroughly review the proposed solutions
- Better aligning the proposal content requested with more comprehensive needs of the internal reviewers
- Providing an approximate value of a potential NWA solution so that bidders can determine if their NWA solution is cost-competitive when compared to the traditional wires solution.
- Providing sample terms and conditions in RFPs to help NWA providers secure/investigate financing options prior to proposal submittal
- Discussing contract structure and performance expectations in the RFP and evaluation process with the active bidders

- Use of a standard template to provide a common format across all RFPs
- Property acquisition responsibility
- Inclusion of details on telemetry and communication protocol. Details are included on how the NWA solution may integrate into the control center operations and what operational coordination may be needed.
- Inclusion of performance expectations and how they relate to the telemetry
- Providing greater clarity for NWA contract terms and performance through updated contract templates
- Greater collaboration between the DR programs and the EE programs
- The Company has drafted a process to dispatch third party NWA assets that include batteries through a real time centralized dispatch protocol, this language will be added to future RFPs
- Addition of new service definitions to expand and create more flexibility to NWA developers; new language was added to encourage customer sided solutions.

During the proposal review process, National Grid provides individual vendor and group updates through our procurement platform for both updates to individual bid status and questions and answers applicable to all bidders.

Vendor Stakeholder Procurement Platform

National Grid aims to use the Piclo Flex platform through 2026 to release NWA RFPs replacing Ariba for certain NWA procurements where National Grid is exploring a more open market-based model as part of the Company's DSO transition plan. In the future, the Company may further utilize market-based platforms to procure flexibility services or return to the existing Ariba procurement tool.

EE/DR Integration

Load reduction from EE and DR programs that National Grid already administers may be a viable mechanism for increasing the cost-effectiveness of an NWA solution. The Company's NWA solution development process evaluates the potential use of existing EE and DR to help reduce system needs. The Company has worked to optimize the locational offerings between NWA procurements and any applicable DR and EE programs, including the new Term, Auto-DLM, and EE programs which require coordination on locational offerings. In addition, a kicker was introduced within the EE portfolio which is focused on an NWA location for peak reduction benefits, please see the Sawyer project referenced above for more details.

Contracting

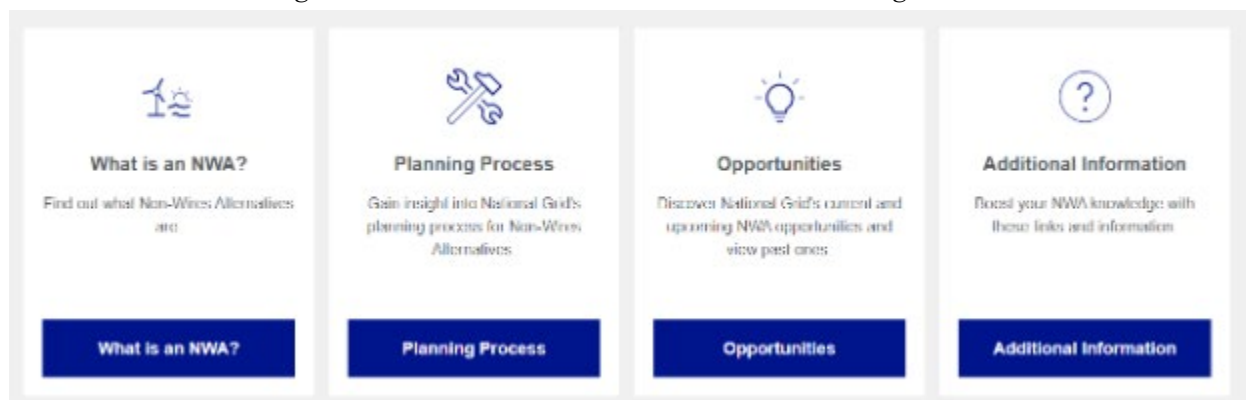
National Grid released an updated contract template with the New Krumkill RFP. Prior to the RFP release, the Company worked with the market to receive feedback on the template. The goal of this template and market feedback collection effort is to decrease timelines associated with RFP development, evaluation, and contracting. Additionally, the contracting template update will provide vendors with more detail on the service requirements, potential liquidated damages and liability requirements. This should enable vendors to provide more confident pricing when

responding to RFPs. National Grid also introduced two new service definitions to expand what the market may offer as NWA solutions; the two new service definitions focus on the telemetry capabilities of an NWA solution.

NWA Website

The Company continues to optimize the NWA website so that potential bidders have more direct access to RFPs, opportunities, and general NWA information. The NWA website's landing screen shot is captured in Figure 2.13.1.

Figure 2.13.1: National Grid's NWA Website Landing Screen



The NWA website contains:

- Introductory information about NWAs and the Company's planning process
- NWA opportunities, both current and upcoming
- Project-specific RFPs
- Links to National Grid's procurement platform and enrollment instructions
- Links to the National Grid System Data Portal
- Links to register to RFPs and learn about upcoming projects through the procurement platform
- Process to contact National Grid NWA team

The website content will be refreshed periodically with specific project information and other information beneficial to potential bidders.

The Company has also established an NWA email address Non-WiresAlternativeSolutions@NationalGrid.com, that stakeholders can utilize as an alternative to contacting specific National Grid employees with specific inquiries. National Grid monitors this NWA mailbox daily under normal conditions.

Land Inventory

In accordance with the 2018 Energy Storage Order, the Company continues to include information regarding suitable, unused and undedicated land in its NWA RFPs. This information includes location and satellite view, footprint available (sq. ft. or acres), and an estimated fair market value or the assessed value used for property tax purposes. The RFP could provide a market value based on a formal appraisal. If a formal appraisal is not the basis of the estimated market value provided in the RFP and there is interest expressed by bidders in the property during the course of responding to an RFP, the utility will proceed with a more formal review. This would include an environmental review and any other reviews needed, followed by securing a formal real estate appraisal of the property to determine the fair market value. This formal appraised value will be used in National Grid's BCA should the bidder elect to proceed with lease or sale of the property.

Interconnection Costs

In accordance with the 2018 Energy Storage Order, the Company provides either the estimated utility-sided interconnection costs in the NWA RFP for non-binding planning purposes for DERs (whereas customer-sided interconnection costs cannot be reasonably estimated at the time of the RFP release), or an indication that interconnection costs for utility-owned equipment will be borne by the utility and will be included as a cost in the BCA. The Company provides guidance on local situations that may have a substantial impact on interconnection costs and can reasonably be anticipated. Any interconnection is highly dependent on the technology proposed and the configuration at the proposed site.

Future Implementation and Planning

Identifying beneficial locations for DER and properly valuing those benefits will continue to be a focus for National Grid over the next five years. Below is a list of National Grid's upcoming NWA solicitations. More information can be found on the Company's NWA website: <https://www.nationalgridus.com/Business-Partners/Non-Wires-Alternatives/>

Table 2.13.3: National Grid's Planned NWA Projects

2025-2028 NWA Projects	Need Date	Estimated Solicitation Timing
New Krumkill	2026	RFP results evaluated in 2025

The Company released an RFP in New Krumkill area on October 31, 2024 and will be analyzing the results for potential NWA solutions. New Krumkill is a 115/13.2 kV substation with 4.16/13.2 kV ties to neighboring substations. Due to increasing forecasted load, the station may be unable to meet its planning requirements of supplying contingency loading from neighboring feeders at peak times of the year. Although the New Krumkill Substation is in the process of being rebuilt to support wider area plans with an anticipated completion date of 2030, an NWA may be implemented in the interim, until such time as the completed capital solution is available to meet future normal and contingency loading. As the New Krumkill Substation has a significant number of feeder ties to other nearby substations in the Albany area, the near-term limited station transformer capacity could cause CI in the event that New Krumkill is unable to supply this feeder

tie load in the event of a contingency. The team will be leveraging lessons learned from the New Krumkill opportunity to optimize the NWA process.

In addition to pursuing solicitations for specific projects, the Company, in concert with stakeholders and the Joint Utilities, will investigate solutions to certain planning challenges with the aim of further enabling NWA opportunities. National Grid continues to investigate unique opportunities and started to look into opportunities for solutions to ancillary service needs such as voltage support; however, studies will be required to better understand the needs and if an inverter-based solution can support a non-wires approach. The Company continuously seeks new opportunities for new uses cases and will continue to explore options that may lead to new project types.

Further improvements efforts are summarized in the following paragraphs.

Improved RFPs

As described previously, National Grid will continue to improve the NWA RFPs and the associated information provided. Future RFPs will be revised thorough a continuous improvement effort including feedback from external stakeholders (e.g., vendors), internal stakeholders, and lessons learned. The Company will take external and internal feedback from the most recent RFP, and incorporate optimization based on lessons learned.

Contracting

The Company learned that contracting for NWA is time-consuming and complex. To simplify the process, National Grid now includes sample contractual terms and conditions in NWA RFPs to alert bidders of their responsibilities and continue to optimize the template based on market feedback and lessons learned. The Company will take in lessons learned from New Krumkill and further update the templates as needed.

NWA projects and processes are under continuous improvement to incorporate lessons learned and industry best practices. The Company will continue to evaluate projects according to the suitability criteria to identify potential NWA projects for 2025 and beyond. The Company will also continue to work in conjunction with the Joint Utilities to incorporate lessons learned from the Joint Utilities, as appropriate. Additionally, the Company is coordinating with internal programs such as DLM and EE programs to optimize NWA offerings and better integrate and leverage customer DERs as “demand-side” NWA solutions to targeted distribution system needs.

Risks and Mitigation

Table 2.13.4: Risks and Mitigations

Risk	Mitigation
Performance Uncertainty of using DER technologies to support system performance	Describing procurement needs in the RFP and working closely with bidders to understand the capabilities of their technologies and proposed solutions; terms are summarized in the RFP and a contract template is shared with the RFP
	Including performance expectations and how they relate to DERs in the RFP and discussing performance expectations in evaluation process with the active bidders early in the process will help solution providers understand the performance expectation
Contracting After selecting a preferred solution, there is the risk that the Company and the bidder cannot come to terms on a contract	Including sample terms and conditions in the NWA RFP and through close collaboration and negotiation to create mutually beneficial compensation and contract terms.
	Working with the market's feedback and lessons learned to optimize the contract and RFP templates and overall NWA process to ease future NWA implementation (including negotiations).

Alignment with CLCPA Goals

Identifying beneficial locations can inform economic deployment of DER, such as energy storage and solar, thereby supporting the clean energy goals of the CLCPA at least cost. Targeting beneficial locations in utility procurements, such as in DLM and NWAs, will provide new opportunities for DER. The Climate Act has established bold clean energy targets that include specific quantities of storage, offshore wind, and solar. To the extent NWAs provide solutions that include energy storage, solar, and/or other renewable generation, NWAs may help achieve Climate Act targets. The lessons learned through the NWA program proliferate among other relevant planning processes to help planners appreciate how to integrate advanced technology and non-traditional solutions into relevant planning processes at all levels (e.g., in the CGPP).

Stakeholder Interface

National Grid continues to collaborate with the other Joint Utilities, as well as NYSERDA and DPS Staff, on NWA projects and process. The Company also engages the NWA solutions providers when an RFP is released through webinars and Q&A sessions. Information regarding NWA opportunities is also available on National Grid's System Data Portal for stakeholders which will lead to the NWA website. The primary resource National Grid uses to share up-to-date information about beneficial locations is the Company's System Data Portal which maintains "tabs" specific to NWA opportunities, LSRV areas, and HCA. National Grid aims to use the Piclo Flex platform through 2026 to release NWA RFPs. Piclo Flex platform currently replaces Ariba for certain NWA procurements where stakeholders can find up to date details on the platform. In the future, National Grid may utilize a different market platform to procure services from DER. Historically, pre-qualified vendors are sent NWA opportunity notifications via Ariba, National Grid's procurement system. At any time interested vendors may contact:

- Non-wiresAlternativesSolutions@nationalgrid.com

3 Other DSIP Information

3.1 DSIP Governance

DSIP Scope, Objectives, and Participants

This 2025 DSIP Update serves as a core planning document, outlining National Grid's plans with respect to the utility role as the DSP that includes DER and EV integration, information sharing, and market services over the course of the next five years based on current Company and NYS priorities and objectives. While the horizon of this plan is five years, it is refreshed on a two-year cycle.

The DSIP is an informational document that offers insight into the Company's on-going efforts and future plans in support of its role as the DSP provider but does not seek funding approval for these efforts. National Grid rate cases and other cost recovery filings with the Commission are the venue for the approval of investments discussed in this 2025 DSIP Update. The DSIP update cycle does not match the Company's rate case cycle and therefore includes work the Company has been approved to proceed with as well as future plans that will be presented in forthcoming rate case proposals. As of the publication of this 2025 DSIP Update, National Grid anticipates filing its next electric and gas rate case in 2027.

DSIP Work Processes and Timing

There are several work processes associated with the development of the DSIP and its implementation. These processes, both internal and external, progress in parallel, sometimes in advance of formal policies and procedures as the DSP evolves.

Externally, National Grid works closely with the other Joint Utilities to foster efficient stakeholder engagement and consistency with respect to the evolution of the DSP. The Joint Utilities have developed a governance structure that includes a Leadership Team that coordinates the activities of two subordinate Joint Utilities committees, the DSP Steering Committee and the Regulatory Policy Steering Committee. These committees then coordinate multiple work teams that focus on the individual topics discussed in this 2025 DSIP Update.

Internally, National Grid develops the DSIP through the contributions of dozens of SMEs representing the breadth of departments and functions within the Company that have a role in DSP activities. An executive level DSIP Steering Committee guides and oversees the development of the DSIP.

Joint Utilities Website

The Joint Utilities collectively maintain and regularly update their website, available at www.jointutilitiesofny.org with valuable resources for interested parties. For example, a summary of current Joint Utilities DSP enablement activities is updated each quarter and posted to the website homepage to keep third parties informed of utility efforts to advance DSP implementation.

The Joint Utilities welcome suggestions to enrich this website through their email address at info@jointutilitiesofny.org.

Stakeholder Engagement

Please see the next section, “Updates Between DSIPs” for information.

Updates Between DSIPs

The Joint Utilities will offer two products to keep stakeholders informed of important developments in DSP capabilities: a quarterly newsletter and a bi-annual webinar. Both items will be produced as a collaborative effort among the Joint Utilities. Content from the newsletters will also be posted, available at www.jointutilitiesofny.org.

To be added to the digital mailing list and receive the invite to the bi-annual webinar, please email info@jointutilitiesofny.org.

National Grid expects the capabilities of the DSP will continuously evolve and as such, the Company’s DSIP needs to be flexible enough to accommodate adaptive goals and paths forward. Progress with respect to this plan and adjustments to the plan will be documented in future DSIP updates that are anticipated to occur biennially.

3.2 Marginal Cost of Service Study

Following a technical conference held on May 2, 2023, the Joint Utilities filed initial comments on DPS Staff's Whitepaper Regarding Marginal Cost of Service (MCOS) Studies in Case 19-E-0283 on July 20, 2023 and raised a proposal to use a deferral value approach for MCOS in LSRV areas and for Non-wires Solution areas.¹¹⁸ The Joint Utilities filed reply comments on August 18, 2023. Additional technical conferences were held on November 28, 2023 and January 10, 2024, followed by Joint Utilities' reply comments and supplemental reply comments filed on January 16, 2024 and February 6, 2024, respectively.

On August 19, 2024, the Commission issued its *Order Addressing Marginal Cost of Service Studies* (MCOS Order).¹¹⁹ The MCOS Order required each of the Joint Utilities to prepare MCOS studies in accordance with the MCOS Order and include those studies in their respective DSIP Update filings on or before June 30, 2025. The MCOS Order also required DPS Staff to convene a collaborative stakeholder process in Case 15-E-0751 to discuss pricing issues within 45 days of the MCOS Order and file a workplan and schedule for the collaborative process on development of a LSRV and Demand Reduction Value (DRV) in Case 15-E-0751. Once the MCOS studies are approved by the Commission, the MCOS Order anticipates that these updated studies will be used to calculate LSRV and DRV components of the Value Stack compensation.

The MCOS Order adopted the proposals in the Staff Whitepaper, with further modification, and established a methodology for estimating marginal costs to inform system wide applications such as DRV. The MCOS Order adopted a traditional approach to develop more system-wide marginal costs for all future MCOS studies, based upon the approach recommended by the National Economic Research Associates (NERA). The traditional NERA method relies upon the costs of actual projects in the utilities' capital plans. The MCOS Order also stipulated that the MCOS studies should reflect long-run, non-zero marginal costs, regardless of whether segments of a utility's distribution system have no avoidable costs due to near-term expected changes in demand and shall use a ten-year planning horizon. The studies shall include all load growth related and multi-value projects (i.e., simultaneously growth and reliability related) planned under a 10-year horizon in the investment cost sample.

The MCOS Order allows each utility to use their own forecasting method to identify the need for those actual projects but should include in their future MCOS study filings a discussion of the robustness of their forecasting methods over the 10-year planning horizon. In addition, a detailed explanation of the extent to which existing and forecasted DER related load reductions are reflected in actual planned investment projects shall be included in future MCOS study filings.

¹¹⁸ Case 19-E-0283, *Proceeding on Motion of the Commission to Examine Utilities' Marginal Cost of Service Studies* (MCOS Proceeding), Joint Utilities' Comments on the Department of Public Service Staff's Whitepaper Regarding Marginal Cost of Service Studies (filed July 20, 2023).

¹¹⁹ MCOS Proceeding, *Order Addressing Marginal Cost of Service Studies* (issued August 19, 2024) (MCOS Order).

The MCOS Order stipulates that marginal costs should be presented for each year of the 10-year study period, on at least a substation level basis. The MCOS studies should continue to be updated and filed on a two-year cadence at the time of the utility's DSIP filings.

National Grid has performed the required MCOS Study for this 2025 DSIP Update filing and the study is attached as Appendix C.

3.3 Benefit-Cost Analysis

The primary purpose of the BCA Handbook is to provide DER developers with a guide as to how the Commission's BCA Framework will be implemented in evaluating proposed DER projects and proposals to meet the system needs set out in this 2025 DSIP Update. The BCA Framework Order states:

*The [BCA] Handbooks would be developed in coordination with each utility's DSIP, where system needs, proposed projects, potential capital budgets, and plans for soliciting DER alternatives will be provided. Because market engagement should be consistent across NY, the Handbooks would establish methodologies based on common analytics and standardized assumptions and would identify various sensitivities and synergies.*¹²⁰

The BCA Framework Order required each utility to file its proposed BCA Handbook with its initial DSIP on June 30, 2016.¹²¹ As required by the BCA Framework Order,¹²² National Grid's BCA Handbook was developed in cooperation with the Joint Utilities and provides a set of common methodologies that apply uniformly across the state. Many of the common methodologies, assumptions, and sources included in the respective BCA Handbooks are provided in Appendix C of the BCA Framework Order. The Joint Utilities' BCA Handbooks deviate from each other only where necessary to accommodate distinctions among the various service territories.

Version 2.0 and 3.0 of the Company's BCA Handbook, filed contemporaneously with the 2018 and 2020 DSIP Updates, respectively, provided updated utility-specific and state-wide input assumptions and sources as well as clarifying edits to Version 1.0 methodological descriptions and additional example applications. As with Version 1.0, National Grid's Version 2.0 and 3.0 BCA Handbooks were developed in cooperation with the Joint Utilities and differ from the other utilities' BCA Handbooks only where necessary to accommodate distinctions between the service territories. Similarly, Version 4.0, filed contemporaneously with the Company's 2023 DSIP Update, provides utility-specific and statewide input assumptions and clarifying edits to Version 3.0.

BCA Handbook Version 5.0, filed contemporaneously by National Grid with this 2025 DSIP Update, provides utility-specific and statewide input assumptions and updating edits to Version 4.0. Some updates in Version 5.0 include the updated ICE 2.0 calculator, including new statistically representative data for the Northeast, as well as upgrades to the functionality of the web-based tool.

¹²⁰ REV Proceeding, Order Establishing the Benefit Cost Analysis Framework (issued January 21, 2016), (BCA Framework Order), p. 29.

¹²¹ *Id.*, p. 31.

¹²² *Id.*

Pursuant to the BCA Framework Order, National Grid has made the calculation methodologies and universal input parameters used for its BCA transparent and publicly available in its 2025 Version 5.0 BCA Handbook, and key assumptions are also shown in Table 3.3.1 below. Version 5.0 of the Company's BCA Handbook will be on the National Grid System Data Portal available at <https://systemdataportal.nationalgrid.com/NY/>.

Table 3.3.1 lists the statewide values and respective sources used and referenced in this BCA Handbook. Source references are included in the footnotes below.

Table 3.3.1: New York Assumptions

New York Assumptions	Source
Energy and Demand Forecast	NYISO: Load & Capacity Data Report ¹²³
Avoided Generation Capacity Cost (AGCC)	DPS Staff: ICAP Spreadsheet Model ¹²⁴
Locational Based Marginal Prices (LBMP)	NYISO: Congestion Assessment and Resource Integration Study Phase 2 (CARIS Phase 2) ¹²⁵
Historical Ancillary Service Costs	NYISO: Markets & Operations Reports ¹²⁶
Allowance Prices (SO ₂ , and NO _x)	NYISO: CARIS Phase 2 ¹²⁷
Renewable Energy Certificate (REC) Price	NYSERDA: Results of most recently completed RECs solicitation ¹²⁸

¹²³ The NYISO 2025 Load & Capacity Data report is *available at*: <https://www.nyiso.com/documents/20142/2226333/2025-Gold-Book-Public.pdf/088438e1-02f1-5316-211b-dbc17c01b4b?t=1745932590307>.

Load & Capacity Data reports and supplemental documents from other years are *available at*: <https://www.nyiso.com/gold-book-resources>.

¹²⁴REV Proceeding, Department of Public Service Staff 2024 ICAP Spreadsheet Model (filed October 3, 2024). The ICAP Spreadsheet Model is found under Case 14-M-0101 at the Commission's website: <http://documents.dps.ny.gov/public/MatterManagement/CaseMaster.aspx?MatterCaseNo=14-M-0101&submit=Search>.

¹²⁵ The NYISO published finalized annual and hourly zonal LBMPs from the 2020 CARIS Phase 2 on May 21, 2021, on the Comprehensive System Planning Process (CSPP), *available at* <https://www.nyiso.com/cspp>. The direct link to the CARIS Phase 2 results is *available at* <https://www.nyiso.com/search?q=CARIS+Phase+2+Base+Case+Hourly+LBMPs+percent28by+Component+percent29&sort=>

¹²⁶ NYISO historical ancillary service costs are *available* at <http://mis.nyiso.com/public/P-6Blist.htm>. The values to apply are described in Section 4.1.5.

¹²⁷ The NYISO publishes price assumptions for NOx and SOx. The most recent of which is the 2020 study *available at*:

https://www.nyiso.com/documents/20142/15571004/03%202020_CARIS_2_ESPWG.pdf/1775a310-7bbc-9254-4c6a-8c668f6fd9f1

¹²⁸ The results of NYSEDA RECs contract solicitations are *available* at <https://www.nyserda.ny.gov/All-Programs/Large-Scale-Renewables/RES-Tier-One-Eligibility/Solicitations-for-Long-term-Contracts>. The weighted average contract price from the most recently completed solicitation is generally used.

Net Marginal Damage Cost of Carbon	DPS Staff: To be provided ¹²⁹

¹²⁹ DPS Staff will perform the modeling, file the results with the Commission on or before July 1 of each year and post the results on the DPS Document and Matter Management (DMM) System under Case 14-M-0101.

4 Appendix A: Tools and Information Sources

National Grid References with Links

- National Grid Internet Homepage:
<https://www.nationalgridus.com/Upstate-NY-Home/Default>
- National Grid Customer Usage Tracking:
<https://www1.nationalgridus.com/SignIn>
- National Grid's IOAP nCAP:
<https://gridforce.my.site.com/s/>
- National Grid System Data Portal:
<https://systemdataportal.nationalgrid.com/NY/>
The above link includes tabs to the categories listed below:
 - Load Forecast Report;
 - HCA;
 - Non-Wires Alternatives opportunities;
 - LSRV areas, and
 - Reports tab (Note: The BCA Handbook will be added to the System Data Portal following its filing on June 30, 2025.)
- National Grid New York Solar Market Place:
<https://www.nationalgridus.com/solar-hub/>
- National Grid Energy Savings Program:
<https://www.nationalgridus.com/Upstate-NY-Home/Energy-Saving-Programs/>
- National Grid ConnectedSolutions:
<https://www.nationalgridus.com/Upstate-NY-Home/ConnectedSolutions/>
- National Grid Electric System Bulletin No. 756:
https://www.nationalgridus.com/media/pronet/shared_constr_esb756.pdf

Joint Utilities of New York and New York REV References with Links

- Joint Utilities of New York:
<http://jointutilitiesofny.org/>
- Joint Utilities of New York EV Readiness Framework:
https://jointutilitiesofny.org/sites/default/files/JU_NY_EV_Readiness_Framework_March_18.pdf
- Joint Utilities Resources:
<http://jointutilitiesofny.org/resources/>
- Utility Specific Non-Wires Alternatives Opportunities:
<http://jointutilitiesofny.org/utility-specific-pages/nwa-opportunities/>
- NY Climate Act:
<https://climate.ny.gov/Our-Impact/Our-Progress>

Other References with Links

- New York State DPS search page:
<https://documents.dps.ny.gov/public/common/search.html>
- DSIP Proceeding Case 16-M-0411:
<http://documents.dps.ny.gov/public/MatterManagement/CaseMaster.aspx?MatterCaseNo=16-m-0411&submit=Search>
- DPS: Interconnection Technical Working Group:
<https://dps.ny.gov/interconnection-technical-working-group>
- 2015 New York State Energy Plan:
<https://energyplan.ny.gov/Plans/2015-Energy-Plan>
- New York's Clean Energy Jobs:
<https://www.nyserda.ny.gov/Goals-Supporting-Clean-Energy-Jobs#:~:text=New%20York's%20ambitious%20climate%20action,in%20communities%20across%20the%20State>
- NYISO Homepage:
<https://www.nyiso.com/>
- NYSERDA Homepage:
<https://www.nyserda.ny.gov/>
- NYSERDA: Electric Vehicle Programs:
<https://www.nyserda.ny.gov/All-Programs/Charging-Station-Programs>
- EPRI: Impact Factors, Methods, and Considerations for Calculating and applying Hosting Capacity:
<https://www.epri.com/#/pages/product/000000003002011009/?lang=en>
- EPRI: Defining a Roadmap for Successful Implementation of a Hosting Capacity Method for New York State:
<https://www.epri.com/#/pages/product/3002008848/?lang=en>
- DOE: Modern Distribution Grid Report:
<https://gridarchitecture.pnnl.gov/modern-grid-distribution-project.aspx>
- DOE: Alternative Fuels Data Center:
<https://afdc.energy.gov/>

- DOE: Modern Distribution Grid:
https://gridarchitecture.pnnl.gov/media/Modern-Distribution-Grid_Volume-I_v1_1.pdf
- ENERGY STAR Portfolio Manager®:
<https://www.energystar.gov/buildings/facility-owners-and-managers/existing-buildings/use-portfolio-manager>
- IEEE: Experimental Evaluation of Load Rejection Overvoltage from Grid-Tied Solar Inverters:
<https://ieeexplore.ieee.org/document/7356399>
- Energy.Gov: Green Button Open Energy Data:
<https://www.energy.gov/data/green-button>
- National Standard Practice Manual:
https://nationalefficiencyscreening.org/wp-content/uploads/2017/05/NSPM_May-2017_final.pdf

DSIP Related Proceedings and Efforts

- In the Matter of SIR Inventory (Matter 13-00205)
 - Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision (REV Proceeding) (Case 14-M-0101)
 - Proceeding on Motion of the Commission to Develop Dynamic Load Management Programs (Case 14-E-0423)
 - Proceeding on Motion of the Commission as to the Policies, Requirements and Conditions for Implementing a Community Net Metering Program (Case 15-E-0082)
 - In the Matter of the Regulation and Oversight of Distributed Energy Resource Providers and Products (Case 15-M-0180)
 - Tariff Filing by Niagara Mohawk Power Corporation to Effectuate Dynamic Load Management Programs (Case 15-E-0189)
 - Proceeding on Motion of the Commission to Implement a Large-Scale Renewable Program and Clean Energy Standard (Case 15-E-0302)
 - In the Matter of the Value of Distributed Energy Resources (VDER) Proceeding (Case 15-E-0751)
 - In the Matter of Distributed System Implementation Plans (Case 16-M-0411)
 - Whole Building Energy Data Aggregation Standard (Cases 16-M-0411 and 14-M-0101)
1. In the Matter of VDER Working Group Regarding Value Stack (Matter 17-01276)
 - In the Matter of VDER Working Group Regarding Rate Design (Matter 17-01277)
 - In the Matter of VDER Low Income Working Group Regarding Low and Moderate Income Customers (Matter 17-01278)
 - In the Matter of the Utility Energy Registry (Case 17-M-0315)
 - In the Matter of Proposed Amendments to the NY-SIR for Small Distributed Generators (Case 18-E-0018)
 - In the Matter of Offshore Wind Energy (Case 18-E-0071)

- In the Matter of Energy Storage Deployment Program (Case 18-E-0130)
- Proceeding on Motion of the Commission Regarding Electric Vehicle Supply Equipment and Infrastructure (Case 18-E-0138)
- In the Matter of a Comprehensive Energy Efficiency Initiative (Case 18-M-0084)
- Proceeding on Motion of the Commission Regarding Cyber Security Protocols and Protections in the Energy Market Place (Case 18-M-0376)
- Proceeding on Motion of the Commission to Examine Utilities' Marginal Cost of Service Studies (Case 19-E-0283)
- In the Matter of Consolidated Billing for Distributed Energy Resources (Case 19-M-0463)
- Proceeding on Motion of the Commission to Consider Resource Adequacy Matters (Case 19-E-0530)
- Joint Petition for Certain Amendments to the NY-SIR for New Distributed Generators and Energy Storage Systems 5 MW or Less Connected in Parallel with Utility Distribution Systems (Case 19-E-0566)
- (Proceeding on Motion of the Commission Regarding Strategic Use of Energy Related Data (Case 20-M-0082)
- Proceeding on Motion of the Commission to Implement Transmission Planning Pursuant to the Accelerated Renewable Energy Growth and Community Benefit Act (Case 20-E-0197)
- In the Matter of a Renewable Energy Facility Host Community Benefit Program (Case 20-E-0249)
- Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Niagara Mohawk Power Corporation d/b/a National Grid for Electric Service (Case 20-E-0380)
- Petition of Interconnection Policy Working Group Seeking a Cost-Sharing Amendment to the New York Standardized Interconnection Requirements (Case 20-E-0543)
- Petition of Interconnection Policy Working Group and Interconnection Technical Working Group Seeking Minor Amendments to the New York State Standardized Interconnection Requirement (Case 21-E-0536)
- In the Matter of the Advancement of Distributed Solar (Case 21-E-0629)
- Proceeding to Establish Alternatives to Traditional Demand-Based Rate Structures for Commercial Electric Vehicle Charging (Case 22-E-0236)
- Proceeding on Motion of the Commission Assessing Implementation of and Compliance with the Requirements and Targets of the Climate Leadership and Community Protection Act (Case 22-M-0149)
- Proceeding on Motion of the Commission Concerning Electric Utility Climate Vulnerability Studies and Plans (Case 22-E-0222)
- In the Matter of the Federal Energy Regulatory Commission (FERC) Order Nos. 2222 and 841, to Modify Rules Related to Distributed Energy Resources (Case 22-E-0549)
- Petition of the IPWG/ITWG Members Seeking Certain Minor Amendments to the New York State Standardized Interconnection Requirements (Case 22-E-0713)
- Proceeding on the Motion of the Commission to Address Barriers to Medium- and Heavy-Duty Electric Vehicle Charging Infrastructure (Case 23-E-0070)

- In the Matter of Commission Registration of Energy Brokers and Energy Consultants Pursuant to Public Service Law Section 66-t (Case 23-M-0106)
- Proceeding on Motion of the Commission Regarding the Grid of the Future (Case 24-E-0165)
- Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Niagara Mohawk Power Corporation d/b/a National Grid for Electric Service (Case 24-E-0322)
- In the Matter of Proactive Planning for Upgraded Electric Grid Infrastructure (Case 24-E-0364)
- Petition of New York Solar Energy Industries Association Seeking Modifications to the New York State Standardized Interconnection Requirements to Allow Use of Alternative Forms of Financial Security for Distribution Upgrades in Excess of \$500,000 for New Distributed Generators and/or Energy Storage Systems 5 MW or Less Connected in Parallel with Utility Distribution Systems (Case 24-E-0414)
- In the Matter of Timely Interconnection of Distributed Energy Resources (Case 24-E-0415)
- In the Matter of Modifications to the New York State Standardized Interconnection Requirements and Application Process for New Distributed Generators and/or Energy Storage Systems 5 MW or Less Connected in Parallel with Utility Distribution Systems (Case 24-E-0621)

5 Appendix B: Additional Topic Details

5.1 Integrated Planning

The following responds to DPS Staff's request to provide additional details to address National Grid's resources and capabilities which support integrated electric system planning.¹³⁰

1. The means and methods used for integrated distribution system planning?

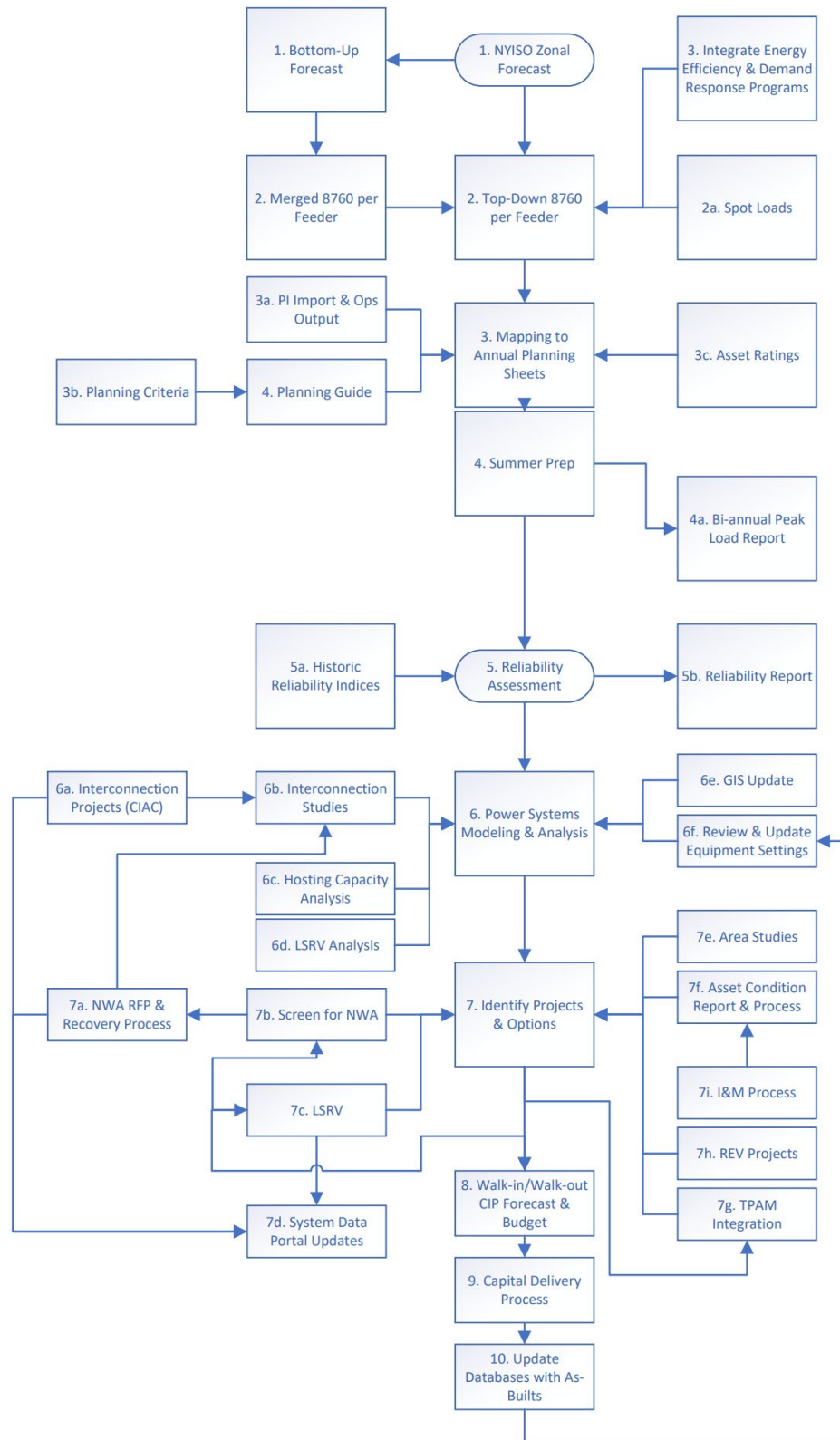
Today's integrated distribution planning process involves many different components and sub-processes, from forecast development through project delivery.

Increasingly, DER opportunities are considered in parallel with the development of traditional utility solutions, such as NWA opportunities identified in accordance with the NWA Screening Criteria Matrix. In the development of project work scopes, historic reliability performance and local asset condition are also reviewed to determine if synergies can be realized by bundling projects.

The diagram below is an illustration of today's integrated planning process that is ever evolving and expanding.

¹³⁰ DSIP Proceeding, *supra* note 11, pp. 9-10.

Figure 5.1.1: Distribution Planning and Asset Management NY Integrated System Planning Process



Process Step Descriptions:

1. Bottom-Up Forecast: High geographical and temporal granular forecast
2. Merged 8,760 per Feeder: Merged top down / bottom-up forecast
3. Integrate Energy Efficiency & Demand Response Programs: Integrate existing and planned EE and DR programs
4. Planning Guide: A how-to guide for criteria analysis and tools available in the planning toolbox
 1. NYISO Zonal Forecast: NYISO forecast
 2. Top-Down Forecast 8,760 per feeder: Allocate top-down forecast on a per feeder level
 - 2a. Spot Loads: Identification of new spot loads based on C&I customer needs
 3. Mapping to Annual Planning Sheets: Map forecasts and spot loads into annual planning spreadsheets for high level assessment
 - 3a. PI Import and Ops Input: Update current loading and power flow values from PI along with operations' inputs
 - 3b. Planning Criteria: Document that defines hard criteria limits that trigger a project need for further investigation
 - 3c. Asset Ratings: Asset ratings database updated as necessary
 4. Summer Prep: Identify high priority projects to ensure reliability for next summer peak load period
 - 4a. Bi-annual Peak Load Report: Updated peak load report
 5. Reliability Assessment: High-level reliability assessment
 - 5b. Reliability Report: Publicly available report filed with the Commission
 6. Power System Modeling & Analysis: Detailed analysis of projects triggered from high-level assessments using PSS®E (NYISO input), ASPEN ("Advanced System for Power Engineering, inc.") and CYME models
 - 6a. Interconnection Projects (Contribution in Aid of Construction): System upgrades identified from interconnection studies (pass-through to interconnection customers)
 - 6b. Interconnection Studies: Power system studies such as power flow, fault analysis, etc. used to determine the need for interconnection upgrade projects
 - 6c. HCA: Analysis to estimate the amount of DERs that may be accommodated without adversely impacting power quality or reliability under current configurations and without requiring infrastructure upgrades
 - 6d. LSRV Analysis: PSS®E analysis that models the Transmission, Sub-T, and Distribution buses used to assess opportunities for DER (DG, ESS) to resolve a system constraint
 - 6e. GIS Update: Geographical information database that captures system assets mapped to a geographical location primarily used to update CYME models
 - 6f. Review & Update Equipment Settings: Protection settings, load tap changer settings, etc. within equipment settings repositories (ASPEN, Cascade, etc.)
 7. Identify Projects & Options: Assessment of proposed solutions to grid problems (also part of capital delivery process) seeking optimal projects that consider overlapping projects, costs, benefits, and risks
 - 7a. NWA RFP & Recovery Process: Competitive solicitation for DER developers and vendors to solve grid problems
 - 7b. Screen for NWA: Review and screening of potential NWA projects

- 7c. LSRV: Determination of locations and capacities of DER (DG, ESS) to resolve system constraints based on the results from step 6d
- 7d. System Data Portal Updates: Periodic updates to the publicly available System Data Portal
- 7e. Area Studies: Large scale area studies (i.e., entire town/city) triggered by scheduled or multiple violations or criteria
- 7f. Asset Condition Report & Process: Review and assessment of asset condition informed by inspection and maintenance (I&M)
- 7g. Transmission Planning Integration: Inform Transmission Planning of planned projects and vice versa and integrate accordingly
- 7h. REV Projects: Projects triggered via rate cases or other means not captured via typical planning process (i.e., grid modernization and demonstration projects)
- 7i. I&M Process: Inspection and maintenance process and schedule
- 8. Walk-In/Walk-Out CIP Forecast & Budget: Budgeting, forecasting and managing of capital and operational expense projects
- 9. Capital Delivery Process: Methodology for ensuring projects are built efficiently and effectively while analyzing alternative solutions
- 10: Update Databases with As-Built: Process for ensuring what is installed in the field is represented in National Grid's documentation

2. How the utility's means and methods enable probabilistic planning which effectively anticipates the inter-related effects of distributed generation, energy storage, electric vehicles, beneficial electrification and energy efficiency?

National Grid's probabilistic planning practices are enabled by the Company's existing load and DER forecasting capabilities and outputs. Forecasting outputs currently include probabilistic elements, specifically related to multiple loading scenarios based on weather probabilities as well as multiple loading scenarios based on the probabilities of different DER penetration levels. See additional details in Section 2.2, Advanced Forecasting. Multiple forecasting scenarios specific to individual feeders within the Company's service territory create the potential for a large spectrum of scenarios to consider. Although some planning processes primarily focus on the assessment of a single, most probable scenario, consideration of the range of different scenarios is being integrated into planning practices when feasible such as when long-term or large area studies are conducted. These new planning methods will continue to be refined and integrated into business-as-usual practices, further improving how planners make decisions and meet customer needs.

3. How the utility ensures that the information needed for integrated system planning is timely acquired and properly evaluated?

National Grid's GIS is the primary repository that maintains key attribute data for distribution assets that enables the Company to develop interconnected models of the distribution system. The GIS is tied to the Company's work management system such that, as projects are completed (e.g., system upgrades, system reconfigurations, DG interconnections and new spot loads), the resulting as-built information is posted to the GIS. Salesforce is the primary repository of DER information for DER applications in queue and connected DER. DER data is fed from Salesforce into GIS to

accurately model DER on National Grid's system. Similarly, GIS is integrated with CYMDIST load flow tools so that the most up-to-date models can be created for Distribution Planning and HCA. Load forecasts are updated on an annual basis in time for summer preparations for system peak. DER forecasts are also generated on an annual basis to inform distribution planners of areas with projected high DER interconnection. The distribution planners are also organized by regional areas, so they have awareness of other variables taking place within their respective areas (*e.g.*, economic development, municipal planning activities, etc.). A Salesforce database tracks EE and can be queried by the planning engineers when performing network analyses. Lastly, loads can be updated in the CYMDIST model via a link to National Grid's EMS and the PI historian database that maintains historic loading information for substations that have real-time monitoring.

4. The types of sensitivity analyses performed and how those analyses are applied as part of the integrated planning process?

On a case-by-case basis National Grid's planning engineers often run multiple scenarios to assess the impact of various assumptions or alternatives. Several examples of the types of sensitivities are provided below:

- Spot load sensitivities
- DG capacity sensitivities
- Alternate load transfers for load balancing and reliability
- Comparison of traditional utility solutions and NWA solutions

These different sensitivities are typically identified as part of the planning criteria and then subsequently studied as part of the power systems modeling steps within the Integrated Planning process outlined in Question 1 of the Integrated Planning Appendix questions within this 2025 DSIP Update. During engineering analyses, planning engineers will iterate over different sensitivity scenarios to ensure the electric system can support the variety of operational and contingency scenarios that may occur. Over the next five years, with the given increase in system complexity and a drive towards a probabilistic approach to forecasting, it is expected a greater number of sensitivities will need to be evaluated by the Company.

5. How the utility will timely adjust its integrated system plan if future trends differ significantly with predictions, both in the short term and in the long term beyond the DSIP timeline?

National Grid refreshes its load and DER forecast on an annual basis. Further, an annual screening assessment of load impacts is performed and immediate issues are resolved as part of a summer readiness effort. In local areas in which there may be a significant capacity need, a more comprehensive area study is completed to develop long-term solutions. Depending on the size of the need and the year in which the need is forecasted, the Company may consider suitable alternatives to long-term infrastructure upgrades such as NWAs, DR, and EE programs. National Grid is exploring the use of targeted DR to address mid-term loading needs by competitively procurement DR in heavily loaded areas through its Term-DLM procurement.

The Company continues to gain experience in designing and facilitating competitive DER procurements. If there is interest by the DER community in entering into short-term contracts to provide targeted load relief to the utility, National Grid may consider these types of procurements or programs as another option for short-term solutions along with its typical summer readiness effort.

6. The factors unrelated to DERs- such as aging infrastructure, electric vehicles, and beneficial electrification – which significantly affect the utility’s integrated plan and describe how the utility’s planning process addresses each of these factors?

National Grid’s electric load forecast includes the impact of EV and electric heating in addition to traditional DERs such as solar PV and ESS. Each DER component of the forecast is comprised of three scenarios that represent the load impact with respect to base, low, and high adoption scenarios. Each adoption scenario is associated with a specific probability of the scenario occurring. Current planning practices leverage all components of the electric load forecast, including load impacts from EV and electric heating resulting from BE, and outline upgrades to the system such that it will be capable of meeting the capacity requirements forecasted in the base, or most probable, scenario. As the Company continues to implement the integrated modeling tool SAInt, additional areas identified for beneficial electrification will be incorporated into forecasting processes and existing planning practices.

Although the electric system impacts of electric vehicles and BE are expected to be significant, National Grid’s integrated plan must also address the persistent threat of aging infrastructure. To evaluate the impact of aging infrastructure on the electric system, the Company produces a biennial report on the physical condition of its T&D facilities. This report, also referred to as the Asset Condition Report, outlines general health of assets operated by the Company as well as highlighting remedial actions that are being pursued to address the most significant asset condition risks. The findings of this report serve as an additional input to the Company’s integrated plan to enable planning engineers to consider the condition of an asset as part of system planning to ensure system reliability and resiliency are prioritized.

7. How the means and methods for integrated electric system planning evaluate the effects of potential energy efficiency measures?

National Grid’s electric load forecast includes the impact of EE programs at both a system-wide and individual feeder level as a specific DER component with different adoption scenarios of base, low, and high, similar to the EV, electric heating, solar PV, and ESS DER components. Current planning practices leverage all components of the electric load forecast, including load reduction resulting from EE measures, and system planning is conducted with those EE impacts considered. However, EE solutions over and above forecasted EE that solve a targeted problem can be proposed as a standalone NWA solution or as part of a portfolio of DER solutions. Additionally, active EE measures (i.e., those that meet utility program requirements) can participate in any of the Company’s DLM programs where in particular the Term-DLM program identifies specific locations where active EE measures can participate. The Company reviews NWA proposals where any proposed active EE measure is evaluated for its ability to solve the local grid need. In addition,

it is expected that a review process of proposed active EE measures for the Term-DLM program will be conducted.

8. How the utility will inform the development of its integrated planning through best practices and lessons learned from other jurisdictions?

The Company participates in various forums in which planning issues are discussed including internal jurisdictional meetings, Joint Utilities' meetings, and ad hoc meetings with utilities in other jurisdictions to compare process and progress. One of the key Joint Utilities' working groups is Integrated Planning where topics such as forecasting, hosting capacity, and planning criteria are discussed on an almost weekly basis. The Company is also a full program subscriber to the EPRI Program 200 – Distribution Operations and Planning which provides research on topics including HCA, DER integration, distribution system automation, and various CEATI programs.

5.2 Advanced Forecasting

The following responds to DSIP Staff's request to provide additional details to address National Grid's resource and capabilities to enable advanced electric system forecasting and provide the most current forecast results.¹³¹

- 1. Identify where and how DER developers and other stakeholders can readily access, navigate, view, sort, filter, and download up-to-date load and supply forecasts.**

National Grid's System Data Portal¹³² provides access to the forecast information for DER developers and other stakeholders.

- 2. Identify and characterize each load and supply forecasting requirement identified from stakeholder inputs.**

Stakeholders required forecasts at multiple geographical and temporal resolutions. As such, the forecasts are provided at the Company's system level, Company's service territory at NYISO load zonal level, and feeder levels. The forecasts are provided for seasonal peaks, peak day 24-hour load profile and in some cases for 8,760 hour-by-hour profiles.

- 3. Describe in detail the existing and/or planned forecasts produced for third-party use and explain how those forecasts fulfill each identified stakeholder requirement for load and supply forecasts.**

National Grid publishes its long-term forecasts via the System Data Portal. The forecasts are issued on an annual basis, usually by the first quarter of each calendar year along with hosting capacity and a report detailing methodologies. As previously mentioned in the Stakeholder Interface in the Advanced Forecasting section 2.2, various stakeholders are able to utilize those resources for their use. Additionally, the Company continues to assess stakeholder data needs through the Joint Utilities.

- 4. Describe the spatial and temporal granularity of the system-level and local-level load and supply forecasts produced.**

Spatially, the forecasts are provided at the Company's system-level, the Company's service territory in NYISO load zonal-level, and feeder-level. Temporally, the forecasts are provided for seasonal peaks, peak day 24-hour load profile and in some cases for 8,760 hour-by-hour profiles to model load impacts.

¹³¹ DSIP Proceeding, *supra* note 11, pp. 10-12.

¹³² <https://systemdataportal.nationalgrid.com/NY/>

5. Describe the forecasts provided separately for key areas including but not limited to photovoltaics, energy storage, electric vehicles, and energy efficiency.

The forecasts are conducted for load and DER technologies, including EE, EHPs, EVs, solar PVs, ESS, and DR. The net load after DER impact is provided by adding up the impacts of these individual components. Please refer to the Company's Peak Report for detailed discussions.¹³³

6. Describe the advanced forecasting capabilities which are/will be implemented to enable effective probabilistic planning methods.

A probabilistic forecast provides possible outcomes and their associated probabilities. It enables probabilistic planning by providing quantitative information on uncertainties.

National Grid has continuously been working on improving its methods and processes to develop probabilistic and scenario-based forecasts. The forecasting process has already incorporated probabilistic forecasting methods for baseload and PV load profiles and various scenarios for DER technologies. Please refer to the Company's Peak Report for detailed discussions on these topics.

National Grid plans to improve its probabilistic load forecasting from the following aspects, among others:

- Further research and refine the probabilistic forecasting method for baseload modeling.
- Continue refining the load impact profiles of DER through exploration of empirical data not limited to the following: AMI, SCADA, etc. The Company implemented a probabilistic method for solar load impacts.

7. Describe how the utility's existing/planned advanced forecasting capabilities anticipate the inter-related effects of distributed generation, energy storage, electric vehicles, beneficial electrification, and energy efficiency. In particular, describe how electric vehicle and energy efficiency forecasts are reflected in utility forecasts.

Each DER technology is currently modeled and forecasted separately. Detailed discussions on the assumptions and methodologies of modeling them are provided in the Company's Peak Report.

8. Describe in detail the forecasts produced for utility use and explain how those forecasts fulfill the evolving utility requirements for load and supply forecasts.

The same forecasts are published for the Company's use and stakeholders. The forecasts support the utility planning requirements as discussed in the Stakeholder Interface subsection of the Advanced Forecasting section of this 2025 DSIP Update.

9. Describe the utility's specific objectives, means, and methods for acquiring and managing the data needed for its advanced forecasting methodologies.

¹³³ *Supra*, note 31.

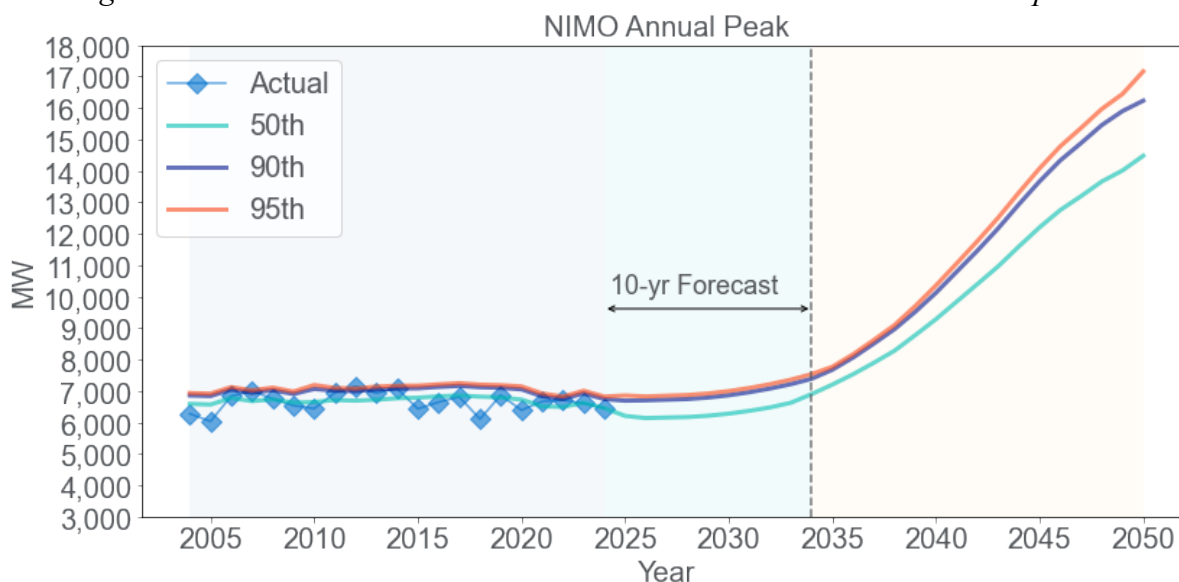
National Grid acquired data for load and DER forecasting through internal and external data sources. Please refer to Appendix D of the Company's Peak Report for the list of data sources.

10. Describe the means and methods used to produce substation-level load and supply forecasts.

The substation-level load is derived by aggregating the feeder-level forecasts.

11. Describe the levels of accuracy achieved in the substation-level forecasts produced to date for load and supply.

Figure 5.2.1: National Grid's Historical Summer Peaks and Forecast Comparison



The above figure shows the historical annual peak (blue squares) and their weather adjusted historical (turquoise) and the projected 50th, 90th, and 95th annual peak. System-level forecasts have generally been accurate within one to three percent range for a single year as well as multiple years forecasting. National Grid is still in the process of developing and enhancing its forecasts at more granular levels, and there still exists challenges of gathering accurate data at more granular levels to explore evaluation processes and practices.

12. Describe the substation-level load forecasts provided to support analyses by DER developers and operators and explain why the forecasts are sufficient for supporting those analyses.

The seasonal peak forecasts and 8760 profiles at substation-level aid DER developers in evaluating impacts such as capacity constraints at peak or off peak, the potential that injections may result in reverse power flows, and the frequency in which DR may be called upon, as well as how loading may impact desired charge and discharge cycles for ESS. Furthermore, the substation-level load

forecast is used to understand load and DER growth at the substation level and thus inform any planning changes at the substation's hosting capacity.

13. Provide sensitivity analyses which explain how the accuracy of substation-level forecasts is affected by distributed generation, energy storage, electric vehicles, beneficial electrification, and energy efficiency measures.

National Grid developed multiple scenarios for DERs for sensitivity analyses. Please refer to Section 6 and Appendix C in the Company's Peak Report for detailed discussions on the different scenarios.

14. Identify and characterize the tools and methods the utility is using/will use to acquire and apply useful forecast input data from DER developers and other third-parties.

The external data informing National Grid's DER forecasts include but are not limited to the following:¹³⁴

- Information received from DG developers as part of interconnection requests
- Information received from EE and DR programs
- Information received from the U.S. Energy Information Association's Annual Energy Outlook and NREL's Electric Vehicle Infrastructure Projection Tool, among other sources
- Information shared by market participants with NYISO for its DER forecasting

15. Describe how the utility will inform its forecasting processes through best practices and lessons learned from other jurisdictions.

The Company continues to enhance the forecasting process by leveraging best practices and lessons learned from other jurisdictions including the following venues:

- Communications with other electric distribution companies
- Independent System Operator – New England (ISO-NE)
- Research conducted by national labs and federal agencies such as NREL for solar PV and EVs, NYSERDA for electric school buses, among other sources.
- Conferences presentation and participation such as International Symposium on Energy Analytics

16. Describe new methodologies to improve overall accuracy of forecasts for demand and energy reductions that derive from EE programs and increased penetration of DER. In particular, discuss how the increased potential for inaccurate load and energy forecasts associated with out-of-model EE and DER adjustments will be minimized or eliminated.

National Grid considers enhancements of its existing methodologies or developing new methodologies to improve its forecast accuracy from the following aspects:

- The Company will continue incorporating up-to-date information in developing adoption forecasts.

¹³⁴ Please refer to Appendix D of the Company's Peak Report for the list of data sources.

- The Company plans to continue exploring building, customer, and end-use data such as AMI data as it becomes available and reliable for adoption and load profiling analysis.
- The Company will continue to explore state-of-the-art methods or products for modeling impacts from DER technologies. This may include tools developed or to be developed by national labs, research institutes, and vendors.

17. Describe where CGPP forecast information can be found.

Forecasts for CGPP can be found posted in the DMM System at Case 20-E-0197, as both a dataset and recorded presentation as part of the Energy Policy Planning Advisory Council (EPPAC) Working Group.

5.3 Grid Operations

The following responds to DSP Staff's request to provide additional details to address resources and capabilities needed to transform grid operations in both the distribution system and the bulk electric system.¹³⁵

1. Describe in detail the roles and responsibilities of the utility and other parties involved in planning and executing grid operations which accommodate and productively employ DERs.

The Company, along with the other Joint Utilities, authored a Draft Communication and Coordination Manual which was the foundation of defining roles and responsibilities. This document was used as a foundation to develop the NYISO Aggregation Manuals as well as more detailed National Grid processes and procedures that have been or are currently under development. Overall, these documents help to optimize the system usage by DERs and to help preserve safety and reliability of the electric system. This set of roles and responsibilities was born from wholesale tariffs enabling DER integration. The Company has established and staffed a Distribution Security Operator position within the control rooms dedicated to the active management and optimization of DERs under the constraints of the as-operated electric distribution network. These Distribution Security Operators will use the emerging technologies described in this section to coordinate safe and reliable operation between distribution control center, transmission control center, and external DER operators.

2. Describe other role and responsibility models considered and explain the reasons for choosing the planned model.

National Grid, along with the other Joint Utilities, undertook an effort in 2017 to develop a Distributed System Platform Roadmap to understand different models of incorporating DERs into wholesale and retail markets while optimizing the value of DERs. While these models were high level, they provided a foundation for market tariffs and a resource for DPS Staff's efforts in evaluating a transactive retail market design.

3. Describe how roles and responsibilities have been/will be developed, documented, and managed for each party involved in the planning and execution of grid operations.

National Grid will continue to develop roles and responsibilities consistent with good utility practices to optimize the usage of the electric system while maintaining safety and reliability. These foundational principles create value for all stakeholders. SMEs from pertinent sectors are typically engaged in discussions associated with developing markets and related roles and responsibilities. This practice will continue as grid and market operations evolve. Much of this is based on traditional roles and responsibilities and good utility practices. Once they have gained some initial experience, DER aggregators could also be added to the SME mix.

¹³⁵ DSIP Proceeding, supra, note 11, pp. 12-13.

4. Describe in detail how the utilities and other parties will provide processes, resources, and standards to support planning and execution of advanced grid operations which accommodate and extensively employ DER services. The information provided should assess:

a. Organizations

The organizations that support DER integration will continue to be evaluated for impacts to workload associated with internal and external processes and will request funding as required through the rate case process. National Grid expects that the requirements will differ from utility to utility based on topology, size, and maturity of applications.

b. Operating Policies and Processes

Operating policies and processes will be developed based on good utility practices and learnings from other jurisdictions as part of incorporating lessons learned and best practices. All policies and processes will follow wholesale and retail tariffs, and requirements set forth by regulating agencies.

The body of the 2025 DSIP Update details current and future investments associated with equipment and capabilities below. Each of the devices and / or systems support DER integration by improving operational processes thereby helping to optimize the system use while maintaining safety and reliability. Ultimately the evolution of applications, devices, and processes facilitate efficiencies that create value for all stakeholders.

c. Information systems for system modeling, data acquisition and management, situational awareness, resource optimization, dispatch, and control, etc.

National Grid is looking to enhance information systems supporting DER integration and advanced grid operations by improving how DER data can be exchanged between utility enterprise systems. DER data can be used to improve grid situational awareness in the control room, support need identification of DER services, and verify DER performance for DER services. In the future, DER data and external datasets could be used to further guide dispatch and control DER through advanced optimization. The Company intends to evolve in how it will provide for advanced grid operations to accommodate and integrate with smart inverters through the Joint Utilities' smart inverter roadmap, including autonomous and interactive grid support of smart inverters.

d. Data communications infrastructure

The Company continues to support existing DER communication requirements for monitoring and control as required in its ESB 756 Appendix B. National Grid is investigating new data communication infrastructure to expand monitoring and control coverage to other DERs, lower the cost of data communication packages, and support current and future DER services. For example, the Company has deployed more advanced data communication infrastructure for installed NWA projects such as Pine Grove. The Company is also considering how AMI data

communications can support improved visibility and control to support more advanced grid operations.

e. Grid sensors and control devices

National Grid has deployed advanced control devices to support dispatch of NWA projects such as the Pine Grove NWA project to allow for real-time dispatch to provide local distribution grid services. The Company continues to look at various ways to evolve grid edge technologies and DER gateways to interactively coordinate with DER for monitoring, control, and dispatch. National Grid will continue to deploy feeder monitors (where viable) and continue to install EMS-RTU equipment in substations to gain visibility of feeder heads. Along the feeders, new/upgraded advanced switched capacitor banks, voltage regulators, and reclosers will receive communications packages to provide engineers and system operators more granular data along such feeders. These grid sensing points will allow for better planning studies for DERs and other interconnections. These sensing points can also be utilized for various DER services and provide better information to inform dispatch decisions. The addition of EMS-RTU equipment will enhance the grid control levels for system operators by allowing for the remote control of breakers, as one example.

f. Grid infrastructure components such as switches, power flow controllers, and solid - state transformers

Installations of more reclosers under programs such as FLISR or as a result of regular business planning enables more granular remote-control functionality on the distribution system. These devices are fitted with a cellular radio that provides both sensing capabilities and trip/close command points for system operators. Utilizing these reclosers (which could be operated in a switch-mode) will allow for future tools to potentially reconfigure the system to maximize performance of a feeder or to enable higher-DER levels under certain conditions.

5. Describe the utility's approach and ability to implement advanced capabilities.

a. Identify the existing level of system monitoring and distribution automation.

National Grid has feeder head monitoring on approximately 91 percent of distribution feeders via substation EMS connectivity or through feeder monitors. The Company also has equipment with monitoring capability such as pole top reclosers, voltage regulators, and advanced switched capacitors. These devices add mid-line monitoring points along the feeders.

To date, National Grid has installed FLISR schemes on 45 distribution schemes and 3 Sub-T schemes, covering 184,082 customers. These FLISR schemes utilize pole top reclosers / sectionalizers to restore unaffected portions of feeders/circuits using a centralized logic controller. Control logic will be taken over by ADMS in coming years to improve the flexibility of automatic restoration logic and reduce the time it takes to put a scheme in service.

b. Identify areas to be enhanced through additional monitoring and/or distribution automation.

National Grid anticipates adding monitoring to the remaining feeder heads that are capable of using the pole top equipment. Adding feeder monitors to feeder heads will bring the monitoring of feeder heads to approximately 95 percent within the Company's service territory. The remaining 5 percent of feeders and associated substations will get EMS installation projects, where feasible, to achieve greater than 99 percent monitoring of the distribution system.

The Company plans to deploy additional FLISR schemes to distribution feeders and Sub-T circuits to achieve a goal of 60 percent of the NY customer base connected to FLISR-enabled feeders/circuits. This means that about 660 distribution feeders and 140 Sub-T circuits would be equipped with FLISR schemes.

c. Describe the means and methods used for deploying additional monitoring and/or distribution automation in the utility's system.

National Grid will add monitoring to the system via the use of feeder monitors where feeder heads currently do not have visibility. In parallel, the Company expects to continue rolling out new EMS projects to substations without SCADA. Along with feeder head projects, the Company will also begin adding communications to all eligible devices to get more granular data along the feeders. These devices include new/upgraded voltage regulators, advanced switched-capacitors, pole top reclosers, and mid-line feeder monitors through the use of 4G cellular radios.

The Company's FLISR schemes utilize an in-house, centralized logic platform using NovaTech Automation Orion RTU's. Engineering identifies locations to install new pole top reclosers and/or utilize existing reclosers at both tie point and midline locations. The engineers then work to coordinate the protection settings of the various devices for contingencies where the FLISR scheme could automatically restore unaffected portions of circuits. Any thermal or voltage violations identified in the study effort are corrected during the construction phase based on engineering judgements to maximize the performance of the FLISR scheme. Once the system is constructed, logic is written with sequential check actions and switching actions to isolate a faulted section of the feeder and restore the unaffected customers based on any thermal or voltage limits determined during the planning study. National Grid expects to begin controlling some FLISR schemes using ADMS logic starting in FY27, allowing FLISR to identify thermal and voltage violations in real time, rather than based on more conservative planning studies.

d. Identify the benefits to be obtained from deploying additional monitoring and/or distribution automation in the utility's system.

The benefits to adding additional monitoring on the system include but are not limited to (i) better planning studies by engineering that may defer upgrades or allow for better placement of new equipment based on the data available; (ii) better visibility for control center operators to identify potential contingencies or issues that arise on the system; and (iii) increased levels of data allowing for improvements in hosting capacity for both new loads and DERs.

FLISR schemes reduce the potential impact of outages to National Grid customers. If a contingency were to occur on a feeder with a FLISR scheme, the system gives the feeders a chance to restore unaffected portions of the feeder through an automated feeder tie during blue-sky and storm conditions. Based on where the fault occurs on the feeder/circuit, the level of impact may vary as to how many customers will be restored. The equipment for FLISR also allows for additional monitoring for engineering and control center operators. Reclosers specifically allow for increased remote-control capability by control center operators as well.

e. Identify the capabilities currently provided by ADMS.

To date, National Grid has accomplished Phase 2 of 3 with the following work related to ADMS and associated systems:

- Installed hardware and software for the ADMS applications
- Developed a network distribution model for the operations HMI and enabled a system monitoring functionality
 - Substation and planned equipment models piloted and progressing
- Initial deployment of manual and automated control applications which include:
 - Fault Location Analysis
 - Bi-directional Unbalanced Load Flow incorporating DER and impacts on power flow
 - Restoration Switching Analysis
- OMS refreshed
 - AMI meter pings
 - Mobile Outage Dispatch
- DSCADA infrastructure built
- Real-time Live Connectivity for 3,473 devices
- Automatic SCADA outage verification on select circuits
- FLISR advisory mode on select circuits

f. Describe how ADMS capabilities will increase and improve over time.

National Grid is currently in the build and test stages of ADMS Phase 3, which will expand ADMS functionality for control and automation on a common platform. OMS, DMS, and DSCADA modules are integrated on a common platform, and configuration and analysis is ongoing to increase operational efficiencies and data sharing. The first ADMS-controlled FLISR scheme is targeted for CY2026. ADMS Phase 3 will extend ADMS functionality with additional automation targeted on active grid management. Other proposed integrations include centralized control of VVO, additional AMI capabilities, short-term forecasting, DERMS integrations, and expansion of mobile dispatch capability. The Company will develop the ability to more broadly share ADMS model and data supporting digital product concepts. In addition, the Company will evaluate other integrations with this foundational application for the DSO Platform.

g. Identify the capabilities currently provided by DERMS.

Currently, National Grid has multiple systems supporting various DERs and DER programs. The Company's EnergyHub system is used to support residential and C&I demand response under the

Company's DLM program such as the CSRP, Term-DLM, Auto-DLM, and DLC (ConnectedSolutions) Programs. The Company is also using an EV Energy system to support the Company's plans for residential managed EV charging program in accordance with the Commission's July 14, 2022 *Order Approving Managed Charging Programs with Modification* in the EVSE Proceeding. The Company's existing NWA projects are currently dispatched from the Company's EMS to support peak load relief needs. Lastly, National Grid has a number of other DER management system modules planned and currently being developed focused on areas such as DER registration, dispatch, edge control and short-term forecasting to support FERC 2222 as well as flexible interconnections.

h. Describe how DERMS capabilities will increase and improve over time.

As part of the Company's plan for Grid DERMS platform development and deployment, DER management use cases can start to consolidate into more of a unified platform approach along with close integration with ADMS and/or EMS and the Company's DRMS where appropriate. A more comprehensive platform for DERMS will provide greater capabilities of dispatch optimization across multiple DER management use cases, improved operator visibility, and bring in more analytic capabilities to support system operations and operational planning decisions. Although most of the Company's current NWA projects and DER management pilots have focused on managing distribution capacity constraints on substation transformer loading, the Company anticipates investigating if DERMS can support constraint management using DER flexibility for feeder capacity constraints as well, considering the complexity of feeder reconfiguration and less availability of granular real-time feeder measurements.

i. Identify other approaches or functionalities used to better manage grid performance and describe how they are/will be integrated into daily operations.

Please refer to Section 2.3, Grid Operations, for details on approaches or functionalities used to better manage grid performance.

5.4 Energy Storage Integration

The following responds to DPS Staff's request to provide additional details specific to ESS resources.¹³⁶

1. Provide the locations, types, capacities (power and energy), configurations (i.e., standalone or co-located with load and/or generation), and functions of existing energy storage resources in the distribution system.

Currently, the Company captures energy storage resources that would like to interconnect on the distribution system through the SIR and NYISO load queues. The following links will share any available information about existing or requested interconnections on the Company's networks. Please see the link to the latest NY-SIR interconnection queue for National Grid for projects below at or below 5 MW. The requested data may be found under "SIR Inventory Information" where interconnection queue data may be downloaded. The SIR Spreadsheet's Column N may be used to filter for any Energy Storage Projects:

<https://dps.ny.gov/distributed-generation-information>

Please also see the link below to access NYISO's interconnection queue spreadsheet where National Grid is identified as "NM-NG" in column L of the spreadsheet:

<https://www.nyiso.com/interconnections>

2. Describe the utility's current efforts to plan, implement, and operate beneficial energy storage applications. Information provided should include:

- a. a detailed description of each project, existing and planned, with an explanation of how the project fits into the utility's long range energy storage plans;
- b. the original project schedule;
- c. the current project status;
- d. lessons learned to-date;
- e. project adjustments and improvement opportunities identified to-date; and
- f. next steps with clear timelines and deliverables.

Information below is based on projects either with a signed letter of intent to proceed, under construction or operation:

¹³⁶ DSIP Proceeding, *supra* note 11, pp. 13-16.

Table 5.4.1: Current Energy Storage Projects

Project	East Pulaski
Description	2 MW 3 MWh lithium-ion battery connected with the Company's local distribution station as a demonstration project as part of the REV Order.
Use Case	Distributed Peak Reduction, Reliability, Wholesale Market Participation (anticipated), Power Quality (anticipated)
Original Schedule	In service by 12/31/2018
Current Status	Online and participating in the NYISO market
Lessons Learned to Date	Challenges with network operation of the ESS may be mitigated by improved monitoring and routine maintenance of servers and network equipment. Project life cycle lessons have been captured on how to properly design, implement, construct, operate and maintain an ESS unit.
Adjustment & Improvements Opportunities Identified to Date	Improved asset monitoring and maintenance plans with vendor to best support and improve the remote access to the ESS.

Project	North Troy
Description	2MW 3 MWh lithium-ion battery connected with the Company's local distribution station as a demonstration project as part of the REV Order.
Use Case	Distributed Peak Reduction, Wholesale Market Participation (potential future use case), Power Quality Improvement (potential future use case)
Original Schedule	In service by 12/31/2018
Current Status	The ESS was placed in service in February 2020. Later in 2020, cybersecurity vulnerabilities were identified in the vendor equipment that required the system to be taken offline for remediation. After remediation, the energy storage asset is online and operational. The asset has been in use over the past year and is used for a pre-

	determined dispatch schedule to offer peak shaving during summer and winter peaks.

Project	North Troy
Lessons Learned To Date	Challenges with technical operation may be improved by additional maintenance plans.
Adjustment & Improvements Opportunities Identified to Date	Incorporation of evolving cybersecurity requirements and external vendor/contractor support requiring remote access to the ESS. Additional lessons learned were captured with troubleshooting mechanical concerns, followed by replacement of new metering devices.

Project	Pine Grove
Description	The completed NWA project deploys 2 grid-tied 5 MW solar arrays, each paired with 5 MW / 20 MWh lithium-ion BESS. The project is utilized for load relief to National Grid's Pine Grove Substation. See NWA section of this 2025 DSIP Update for details.
Use Case	NWA for reliability (substation N-1)
Original Schedule	Target: Summer 2021 (Actual: Summer 2022)
Current Status	Operational
Lessons Learned To Date	See NWA section of this 2025 DSIP Update for lessons learned
Adjustment & Improvements Opportunities Identified to Date	See NWA section of this 2025 DSIP Update for process improvements

Project	Watertown
Description	The storage plus solar NWA solution is currently under construction to meet the 5.7 MW/40 MWh need. See NWA section of this 2025 DSIP Update for details.
Use Case	NWA for reliability (substation N-1)
Original Schedule	
Current Status	Operational
Lessons Learned to Date	See NWA section of this 2025 DSIP Update for lessons learned
Adjustment & Improvements Opportunities Identified to Date	See NWA section of this 2025 DSIP Update for process improvements

Project	Gilmanstown
Description	Combined 5 MW and 15 MWh ¹³⁷ of ESS in coordination with line assets to monitor and detect outages and deploy a microgrid to customers affected by upstream outages.
Use Case	Form a microgrid for system resiliency and reliability during outages experienced on the Sub-T line supplying the station.
Original Schedule	Target: Complete by Spring 2029 ¹³⁸
Current Status	This project is currently being scoped to meet the planning need and in the preliminary engineering stage. Further scoping of project location, interconnection, and required network upgrades to support the project design are in development.
Lessons Learned to Date	See Section 2.13 of this 2025 DSIP Update on NWA and DER integration for lessons learned related to this project.
Adjustment & Improvements Opportunities Identified to Date	See Section 2.13 of this 2025 DSIP Update on NWA and DER integration for lessons learned related to this project.

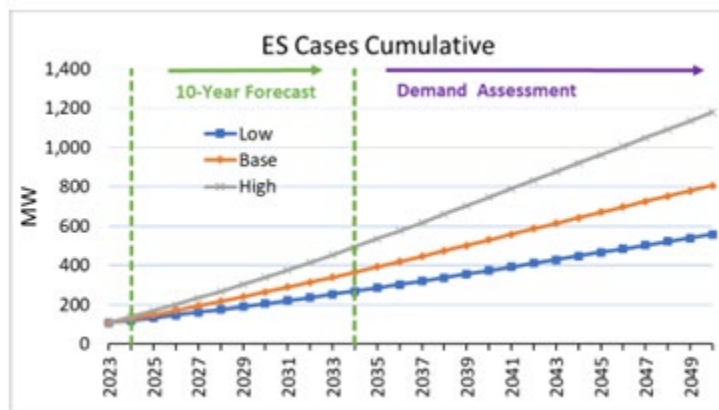
¹³⁷ Project size is conceptual and subject to change.

¹³⁸ Project schedule is subject to change.

3. **Provide a five-year forecast of energy storage assets deployed and operated by third-parties. Where possible, include the likely locations, types, capacities, configurations, and functions of those assets.**

Energy storage forecasts for the next five years are provided and discussed in the Niagara Mohawk Power Company Electric Peak (MW) Forecast Report (Appendix C and D of the report).¹³⁹

Figure 5.4.1: Forecasted Increase of Energy Storage Assets in MW by Year and Scenario, per the National Grid Peak Load Forecast Report, 2025



As of now, in its load forecasting process, National Grid considers storage paired with solar PV type on the distribution system, based on the assumption that the paired systems will enroll in Value Stack compensation. A peak shaving use case that assumes storage to discharge during typical peak hours in a day and charge during the hours when solar PV is expected to generate is used to model the load impact.

4. **Identify, describe, and prioritize the current and future opportunities for beneficial use of energy storage located in the distribution system. Uses considered should encompass functions which benefit utility customers, the distribution system, and/or the bulk power system. Each opportunity identified should be characterized by:**
 - a. **location;**
 - b. **energy storage capacity (power and energy);**
 - c. **function(s) performed;**
 - d. **period(s) of time when the function(s) would be performed; and**

¹³⁹ Available at https://systemdataportal.nationalgrid.com/NY/documents/Peak_Load_Forecast.pdf

- e. the nature and estimated economic value of each benefit derived from the energy storage resource.

National Grid has begun to leverage ESS within its operations and continues to look for opportunities to cost-effectively deploy ESS. Currently the Company assesses benefits that energy storage can provide through a multitude of factors, including ownership models and associated program value, locational benefit, power & energy capacity, and the period of time the project would be in place, as all of these factors have an impact in determining benefits to customers. This determination is undertaken on a case-by-case basis, however, the Company does look to implement solutions on a low-cost, fit-for-purpose methodology to ensure the most benefit to the customer is provided in selecting solutions for planning requirements. National Grid has identified the following use cases for use of energy storage below. These identified use cases may range in size and period of use, depending on the planning requirement they may be supporting, or location of interconnection may be available:

- **Distributed (localized) Peak Reduction** – ESS can provide relief for a localized peak load issue (*e.g.*, station bank or feeder limitation). This would likely occur in a relatively small number of hours annually.
- **Demand Charge Reduction** – ESS can be installed BTM to reduce the peak demand of a given customer by dispatching during peak usage. The ESS would perform this function at targeted intervals in each billing period.
- **Wholesale Market Participation** - Energy, capacity, voltage regulation, operating reserves, and DR could be provided by ESS year-round.
- **Increased Hosting Capacity/Decreased Interconnection Costs** – ESS can increase the hosting capacity on any given feeder (depending on the limiting asset constraint) by charging with mid-day energy from a feeder with a high concentration of solar PV and then discharging during times of higher load. Such an ESS would likely be operated on daily cycles with seasonal variation.
- **Reduced Generation Intermittency**– Intermittent (often renewable) sources of generation can have a more limited number of use cases because they cannot be considered ‘dispatchable.’ By pairing ESS with these generation sources, the generation source’s intermittency can be reduced, increasing the number of applicable use cases for these existing systems and therefore their value. The ESS would likely perform some daily smoothing to maximize the operator’s revenue.
- **Power Quality** – Flicker, harmonic filtering, voltage, and Volt Amp Reactive (VAR) support are functions that ESS could provide year-round.
- **Reliability** – Support for load transfers, preventing/responding to N-1 thermal/voltage impacts, grid stability, and black start capability are functions that ESS could provide year- round, with a specific focus on high-load periods.
- **Optimal Dispatch of Conventional Generation** – Many types of conventional generation have an optimal power output for fuel efficiency but may need to operate above or below that point at times to follow the load. Adding dynamically dispatched ESS can reduce the need for the generator to ramp up or down, allowing it to remain at optimal efficiency or even replace peaking units. ESS could provide these functions year-round.

- **Mobile Energy Storage** – ESS can provide benefits pertaining to the use cases above but at different locations and different times. The ability for ESS to be mobile provides a means to optimize and increase the utilization of a specific ESS to provide stacked benefits while considering the potentially increased cost of mobile energy storage compared to stationary storage.

Further use cases, specifically to support T&D system needs, are being investigated by the ESSC within the ATWG comprised of members of the Joint Utilities, EPRI, NY-BEST, NYSERDA and DPS Staff. The task force plans to conduct a study with a consultant to investigate grid support use cases of energy storage based on experience across the energy storage industry and identify how the use cases can be applied cost effectively in New York.

5. Identify and describe all significant resources and functions that the utility and stakeholders use for planning, implementing, monitoring, and managing energy storage at multiple levels in the distribution system.

- a. Explain how each of those resources and functions supports the utility's needs;**
- b. Explain how each of those resources and functions supports the stakeholders' needs.**

National Grid continues to improve and advance current tools and investigate new tools to support the planning, implementing, monitoring, and managing of energy storage on the distribution system. The Company continues to advance its modeling capabilities within CYME's software application to model energy storage and is exploring valuation estimation tools to model how ESS can support distribution system needs such as backup power support (e.g., microgrids). In addition, the Company has been advancing modeling capabilities with software platforms, such as PSCAD, to perform more granular studies and recognize impact of interconnections of energy storage projects to be implemented. Such findings will allow for more comprehensive customer interconnection opportunities and new opportunities for energy storage to meet planning use cases.

The Company is also continuing its efforts to incorporate within its ADMS deployment the means to improve visibility and modeling of energy storage as part of its distribution system operations. There are on-going efforts to consider the most suitable means to optimize and manage the scheduling and dispatch of ESS and whether that is in ADMS, DERMS, or a combination of both. Such developments will enable the Company's operations personnel to better monitor, analyze and make more informed decisions moving forward.

For Company assets participating in the wholesale market, as is the case regarding the East Pulaski BESS, National Grid has procured consultancy, training, and market operations services from a third-party marketer.

6. Describe the means and methods for determining the real-time status, behavior, and effect of energy storage resources currently deployed in the distribution system. Information produced by those means and methods could include:

- a. the amount of energy currently stored (state of charge);**
- b. the time, size, duration, energy source (grid and/or local generation), and purpose of charging events;**

- c. the time, size, duration, consumer (grid and/or local load), and purpose of energy storage discharges;**
- d. the net effect (amount and duration of supply or demand) on the distribution system of charge/discharge events (considering any co-located load and/or generation); and**
- e. the capacity of the distribution system to deliver or receive power at a given location and time.**

For the current two Company-owned energy storage projects and existing and planned contracted NWA projects, EMS is used to monitor the projects' input/output power and control the interconnecting circuit breakers. National Grid can monitor the state of charge effect of storage discharges. In addition, the Company can access the energy storage plant controller for more detailed, real-time analysis. EMS is also used to monitor the input/output power and control the interconnecting PCC reclosers of third party-owned energy storage resources. Characteristics such as schedule, purpose of discharges, and state of charge are not actively monitored for third-party locations. However, these attributes are typically captured as part of the NY-SIR process and are required to ensure prevention of operational constraints to the Company.

In collaboration with the Joint Utilities, National Grid continues to examine monitoring and control requirements for smart inverters as this impacts the real-time status, behavior, and effect of energy storage resources on the distribution system. The Joint Utilities have released their Phase Two smart inverter roadmap requirements which have been incorporated by the Company into its ESB 756B. Phase Three of the Joint Utilities' smart inverter roadmap is expected to inform how National Grid can interact more dynamically with smart inverters, including inverter-based energy storage resources.

As part of the Company's plans, National Grid intends to transition monitoring and control of energy storage resources to ADMS and is currently investigating whether scheduling and dispatch of Company-owned or contracted energy storage resources supporting distribution system needs should be managed through ADMS, DERMS, or a combination of both. Such systems will offer additional monitoring of energy storage systems, both Company and third-party owned, and will support efforts for reviewing net effects of charge and discharge impacts in more granular detail.

- 7. Describe the means and methods for forecasting the status, behavior, and effect of energy storage resources in the distribution system at future times. Forecasts produced by the utility could include:**
- a. the amount of energy stored (state of charge);**
 - b. the time, size, duration, energy source (grid and/or local generation), and purpose of charging events;**

- c. the time, size, duration, consumer (grid and/or local load), and purpose of energy storage discharges;
- d. the net effect on the distribution system of each charge/discharge event (considering any co-located load and/or generation);
- e. the capacity of the distribution system to deliver or receive power at a given location and time.

The Company provides two responses to this question: one addressing a long-term forecasting and the other addressing short-term forecasting.

Long-Term Forecast Response

In the current long-term load forecasting process, National Grid considers storage paired with solar PV type and a peak-shaving use case by assuming storage to discharge during typical peak hours in a day and charge during the hours when solar PV is expected to generate. However, the amount of energy stored, charge/discharge characteristics, or purpose of discharges are not currently captured in an explicit manner in the Company's Long-Term Forecast. The assumptions for developing the energy storage projection are discussed in the Company's Peak Report. Energy storage is assumed to discharge during peak hours for a duration of four to five hours to help shave the peak. It is assumed to charge throughout the daytime when solar PV is generating. The estimated impact to at-peak load time is presented in Appendix A of the Company's Peak Report.

Short-Term Forecast Response

The Company is also exploring ways to expand its short-term load and generation forecasting methods, starting with the ability to forecast loading on specific circuits and substations to assess day-ahead operating plans and DER availability for participation in the NYISO wholesale market under FERC 2222. The short-term forecasting is also used to help support activation of targeted load relief and NWA. Such factors as capacity, purpose of charging/discharging events, and effects on the distribution system will all be considered in a short-term forecast response for a limited and specific number of projects, such as the NWA projects. The ability to incorporate more complex, short-term forecasting features, such as the operation of energy storage in general, into load forecasts is being considered as a follow-up activity once National Grid has developed some experience with short-term load forecasting.

8. Describe the resources and functions needed to support billing and compensation of energy storage owners/operators.

Compensation of energy storage for both net metering and Value Stack projects is already automated and integrated into the Company's billing system based on customer type and project configuration. This function is supported by the Company's billing specialists and CEI consultants utilizing National Grid's CSS and Salesforce systems. For NWAs, the Company can use the NWA recovery mechanism, detailed in the Electricity Tariff, to recover funds related to NWA solutions

which may include energy storage compensation.. The NWA recovery mechanism provides the ability to collect certain NWA charges through a customer surcharge.

9. Identify the types of customer and system data that are necessary for planning, implementing, and managing energy storage and describe how the utility provides those data to developers and other stakeholders

In support of NWA planning and implementation, necessary customer and system data of energy storage includes hourly load and generation for the affected system assets. i This data is developed into a needs statement to determine the amount of energy capacity, power capacity, and duration required to meet the system load relief, reliability, and/or resiliency need. A needs statement would then be used to communicate the proper technical parameters to bidders within an RFP.

Energy developers and other stakeholders can also access the Company's ESS Hosting Capacity maps within National Grid's System Data Portal, an interactive resource by which to assess energy storage opportunities. Additional efforts to create a centralized data platform are being explored as part of the IEDR. See Section 2.8 – Data Sharing and Section 2.9 – Hosting Capacity of this 2025 DSIP Update for additional information.

10. By citing specific objectives, means, and methods, describe in detail how the utility's accomplishments and plans are aligned with the objectives established in the CLCPA.

National Grid remains committed to advancing how energy storage can be interconnected and integrated into the T&D system to advance the objectives established in CLCPA. There is a suite of initiatives accomplished to date as well as future plans for improving the interconnection process for energy storage. These include publishing and evolving the Company's ES Hosting Capacity maps, and devising innovative alternative ways to interconnect energy storage more cost effectively and expeditiously while maintaining the safety and reliability of the electric system. The Company continues to investigate ways to beneficially incorporate energy storage as a NWA solution. The ESS projects currently in the planning stages will provide valuable experience on how energy storage can address T&D reliability needs and advance National Grid's capability to plan, engineer, construct, operate, and maintain energy storage systems. The studies that National Grid is embarking on, including those in collaboration with others, such as members of the ATWG, will bring further clarity to the value proposition that energy storage can unlock within New York.

5.5 Electric Vehicle Integration

The following responds to DSP Staff's request to provide additional details regarding EV integration.¹⁴⁰

- 1. Using a common framework (organization, format, semantics, definitions, etc.) developed jointly with the other utilities, identify and characterize the existing and anticipated EV charging scenarios in the utility's service territory. Each scenario identified should be characterized by:**
 - a. the type of location (home, apartment complex, store, workplace, public parking site, rest stop, etc.);**
 - b. the number and spatial distribution of existing instances of the scenario;**
 - c. the forecast number and spatial distribution of anticipated instances of the scenario over the next five years;**
 - d. the type(s) of vehicles charged at a typical location (commuter car, bus, delivery truck, taxi, ride-share, etc.);**
 - e. the number of vehicles charged at a typical location, by vehicle type;**
 - f. the charging pattern by vehicle type (frequency, times of day, days of week, energy per charge, duration per charge, demand per charge);**
 - g. the number(s) of charging ports at a typical location, by type;**
 - h. the energy storage capacity (if any) supporting EV charging at a typical location;**
 - i. an hourly profile of a typical location's aggregated charging load over a one-year period;**
 - j. the type and size of the existing utility service at a typical location;**
 - k. the type and size of utility service needed to support the EV charging use case; region, area, substation, circuit, tap, and transformer**

National Grid develops multiple scenarios in addition to a base case EV forecast, including a baseline forecast representing the expected EV load growth and peak demand, aligned with state regulations, policies and programs. For LDVs, the forecast aligns with the California Advanced Clean Car II regulations, and the MHDV forecast aligns with the recently adopted California

¹⁴⁰ DSIP Proceeding, *supra* note 11, pp. 16-18.

Advanced Clean Trucks regulations. The Company also creates a high and low scenario that allows for accelerated EV adoption and high levels of managed charging, respectively. These scenarios are useful for assessing the impacts of EV loads under different levels of adoption and incorporate different mixes and locations of EV charging infrastructure. The scenarios consider a mix of charging from both L2 and DCFC infrastructure for National Grid residential and commercial customers. These EV charging loads are aggregated into the Company's load forecast.

As discussed in this 2025 DSIP Update, National Grid introduces probabilities to each of these scenarios in order to build a more holistic perspective on the projected demand at a feeder level from distributed loads such as EV charging. The current scenarios will be given a probability of occurrence, and the estimated probability of each scenario will provide a range of probable outcomes for EV charging at the feeder level. This probabilistic forecast will incorporate policy, market, technology, and financial drivers to determine the likely outcomes for both hourly and multi-year forecasts.

2. Describe and explain the utility's priorities for supporting implementation of the EV charging use cases anticipated in its service territory.

National Grid has planned for EV charging use cases of all types throughout the service territory, to provide a comprehensive suite of charging solutions for all customers. Customers require flexibility for EV charging and accelerating the state's EV adoption goals require deploying a holistic set of charging solutions for all customers.

To support this flexible network of charging solutions, National Grid is addressing customer needs as follows:

- EV Make-Ready Infrastructure Programs: The EV Make-Ready Program, Medium- and Heavy-Duty Make-Ready Pilot, Transit Authority Pilot, and Micromobility Pilot.
- Operating Cost Relief Programs: The DCFC PPI Program, Demand Charge Rebate, Commercial Managed Charging Program, and Residential Managed Charging Program

Proactive Planning Proceeding

The Company will also build upon its experience from its existing EV charging programs, its robust trade ally network, and other industry stakeholders to support new technologies and business models as they evolve throughout the planning period.

3. Identify and describe all significant resources and functions that the utility and stakeholders use for planning, implementing, monitoring, and managing EV charging at multiple levels in the distribution team.

a. Explain how each of those resources and functions supports the utility's needs.

While implementing the Company's EV charging programs described above, National Grid has worked closely with trade allies and site hosts to determine the least cost sites for deploying EV charging infrastructure. The EV forecasts are aggregated into the total forecasted load at the feeder level and this data is used to determine the availability and costs for installing EV charging

infrastructure at a potential site. The probabilistic forecasts going forward will provide “kW band” of projected hourly load at the feeder and system level, further enhancing the value in the discussions between National Grid, site hosts, and developers.

Additionally, the Company has conducted several efforts to proactively plan for large spot loads of EV charging from MHDVs throughout the service territory. This practice gives greater insight into both National Grid planning teams and industry partners about where to install EV charging infrastructure. By placing EV charging infrastructure in highly traveled areas, these models help accelerate EV adoption and the state’s achievement of ZEV goals. These efforts are described in further detail in the National Grid and Joint Utilities filings in Case 23-E-0070.¹⁴¹

b. Explain how each of those resources and functions supports the stakeholders’ needs.

As outlined in the Electric Vehicle Integration section of this 2025 DSIP Update, the trade ally network has been a key factor in hitting the goals of the EV charging programs. The trade ally network of entities, such as EV charging installers, electricians, and equipment manufacturers, has provided essential insight into the needs of the Company’s customers. The Company’s forecasting and planning efforts help accelerate the engagement process with trade allies and site hosts and simplify the process of finding low-cost areas for EV charging infrastructure.

National Grid provides trade allies with EV charging program training materials for inclusion in marketing and recruiting activities, as well as collaborating with trade allies to build a combined experience in deploying EV charging infrastructure. The Company plans to continue to support these stakeholder engagements with additional capacity forecasting details in order to provide the lowest-cost EV charging infrastructure for all customers in the Company’s service territory, inclusive of both LDV and MHDV.

4. Identify the types of customer and system data that are necessary for planning, implementing, and managing EV charging infrastructure and services and describe how the utility provides those data to interested third parties.

Planning, implementing, and managing EV charging requires several types of data, including customer data, site host data, and system data. National Grid’s experience with EV charging programs since 2018 provides a foundation to continue to build upon during the planning period. This data is shared with all stakeholders via the annual reporting process for the EV Make-Ready Infrastructure Program, as well as through National Grid filings in Case 18-E-0138¹⁴² regarding LDV make-ready programs, Residential Managed Charging Programs, and the PPI program. In particular, the main types of data for planning purposes are:

- Expected EV charging demand and utilization: The Company has operational data that informs both internal planning teams and interested third parties. Charging data gives greater insight into charging loads, charging behaviors, and number of drivers by segment. The Company also uses this information to determine the level of charging at each

¹⁴¹ *Supra* note 70.

¹⁴² *Supra* note 60.

customer type (L2 or DCFC). This insight will continue to become more valuable as EV adoption continues to grow.

- Customer load profile: The Company uses existing customer load profile data to understand the impact of EV charging infrastructure installation. This load profile informs the customer about what type of charging to install, as well as system-level impacts.
- Driving behavior: Traffic flow and driving behavior is important to understand when planning for EV charging infrastructure deployment. The Company incorporates transportation patterns as part of the load forecasting process, which will inform system planners and third parties about where EV adoption is likely to occur.
- Siting of EV charging infrastructure: The EV charging programs have provided insights into the cost components in installing EV infrastructure and that costs can vary depending on where the charging ports are installed (e.g., trenching and cutting costs). The Company can help inform customers of these costs once the location is known, ideally early in the development process, in order to provide the lowest-cost solution.
- Distribution asset load profile: The Company will need to know the load profile on the nearest substation or similar distribution asset to understand the likely impact that may arise from increased load attributable to EV charging. This will enable National Grid to update its asset management strategy for that substation or feeder.
- Clusters of commercial fleets: The Company has also conducted several studies to address the charging needs of commercial fleets located in close proximity to each other, and their impacts to the T&D system. These efforts are described in further detail in the National Grid and Joint Utilities filings in Case 23-E-0070.

5. Describe the resources and functions needed to support billing and compensation of EV and EVSE owners/operators.

The Company has made many adjustments to its billing and compensation systems to support customers of all types participating in EV charging programs, including EV charging site hosts and residential drivers. Site hosts participating in the EV Make-Ready Infrastructure Program receive rebates directly from National Grid, and residential customers participating in the EV Charge Smart Plan receive charges and rebates associated with the program on their utility bills. Future EV programs, such as the EV Rate Design Programs discussed above, will likely require programming changes to commercial customer billing systems.

6. By citing specific objectives, means, and methods describe in detail how the utility's accomplishments and plans are aligned with New York State policy, including its established goals for EV adoption.

This is addressed in National Grid's response to Question 7 below.

7. Describe the utility's current efforts to plan, implement, and manage EV-related projects. Information provided should include:

- a. a detailed description of each project, existing and planned, with an explanation of how the project fits into the utility's long-range EV integration plans;

- b. the original project schedule;
- c. the current project status;
- d. lessons learned to-date;
- e. project adjustments and improvement opportunities identified to-date; and
- f. next steps with clear timelines and deliverables

Table 5.5.1: Current EV-Related Projects

National Grid's EV Infrastructure Programs	
Detailed Description of Initiative with Explanation of Alignment to National Grid's Long-Range EV Integration Plan	In 2020, the Company received approval for an EV Make-Ready Infrastructure Program to enable the installation of EV charging stations at customers' properties and to provide incentives to customers to encourage the installation of these charging stations. These programs enable investment in electrical infrastructure on both the utility and the customer side of the meter. This program helps to meet the state's ZEV goals and helps to reduce GHG emissions throughout the Company's service territory, accelerating achievement of CLCPA goals. It has enabled commercial customers such as retailers, workplaces, fleet operators, and apartment owners overcome the costs of installing EV infrastructure. The programs include the Make Ready Program, MHDV Make-Ready Pilot, Transit Authority Pilot, Micromobility Pilot, and the Load Management Technology Incentive program.
Original Project Schedule	The EV Make-Ready Infrastructure Programs are approved through 2025.
Current Project Status	The EV Make-Ready Infrastructure Programs are currently undergoing a program review. The end-of-program review commenced in March with a stakeholder webinar, and over the course of the review, feedback from the utilities, industry stakeholders, interest groups, and government entities will inform the next steps for a future of funding EV charging in New York through 2030 and beyond. The MRP review will also assess the LMTIPs, evaluating the implementation to date and determining whether they should be re-authorized with additional funds. A forthcoming Commission order is expected to authorize a full-scale MHD program to replace the MHD Pilot and continue to meet MHD stakeholders' needs beyond 2030.
Lessons Learned to Date	To date, the MRP has shown that utility support and investment remain necessary for the industry to progress. Supporting programs such as the Load Management Technology Incentive Program are also important in enabling customers to avoid peak charging times and lower the grid

National Grid's EV Infrastructure Programs	
	impact of EVs. For MHDVs, significantly increased investment is needed to advance to a full-scale deployment of MHD charging infrastructure. The program that will replace the MHDV Make-Ready Pilot should use the learnings from that pilot to offer incentives with fewer restrictions to use.
Project Adjustments and Improvement Opportunities Identified to Date	As detailed in the Electric Vehicle Integration section of this 2025 DSIP Update, several adjustments and improvements are underway for the EV infrastructure programs. These include a formal review of the make-ready program, an assessment of the Load Management Technology Incentive Program, and a forthcoming full-scale MHD program to replace the MHD Pilot. The details regarding these EV infrastructure programs can be found in Cases 18-E-0138, 22-E-0236, and 23-E-0070.
Next Steps with Clear Timelines and Deliverables	Please see Figure 2.5.2 of this 2025 DSIP Update for milestones and next steps for the EV Infrastructure Programs.

National Grid's EV Operating Cost Relief Programs	
Detailed Description of Initiatives with Explanation of Alignment to National Grid's Long-Range EV Integration Plan	The Company is implementing several operating cost relief programs: the DCFC PPI, Demand Charge Rebate, Time of Use Rates, Commercial Managed Charging Program, and Residential Managed Charging Program. These programs all help to meet stakeholder needs by significantly reducing the operating costs for owners of EV charging stations, a major barrier to EV adoption. These programs also enable utilities to extract value from their investment in EV charging stations, by shifting charging to off-peak times, thereby lowering total costs to all ratepayers.
Original Project Schedule	These programs are on various timelines, as outlined in Section 2.5 of this 2025 DSIP Update.
Current Project Status	• DCFC PPI: Stopped accepting applications in March 2023 • Demand Charge Rebate: Actively enrolling participants but will be replaced by the EV Phase-In-Rate • Time of Use Rates: The Company is currently developing the processes and system changes necessary to launch the EV Phase-In-Rate in the fall of 2025 • Commercial Managed Charging Program: Awaiting a Commission order, with an anticipated launch date in late 2025 or early 2026 • Residential Managed Charging Program: Enrolling participants through 2025, with a filed petition requesting an extension for future iterations of the program awaiting Commission action
Lessons Learned to Date	These programs are crucial to incentivize customers to shift EV charging load from on-peak hours to off-peak hours, through rate signals, rebates, and peak avoidance incentives. These types of programs enable the electrical grid to incentivize grid-beneficial

National Grid's EV Operating Cost Relief Programs	
	behavior. In the future, as electrical demand related to EV charging increases, grid resilience will become more important.
Project Adjustments and Improvement Opportunities Identified to Date	As detailed in the Electric Vehicle Integration section of this 2025 DSIP Update, several adjustments and improvements are underway for the EV Cost Relief Programs. These include a petition requesting Commission authorization to continue the Residential Managed Charging Program through 2026 with the opportunity to evaluate programs in a program review. The Demand Charge Rebate will be replaced by the Phase-In-Rate once it is available in late 2025, and the commercial managed charging program is expected to launch in late 2025 or 2025. Program details can be found in Cases 18-E-0138 and 22-E-0236.
Next Steps with Clear Timelines and Deliverables	Please see Figure 2.5.2 of this 2025 DSIP Update for milestones and next steps for the EV Operating Cost Relief Programs.

National Grid's Proactive Planning Proceeding	
Detailed Description of Initiative with Explanation of Alignment to National Grid's Long-Range EV Integration Plan	On August 15, 2024, the Commission established the Proactive Planning Proceeding in Case 24-E-0364 building upon work done in the MHDV Proceeding . The Proactive Planning Proceeding's purpose is to allow for grid investments and upgrades to enable growing electricity demand primarily driven by vehicle and building electrification. The order establishing the proceeding (Establishing Order) allows utilities to plan for and construct these upgrades proactively, rather than the traditional and reactive way of waiting for an interconnection request to begin upgrades.
Original Project Schedule	The Establishing Order is divided into two parts: the first allowed utilities to submit a portfolio of 'Urgent Projects,' and the second asked for utilities to propose a long-term framework to more granularly forecast growing load, develop methodologies to prioritize projects, and develop projects to address those growing needs.
Current Project Status	The 'Urgent Projects' portfolio was filed in November 2024 that includes projects to address both vehicle and building electrification.
Lessons Learned to Date	The Company's first Urgent Projects filing in November 2024 highlighted the urgent need for these types of investments to vehicle electrification in the state. The submitted vehicle electrification portfolio included the construction of five greenfield substations to create 100+MW of capacity along the New York Thruway; three mobile storage units to serve as bridge-to-wires solutions to provide near-term capacity until more permanent solutions come online; and four off I-90 projects to provided additional capacity to travel plazas and fleet depots in the Company's service territory. In June 2025, the Commission issued an order whereby the Company is authorized to proceed with 22 projects supporting building electrification and EV

National Grid's Proactive Planning Proceeding	
	charging including mobile battery storage and projects supporting EV charging along major travel corridors and school bus electrification. .
Project Adjustments and Improvement Opportunities Identified to Date	The long-term proactive framework submitted by the Joint Utilities in December 2024 lays out how utilities will conduct future load studies, develop projects, cost allocation, and how the process will interact with other statewide proceedings like the CGPP.
Next Steps with Clear Timelines and Deliverables	The Joint Utilities will be following the long-term framework as filed in Case 24-E-0364.

8. Describe how the utility is coordinating with the efforts of the New York State Energy Research and Development Authority (NYSERDA), the NYPA, New York State Department of Environmental Conservation (NYSDEC), and DPS Staff to facilitate statewide EV market development and growth.

The utilities have collaborative partnerships with many state agencies who represent stakeholders to EV policy and program implementation in New York. The Joint Utilities meet regularly with DPS Staff about the implementation of the Make-Ready Program, Managed Charging Programs, LMTIP, and rate design programs. They share insights into market trends, program progress, stakeholder feedback, and emerging technologies. They further discuss the challenges faced by program participants and propose solutions to address such issues.

The utilities also participate in frequent meetings with state agencies, such as NYSERDA and NYSED, to ensure coordination between utility and state incentive programs and state EV adoption mandates and policy goals. Where utility incentive programs may overlap with incentives offered from the state (such as the utility MHD Pilot and the NYSERDA NYSBIP charging voucher), utilities coordinate with the State to ensure that each incentive is appropriately awarded. Where State incentives may require utility data (such as a utility rate analysis for a site undergoing a NYSERDA Fleet Electrification Plan), the utilities have extensively collaborated with the other agency to ensure well-documented processes for information exchange.

The utilities have facilitated consistent communication with NYPA, NYSDOT, and NYSERDA, regarding high-profile federally funded EV charging installations that also participate in the Make-Ready program, to ensure that they move efficiently through the program to help meet the State's goals.

5.6 Clean Heat Integration

The following responds to DSP Staff's request to provide additional details regarding clean heat integration.¹⁴³

1. **Using a common framework (organization, format, semantics, definitions, etc.) developed jointly with the other utilities, identify and characterize the existing and clean heat installation scenarios in the utility's service territory. Each scenario identified should be characterized by:**
 - a. **the type of location (single family residence, multifamily residence, commercial space, office space, school, hospital, etc.).**

The Clean Heat Program installs heat pumps in single family homes, multifamily homes, small businesses, and commercial and industrial buildings.

- b. **the number and spatial distribution of existing instances of the scenario;**

Premise Type	Count
Multi Family Home	472
Single Family Home	6586
Small Business	220
Grand Total	7278

2020 – 2024

Premise Type	Unit Count
Single Family Home	14,212
Multi Family Home	1,032
Small Business	519
Grand Total	15,763

- c. **the forecast number and spatial distribution of anticipated instances of the scenario over the next five years;**

The NYS Clean Heat Program does not plan or project specific instances of spatial distribution into the implementation plan. Rather, the Company plans at an MMBtu level across all sectors. The Company anticipates installing a heat pump distribution that includes the eligible configurations listed in table 2.6.1: *National Grid Clean Heat Incentives* in the body of the Clean Heat section of this 2025 DSIP Update.

¹⁴³ DSIP Proceeding, *supra* note 11, pp. 18-20.

- d. **the type(s) of clean heat solution installed at a typical location (ASHP, GSHP, HPWH, etc.);**

Locations can have air source heat pumps (central air or mini split systems), ground source heat pumps and/or heat pump water heaters.

- e. **an hourly profile of a typical location's aggregated clean heating load over a one-year period;**

This data is not collected.

- f. **the type and size of the existing utility service at a typical location; and**

It depends on the customer as there are several variables to consider and there is no typical service or typical location.

- g. **the type and size of utility service needed to support the clean heating use case.**

It depends on the size of the customer and the end use case. For example, most residential customers will need a 200 Amp service for heat pump applications.

2. Describe and explain the utility's priorities for supporting implementation of the clean heating use cases anticipated in its service territory.

National Grid is a member of the Joint Management Committee which meets regularly to discuss planning and progress, quality assurance and quality control, technical considerations, and marketing of the program. National Grid also works with several vendors that help support the program by ensuring the Company has a network of qualified contractors to install heat pumps, and that they are installed to our standards.

3. Identify and describe all significant resources and functions that the utility and stakeholders use for planning, implementing, monitoring, and managing clean heating at multiple levels in the distribution system.

- a. **Explain how each of those resources and functions supports the utility's needs.**

JMC Planning Working Group- This is a platform to discuss potential program changes using a new product tracker to handle statewide program issues.

JU Quality Assurance / Quality Check Call- This group reviews contractor evaluations to update statuses, any QA checklist for revisions/updates, Clean Heat Connect updates, and policies and procedures documents.

JU Marketing Meeting- National Grid coordinates with JMC on NYSERDA-funded marketing to run a statewide campaign.

JMC Weekly Meeting- This meeting focuses on preparing for and responding to stakeholder engagement, including quarterly Participating Contractor and Industry Partner webinar and Staff requests. It works through comments and edits to program documents and reporting.

JMC Technical Consideration Call- The JMC explores and resolves program technical issues, including NEEP listings, edits to the Program Manual, and custom project exceptions. This community also evaluates new technology for program inclusion.

b. Explain how each of those resources and functions supports the stakeholders' needs.

Please refer to the responses above.

4. Identify the types of customer and system data that are necessary for planning, implementing, and managing clean heating infrastructure and services and describe how the utility provides this data to interested third parties.

National Grid has six residential customer segments, and we use them to optimize targeting efforts and spending by engaging those with higher propensity to participate. Many attributes go into determining the customer's segment, including usage, income, behaviors, education, and age.

Once a customer has participated in the Clean Heat program, we keep data to track National Grid's performance. Some customer data retained is name, address and bill account number. Data retained on program information are type of heat pump, type of load, incentive cost, and total number of MMBTU's saved.

5. By citing specific objectives, means, and methods describe in detail how the utility's accomplishments and plans are aligned with New York State policy, including its established goals for clean heat adoption.

The Clean Heat program's goal is to electrify customers so as make progress towards National Grid's and the state's carbon reduction goals. National Grid is expanding its contractor network so as to have more qualified workers to speak to customers and encourage them to install heat pumps and electrify their homes.

6. Describe the utility's current efforts to plan, implement, and manage clean heat-related projects. Information provided should include:

a. a detailed description of each project, existing and planned, with an explanation of how the project fits into the utility's long-range clean heat integration plans;

National Grid has hundreds of contractors working every day to install heat pumps and heat pump water heaters for our customers. Every contractor is required to submit a manual J or an alternate approved energy analysis with the heat load calculations to ensure heat pumps are properly designed to efficiently heat the customer's home.

b. the original project schedule;

Residential air source heat pump projects are generally completed the same day. Ground source heat pump projects generally take a few days and depending on the size and type of loops they can take up to 2 weeks.

Custom Commercial and Large Multifamily heat pump project lead times vary for a variety of reasons, including project scope, building accessibility, technology type, etc. Incentive applications are submitted prior to construction, reviewed for savings, approved, and post-inspected upon completion prior to issuing payment.

c. the current project status;

In program year 2024, the National Grid Clean Heat Program outperformed expectations in the Commercial, Industrial, and Multifamily sectors, accounting for a 72 percent increase in savings above 2023 levels. However, in aggregate, the Clean Heat Program savings were approximately 1 percent lower than 2023 achievements. The reduction in year-over-year savings within the residential sector can largely be attributed to the removal of Category 1 incentives for partial rebate installations. As of this 2025 DSIP Update filing, the 2025 pipeline for Clean Heat projects has yet to materialize at the same rate and pace as prior years. The reduction in pipeline activity and participation has been experienced across all New York service territories and is likely a result of economic uncertainty and increased costs associated with heat pump equipment and installations.

d. lessons learned to-date;

The Company will continue to monitor the 2025 and 2026 pipeline and explore Limited-Time Offerings, program design modifications, and adjustments to incentive structures to reduce program barriers that may be limiting customer participation.

e. project adjustments and improvement opportunities identified to-date; and

Recognizing the downward trend in project volume and claimable savings, the Company decided to increase incentives and provide Limited-Time Offerings both in the 2024 September Program Manual and in the 2025 April Program Manual updates. And while program activity did increase after the release of Limited-Time Offerings, the total project volume remains below planned values, in part due to increased equipment and installation costs, and general economic uncertainty.

f. next steps with clear timelines and deliverables

The next Clean Heat Program Manual update will occur in September of 2025. The Company anticipates that the EE/BE Order will likely influence or necessitate specific Program Manual updates.

- 7. Describe how the utility is coordinating with the efforts of NYSERDA, NYPA, New York Department of Environmental Conservation (DEC), DPS Staff, or other governmental entities to facilitate statewide clean heat market development and growth.**

National Grid meets with NYSERDA biweekly to discuss and promote joint marketing efforts all over the State. DPS Staff join the JMC Weekly meeting once a month to discuss the current state of the program. National Grid also provides DPS Staff with the number of heat pumps installed by category, fuel type replaced, and whether it was new construction or not.

5.7 Energy Efficiency Integration and Innovation

The following responds to DSP Staff's request to provide additional details regarding EE integration and innovation.¹⁴⁴

1. The resources and capabilities used for integrating energy efficiency within system and utility business planning.

As the Company's DLM portfolio continues to expand, it increasingly can play a role within the system planning and NWA process. Over the next 3-5 years, the rollout of AMI will vastly increase the pool of potential DLM participants, as customers who were once unable to participate in programs like CSRP and Term-DLM due to metering, will now be able to participate within aggregations in those programs. A large portion of these customers are served at the distribution level. This expanded participation among distribution customers will translate to more available capacity in constrained locations, expanding the potential customers available to participate in new NWA locations as those projects develop.

2. The locations and amounts of current energy and peak load reductions attributable to energy efficiency and how the utility determines these.

Please refer to *Table 2.7.3: National Grid's CSRP Annual Results*, and *Table 2.7.4: National Grid's Term-DLM Annual Results* as well as the supporting narrative for these tables in Section 2.7 Energy Efficiency Integration and Innovation of this 2025 DSIP Update.

3. A high-level description of how the utility's accomplishments and plans are aligned with New York State climate and energy policies and incorporate innovative approaches for accelerating progress to ultimately align with the CLCPA.

National Grid's energy efficiency and building electrification programs help customers save energy, increase the comfort of their homes and businesses, and reduce their carbon footprint. Energy efficiency and building electrification are the foundation necessary to meet CLCPA goals. The Company monitors developments – in technology, finance and understanding of consumer behavior – to adjust program offerings as needed. In addition, the Company is committed to the CLCPA's goals of increased investment in DACs. The Company is working with DPS Staff, NYSERDA and other utilities to create a tracking and reporting mechanism in support of the State's compliance efforts to ensure at least 35 percent of clean energy investments accrue to DACs. In furtherance of this effort, consideration of how to reach DACs is being integrated into the Company's program design and delivery.

¹⁴⁴ DSIP Proceeding, *supra* note 11, pp. 20-22.

4. Summary information on energy efficiency programs offered by the utility, with direction to annual filings for more detailed information on energy efficiency programs.

The Company offers Commercial & Industrial, Residential, and Multifamily programs. For more information, please see the annually filed SEEP.

5. Describe how the utility is coordinating and partnering with NYSERDA's related ongoing statewide efforts to facilitate energy efficiency market development and growth.

National Grid is in regular communication with NYSERDA counterparts, at both the executive and program administration levels, to facilitate alignment and collaboration. This includes, for example, transitioning NYSERDA market development and pilot activities to the utility portfolios (e.g., RTEM, weatherization), coordinating delivery of workforce development, refinements to the TRM and joint EM&V for statewide initiatives. The Company is also actively involved with NYSERDA's Empower+ program for LMI customers. National Grid supplies both referrals and funding to this program through a joint task force with the Joint Utilities and NYSERDA.

5.8 Data Sharing

The following responds to DPS Staff's request to provide additional details which are specific to data sharing.¹⁴⁵

1. Provide a functional overview of the planned IEDR.

The IEDR plan currently contains two phases; Phase 1 was completed in Q1 2024 and consisted of three use cases associated with IPV and five use cases associated with MVP, while Phase 2 will enable over thirty-one additional data use cases over thirty to thirty-six months (2027 completion). NYSERDA serves as the Program Sponsor for this effort and forms the Steering Committee with DPS Staff. The Commission approved a National Grid Phase 2 budget of \$2.715 million and described the program schedule, governance structure, and reporting requirements.

2. Provide an overview of NYSERDA's IEDR implementation program, including information pertaining to stakeholder engagement.

On May 24, 2021, NYSERDA, as the IEDR Program Sponsor, issued a notice inviting stakeholders to provide comments identifying, characterizing, and prioritizing a preliminary set of potential Use Cases for Phase 1 of the IEDR. The Joint Utilities and other stakeholders submitted IEDR Use Case comments on July 23, 2021. The Joint Utilities proposed Use Cases that would benefit stakeholders across NYS from their perspective, as noted by NYSERDA's instructions, but emphasized that the IEDR should prioritize Use Cases from developers and other stakeholders that maximize societal value. NYSERDA guided the prioritization and selection of the Use Cases to move forward with Phase 1 of the IEDR design and implementation.

In Q3 2022, NYSERDA announced the selection of E Source to lead the IEDR Development Team. The Development Team also includes UtilityAPI, Flux Tailor, TRC Companies, and HumanLogic. Together, the team is responsible for designing, building, and operating the IEDR platform to accomplish the policy goals and program outcomes in a cost efficient and expeditious manner. The Development Team will leverage E Source's OneInform and UtilityAPI's GBC offerings to enable the data access, governance, querying, analysis, and consent processes that will be required to deliver the full benefit of stakeholder submitted use cases.

The IEDR Program Team, comprised of NYSERDA and its program manager, Deloitte Consulting, LLP and utility data advisor, Pecan Street Inc., as well as the IEDR Development Team, implemented the following use cases for the IEDR IPV in Q1 2023.

¹⁴⁵ DSIP Proceeding, *supra* note 11, pp. 22-23.

Table 5.8.1: IPV Use Cases

Use Case	Description
Consolidated Hosting Capacity Maps	This use case supports DER developers, DER owners, and/or utilities to view all Hosting Capacity maps for the entire state in one map view with consistent data, so that users can site new DERs and monitor the state of DER development in New York accurately. Foundational functionality will be implemented in IPV, with enhancements to Hosting Capacity maps expected to be developed in future releases.
Large Installed DERs	This use case supports ESE and/or government staff members who want to view all installed DERs that utilities have data on (e.g., over 300 kW), so they can site new DERs or monitor the state of DER development in New York. This use case provides access to the necessary information pertaining to installed DERs including attributes, location, and status in a consistent format across the entire utility service territories.
Large Planned DERs (Interconnection Queue)	This use case also supports ESE and/or government staff members who want to view and monitor all planned DERs that utilities have data on (e.g., over 300 kW), so they can site new DERs or monitor the state of DER development in New York. This use case provides access to the necessary information that pertains to large planned DERs including attributes, location, and status in a consistent format across the entire utility service territories.

The IEDR Program Team implemented the following use cases for the IEDR MVP in Q1 2024.

Table 5.8.2: MVP Use Cases

Use Case	Description
DER Siting	This use case will support local governments and community solar developers who would want to accelerate the process for identifying, selecting, and negotiating site agreements for community solar projects in order to deploy available capital more quickly and increase the amount of clean energy available to NY electricity customers. The IEDR will serve as a one-stop shop for standardized DER data and will operationalize the demand flexible market.
Hosting Capacity and DER Map Enhancements	This use case will support DER developers, DER owners, and/or utilities to better understand and accelerate the interconnection approval process for planned/installed DER systems, so that DER projects can deliver clean energy to customers as soon as possible. Accelerating the interconnection process also includes a clearer understanding and evaluation of the process of siting the location of a DER installation. The goals could be achieved by enhancing existing Hosting Capacity maps through standardization, the addition of interconnection approval time and interconnection cost information, and corresponding forecast of hosting capacity updates.

Use Case	Description
Efficient and Effective Access to Existing Customer Billing Data	Current access to bill data is problematic as the only way to access bill image PDFs is through a customer online account where separate actions are required for each customer account at the time of the authorization request. Ideally, customer consent can be granted both in advance and at the moment of the request, and it should be possible to grant access via mobile phone. This use case would help improve the timeliness of bill payment, reduce late fees, and verify customer savings.
Access to Basic Rate Data and Tariff Book for Individual Rate Find and Filter Rate Options Across NYS IOUs	This epic is comprised of features that enable those estimating energy customer bills to access the data they need to do so more easily and precisely than they are currently able to. 1. Make rate parameters that change slowly available in structured format: Rate periods, Holidays, Seasons, minimum and other fixed charges, and baseline allowances (aka tiered block rates). 2. Facilitate easier navigation to the section of the tariff book where rate parameters for a given rate can be found, which includes easier navigation to both the most recent version of the tariff book itself and historical versions of the tariff book.

NYSERDA's IEDR Project Phase 2 status, and updates about upcoming releases of the IEDR and new functionality, improvements to existing functionality, or bug fixes that will be available soon on the IEDR platform is on NYSERDA's website available at <https://iedr.ideas.aha.io/sections/7216419530855529789>.

The NYSERDA IEDR Program, which is fully detailed on the NYSERDA website, available at <https://www.nyserda.ny.gov/All-Programs/Integrated-Energy-Data-Resource-Program>, contains a section titled Program Participants which elaborates further on the involvement of stakeholders, other providers of energy data, and the IEDR Program Team.

Stakeholder engagement and their involvement in the IEDR Use Cases development and prioritization that values the greatest value to New York residents as the state achieves its climate goals is available on the NYSERDA website at <https://www.nyserda.ny.gov/All-Programs/Integrated-Energy-Data-Resource-Program/Use-Case-Development>.

3. Provide the web link to NYSERDA's IEDR home page along with a summary of the information provided therein.

A link to NYSERDA's IEDR dashboard can be found at <https://www.nyserda.ny.gov/All-Programs/Integrated-Energy-Data-Resource-Program/Program-Milestones> which includes information on the milestones schedule, use case development, meetings, program participants, and other IEDR resources such as NYSERDA's quarterly reports.

4. Describe the utility's role in supporting IEDR design, implementation, and operation.

National Grid continues to support the IEDR platform customer, network, and rate plan specific data requirements with scheduled data file transfers on a daily, monthly and as needed basis.

The Joint Utilities continue to facilitate ongoing coordination with NYSERDA and DPS Staff by attending the UCG bi-weekly meetings and additional workshops as required. Topics discussed during UCG meetings include:

- Utility to IEDR data transfer methodology
- Customer consent considerations and the impact of policy and statutory requirements on the IEDR Platform, including but not limited to indemnity and liability issues, state legislation indicating opt-in approaches may be required, federal legislation on data sharing requirements, and other regulatory requirements governing privacy policies and data sharing responsibilities
- Consistency of data element nomenclature and harmonization across all utilities
- Consistency of file name nomenclature across all utilities
- Data Quality Reporting
- Sensitivity of certain requested data elements
- Green Button Connect / Single Sign On
- Unified Network Model
- Utility involvement within the Use Case Discovery and Development Process
- Utility rate plan data table samples to support IEDR Development Team rate plan schema development
- IEDR Development Team milestones and Utility Engagement Roadmaps to support these milestones

National Grid, as an IEDR Tier 2 Advisory Group Member, participates as requested in the Use Case Discovery and Development Process, to provide utility specific insights for consideration by the IEDR Development Team.

5. Describe the utility's progress, plans, and investments for generating and delivering its system and customer data to the IEDR.

In line with National Grid's "One System, One Model" data, the Company and its affiliates are investing in data management tools to enable a wide variety of data use cases for grid modernization and electric business needs. This will also be used to support data sourcing and compilation requirements for IEDR. This is currently being referred to as the Data Management Platform (electric) and DataHub Platform (gas). In the future, these two platforms will be combined into a single National Grid platform named Grid Lake. The work to deploy the current platform is included in the creation of a cloud-based data platform, the use of data cataloging and quality tools, and additional capture of metadata across a variety of the business processes and use cases of the Company and its affiliates. This approach will be used to more efficiently, consistently, and effectively source data across processes and systems to enable more meaningful, data-driven decision making. Future work phases will build out the Grid Lake platform and will include any remaining key datasets. The Grid Lake platform will reduce the effort and cost to source and

integrate data for several other related efforts. These include ADMS, Telecom Operations Management, and digital projects such as FutureNow and On My Way. The data management capabilities of the Company and its affiliates will be enhanced through these additional tools that enable easier data integration and master data management.

6. Identify and characterize each type of data to be delivered to the IEDR.

National Grid is providing electric network, gas network, customer, and rate plan information to the IEDR.

Table 5.8.3: IEDR Data and Data Type

Data	Data Items
Electric Network	Circuit Details Substation Details Substation Bus Details Substation Transformer Details Service Transformer Details Service Point Details Power quality event details Installed DER Queued DER Forecasted DER Digitized Bulk Power Market Details Digitized Distribution Network Value Details Distribution Investment Plan Details Distributed NWA Opportunity Details Metadata for Digitized Documents and Other Unstructured Data Items
Customer	Customer Details Meter Details Grid Sensor Details Registered EV Details Forecasted EV Details Installed EV Charger Details Forecasted EV Charger Details Registered Internal Combustion Engine Vehicle Details Forecasted Internal Combustion Engine Vehicle Details Existing Building Details Forecasted New Building Details Forecasted Building Modification Details
Gas Network	Service Point Details

Data	Data Items
Rate Plan	Service Classification Details Rate Plan Eligibility Limit Details Rate Plan Eligibility Criteria Details Rate Plan Period Details Rate Plan Seasons Details Rate Plan Holiday Details Rate Plan Tier Thresholds Details Rate Plan Minimum Charges Details Rate Plan Other Fixed Charges Details Rate Plan Non Time Varying Charges Details

7. Describe the resource(s) and method(s) used to deliver each type of data to the IEDR.

National Grid will be building pipelines from data platforms that will transfer data in a CSV or geodatabase (GDB) file format to the IEDR platform via secure file transfer protocol (SFTP) at the cadence requested. For example, the data required for IPV will be transferred as follows:

- Large Installed DERs: Monthly transfers of CSV file
- Large Planned DERs (Interconnection Queue): Monthly transfers of CSV file
- Consolidated Hosting Capacity Maps: Bi-annual data transfer

For example, the data required for MVP will be transferred as follows:

- DER Siting: Annual transfer of GDB files
- Hosting Capacity and DER Map Enhancements: Monthly transfers of GDB files
- Access to Basic Rate Data and Tariff Book for Individual Rate Find and Filter Rate Options Across NYS IOUs: As required transfer of CVS files

8. Describe how and when each type of data provided to the IEDR will begin, increase, and improve as IEDR implementation progresses.

As additional Phase 2 data needs are identified by the IEDR Development Team, National Grid will work to add and enhance data platforms to accommodate data to support.

National Grid initiated the transfer of Network and Hosting Capacity in Q1 of 2023 as part of the IEDR IPV, and enhanced the data provided to the IEDR platform as part of the IEDR MVP in Q1 of 2024. This data is refreshed according to the following schedule:

- Installed and Planned DER – Refreshed monthly
- Hosting Capacity (PV and ESS) – Refreshed Annually in April
- Load Capacity (EV) - Refreshed Annually in April

National Grid is working on an as needed basis with the IEDR Development Team to assist them in their data quality reporting efforts outlined within the UCG meetings and is assisting them with the assessment of a Unified Network Model that utilized the utility specific network data.

National Grid initiated the transfer of the required eleven customer data tables in Q1 2024. This data is refreshed on a daily basis. National Grid is working on an as needed basis with the IEDR Development Team to assist them in their data quality reporting efforts outline within the UCG meetings and is working with the IEDR Development Team to provide meter interval data to the IEDR platform.

National Grid initiated the transfer of Rate Plan data tables for four companies: Niagara Mohawk Electric, Niagara Mohawk Gas, The Brooklyn Union Gas Company, and KeySpan Gas East Corporation, in February 2024. The Brooklyn Union Gas Company and KeySpan Gas East Corporation data was updated in September 2024. Niagara Mohawk Electric data was updated in December 2024. The company specific rate plan data is refreshed on an as needed basis. National Grid is developing a process to automate and standardize the current manual process of identifying and updating modifications to the rate plan data. National Grid anticipates working with the IEDR Development Team during 2025 to support their anticipated update of the Rate Plan Data Transfer Specifications which will result in enhancements to the data being provided to the IEDR platform in support of use cases.

National Grid has initiated the development of a data quality reporting toolset that will provide details of the data provided to the IEDR platform and assist National Grid in evaluating questions from the IEDR Development Team's data quality reporting effort.

9. Customer Data Sharing: identify and characterize any existing and future utility efforts to share system and customer data with customers and third parties through means that are separate from the IEDR.

National Grid enabled GBC for all residential customers on March 31, 2021. Once authorized by the customer, GBC shares relevant customer data with certified third-party companies. To qualify, third-party companies must execute a Data Security Agreement (DSA) and complete the Self-Attestation Form.

As of March 05, 2025, fifty-two qualified third-party companies have registered with the Company's GBC platform. The Company also made process improvements to the website to streamline the registration process by making it possible for third parties to complete the DSA and Self-Attestation Form online instead of having to complete and submit in hard copy. The Company's GBC administrator receives an automated message prompting them to log into the system to review and approve each third party. Once approved, third-party companies will receive an email notifying them of such approval and will receive access to customers' energy data.

The Company is actively expanding GBC to National Grid gas affiliates in downstate New York as well as its Massachusetts affiliate, pending rate case approvals. The Company's website has also been updated to display all authorized third parties and their contact information. A link to the website and a list of registered and authorized third-party companies is *available at* <https://www.nationalgridus.com/Upstate-NY-Home/More-Efficiency-Solutions/green-button-connect>.

The Company will continue to provide input to IEDR use cases that target customer data to ensure all existing data sharing functionality provided by GBC is retained.

5.9 Hosting Capacity

The following responds to DPS Staff's request to provide additional details which are specific to hosting capacity.¹⁴⁶

1. Describe the utility's current efforts to plan, implement and manage projects related to hosting capacity. Information provided should include:

- a. detailed description of each project, existing and planned, with an explanation of how the project fits into the utility's long range hosting capacity plans;**

In Stage 1 several parameters such as voltage class, feeder load level, station transformer fusing, level of existing connected DG, and station 3V0 were assessed and results were presented in a red zone map. This was a simple approach to conducting a HCA but provided solid foundations for the future stages described below. In Stage 2 analyses were carried out on a full feeder-level for all voltage classes, and a maximum and a minimum hosting capacity value were provided for each feeder analyzed. Each circuit's hosting capacity was determined by evaluating what level of solar PV interconnection would lead to planning criteria violations. The analysis was performed by adding PV systems with an AC nameplate rating starting at 300 kW and gradually increasing installations on the three-phase distribution lines until the hosting capacity limit was determined.

Stage 2.1 provided an additional substation level data element that included information on the substation bank which the selected feeder is tied to. Stage 3 evaluations provided sub-feeder level hosting capacity incorporating existing installed DER (all technologies and sizes) into the modeling as well as upstream station constraints such as 3V0 and transformer bank loading.

The Stage 3.1 release displayed additional data in the pop-ups. These pop-ups items included substation thermal ratings, 3V0 thresholds, and feeder notes. Stage 3.5 involved the development of capacity maps for both EV and ESS, each of which have their own tab on National Grid's System Data Portal. Stage 4 and 4.1 involved adding additional granularity to the solar PV and ESS Hosting Capacity maps which was achieved by expanding the previously provided sub-feeder level hosting capacity results with nodal results unique to each three-phase line segment. To further expand the granularity of data provided on the maps, each three-phase line includes hosting capacity values per evaluation criterion considered when performing HCA such as over-voltage, under-voltage, voltage deviation, thermal, anti-islanding, etc.

Stage 5 is expected to expand upon the recent improvements to data granularity by adding hosting capacity data with respect to different operational scenarios in addition to incorporating further stakeholder input. Scenarios are yet to be fully determined but it will be defined while incorporating stakeholder inputs and the status of DER at that time.

¹⁴⁶ DSIP Proceeding, *supra* note 11, pp. 23-25.

b. the original project schedule

Stage 3 from the original schedule was replaced with Stage 2.1. The original scope of Stage 3 was altered, and the completion date was changed and completed on October 1, 2019 with Stage 3.1 released on April 1, 2020. Stage 3.5, which included the release of both the EV and ESS maps, was released over the course of one and a half years with the EV map added in late 2020 and the ESS map added in April 2022. The scope of Stage 4 was altered to focus on data granularity improvements including unique nodal hosting capacity values specific to each evaluation criterion and was deployed to the Company's System Data Portal by April 2023. The EV map has since evolved into a general electrification map with plans for expansion of additional line voltage data by April 2025.

c. the current project status

As described previously, National Grid is currently working on developing a roadmap for Stage 5.0+ releases and is focusing efforts on further increasing the refresh rate of the analysis and inclusion of additional hosting capacity values with respect to different operational scenarios as described in the Hosting Capacity section of this 2025 DSIP Update.

d. lessons learned to-date

The Joint Utilities established a common method for performing HCA using the EPRI DRIVE tool. EPRI assisted the Joint Utilities in developing several assumptions and criteria that provided the framework for the HCA. In order to deliver accurate information on the System Data Portal, the distribution feeder level data was first verified and corrected before using the EPRI DRIVE tool. Much of the work and projects associated with hosting capacity to date have focused on data, modeling, and analysis required to perform the actual HCA. Due to the large scale of the hosting capacity initiative and the need for accurate data, this was recognized as a valuable opportunity to identify specific areas where overall data clean-up was most needed. During the feeder level verification, National Grid kept records of all data errors that were encountered and has begun to implement solutions for correcting this data moving forward. The quality of the data used for individual feeder models proved to be the biggest challenge in completing the Stage 3+ HCA. The volume of data quality issues and the time required to correct them required a better solution for an efficient refresh process and for future stages. To address this, National Grid was able to successfully automate several functions that were used to identify, record, and correct data errors which largely eliminated the most time-consuming portion of the hosting capacity procedure.

e. project adjustments and improvement opportunities identified to-date; and

Please see the Company's response in item d above.

f. next steps with clear timelines and deliverables.

Please refer to the Future Implementation and Planning section in section 2.9 Hosting Capacity of this 2025 DSIP Update.

2. Describe where and how DER developers/operators and other third parties can currently access the utility's hosting capacity information

All hosting capacity information that is available to third parties is available on the National Grid System Data Portal.

3. Describe how and when the existing hosting capacity assessment information provided to DER developers/operators and other third parties will increase and improve as work progresses. This should include discussion of the transition of hosting capacity information access from the utility's current hosting capacity information portal to the statewide hosting capacity solution in development on the IEDR.

All hosting capacity information that is available to third parties, and data that will be made available as part of future enhancements outlined in the HCA roadmap, is available and will continue to be available on the National Grid System Data Portal. However, efforts to develop the statewide IEDR platform, a centralized statewide hosting capacity solution, is ongoing with National Grid collaborating with all stakeholders including the Joint Utilities, NYSERDA, and the IEDR Development Team to ensure hosting capacity data is effectively transferred and displayed in the IEDR platform. Additional details regarding the IEDR effort can be found in the Data Sharing section of the 2025 DSIP Update. HCA data on the Company's System Data Portal will be fully updated on a yearly basis, whereas feeders with a change in connected DG greater than 500 kW since the last HCA refresh will be updated every six months, and DG in queue and connected information will be updated monthly. The next full update will occur by April 1, 2025.

4. Describe the means and methods used for determining the hosting capacity currently available at each location in the distribution system.

National grid uses CYMDIST distribution power flow software to develop feeder models and the DRIVE software tool by EPRI to evaluate each radial distribution feeder's ability to host DERs without causing adverse impacts to the distribution system. More details on the means and methods used for determining the hosting capacity are provided in the Current Progress of the Hosting Capacity section of this 2025 DSIP Update.

5. Describe the means and methods used for forecasting the future hosting capacity available at each location in the distribution system.

Although forecasted hosting capacity was identified as a very important future enhancement, the Joint Utilities are in preliminary discussions on methods and approaches to provide forecasted hosting capacity as it is a complex topic and requires the development of new processes and likely software changes/additions.

6. Describe how and when the future hosting capacity forecast information provided to DER developers/operators and other third parties will begin, increase, and improve as work progresses.

As described in the prior answer, the Joint Utilities will be determining the timeline for this item as part of a longer-term roadmap in 2025.

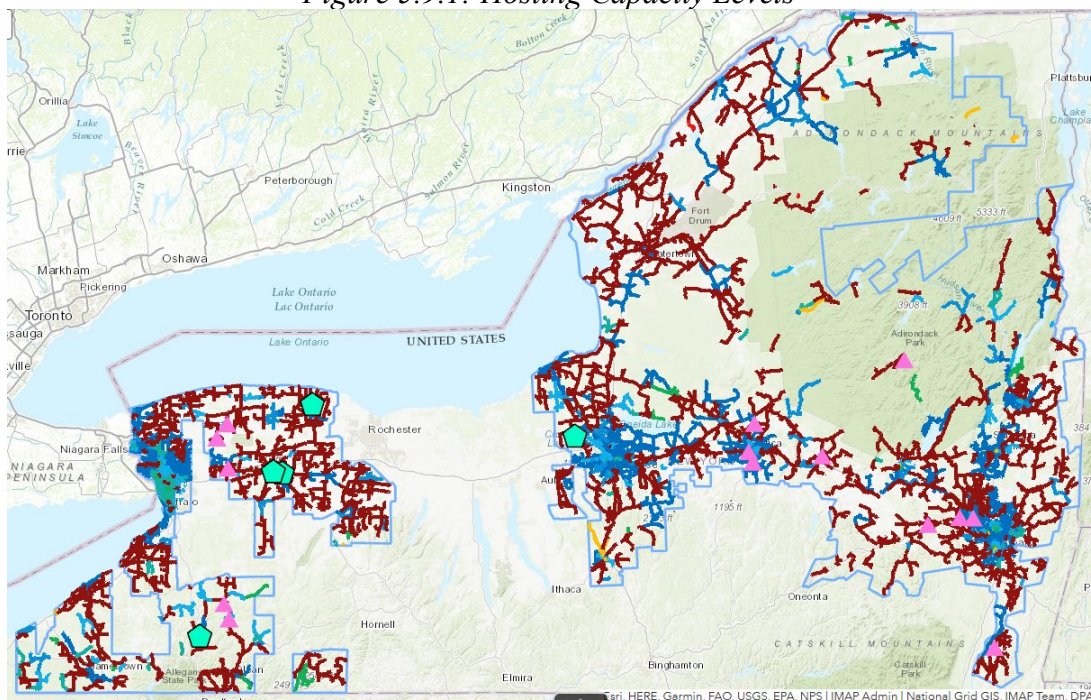
7. Summarize the utility's specific objectives and methods for:

- a. identifying and characterizing locations in the utility's service area where limited hosting capacity is a barrier to productive DER development, directing users to the CGPP filing for further information; and**

Hosting capacity levels can be identified for each National Grid feeder on the System Data Portal. In addition, data showing DG connected and DG in queue is provided to help DER developers identify the remaining hosting capacity on each feeder. Figure 5.9.1 below provides a geographic overview of the relative hosting capacity across the Company's service territory. The areas shown in blue have higher hosting capacity and non-blue colors show lower values of hosting capacity. Typically, the major limitations to hosting capacity are:

- Voltage class (i.e., 5 kV that represents approximately 50 percent of National Grid's feeders)
- The amount of DER already connected
- Distribution system equipment limitations such as thermal constraints, recloser settings, voltage regulation capabilities, fixed shunt capacitor banks, and protection challenges

Figure 5.9.1: Hosting Capacity Levels



b. timely increasing hosting capacity to enable productive DER development at those locations, directing users to the IEDR platform when applicable for more information.

National Grid has progressed pilots and programs to increase hosting capacity in regions with insufficient hosting capacity to support projected DG, with an associated cost sharing methodology to reduce barrier to entry for DER developers, as described in more detail in the DER Interconnections section of this 2025 DSIP Update. The section also includes the Company's future program expansion plans. As discussed in the Hosting Capacity section, Cost-Sharing 2.0 projects are displayed on the Hosting Capacity maps for improved transparency.

In addition, National Grid has modified distribution and substation design standards for new equipment installation that will indirectly increase hosting capacity. Similarly, where the Company has plans to either replace assets such as transformer banks or conductors, make voltage class upgrades, or undertake other asset replacements for normal system improvement reasons, hosting capacity will likely, yet indirectly, be increased.

5.10 Billing and Compensation

The following responds to DPS Staff's request to provide additional details which are specific to billing and compensation.¹⁴⁷

- 1. Describe the various DER-related billing and compensation programs (including demand response) implemented or revised by the utility since the last update. For this first inclusion in the DSIP, describe developments that have occurred since the beginning of NEM, RNM, CDG, and VDER.**

The Company has implemented and automated numerous DER-related programs since NEM began in 2015. Grandfathered NEM and other pre-VDER programs have been automated in the CSS system for some time. The most recent effort programs to be implemented are the Statewide Solar for All (S-SFA) and the REACH. Along with offering multiple discount rates starting in June 2025.

- 2. Describe the customer billing/compensation functions and data generally needed to expand deployment and use of DERs in the utility's service area. Include descriptions of the existing and planned components (processes, resources, and data exchanges) that will support those needs. For planned components, provide the sequence and timing of key investments and activities required for component implementation.**

National Grid has implemented an automated process to more efficiently verify and apply allocation lists from CDG hosts in the billing system. The Company is investigating other automated processes that could apply to DG billing.

- 3. Describe the customer billing/compensation functions and data needed to enable DER participation in the NYISO's wholesale markets for energy, capacity, and ancillary services. This should include information regarding the utility's implementation of its Wholesale Distribution Services (WDS), Wholesale Value Stack (WVS), and related non-wholesale value stack (VDER without whole energy and capacity components). Also include descriptions of the existing and planned components (processes, resources, and data exchanges) that will support those needs. For planned components, provide the sequence and timing of key investments and activities requires for component implementation.**

FERC 222 Aggregation

Customer data needed to make appropriate billing changes under FERC 2222 wholesale market aggregations will include the following:

- **Facility location (address)**
- **Customer billing account number**
- **Current compensation tariffs/program participation**

¹⁴⁷ DSIP Proceeding, *supra* note 11, pp. 25-27.

- **Meter Number**
- **Interconnection ID for (DG projects only)**
- **System owner name and contact information DER system capacity (size)**
- **Distribution System Infrastructure information**

The Company will receive this information via encrypted electronic transfer on Box.com from the NYISO. DER system owners will share DER system information with DER Aggregators, who will compile all necessary information and share it with the NYISO.

Changes to customer billing accounts will leverage an existing process of account setup to ensure continuity of compensation for the DER system owners.

Billing and compensation changes for retail customers who opt to participate in the wholesale market through a DER Aggregation will be managed to avoid duplicative compensation. Rather, each retail customer participating in a wholesale aggregation will need to participate in an appropriate retail tariff that allows for dual participation in both the wholesale and retail markets. Dual compensation will be allowed, where retail customers can be compensated partially through a retail program, and for one or more ancillary services.

There are currently six ancillary services markets but DERs can only participate in two – regulation market and reserves market. Under FERC 2222, a DER aggregation may receive compensation for their participation in any/all the NYISO markets including energy, capacity, and ancillary services. Participation in some of the markets may require customers to dual-participate in other markets. For instance, a market participant that clears a capacity commitment in the capacity market may be required to bid into the energy market. However, the actual settlements that customer would receive would be separately administered based on the market services that participant provided to each of the respective markets.

At the time an application for a new wholesale aggregation is received, National Grid will review each customer account to identify current retail compensation, or the compensation a customer receives before participating in wholesale markets. Depending on the retail tariff a customer is operating under, the need for partial or complete unenrollment will be identified and executed by the Company.

For example, if an individual DER customer is enrolled in VDER Value Stack and is compensated for both the energy and capacity of their system, they must forfeit compensation for at least one of those to participate in the wholesale market. The customer will be moved from the VDER Value Stack tariff to the Wholesale Value Stack tariff. Under the Wholesale Value Stack tariff the DER customer will continue to receive compensation for most of the Value Stack components except for the energy or capacity components as they may be compensated for those by the NYISO. For instance, a DER customer may sell either energy, capacity or both to the NYISO in accordance with the NYISO tariffs. The Wholesale Value Stack tariff will prevent these customers from being compensated twice for the same thing.

An alternative scenario would be a DER customer who is compensated for their energy generation under the NEM program, where compensation is not broken out into value streams. In these cases,

a NEM customer would be completely unenrolled from the NEM tariff, and their billing account would include only wholesale compensation mechanisms.

The Company, similar to the other NY electric utilities, plans to file with FERC a Wholesale Distribution Tariff. FERC Order 841 does not allow retail rates to apply to an energy storage system's charging when it is used for the purpose of participation in the NYISO wholesale market. Once the Wholesale Distribution Service tariff is approved, this will allow the Company to charge stand-alone energy storage systems participating in the NYISO markets for the energy provided for the systems charging. The Wholesale Distribution Service tariff will also propose rates for the use of the distribution system to deliver the system's energy to the NYISO (i.e., buyback rates). The Wholesale Distribution Service tariffs are expected to be filed with FERC during the summer of 2023.

4. Describe the utility's plans to implement or modify DER-related billing and compensation capabilities, including automation, to address the Community Distributed Generation (CDG) billing and crediting problems that were the focus of the Commission's September 15, 2022, Order in Cases 19-M-0463. et. al.

See Future Planning and Implementation section under Section 2.10, Billing and Compensation, of this 2025 DSIP Update.

5. For each type of DER billing and compensation, including for CDG and wholesale market participation, describe the current information system constraints preventing full automation of DER billing and compensation.

While the billing system is programmed to automatically calculate credits due and customer bills, parts of managing billing processes will remain manual as they require trained staff expertise.

Expanded Solar for All, Statewide Solar for All, and Renewable Energy Access and Community Help

In these programs, the host is manually billed but allocation of the credit pool to eligible customers is automated. Automation of the host billing and allocation tracking process is tentatively planned for next year.

Wholesale VDER

As of the Wholesale VDER market start date, projects will be manually billed. Automation will be considered if the program expands.

Multiple Discount Rate- For Multiple Discount Rates there will be a manual process until updates in the billing system can be made and then it will become automated.

6. Describe how DER billing and compensation affects other programs such as budget billing, time of use rates, and consolidated billing for Energy Service Companies (ESCOs).

Table 5.10.1: DER Billing and Compensation Effects on Other Programs

Program	Budget Billing	Time-of-Use rates	Energy Service Companies
Monetary (non-CDG) NEM	The amount due on bill will be the budget amount minus the monetary credit transfer. The monthly budget amount is not impacted by the credit and the credit will not change the budget amount.	Time-of-Use customers are billed for their time-of-use periods and the credit is calculated and applied to each period's charges.	No impact. Energy Service Company supply charges are billed as normal, and the credit is applied afterwards.
Volumetric / Phase 1 NEM	The amount due on the bill would be just the budget amount. The credit calculated by the transferred kWh would reduce the supply and delivery bill charges and be reflected in the budget billing 'accumulated actual charges.' The monthly budget amount is impacted by the transfer and would auto-recalculate in three months.	Time-of-Use customers are billed for their time-of-use periods and the credit is calculated and applied to each period's charges.	No impact. Energy Service Company supply charges are billed as normal, and the credit is applied afterwards.
Value Stack	The amount due on the bill will be the budget amount minus the VDER credit. The monthly budget amount is not impacted by the VDER credit.	Time-of-Use customers are billed for their time-of-use periods and the credit is calculated and applied to each period's charges applied afterwards.	No impact. Energy Service Company supply charges are billed as normal, and the credit is applied afterwards.

7. Describe the utility's means and methods – existing and planned-for monitoring and testing new or modified customer billing and compensation functions.

National Grid implements billing requirements as directed by Commission orders. Tariff leaves and implementation plans are typically filed in response to these orders. Once all the program requirements are known, IT requirements are scoped including timeline and budget. Once an IT billing project reaches its turn in the IT billing queue, code is developed and rigorously tested to ensure that there are no adverse impacts by the new code on any other utility billing functions. Once the testing is verified, the code is pushed into the billing system. Accounts are monitored by the customer billing team for the first several bill cycles after new programming is applied to ensure their accuracy.

8. Describe the utility's means and methods – existing and planned – for supporting customer outreach and education, including where and how customers, DER developers/operators and other third parties can readily access information on the utility's billing and compensation procedures.

The Solar Hub will serve both end-use customers who have DG systems or develop commercial projects as well as those customers who wish to participate as CDG satellites.

National Grid encourages CDG hosts to utilize the MyBusiness Account portal.

9. Describe the utility's means and methods – existing and planned- for receiving, investigating, and monitoring customer complaints and/or inquiries regarding billing and compensation issues related to DERs.

Inquiries received through the interconnection portal can be escalated internally to the appropriate Company managers and National Grid's DG Ombudsperson. In addition, Commission complaints that are transferred to the Company through the Office of the President are tracked and monitored to ensure responses within mandated timelines.

5.11 DER Interconnections

The following responds to DPS Staff's request to provide additional details specific to DER interconnections.¹⁴⁸

Implementing the utility resources and capabilities that enable DER interconnections to the distribution system is a critical early objective. Many of the details which identify and characterize those resources and capabilities are being worked out by the ITWG and the IPWG, which are stakeholder collaboratives led jointly by DPS Staff and NYSERDA. The goal of both working groups is to establish the requirements for standard resources, processes, specifications, and policies which foster efficient, timely, safe, and reliable DER interconnections. Along with satisfying the general guidelines for information related to each topic (see Section 3.1), DPS Staff recommend that the DSIP Update should provide the following additional details, which are specific to DER interconnections:

1. Describe in detail (including the web URL) the web portal that provides efficient and timely support for DER developers' interconnection applications.

Web Portal is *available at* <https://gridforce.my.site.com/s/homepage>

This is a Salesforce-based web platform that National Grid has customized to enable customers to submit interconnection applications. For customers that have logged in and already submitted (or started drafting application materials) there is a chatter feature on each case that allows users to directly contact the National Grid case owner to exchange messages. Aside from the chatter feature, National Grid also has a "Contact Us" form on the home page of the Company's portal that can be used by anyone (logged in or not) to submit ad hoc requests that are not related to a specific case or for requests that occur either before or after the interconnection process.

National Grid's publicly available customer application portal (<https://ngus.force.com/s/ny-home>), nCAP, is an online application portal to facilitate electronic submission of applications and associated payments. The portal provides the applicant with a more streamlined experience.

Customers are able to check project status, meter set dates, and estimated completion dates, sign documents electronically, and request changes to existing interconnection applications online. The Company has further enhanced nCAP to automate certain technical screens to further expedite the interconnection process.

2. Describe where, how, and when the utility will implement and maintain a resource where DER developers and other stakeholders with appropriate access controls can readily access, navigate, view, sort, filter, and download up-to-date information about all DER interconnections in the utility's system. The resource should provide the following information for each DER interconnection:

¹⁴⁸ DSIP Proceeding, *supra* note 11, pp. 27-28.

a. DER type, size, and location;

National Grid's customer application portal, nCAP, tracks the DER type, size, and location for each application. The interconnection queue with this information is available on the DPS public website.¹⁴⁹ The queue can also be found on the nCAP website where the size of the generation and interconnection feeder is identified, as well as case number, application status, opening date/time, queue date, and connected date (where applicable). ESS Information is collected through the nCAP portal which includes but is not limited to ESS size, configuration, and an operating narrative. Access to specific project information can be accessed via the nCAP portal only with appropriate login and password verification.

b. DER developer;

The interconnection queue publicly provided on the DPS website provides the company name of each DER developer in the queue. This data is available as an Excel file.

c. DER owner;

National Grid's customer application portal, nCAP, tracks the DER owner for operation of the connected DER facility; however, this data is not publicly available and is only accessed via login for the user's specific project.

d. DER operator;

National Grid's customer application portal, nCAP, tracks contact information for various customer stakeholders as shown below but does not currently track DER operator information. In case of emergencies or outages, the Company would contact the system owner and/or applicant.

For large, complex DER interconnections, contact information and switching procedures are established with National Grid's control centers.

Figure 5.11.1: Customer Stakeholder Tracking in National Grid's nCAP

▼ Application Role Information	
Primary Developer	Primary Developer Email
Primary Contractor	Primary Contractor Email
Application Owner	Application Owner Email
System Owner	System Owner Email
Land Owner	Land Owner Email
Agent Name	Billing Customer Email
Municipal Inspector Name	Municipal Inspector Email
Customer Engineer	

e. the connected substation, circuit, phase, and tap;

National Grid's customer application portal, nCAP, tracks DER by circuit, substation transformer, and substation. It identifies if an application is single phase or three phase, but it does not track which phase or tap it is connected to. The substation and feeder circuit are publicly available on the DPS website interconnection queue.

¹⁴⁹ Available at <https://dps.ny.gov/distributed-generation-information>

f. the DER's remote monitoring, measurement, and control capabilities;

National Grid's ESB 756 Appendix B specifies the DER customer's requirements for M&C in accordance with the NY-SIR, which may be amended periodically. Those DER facilities with M&C are integrated into National Grid's EMS to enable the Company's distribution system operators to remotely trip the generation, or DER facility, from the Company's EPS if necessary to maintain reliability.

g. the DER's primary and secondary (where applicable) purposes;

National Grid's customer application portal, nCAP, does not track the applicant's intended purpose for their DER operation or whether the application has a primary or secondary purpose.

h. the DER's current interconnection status (operational, construction in-progress, construction scheduled, or interconnection requested) and its actual/planned in-service date.

National Grid's customer application portal, nCAP, tracks the DER facility's interconnection status for interconnection requested, planned, and actual in-service dates, construction scheduled, construction in-progress, and operational dates on each application. The date of DER application, final letter of acceptance, and project completed status are all publicly available on the DPS website interconnection queue.

5.12 Advanced Metering Infrastructure

Advanced Metering Infrastructure (AMI) provides grid-edge measurement, data acquisition, and control capabilities which are either essential or beneficial to a number of important functions in a modern distribution system. Granular time-series data from smart meters and other intelligent devices at customers' premises enables advanced analyses, innovative rate designs, and customer engagement strategies which benefit both the customers and the grid. Voltage sensing and measurement functions support increased system efficiency and enable improved outage detection and restoration processes. Capabilities supporting DER measurement, monitoring, and control are essential for DER integration.

Along with satisfying the general guidelines for information related to each topic (see Section CASE 16-M-0411 -29-3.1), DPS Staff recommends that the DSIP Update should provide the following additional details which are specific to AMI:

- 1. Provide a summary of the most up-to-date AMI implementation plans, including where AMI has been deployed to date.**

See Section 2.12, Advanced Metering Infrastructure – Current Progress.

- 2. Provide a summary of all new capabilities that AMI has enabled to date, and how these capabilities benefit customers, including, as applicable, customer engagement, energy efficiency, and innovative rates.**

See Section 2.12, Advanced Metering Infrastructure – Current Progress.

- 3. Describe the AMI-acquired data and information that is planned to be available through the IEDR.**

The Company is assessing the capabilities and frequency to provide raw and verified metered interval data to the IEDR platform resulting from the transition to AMI smart meters. National Grid will have electric meter read intervals every fifteen minutes and gas readings up to every forty-five minutes. Below is a list of billing data information that National Grid will begin to collect and possibly share with the IEDR.

Table 5.12.1: National Grid Billing Data for IEDR

Read Date & Days	Late Payment Charges	Billed On-Peak kW
Read Type	Total Charges	Time-of-Use On-Peak kWh (as applicable to specific rate design)
Total kWh	Metered Peak kW	Time-of-Use Off-Peak kWh (as applicable to specific rate design)
Delivery Charges	Metered On-Peak kW	RkVA – reactive kVA – Three Phase Load Factor
Supply Charges	Billed Peak kW	Load Factor

- 4. Describe where and how DER developers, customers, and other stakeholders can access up-to-date information about the locations and capabilities of existing and planned smart meters.**

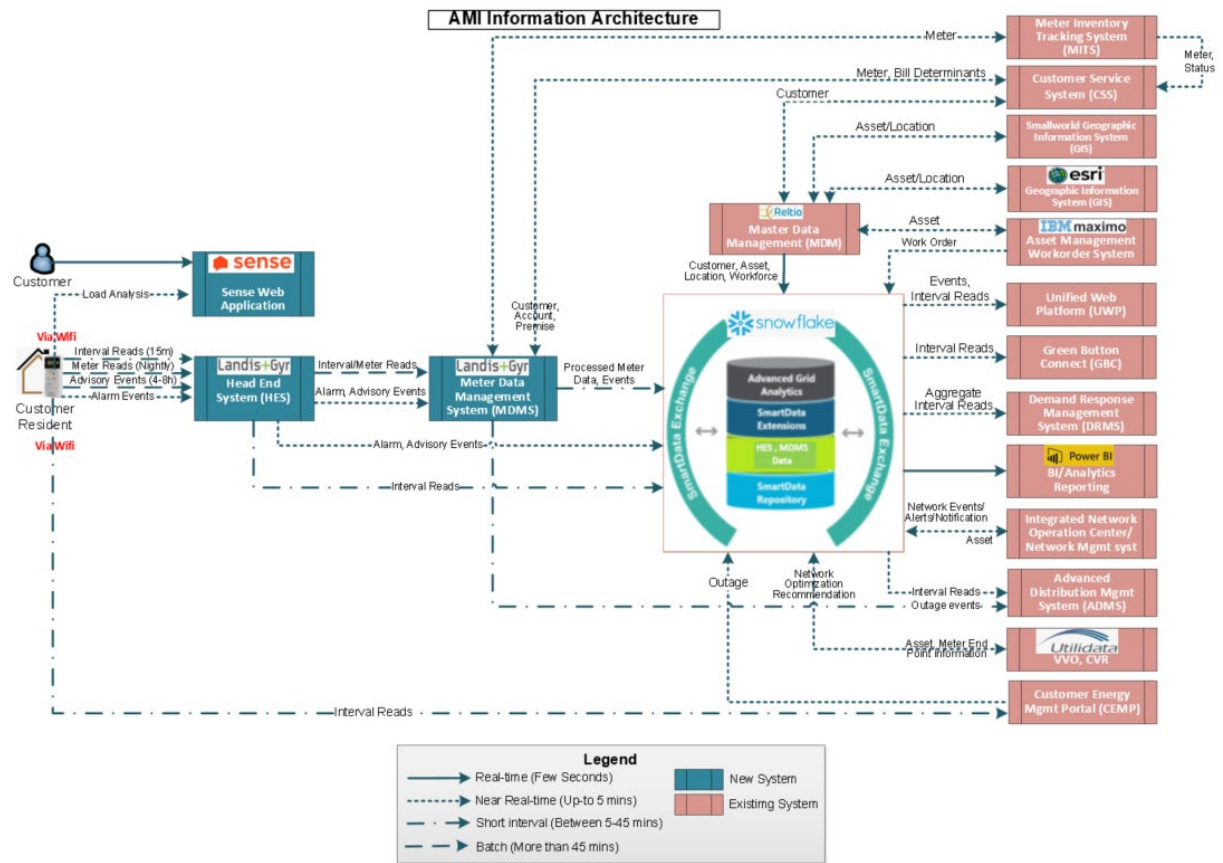
Once smart meters are deployed, National Grid will make it known which areas and customers have been installed on its website as it currently does today with DER deployments. This will also be uploaded into the IEDR once it is made available. As new customers come online with smart meters, the Company will actively market and inform them of the new services that their meters can provide and let them understand the benefits of them.

- 5. Provide a summary of plans and timelines for future expansion and/or enhancement of AMI functions.**

See Section 2.12, Advanced Metering Infrastructure, of this 2025 DSIP Update, for current progress.

- 6. Describe where and how each type of AMI-acquired data is stored, managed, and shared with, and used by other utility information systems such as those used for billing/compensation, customer service, work management, asset management, grid planning, and grid operations.**

Figure 5.12.1: AMI Information Architecture



5.13 Beneficial Locations for DERs and Non-Wires Alternatives

The following responds to DPS Staff's request for additional details specific to National Grid's resources and capabilities in supporting the identification and presentment of beneficial locations for DERs and NWAs.¹⁵⁰

1. Describe where and how developers and other stakeholders can access resources for:

- a. accessing up-to-date information about beneficial locations for DERs and/or energy efficiency measures; and
- b. efficiently sorting and filtering locations by the type(s) of capability needed, the timing and amount of each needed capability, the type(s) and value of desired benefit, the serving substation, the circuit, and the geographic area.

The primary resource National Grid uses to share up-to-date information about beneficial locations is the Company's System Data Portal which maintains "tabs" specific to NWA opportunities, LSRV areas, and HCA. The information is presented on interactive geographic maps when suitable and tabular information is provided in pop-up windows. The ability to query, filter, and sort is available for some information, and the Company is working to expand that capability for additional datasets. National Grid's NWA information can be found on the following websites:

- National Grid: <https://www.nationalgridus.com/Business-Partners/Non-Wires-Alternatives/>
- System data portal:
- Joint Utilities: <http://jointutilitiesofny.org/utility-specific-pages/nwa-opportunities>
- REV Connect: <https://nyrevconnect.com/non-wires-alternatives/>
- Piclo Flex: <http://usa.picloflex.com/>
- National Grid aims to use the Piclo Flex platform through 2026 to release NWA RFPs. Piclo Flex platform currently replaces Ariba for certain NWA procurements where National Grid is exploring a more open market-based model as part of the Company's DSO transition plan. In the future, National Grid may utilize a different market platform to procure services from DER, Aggregators and Energy Efficiency.

Historically, pre-qualified vendors are sent NWA opportunity notifications via Ariba, National Grid's procurement system. At any time interested vendors may contact:

- Non-wiresAlternativesSolutions@nationalgrid.com

2. Describe the means and methods for identifying and evaluating locations in the distribution system where:

- a. an NWA comprising one or more DERs and/or energy efficiency measures could timely reduce, delay, or eliminate the need for upgrading distribution infrastructure and/or materially benefit distribution system reliability, efficiency,

¹⁵⁰ DSIP Proceeding, supra note 11, pp. 14-15.

and/or operations; and/or

- b. one or more DERs and/or energy efficiency measures including increased value-based customer incentives could reduce, delay, or eliminate the need for upgrading bulk electric system resources and/or materially benefit bulk electric system reliability, efficiency, and/or operations.**

National Grid will determine future constraints and needs of the transmission, sub-Transmission and distribution systems to maintain safe and reliable service to customers. With growing levels of DER deployment, the method in which DER impacts are analyzed and incorporated by National Grid's Planning groups into the Company's integrated planning process and studies continue to evolve such as through its integrated T&D assessment. Planning assessments developing traditional infrastructure enhancement solutions, and appropriately applying the suitability criteria, all contribute to accurately and comprehensively identifying those traditional utility projects that may be deferred through utility DER programs and procurements such as NWA opportunities. EE programs generally provide system-wide benefits and are not usually geographically targeted. However, targeted EE initiatives are being explored in NWA locations in an effort to develop least cost NWA solutions. National Grid has worked to optimize the locational offerings between NWA procurements and any applicable DR and EE programs, including the new Term, Auto DLM, and EE programs which require coordination on locational offerings. In addition, a kicker was introduced within the EE portfolio which is focused on an NWA location for peak reduction benefits. The Company is in the process of evaluating this offering for additional opportunities.

The Company is also considering how DER can be utilized to provide a partial solution to complement a traditional utility project (i.e. hybrid) to address an overall system need. Additionally, National Grid's Planning groups document the amount and location of load relief needed to mitigate system capacity or reliability needs where appropriate.

3. Describe how the NWA procurement process works within utility time constraints while enabling DER developers to properly prepare and propose NWA solutions which can be implemented in time to serve the system need. Details should include:

- a. how utility and DER developer time and expense are minimized for each procurement transaction;**
- b. how standardized contracts and procurement methods are used across the utilities.**

The Company has developed a detailed NWA implementation process to maximize the efficiency of the procurement and implementation through operation of the NWA solution. This process clearly defines responsible, accountable, consulting, and informed parties for each step, allowing for quick turnaround and minimized costs. National Grid has taken a number of steps to minimize DER providers' time and expenses as described in more detail in the prior Current Progress and Risk and Mitigation sections.

Emerging system needs are identified as early as possible. This allows for comprehensive consideration of the NWA and wires solutions as part of the electric distribution system planning process.

- System Needs Identified: The need is identified as a result of studies, operational issues, process safety issues, occupational safety issues, regulatory requirements, and/or customer requests. Planning teams develop a Needs Case, fully justifying the system need(s) and concerns of the study area.
- NWA Screening Criteria: Where a system need has been identified, Planning performs an initial screening for NWA, considering the criteria listed in previously. Projects not meeting the criteria continue with wires or traditional solutions.
- Request for Proposals: RFPs are developed and issued through our procurement platform as previously mentioned.
- Starting in 2023, National Grid has begun an effort to more simply broadcast service window and technical requirements within long form RFP documentation and on usa.picloflex.com, the intent is to enable DER developers to properly model and design to meet the National Grid service requirements.
- Starting at the end of 2022 National Grid began a review and revision process of the Non-Wires Alternative Service agreement. The intent is to move to a pro-forma model of this agreement such that vendors can easily understand the performance requirements and liabilities with providing Non-Wires Services as well as minimize contract negotiations.
- Solution Delivery: Evaluation of submitted proposals are completed and if successfully pass technical viability and the BCA, an award made to the successful bidder. Projects that do not pass technical viability and the BCA continue with the wires or traditional solution.

The Company has worked with the Joint Utilities to create a more streamlined approach to procurement with DER providers with respect to contract terms and conditions of work. The Company includes sample terms and conditions in RFPs to help NWA providers secure/investigate financing options prior to proposal submittal. National Grid plans to continue developing a standardized contract and will continue to share with the Joint Utilities' best practices for issuing contracts and implementing procurement methods.

4. Describe where and how DER developers and other stakeholders can access up-to-date information about current NWA project opportunities.

National Grid's NWA information can be found on the following websites:

- National Grid: <https://www.nationalgridus.com/Business-Partners/Non-Wires-Alternatives/>
- Joint Utilities: <http://jointutilitiesofny.org/utility-specific-pages/nwa-opportunities>
- Piclo Flex: <http://usa.picloflex.com/>
- Beginning in 2023 the National Grid procurement team will be running a pilot using the Piclo Flex platform to release RFPs. The intent of the pilot is to move away from a closed RFP model to a more open market-based model as part of the company's DSO transition plan. This pilot will run through 2023 replacing Ariba. In the future, National Grid may utilize a different market platform to procure services from DER, Aggregators and Energy Efficiency.

Historically, pre-qualified vendors are sent NWA opportunity notifications via Ariba, National Grid's procurement system. At any time interested vendors may contact:

- Non-wiresAlternativesSolutions@nationalgrid.com

5. Describe how the utility considers all aspects of operational criteria and public policy goals when deciding what to procure as part of a NWA solution.

The area of need is studied internally with all required teams and SMEs.

- i. Control center inputs so requirements are set
- ii. Community atmosphere

National Grid evaluates the NWA solution bids proposed by vendors using a systematic approach which considers technical and economic factors. A BCA will be performed to determine the cost-effectiveness of NWA solutions. NWA projects must provide a safe, reliable, and cost-effective solution when compared to the wires solution.

Figure 5.13.1: Overview of Proposal Evaluation



Proposals are ranked based on their criteria scores. The number of projects which National Grid will procure is a function of the proposal price, scoring of proposals based on evaluation criteria, capability of each proposal to fully or partially address the NWA solution requirements, and National Grid's final discretion. See below for a summary of the criteria and the process by which the review team will evaluate and prioritize bids.

Table 5.13.1: Summary of Proposal Evaluation Categories

Proposal Content & Presentation	Safety
Developer Experience	Customer and Socio-Economic Impacts
Environmental	Scheduling
Project Viability	Offer Price
Functionality	Adherence to Terms
Technical Reliability	Credit

The figure below provides an excerpt from the NWA screening tool used to narrow down to the best proposals:

Figure 5.13.2: Excerpt from the NWA screening tool used to narrow down to the best proposals

4	Control, Comms & Operations	Weight, %	Rating	Weighted Score	Comments
	Local & substation level controls and communication clearly defined and feasible	30%		0.00	
	Control center operators ability to control & monitor the NWA as necessary	20%		0.00	
	Line crew, safety, maintenance & support (ability to respond to NWA technical issues)	40%		0.00	
	Coordination potential with DSP systems and concepts	10%		0.00	
	TOTAL Control, Comms & Operations	100%		0.00	

National Grid also includes performance requirements and expectations in the RFP so that developers are aware of the operational criteria needed for the NWA solution.

6. Describe where, how, and when the utility will provide DER developers and other stakeholders with a resource for accessing up-to-date information about all completed and in-progress NWA projects. The information provided for each project should:

- a. describe the location, type, size, and timing of the system need addressed by the project;
- b. provide the amount of traditional solution cost that was/will be avoided;
- c. explain how the selected NWA solution enables the savings; and
- d. describe the structure and functional characteristics of the procurement transaction between the utility and the solution provider(s)

National Grid's NWA opportunities are presented on the National Grid website and System Data Portal, Joint Utilities website, and the REV Connect Site. Pre-qualified vendors are sent NWA opportunity notifications via Ariba, National Grid's procurement system. For 2025, NWA opportunities are visible to any interested parties on usa.picloflex.com and are always visible on the NWA website. Additionally, at any time interested vendors may contact: Non-wiresAlternativesSolutions@nationalgrid.com

Identified projects that meet applicable NWA suitability criteria and are deemed technically feasible will be sourced through National Grid's procurement process. RFP development includes compiling a procurement solicitation and information that informs stakeholders/potential partners about the area and its electrical system needs. The area needs assessment will include information such as:

- size of the load relief required (in kw or MW)
- daily peak load profiles, duration of need
- mapping illustrating the area of need

- characterization of customers (how many residential and C&I customers).

In addition, performance attributes, utility costs, technology suitability, and hosting capacity may be included in the solicitation. The Commission's orders addressing anonymized aggregated data and customer data protections will guide any public solicitation which relies on the provision of customer data.

As NWA RFPs are released, closed or awarded, the Company files a publicly available report with the Commission which is posted to the DPS website and the Company website. Quarterly reports and the implementation plan can be found that highlight active project updates. BCAs are also filed for implemented and operational NWAs and would include the amount of traditional solution cost that was/will be avoided.

The structure and functional characteristics of a procurement transaction is based on the individual contract that is executed with the NWA solution provider; each contract may have individual payments terms and structures. The BCA ensures that the payments remain cost-effective.

6. Appendix C: MCOS Study



**Niagara Mohawk Power Corporation
d/b/a National Grid**

Electric Marginal Cost of Service Study

Cases 19-E-0283 and 15-E-0751

June 30, 2025

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Marginal Cost of Service Study
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Purpose

This document describes the electric Marginal Cost of Service (“MCOS”) Study prepared by Niagara Mohawk Power Corporation (“National Grid” or the “Company”), in compliance with the August 19, 2024 *Order Addressing Marginal Cost of Service Studies* of the New York State Public Service Commission (“Commission”) in Cases 19-E-0283 and 15-E-0751 (“MCOS Order”).¹

The purpose of a marginal cost of service study is to determine the incremental cost to provide an incremental megawatt (“MW”) of capacity on the Company’s distribution system. Marginal cost includes capital costs and operating costs. The costs are presented as an annual revenue requirement; that is, once the initial capital cost and the ongoing operating costs are determined, the annual revenue requirement needed to provide a return on capital and operating costs can be determined.

The MCOS Order requires that the Company determine marginal costs for each applicable substation serving area with planned capacity expansion, for each year over the next 10 years. National Grid utilized its latest 10-year, fiscal year (“FY”) 2026 to 2036,² capital investment plan. The Company’s planned capital expenditures were based on its forecasted load requirements. Transmission load forecasts are developed using New York Independent System Operator (“NYISO”) forecasts, while distribution load forecasts utilize the Company’s 10-year Electric Peak Forecast, developed annually, with the most recent forecast issued March 21, 2025. The latest peak forecast report can be found on the National Grid New York System Data Portal.³ The MCOS Order further states that the MCOS Study should use the same information as would be presented in a utility’s major rate case filing; that is, the MCOS should reflect the Company’s actual expected capital costs, operating costs, and forecasted load.

Capital Projects

To begin the MCOS Study, National Grid leveraged its latest developed capital investment plan for the period of time between FY 2026 and FY 2036. The Company excluded projects with a total cost of less than \$1M, as generally those projects do not support material system capacity expansion. Where possible, the Company identified the capacity enabled by each project or group of projects, the corresponding total cost, and the impacted system facilities (e.g., substations). This resulted in a portfolio of 440 discrete, mostly substation and line, projects. In many instances, projects need to be executed in conjunction with one another to enable any expansion of system capacity. This resulted in system capacity expansion at 153 assets (i.e., substations, transmission network). For each project or group of projects, the following was identified:

¹ Cases 19-E-0283 et al., *Proceeding on Motion of the Commission to Examine Utilities’ Marginal Cost of Service Studies*, Order Addressing Marginal Cost of Service Studies (issued August 19, 2024) (“MCOS Order”).

² FY 2026 begins on April 1, 2025 and FY 2036 ends on March 31, 2036.

³ Available at <https://systemdataportal.nationalgrid.com/NY/>

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- Substation area
- Purpose of the project (*i.e.*, spending rationale): Multi-Value Transmission (“MVT”), Multi-Value Distribution (“MVD”) or System Capacity. Please note, Multi-Value projects are performed both to increase capacity and to maintain or improve system reliability, whereas System Capacity projects are undertaken to increase capacity on the distribution system.
- Capacity Added for the substation measured in MWs.
 - Capacity Added means the demand that can be served in the substation area when all of the projects in that substation area are completed, compared to the demand that could be served if none of the work is undertaken and completed.
 - All projects that affect a substation are grouped to form the total Capacity Added MW quantity for that substation.
- Asset types affected: Transmission Station (“T-Station”), Transmission Line (“T-Line”), Distribution Station (“D-Station”) and Distribution Line (“D-Line”).
 - Transmission level are assets operating at or above 69 kilovolts (“kV”).
- Annual capital spending and total forecasted spend, shown by asset type (T-Station, T-Line, D-Station, D-Line).

The portfolio of projects included in this analysis totals \$10.7 billion and was grouped by substation, transmission network, or sub-transmission network.

Capital Cost per Capacity Added MW

For each of the 153 assets identified, the individual projects were summarized, as provided in Exhibit 1, to determine the following:

- Capacity Added for the substation area (*Exhibit 1, Column B*).
- Annual capital spending, by fiscal year, for 2026 through 2036 (*Exhibit 1, Columns C26X through C36*). The C26X column is the total spend of included projects prior to FY2026.
- Total Capital spending over the period, broken out by component: T-Station, T-Line, D-Station, D-Line (*Exhibit 1, Columns C-TS, C-TL, C-DS, C-DL and C*).

This information was used to compute capital cost per MW of Capacity Added for each component (T-Station, T-Line, D-Station, D-Line), and in total (*Exhibit 1, Columns D-TS, D-TL, D-DS, D-DL and D*). These values are equal to Total Capital spending for each component, divided by Capacity Added.

While capital spending takes place over the years the project is under construction, the Capacity Added to the distribution system is not available until the project is completed and in service. Therefore, the last year of capital spending for all projects in the substation area was determined to be the year that capacity was added (*i.e.*, in-service year) (*Exhibit 1, Column F*).

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Marginal Cost: Revenue Requirement per Capacity Added MW

For each substation, the Company multiplied i) capital cost per MW of Capacity Added by component by ii) Economic Carrying Charge Rate (“ECCR”) for that component, to determine iii) the annual revenue requirement needed to provide return on capital, return of capital, and operating costs. The annual revenue requirement for each component is shown in *Exhibit 1, Columns E-TS, E-TL, E-DS, E-DL*; the total annual revenue requirement is shown in *Exhibit 1, Column E*. This annual revenue requirement is the marginal cost to provide one additional MW of capacity.

The marginal cost determined above represents the marginal cost for the year that the project’s added capacity went into service. To determine the marginal cost over the 10-year period, the annual marginal cost was deflated annually for years prior to the in-service year or inflated annually for years after the in-service year by the inflation rate (*Exhibit 1, Columns F26 through F36*). The inflation rate reflects the current expectations about inflation from the most up-to-date BlueChip consensus forecast of the Gross Domestic Price implicit price deflator, as recommended by the Staff Whitepaper in the VDER Proceeding,⁴ and further supported by the Commission in the MCOS Order. As such, National Grid used a 2.1% inflation rate per the June 2, 2025 Blue Chip Financial Forecasts.

The Company also computed a system-wide average marginal cost per MW by year, with the results shown on *Page 28 of Exhibit 1, line 250*. This was computed as follows:

- For each fiscal year, the capacity of all projects that go into service that year was determined (*Page 28 of Exhibit 1, line 247*).
- The discount factor from that year back to FY 2026 was determined, using the annual inflation rate of 2.1% (*Page 28 of Exhibit 1, line 248*).
- Total marginal cost of capacity added in the year was determined by multiplying capacity added (*Page 28 of Exhibit 1, line 247*) by average marginal cost for the year (*Page 28 of Exhibit 1, line 245*), with the results on *Page 28 of Exhibit 1, line 249*.
- Each annual amount was discounted back to FY 2026, by dividing total marginal cost of capacity in the year (*Page 28 of Exhibit 1, line 249*) by the applicable discount factor (*Page 28 of Exhibit 1, line 248*), with the results on *Page 28 of Exhibit 1, line 250*.
- The annual amounts on *Page 28 of Exhibit 1, line 250* were summed and the sum was divided by total capacity added of 11,533 MW, to arrive at the system-wide average annual marginal cost per MW of \$71,524 (*Page 28 of Exhibit 1, line 251*). This is equal to the FY 2026 Annual Marginal Cost per MW (*Page 28 of Exhibit 1, line 245, column F26*).
- This calculation includes only substations with capital projects over the period FY 2026-FY 2036 that are included in the MCOS Study.

⁴ Case 15-E-0751, *In the Matter of the Value of Distributed Energy Resources* (VDER Proceeding), Department of Public Service Staff Whitepaper on Allocated Cost of Service Methods Used to Develop Standby and Buyback Service Rates (filed November 25, 2020) (Staff Whitepaper).

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Economic Carrying Charge Rate (ECCR)

The ECCR is a rate that is applied to a capital cost in order to determine the annual revenue requirement needed to provide return on capital, return of capital, and operating costs.

The following inputs are used in computing the ECCR (using data from the National Grid electric rate case currently pending before the Commission):⁵

- Return on capital and return of capital:
 - Weighted average cost of capital and weighted return on equity
 - Federal and State income tax rates
 - Federal: Depreciation life, depreciation method, Year 1 depreciation, Double Declining Balance (“DDB”) Rate
 - State: Depreciation life, depreciation method, Year 1 depreciation, DDB Rate
 - Book: Depreciation life, salvage value
- Operating costs:
 - Operation & Maintenance (“O&M”) as percent of Plant
 - Property Tax as percent of Plant
 - Insurance as percent of Plant

The rate base applicable to the asset is determined for each year, based on original cost, depreciation, and accumulated deferred income tax (the difference between taxes paid and taxes included in rates). A return on rate base is determined, reflecting the after-tax cost of capital and a gross-up for income taxes. Next, annual depreciation expenses is computed. Finally, operating expenses are computed. The annual revenue requirement is the sum of return on capital, return of capital, and operating expenses.

The ECCRs for each component of assets included in the MCOS are shown below. The percentages are multiplied by the original capital cost to determine annual revenue requirement.

T-Station	8.21%
T-Line	8.44%
D-Station	8.06%
D-Line	14.13%

The calculation of the ECCRs and supporting detail are provided in Exhibit 2.

⁵ Case 24-E-0322, *Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Niagara Mohawk Power Corporation d/b/a National Grid for Electric Service* (“National Grid Electric 2024 Rate Case Proceeding”).

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Exhibits

Exhibit 1	Capital Spending, Cost per MW, and Marginal Cost by Substation
Exhibit 2	Economic Carrying Charge Rates
Exhibit 2-TS	Transmission Stations Economic Carrying Charge Rate
Exhibit 2-TL	Transmission Lines Economic Carrying Charge Rate
Exhibit 2-DS	Distribution Stations Economic Carrying Charge Rate
Exhibit 2-DL	Distribution Lines Economic Carrying Charge Rate
Exhibit 2-OM	O&M Costs
Exhibit 2-Tax	Other Taxes Applicable to Plant

Capital Spending, Capital Cost per MW and Marginal Cost BY SUBSTATION

				Capital Spending \$000s												
Line	Reference	Station	Capacity Added MW	Prior to 2026 CapEx	FY26 Capex	FY27 Capex	FY28 Capex	FY29 Capex	FY30 Capex	FY31 Capex	FY32 Capex	FY33 Capex	FY34 Capex	FY35 Capex	FY36 Capex	Sum
	(A)	(A1)	(B)	(C26X)	(C26)	(C27)	(C28)	(C29)	(C30)	(C31)	(C32)	(C33)	(C34)	(C35)	(C36)	(C-Sum)
1	FN000507	HAGUE	1.5	110	751	2,167	-	-	-	-	-	-	-	-	-	3,029
2	FN010416	GREENBUSH	2.2	121	-	700	-	-	-	-	-	-	-	-	-	821
3	FN010097	Sawyer Ave	12.0	-	130	520	2,922	50	-	-	-	-	-	-	-	3,622
4	FN000138	BRUNSWICK	2.2	41	-	271	-	-	-	-	-	-	-	-	-	312
5	FN002420	STARR RD.	2.6	133	-	1,071	-	-	-	-	-	-	-	-	-	1,204
6	FN014043	New 3rd Ave S	40.0	-	80	240	680	690	5,302	8,769	6,207	8,602	8,602	5,255	1,561	45,988
7	FN000570	THOUSAND ISL	0.3	45	306	-	-	-	-	-	-	-	-	-	-	350
8	FN014243	ALTAMONT	26.5	-	-	-	-	100	3,900	4,439	-	-	-	-	-	8,439
9	FN011042	Avenue A	6.4	21	102	0	36	3,010	7,590	8,409	5,709	1,053	-	-	-	25,929
10	FN011558	BAKER STREET	5.0	-	-	-	-	1,891	1,218	693	-	-	-	-	-	3,802
11	FN011559	BAKER STREET	5.0	-	-	-	-	-	-	250	1,300	2,610	950	-	-	5,110
12	FN011978	BALLSTON	17.6	-	-	-	-	-	-	-	-	105	1,397	1,256	4,303	7,062
13	FN014323	Beech	40.0	-	-	1,260	1,800	2,168	10,253	13,774	13,542	8,461	-	-	-	51,258
14	FN012619	Belmont	10.0	-	-	-	-	-	-	127	1,048	607	906	-	-	2,688
15	FN002393	BETHLEHEM	0.5	114	398	-	-	-	-	-	-	-	-	-	-	512
16	FN012008	BETHLEHEM	1.0	-	-	-	-	172	662	769	-	-	-	-	-	1,603
17	FN011227	Birch Avenue	1.5	93	-	446	1,469	-	-	-	-	-	-	-	-	2,008
18	FN012140	Birch Avenue	24.6	-	-	-	-	320	3,184	1,647	11,744	14,553	7,710	10,995	-	50,154
19	FN011964	Gabriels Statio	4.0	-	-	-	375	1,501	1,501	1,500	-	-	1,378	574	-	6,830
20	FN011975	Boyntonville	32.5	-	-	-	-	617	3,597	2,563	1,442	9,579	9,579	5,794	-	33,171
21	FN011363	Bridgeport	15.0	-	-	-	-	-	128	1,059	1,520	3,526	3,409	354	-	9,996
22	FN012610	Bridgeport	15.0	-	-	-	-	-	-	127	1,048	607	960	-	-	2,742
23	FN011439	Brook Road	43.4	-	-	-	-	-	-	-	-	-	128	1,697	613	2,438
24	FN011352	Brunswick	12.5	-	-	-	-	-	-	121	1,428	6,483	9,483	8,794	-	26,309
25	FN011997	Buckley	32.5	-	-	-	-	-	-	99	2,131	5,219	5,914	9,204	4,562	27,130
26	FN011369	Buffalo Station	5.3	-	-	-	-	-	-	-	-	-	171	1,886	2,799	4,856
27	FN012851	54 MAIN	5.0	-	-	-	-	-	-	-	-	-	-	3,841	4,432	8,274
28	FN012851A	Buffalo Station	40.0	-	-	-	-	-	-	-	128	1,697	613	1,515	10,058	14,010
29	FN012817	61 STATION 61	5.0	-	-	-	-	-	-	-	417	2,951	4,432	4,095	4,938	16,834
30	FN005875	Buffalo Station	6.0	21,103	1,399	-	-	-	-	-	-	-	-	-	-	22,502
31	FN005840	Buffalo Station	9.0	-	150	150	733	776	2,432	1,200	2,440	7,950	2,890	-	-	18,721
32	FN005818	30 SPILLMAN	9.0	6,891	365	2,267	4,355	7,562	6,119	524	-	-	-	-	-	28,083
33	FN005832	31 STATION	9.0	10,741	5,586	8,176	4,693	457	-	-	-	-	-	-	-	29,652
34	FN005771	32 BAILEY	9.0	36,807	3,278	808	-	-	-	-	-	-	-	-	-	40,893
35	FN005819	34 BEST ST.	9.0	-	-	51	250	100	2,364	3,664	4,874	3,834	63	-	-	15,200
36	FN005842	35 WALDEN	9.0	-	150	510	2,061	1,009	2,430	7,580	8,850	580	-	-	-	23,170
37	FN005791	38 SPRING	9.0	30,314	5,245	5,295	-	-	-	-	-	-	-	-	-	40,854

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Line	Reference	Station	Capacity Added MW	Capital Spending \$000s					Capital \$000s per Capacity Added MW					Sum
				T_Station	T_Line	D_Station	D_Line	Sum	T_Station	T_Line	D_Station	D_Line	Sum	
				(C-TS)	(C-TL)	(C-DS)	(C-DL)	(C)	(D-TS)	(D-TL)	(D-DS)	(D-DL)	(D)	
				(C-TS)/(B)	(C-TL)/(B)	(C-DS)/(B)	(C-DL)/(B)	(C)	(D-TS)/(B)	(D-TL)/(B)	(D-DS)/(B)	(D-DL)/(B)	(D)	
1	FN000507	HAGUE	1.5	-	-	-	3,029	3,029	-	-	-	2,019	2,019	
2	FN010416	GREENBUSH	2.2	-	-	-	821	821	-	-	-	373	373	
3	FN010097	Sawyer Ave	12.0	650	-	-	2,972	3,622	54	-	-	248	302	
4	FN000138	BRUNSWICK	2.2	-	-	-	312	312	-	-	-	142	142	
5	FN002420	STARR RD.	2.6	-	-	-	1,204	1,204	-	-	-	463	463	
6	FN014043	New 3rd Ave S	40.0	-	-	25,424	20,564	45,988	-	-	636	514	1,150	
7	FN000570	THOUSAND ISL	0.3	-	-	-	350	350	-	-	-	1,062	1,062	
8	FN014243	ALTAMONT	26.5	-	-	8,439	-	8,439	-	-	318	-	318	
9	FN011042	Avenue A	6.4	-	-	20,894	5,035	25,929	-	-	3,265	787	4,051	
10	FN011558	BAKER STREET	5.0	-	-	-	3,802	3,802	-	-	-	760	760	
11	FN011559	BAKER STREET	5.0	-	-	-	5,110	5,110	-	-	-	1,022	1,022	
12	FN011978	BALLSTON	17.6	3,415	-	-	3,647	7,062	194	-	-	207	401	
13	FN014323	Beech	40.0	-	-	37,009	14,249	51,258	-	-	925	356	1,281	
14	FN012619	Belmont	10.0	-	-	-	2,688	2,688	-	-	-	269	269	
15	FN002393	BETHLEHEM	0.5	-	-	-	512	512	-	-	-	1,024	1,024	
16	FN012008	BETHLEHEM	1.0	-	-	-	1,603	1,603	-	-	-	1,603	1,603	
17	FN011227	Birch Avenue	1.5	-	-	-	2,008	2,008	-	-	-	1,339	1,339	
18	FN012140	Birch Avenue	24.6	-	-	50,154	-	50,154	-	-	2,039	-	2,039	
19	FN011964	Gabriels Statio	4.0	-	-	3,829	3,001	6,830	-	-	957	750	1,707	
20	FN011975	Boyntonville	32.5	-	-	28,716	4,455	33,171	-	-	884	137	1,021	
21	FN011363	Bridgeport	15.0	-	-	9,996	-	9,996	-	-	666	-	666	
22	FN012610	Bridgeport	15.0	-	-	-	2,742	2,742	-	-	-	183	183	
23	FN011439	Brook Road	43.4	-	-	2,438	-	2,438	-	-	56	-	56	
24	FN011352	Brunswick	12.5	-	-	26,309	-	26,309	-	-	2,105	-	2,105	
25	FN011997	Buckley	32.5	-	-	11,461	15,669	27,130	-	-	353	482	835	
26	FN011369	Buffalo Station	5.3	-	-	2,412	2,444	4,856	-	-	459	466	925	
27	FN012851	54 MAIN	5.0	-	-	-	8,274	8,274	-	-	-	1,655	1,655	
28	FN012851A	Buffalo Station	40.0	-	-	14,010	-	14,010	-	-	350	-	350	
29	FN012817	61 STATION 61	5.0	-	-	-	16,834	16,834	-	-	-	3,367	3,367	
30	FN005875	Buffalo Station	6.0	-	-	17,406	5,096	22,502	-	-	2,901	849	3,750	
31	FN005840	Buffalo Station	9.0	-	-	15,890	2,831	18,721	-	-	1,766	315	2,080	
32	FN005818	30 SPILLMAN	9.0	-	-	27,148	935	28,083	-	-	3,016	104	3,120	
33	FN005832	31 STATION	9.0	-	-	27,070	2,582	29,652	-	-	3,008	287	3,295	
34	FN005771	32 BAILEY	9.0	-	-	32,772	8,121	40,893	-	-	3,641	902	4,544	
35	FN005819	34 BEST ST.	9.0	-	-	12,460	2,740	15,200	-	-	1,384	304	1,689	
36	FN005842	35 WALDEN	9.0	-	-	20,000	3,170	23,170	-	-	2,222	352	2,574	
37	FN005791	38 SPRING	9.0	-	-	25,137	15,717	40,854	-	-	2,793	1,746	4,539	

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		CCR Rates=>							
						8.21%	8.44%	8.06%	14.13%
		Annual Cost \$000s Using ECCR per Capacity Added MW							
Line	Reference	Station	Capacity Added MW	In-Service Year	T_Station	T_Line	D_Station	D_Line	Sum
(A)	(A1)	(B)	(F)		(E-TS)	(E-TL)	(E-DS)	(E-DL)	(E)
					(D-TS)*ECCR	(D-TL)*ECCR	(D-DS)*ECCR	(D-DL)*ECCR	
1	FN000507	HAGUE	1.5	2027	-	-	-	285	285
2	FN010416	GREENBUSH	2.2	2027	-	-	-	53	53
3	FN010097	Sawyer Ave	12.0	2029	4	-	-	35	39
4	FN000138	BRUNSWICK	2.2	2027	-	-	-	20	20
5	FN002420	STARR RD.	2.6	2027	-	-	-	65	65
6	FN014043	New 3rd Ave S	40.0	2036	-	-	51	73	124
7	FN000570	THOUSAND ISL	0.3	2026	-	-	-	150	150
8	FN014243	ALTAMONT	26.5	2031	-	-	26	-	26
9	FN011042	Avenue A	6.4	2033	-	-	263	111	374
10	FN011558	BAKER STREET	5.0	2031	-	-	-	107	107
11	FN011559	BAKER STREET	5.0	2034	-	-	-	144	144
12	FN011978	BALLSTON	17.6	2036	16	-	-	29	45
13	FN014323	Beech	40.0	2033	-	-	75	50	125
14	FN012619	Belmont	10.0	2034	-	-	-	38	38
15	FN002393	BETHLEHEM	0.5	2026	-	-	-	145	145
16	FN012008	BETHLEHEM	1.0	2031	-	-	-	226	226
17	FN011227	Birch Avenue	1.5	2028	-	-	-	189	189
18	FN012140	Birch Avenue	24.6	2035	-	-	164	-	164
19	FN011964	Gabriels Statio	4.0	2035	-	-	77	106	183
20	FN011975	Boyntonville	32.5	2035	-	-	71	19	91
21	FN011363	Bridgeport	15.0	2035	-	-	54	-	54
22	FN012610	Bridgeport	15.0	2034	-	-	-	26	26
23	FN011439	Brook Road	43.4	2036	-	-	5	-	5
24	FN011352	Brunswick	12.5	2035	-	-	170	-	170
25	FN011997	Buckley	32.5	2036	-	-	28	68	97
26	FN011369	Buffalo Station	5.3	2036	-	-	37	66	103
27	FN012851	54 MAIN	5.0	2036	-	-	-	234	234
28	FN012851A	Buffalo Station	40.0	2036	-	-	28	-	28
29	FN012817	61 STATION 61	5.0	2036	-	-	-	476	476
30	FN005875	Buffalo Station	6.0	2026	-	-	234	120	354
31	FN005840	Buffalo Station	9.0	2034	-	-	142	44	187
32	FN005818	30 SPILLMAN	9.0	2031	-	-	243	15	258
33	FN005832	31 STATION	9.0	2029	-	-	242	41	283
34	FN005771	32 BAILEY	9.0	2027	-	-	293	127	421
35	FN005819	34 BEST ST.	9.0	2034	-	-	112	43	155
36	FN005842	35 WALDEN	9.0	2033	-	-	179	50	229
37	FN005791	38 SPRING	9.0	2027	-	-	225	247	472

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Line	Reference	Station	Capacity Added MW	In-Service Year	Rationale	Annual Inflation=> 102.1%										
						Marginal Cost \$000s in Each Year										
						2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
	(A)	(A1)	(B)	(F)	(F-1)	(F26)	(F27)	(F28)	(F29)	(F30)	(F31)	(F32)	(F33)	(F34)	(F35)	(F36)
1	FN000507	HAGUE	1.5	2027	Cap	279	285	291	297	304	310	317	323	330	337	344
2	FN010416	GREENBUSH	2.2	2027	MVD	52	53	54	55	56	57	59	60	61	62	64
3	FN010097	Sawyer Ave	12.0	2029	Cap	37	38	39	39	40	41	42	43	44	45	46
4	FN000138	BRUNSWICK	2.2	2027	Cap	20	20	20	21	21	22	22	23	23	24	24
5	FN002420	STARR RD.	2.6	2027	Cap	64	65	67	68	70	71	73	74	76	77	79
6	FN014043	New 3rd Ave S	40.0	2036	MVD	101	103	105	107	109	112	114	116	119	121	124
7	FN000570	THOUSAND ISL	0.3	2026	Cap	150	153	156	160	163	166	170	173	177	181	185
8	FN014243	ALTMONT	26.5	2031	MVD	23	24	24	25	25	26	26	27	27	28	28
9	FN011042	Avenue A	6.4	2033	MVD	324	330	337	344	352	359	367	374	382	390	398
10	FN011558	BAKER STREET	5.0	2031	Cap	97	99	101	103	105	107	110	112	114	117	119
11	FN011559	BAKER STREET	5.0	2034	Cap	122	125	127	130	133	136	139	141	144	147	151
12	FN011978	BALLSTON	17.6	2036	MVD	37	37	38	39	40	41	42	42	43	44	45
13	FN014323	Beech	40.0	2033	MVD	108	110	113	115	117	120	122	125	128	130	133
14	FN012619	Belmont	10.0	2034	Cap	32	33	34	34	35	36	36	37	38	39	40
15	FN002393	BETHLEHEM	0.5	2026	Cap	145	148	151	154	157	160	164	167	171	174	178
16	FN012008	BETHLEHEM	1.0	2031	MVD	204	208	213	217	222	226	231	236	241	246	251
17	FN011227	Birch Avenue	1.5	2028	Cap	181	185	189	193	197	201	206	210	214	219	223
18	FN012140	Birch Avenue	24.6	2035	MVD	136	139	142	145	148	151	154	158	161	164	168
19	FN011964	Gabriels Statio	4.0	2035	MVD	152	155	158	162	165	169	172	176	179	183	187
20	FN011975	Boyntonville	32.5	2035	MVD	75	77	78	80	82	83	85	87	89	91	92
21	FN011363	Bridgeport	15.0	2035	MVD	45	45	46	47	48	49	50	52	53	54	55
22	FN012610	Bridgeport	15.0	2034	Cap	22	22	23	23	24	24	25	25	26	26	27
23	FN011439	Brook Road	43.4	2036	MVD	4	4	4	4	4	4	4	4	4	4	5
24	FN011352	Brunswick	12.5	2035	MVD	141	144	147	150	153	156	159	163	166	170	173
25	FN011997	Buckley	32.5	2036	MVD	78	80	82	83	85	87	89	91	93	95	97
26	FN011369	Buffalo Station	5.3	2036	Cap	84	85	87	89	91	93	95	97	99	101	103
27	FN012851	54 MAIN	5.0	2036	MVD	190	194	198	202	206	211	215	220	224	229	234
28	FN012851A	Buffalo Station	40.0	2036	MVD	23	23	24	24	25	25	26	27	27	28	28
29	FN012817	61 STATION 61	5.0	2036	MVD	386	395	403	411	420	429	438	447	456	466	476
30	FN005875	Buffalo Station	6.0	2026	MVD	354	361	369	377	384	393	401	409	418	427	436
31	FN005840	Buffalo Station	9.0	2034	MVD	158	161	165	168	172	175	179	183	187	191	195
32	FN005818	30 SPILLMAN	9.0	2031	MVD	232	237	242	247	252	258	263	269	274	280	286
33	FN005832	31 STATION	9.0	2029	MVD	266	271	277	283	289	295	301	307	314	321	327
34	FN005771	32 BAILEY	9.0	2027	MVD	412	421	430	439	448	457	467	477	487	497	508
35	FN005819	34 BEST ST.	9.0	2034	MVD	131	134	136	139	142	145	148	151	155	158	161
36	FN005842	35 WALDEN	9.0	2033	MVD	198	202	206	211	215	220	224	229	234	239	244
37	FN005791	38 SPRING	9.0	2027	MVD	462	472	482	492	502	513	524	534	546	557	569

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				Capital Spending \$000s												
Line	Reference	Station	Capacity Added MW	Prior to 2026 CapEx	FY26 Capex	FY27 Capex	FY28 Capex	FY29 Capex	FY30 Capex	FY31 Capex	FY32 Capex	FY33 Capex	FY34 Capex	FY35 Capex	FY36 Capex	Sum
	(A)	(A1)	(B)	(C26X)	(C26)	(C27)	(C28)	(C29)	(C30)	(C31)	(C32)	(C33)	(C34)	(C35)	(C36)	(C-Sum)
38	FN005820	41 STATION 41	9.0	-	-	51	250	100	2,364	3,664	4,874	3,834	63	-	-	15,200
39	FN010096	Buffalo Station	9.0	10,975	260	1,683	2,710	8,595	5,966	1,505	-	-	-	-	-	31,693
40	FN005821	51 ELK ST	9.0	10,873	171	306	352	2,632	4,165	9,038	5,935	72	-	-	-	33,544
41	FN005822	68 ELMWOOD	9.0	-	-	-	51	339	2,374	3,664	4,874	3,834	63	-	-	15,199
42	FN011290	New Buffalo St	15.0	-	-	-	-	-	-	-	2,134	1,984	2,941	14,554	14,830	36,443
43	FN014248	Burdeck	19.9	-	-	-	56	741	268	661	4,501	5,856	3,184	1,479	10,739	27,484
44	FN014222	Burgoyne	8.8	42	15	616	-	-	-	-	-	-	-	-	-	673
45	FN011414	Burgoyne	17.6	-	-	-	-	110	1,466	529	1,479	10,739	10,739	6,496	-	31,559
46	FN012964	171 BURT	5.0	55	569	4,510	-	-	166	638	2,543	677	202	776	3,091	13,227
47	FN011413	Butler	17.6	-	-	-	-	110	1,466	529	1,308	8,689	8,689	5,255	-	26,047
48	FN012612	Butternut	15.0	-	-	-	-	-	-	-	-	140	1,156	758	390	2,444
49	FN011415	Cedar	15.0	-	-	-	-	-	-	-	-	-	-	122	1,617	1,738
50	FN012138	Chestertown	34.5	-	-	-	-	250	2,020	8,577	15,707	27,553	28,432	37,194	15,945	135,679
51	FN011946	New Cicero Su	80.0	3,017	1,024	2,793	3,926	20,715	15,428	2,390	3	-	-	-	-	49,295
52	FN014417	Cleveland	7.0	-	240	1,273	5,805	7,094	3,435	489	-	-	-	-	-	18,336
53	FN011920	COBLESKILL	9.4	1,921	1,838	2,121	1,032	-	-	-	-	-	-	-	-	6,913
54	FN011848	Coffeen	5.0	-	-	-	240	940	1,090	-	-	-	-	-	-	2,270
55	FN006634	RUSSELL RD	1.0	192	191	191	144	3,339	494	85	-	-	-	-	-	4,635
56	FN006637	Commerce	4.4	519	211	803	914	335	7,190	494	-	-	-	-	-	10,466
57	FN011440	Corinth	9.5	-	-	-	-	122	1,617	583	1,442	9,579	9,579	5,794	-	28,716
58	FN010312	Vail Mills	2.5	14	-	192	-	-	-	-	-	-	-	-	-	206
59																
60	FN011976	CURTIS GREEN	40.0	-	-	-	-	857	4,291	3,869	1,246	578	8,275	5,005	-	24,121
61	FN004729	Delanson	1.2	23	164	-	-	-	-	-	-	-	-	-	-	188
62	FN004723	Delanson	1.2	38	207	-	-	-	-	-	-	-	-	-	-	245
63	FN010831	Delanson	11.2	-	-	-	-	-	55	1,100	1,100	1,600	3,400	2,050	205	9,510
64	FN011939	Delmar	7.2	10,352	8,745	6,162	2,883	1,465	189	-	-	-	-	-	-	29,795
65	FN011387A	Dorwin	2.0	-	-	410	1,575	6,277	401	-	-	-	-	-	-	8,663
66	FN011971	East Fulton	40.0	-	-	-	-	-	-	176	2,691	6,924	8,307	7,117	99	25,314
67	FN011545	BATAVIA STAT	5.0	-	-	-	-	-	-	-	426	1,634	1,901	-	-	3,960
68	FN011544	EAST GOLAH	5.0	-	-	-	-	-	-	250	1,830	1,850	1,020	-	-	4,950
69	FN011543	EAST GOLAH	5.0	-	-	-	-	-	-	-	426	1,634	1,901	-	-	3,960
70	FN000216A	East Pulaski	15.6	6	70	180	480	2,320	7,250	360	-	-	-	-	-	10,666
71	FN011402	East Schodack	15.3	-	-	-	-	-	-	-	120	1,428	9,483	9,483	5,794	26,309
72	FN010022	Sawyer Ave	20.0	-	-	-	-	-	100	500	5,000	2,000	100	-	-	7,700
73	FN012052	Delameter	40.0	-	125	250	870	5,120	5,160	500	-	-	-	-	-	12,025
74	FN012051	Delameter	40.0	-	1,200	1,100	2,700	7,600	6,900	1,000	-	-	-	-	-	20,500

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Line	Reference	Station	Capacity Added MW	Capital Spending \$000s					Capital \$000s per Capacity Added MW					E
				T_Station	T_Line	D_Station	D_Line	Sum	T_Station	T_Line	D_Station	D_Line	Sum	
				(C-TS)	(C-TL)	(C-DS)	(C-DL)	(C)	(D-TS)	(D-TL)	(D-DS)	(D-DL)	(D)	
				(C-TS)/(B)	(C-TL)/(B)	(C-DS)/(B)	(C-DL)/(B)		(D-TS)/(B)	(D-TL)/(B)	(D-DS)/(B)	(D-DL)/(B)		
38	FN005820	41 STATION 41	9.0	-	-	12,460	2,740	15,200	-	-	1,384	304	1,689	
39	FN010096	Buffalo Station	9.0	-	-	29,861	1,832	31,693	-	-	3,318	204	3,521	
40	FN005821	51 ELK ST	9.0	-	-	31,896	1,648	33,544	-	-	3,544	183	3,727	
41	FN005822	68 ELMWOOD	9.0	-	-	12,460	2,739	15,199	-	-	1,384	304	1,689	
42	FN011290	New Buffalo St	15.0	-	-	32,465	3,978	36,443	-	-	2,164	265	2,430	
43	FN014248	Burdeck	19.9	-	-	27,484	-	27,484	-	-	1,381	-	1,381	
44	FN014222	Burgoyne	8.8	-	-	-	673	673	-	-	-	76	76	
45	FN011414	Burgoyne	17.6	-	-	31,559	-	31,559	-	-	1,793	-	1,793	
46	FN012964	171 BURT	5.0	-	-	515	12,712	13,227	-	-	103	2,542	2,645	
47	FN011413	Butler	17.6	-	-	26,047	-	26,047	-	-	1,480	-	1,480	
48	FN012612	Butternut	15.0	-	-	-	2,444	2,444	-	-	-	163	163	
49	FN011415	Cedar	15.0	-	-	1,738	-	1,738	-	-	116	-	116	
50	FN012138	Chestertown	34.5	-	-	30,539	105,140	135,679	-	-	885	3,048	3,933	
51	FN011946	New Cicero Su	80.0	-	-	35,188	14,106	49,295	-	-	440	176	616	
52	FN014417	Cleveland	7.0	-	-	-	18,336	18,336	-	-	-	2,619	2,619	
53	FN011920	COBLESKILL	9.4	-	-	3,723	3,190	6,913	-	-	396	339	735	
54	FN011848	Coffeen	5.0	-	-	-	2,270	2,270	-	-	-	454	454	
55	FN006634	RUSSELL RD	1.0	-	-	-	4,635	4,635	-	-	-	4,635	4,635	
56	FN006637	Commerce	4.4	-	-	10,466	-	10,466	-	-	2,379	-	2,379	
57	FN011440	Corinth	9.5	-	-	28,716	-	28,716	-	-	3,023	-	3,023	
58	FN010312	Vail Mills	2.5	-	-	-	206	206	-	-	-	82	82	
59														
60	FN011976	CURTIS GREEN	40.0	-	-	17,110	7,012	24,121	-	-	428	175	603	
61	FN004729	Delanson	1.2	-	-	-	188	188	-	-	-	151	151	
62	FN004723	Delanson	1.2	-	-	-	245	245	-	-	-	197	197	
63	FN010831	Delanson	11.2	-	-	9,510	-	9,510	-	-	849	-	849	
64	FN011939	Delmar	7.2	-	-	19,142	10,653	29,795	-	-	2,659	1,480	4,138	
65	FN011387A	Dorwin	2.0	-	-	-	8,663	8,663	-	-	-	4,332	4,332	
66	FN011971	East Fulton	40.0	-	-	-	25,314	25,314	-	-	-	633	633	
67	FN011545	BATAVIA STAT	5.0	-	-	-	3,960	3,960	-	-	-	792	792	
68	FN011544	EAST GOLAH	5.0	-	-	-	4,950	4,950	-	-	-	990	990	
69	FN011543	EAST GOLAH	5.0	-	-	-	3,960	3,960	-	-	-	792	792	
70	FN000216A	East Pulaski	15.6	-	-	10,666	-	10,666	-	-	684	-	684	
71	FN011402	East Schodack	15.3	-	-	26,309	-	26,309	-	-	1,718	-	1,718	
72	FN010022	Sawyer Ave	20.0	-	-	-	7,700	7,700	-	-	-	385	385	
73	FN012052	Delameter	40.0	-	-	-	12,025	12,025	-	-	-	301	301	
74	FN012051	Delameter	40.0	-	-	20,500	-	20,500	-	-	513	-	513	

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CCR Rates=>									
8.21% 8.44% 8.06% 14.13%									
Annual Cost \$000s Using ECCR per Capacity Added MW									
Line	Reference	Station	Capacity Added MW	In-Service Year	T_Station	T_Line	D_Station	D_Line	Sum
(A)	(A1)	(B)	(F)		(E-TS)	(E-TL)	(E-DS)	(E-DL)	(E)
					(D-TS)*ECCR	(D-TL)*ECCR	(D-DS)*ECCR	(D-DL)*ECCR	
38	FN005820	41 STATION 41	9.0	2034	-	-	112	43	155
39	FN010096	Buffalo Station	9.0	2031	-	-	267	29	296
40	FN005821	51 ELK ST	9.0	2033	-	-	286	26	311
41	FN005822	68 ELMWOOD	9.0	2034	-	-	112	43	155
42	FN011290	New Buffalo St	15.0	2036	-	-	174	37	212
43	FN014248	Burdeck	19.9	2036	-	-	111	-	111
44	FN014222	Burgoyne	8.8	2027	-	-	-	11	11
45	FN011414	Burgoyne	17.6	2035	-	-	145	-	145
46	FN012964	171 BURT	5.0	2036	-	-	8	359	368
47	FN011413	Butler	17.6	2035	-	-	119	-	119
48	FN012612	Butternut	15.0	2036	-	-	-	23	23
49	FN011415	Cedar	15.0	2036	-	-	9	-	9
50	FN012138	Chestertown	34.5	2036	-	-	71	431	502
51	FN011946	New Cicero Su	80.0	2032	-	-	35	25	60
52	FN014417	Cleveland	7.0	2031	-	-	-	370	370
53	FN011920	COBLESKILL	9.4	2028	-	-	32	48	80
54	FN011848	Coffeen	5.0	2030	-	-	-	64	64
55	FN006634	RUSSELL RD	1.0	2031	-	-	-	655	655
56	FN006637	Commerce	4.4	2031	-	-	192	-	192
57	FN011440	Corinth	9.5	2035	-	-	244	-	244
58	FN010312	Vail Mills	2.5	2027	-	-	-	12	12
59									
60	FN011976	CURTIS GREEN	40.0	2035	-	-	34	25	59
61	FN004729	Delanson	1.2	2026	-	-	-	21	21
62	FN004723	Delanson	1.2	2026	-	-	-	28	28
63	FN010831	Delanson	11.2	2036	-	-	68	-	68
64	FN011939	Delmar	7.2	2030	-	-	214	209	423
65	FN011387A	Dorwin	2.0	2030	-	-	-	612	612
66	FN011971	East Fulton	40.0	2036	-	-	-	89	89
67	FN011545	BATAVIA STAT	5.0	2034	-	-	-	112	112
68	FN011544	EAST GOLAH	5.0	2034	-	-	-	140	140
69	FN011543	EAST GOLAH	5.0	2034	-	-	-	112	112
70	FN000216A	East Pulaski	15.6	2031	-	-	55	-	55
71	FN011402	East Schodack	15.3	2036	-	-	138	-	138
72	FN010022	Sawyer Ave	20.0	2034	-	-	-	54	54
73	FN012052	Delameter	40.0	2031	-	-	-	42	42
74	FN012051	Delameter	40.0	2031	-	-	41	-	41

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Line	Reference	Station	Capacity Added MW	In-Service Year	Rationale	Annual Inflation=> 102.1%										
						Marginal Cost \$000s in Each Year										
						2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
	(A)	(A1)	(B)	(F)	(F-1)	(F26)	(F27)	(F28)	(F29)	(F30)	(F31)	(F32)	(F33)	(F34)	(F35)	(F36)
38	FN005820	41 STATION 41	9.0	2034	MVD	131	134	136	139	142	145	148	151	155	158	161
39	FN010096	Buffalo Station	9.0	2031	MVD	267	273	278	284	290	296	302	309	315	322	329
40	FN005821	51 ELK ST	9.0	2033	MVD	269	275	281	287	293	299	305	311	318	325	332
41	FN005822	68 ELMWOOD	9.0	2034	MVD	131	134	136	139	142	145	148	151	155	158	161
42	FN011290	New Buffalo St	15.0	2036	Cap	172	176	179	183	187	191	195	199	203	208	212
43	FN014248	Burdeck	19.9	2036	MVD	90	92	94	96	98	100	102	105	107	109	111
44	FN014222	Burgoyne	8.8	2027	Cap	11	11	11	11	11	12	12	12	12	13	13
45	FN011414	Burgoyne	17.6	2035	MVD	120	122	125	128	130	133	136	139	142	145	148
46	FN012964	171 BURT	5.0	2036	MVD	299	305	311	318	324	331	338	345	353	360	368
47	FN011413	Butler	17.6	2035	MVD	99	101	103	105	107	110	112	114	117	119	122
48	FN012612	Butternut	15.0	2036	Cap	19	19	19	20	20	21	21	22	22	23	23
49	FN011415	Cedar	15.0	2036	MVD	8	8	8	8	8	8	9	9	9	9	9
50	FN012138	Chestertown	34.5	2036	MVD	408	416	425	434	443	452	462	472	481	492	502
51	FN011946	New Cicero Su	80.0	2032	Cap	53	54	56	57	58	59	60	62	63	64	66
52	FN014417	Cleveland	7.0	2031	Cap	334	341	348	355	362	370	378	386	394	402	411
53	FN011920	COBLESKILL	9.4	2028	MVD	77	78	80	82	83	85	87	89	90	92	94
54	FN011848	Coffeen	5.0	2030	Cap	59	60	62	63	64	65	67	68	70	71	73
55	FN006634	RUSSELL RD	1.0	2031	Cap	590	603	615	628	641	655	669	683	697	712	727
56	FN006637	Commerce	4.4	2031	Cap	173	176	180	184	188	192	196	200	204	208	213
57	FN011440	Corinth	9.5	2035	MVD	202	206	211	215	220	224	229	234	239	244	249
58	FN010312	Vail Mills	2.5	2027	MVD	11	12	12	12	12	13	13	13	13	14	14
59																
60	FN011976	CURTIS GREEN	40.0	2035	MVD	49	50	51	52	53	55	56	57	58	59	60
61	FN004729	Delanson	1.2	2026	Cap	21	22	22	23	23	24	24	25	25	26	26
62	FN004723	Delanson	1.2	2026	Cap	28	28	29	30	30	31	32	32	33	34	34
63	FN010831	Delanson	11.2	2036	Cap	56	57	58	59	60	62	63	64	66	67	68
64	FN011939	Delmar	7.2	2030	Cap	390	398	406	415	423	432	441	451	460	470	480
65	FN011387A	Dorwin	2.0	2030	MVD	563	575	587	599	612	625	638	651	665	679	693
66	FN011971	East Fulton	40.0	2036	MVD	73	74	76	77	79	81	82	84	86	88	89
67	FN011545	BATAVIA STAT	5.0	2034	Cap	95	97	99	101	103	105	107	110	112	114	117
68	FN011544	EAST GOLAH	5.0	2034	Cap	118	121	123	126	129	131	134	137	140	143	146
69	FN011543	EAST GOLAH	5.0	2034	Cap	95	97	99	101	103	105	107	110	112	114	117
70	FN000216A	East Pulaski	15.6	2031	Cap	50	51	52	53	54	55	56	57	59	60	61
71	FN011402	East Schodack	15.3	2036	MVD	113	115	117	120	122	125	127	130	133	136	138
72	FN010022	Sawyer Ave	20.0	2034	Cap	46	47	48	49	50	51	52	53	54	56	57
73	FN012052	Delameter	40.0	2031	Cap	38	39	40	41	42	42	43	44	45	46	47
74	FN012051	Delameter	40.0	2031	Cap	37	38	39	40	40	41	42	43	44	45	46

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Line	Reference	Station	Capacity Added MW	Capital Spending \$000s												Sum
				Prior to 2026 CapEx	FY26 Capex	FY27 Capex	FY28 Capex	FY29 Capex	FY30 Capex	FY31 Capex	FY32 Capex	FY33 Capex	FY34 Capex	FY35 Capex	FY36 Capex	
	(A)	(A1)	(B)	(C26X)	(C26)	(C27)	(C28)	(C29)	(C30)	(C31)	(C32)	(C33)	(C34)	(C35)	(C36)	(C-Sum)
75																
76	FN012062	Bridgeport	22.0	-	120	220	1,070	7,450	1,990	500	-	-	-	-	-	11,350
77	FN012061	Bridgeport	25.0	-	2,300	850	5,100	8,500	5,300	1,000	-	-	-	-	-	23,050
78	FN012057	East Molloy	22.0	-	120	220	1,580	7,150	3,040	500	-	-	-	-	-	12,610
79	FN012055	East Molloy	25.0	-	2,300	850	5,100	7,100	5,850	1,000	-	-	-	-	-	22,200
80	FN012048	BATAVIA STAT	40.0	-	120	275	1,190	5,700	5,750	500	-	-	-	-	-	13,535
81	FN012041	BATAVIA STAT	40.0	-	2,300	850	5,100	7,670	5,850	1,000	-	-	-	-	-	22,770
82	FN014033	Everett	15.0	762	-	-	-	323	-	-	-	1,515	-	220	2,932	5,753
83	FN013818	64 STATION 64	4.6	213	-	-	-	-	798	-	-	-	-	-	-	1,011
84	FN005770	Fayette St	41.5	10,897	9,117	15,915	13,464	9,764	5,239	223	-	-	-	-	-	64,619
85	FN000459	FIREHOUSE	10.0	159	-	-	24	1,900	-	-	-	-	-	-	-	2,083
86	FN011347	FIREHOUSE	15.0	-	-	-	-	-	-	-	-	-	154	2,032	1,179	3,365
87	FN006171	Florida	2.0	-	-	15	338	-	-	-	-	-	-	-	-	353
88	FN014455	FRENCH MOUNTAIN	5.0	-	-	350	-	-	-	-	-	-	-	-	-	350
89	FN013397	Geneseo	6.8	-	-	-	-	-	-	-	128	1,672	970	3,526	3,409	9,705
90	FN013415	Geneseo	1.4	-	-	-	-	-	-	-	100	3,574	3,199	3,199	3,199	13,271
91	FN000195A	Gilbert Mills	15.0	906	238	662	774	5,343	5,746	-	-	-	-	-	-	13,668
92	FN011476	Gilmantown	10.0	-	-	-	137	525	2,383	2,379	-	-	-	-	-	5,423
93	FN011422	GLOVERSVILLE	15.0	-	-	-	-	105	1,397	504	4,409	11,228	11,228	1,186	-	30,056
94	FN011970	GRANBY CENT	32.9	-	-	-	128	1,059	1,583	2,884	15,726	10,208	2,578	-	-	34,166
95	FN002240	Grand Island	15.0	3,863	1,060	-	-	-	-	289	3,520	1,894	-	-	-	10,625
96	FN011384	Grand Island	22.6	-	-	-	-	-	-	-	116	1,540	556	1,374	9,123	12,709
97	FN006457	GREENBUSH	12.5	-	15	-	2,170	-	-	-	-	-	-	-	-	2,185
98	FN011442	New Greenwic	20.0	-	-	-	-	-	-	-	-	100	1,330	480	1,342	3,252
99	FN011527	GROOMS	29.7	-	-	-	-	-	-	134	2,425	3,798	11,063	17,932	12,405	47,757
100	FN002374	HAGUE	4.0	192	734	807	-	-	-	-	-	-	-	-	-	1,733
101	FN011445	Hague	17.6	-	-	-	-	-	-	134	1,782	2,233	8,561	12,561	6,388	31,659
102	FN011353	Hemstreet	12.5	-	-	-	-	-	-	-	-	-	-	139	1,853	1,992
103	FN014119	Indian Lake	12.0	-	-	-	-	-	-	-	-	-	155	2,063	745	2,963
104	FN011417	Inman	14.0	-	-	-	-	-	1,660	6,381	9,605	-	-	-	-	17,646
105	FN010667	68 ELMWOOD	2.2	78	-	-	-	-	706	-	-	-	-	-	-	784
106	FN011010	Karner	17.5	17,369	1,996	12,500	18,408	3,835	842	439	-	-	-	-	-	55,389
107	FN011605	Kenmore Statio	2.0	-	-	-	-	-	10	40	1,050	2,300	800	-	-	4,200
108	FN005761	Lakeville	10.0	35,084	2,577	293	-	-	-	-	-	-	-	-	-	37,954
109	FN011371	LASHER	11.0	-	-	-	-	-	-	-	-	-	-	1,505	5,788	7,293
110	FN011411	Latham	7.5	-	-	-	-	-	128	1,697	613	1,515	10,058	10,058	6,084	30,152
111	FN011974	Liberty Street	6.3	3,342	511	2,159	8,577	6,971	2,279	2,362	-	-	-	-	-	26,201

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Line	Reference	Station	Capacity Added MW	Capital Spending \$000s					Capital \$000s per Capacity Added MW					<i>E</i>
				T_Station	T_Line	D_Station	D_Line	Sum	T_Station	T_Line	D_Station	D_Line	Sum	
				(C-TS)	(C-TL)	(C-DS)	(C-DL)	(C)	(D-TS)	(D-TL)	(D-DS)	(D-DL)	(D)	
				(C-TS)/(B)	(C-TL)/(B)	(C-DS)/(B)	(C-DL)/(B)		(D-TS)/(B)	(D-TL)/(B)	(D-DS)/(B)	(D-DL)/(B)		
75														
76	FN012062	Bridgeport	22.0	-	-	-	11,350	11,350	-	-	-	516	516	
77	FN012061	Bridgeport	25.0	-	-	23,050	-	23,050	-	-	922	-	922	
78	FN012057	East Molloy	22.0	-	-	-	12,610	12,610	-	-	-	573	573	
79	FN012055	East Molloy	25.0	-	-	22,200	-	22,200	-	-	888	-	888	
80	FN012048	BATAVIA STAT	40.0	-	-	-	13,535	13,535	-	-	-	338	338	
81	FN012041	BATAVIA STAT	40.0	-	-	22,770	-	22,770	-	-	569	-	569	
82	FN014033	Everett	15.0	1,576	-	1,577	2,600	5,753	105	-	105	173	384	
83	FN013818	64 STATION 64	4.6	-	-	-	1,011	1,011	-	-	-	221	221	
84	FN005770	Fayette St	41.5	-	-	41,208	23,411	64,619	-	-	993	564	1,557	
85	FN000459	FIREHOUSE	10.0	-	-	-	2,083	2,083	-	-	-	208	208	
86	FN011347	FIREHOUSE	15.0	-	-	3,365	-	3,365	-	-	224	-	224	
87	FN006171	Florida	2.0	-	-	-	353	353	-	-	-	177	177	
88	FN014455	FRENCH MOUNTAIN	5.0	-	-	-	350	350	-	-	-	70	70	
89	FN013397	Geneseo	6.8	-	-	9,705	-	9,705	-	-	1,427	-	1,427	
90	FN013415	Geneseo	1.4	-	-	-	13,271	13,271	-	-	-	9,216	9,216	
91	FN000195A	Gilbert Mills	15.0	-	-	13,668	-	13,668	-	-	911	-	911	
92	FN011476	Gilmantown	10.0	-	-	5,423	-	5,423	-	-	542	-	542	
93	FN011422	GLOVERSVILLE	15.0	-	-	30,056	-	30,056	-	-	2,004	-	2,004	
94	FN011970	GRANBY CENT	32.9	-	-	-	34,166	34,166	-	-	-	1,038	1,038	
95	FN002240	Grand Island	15.0	-	-	10,625	-	10,625	-	-	708	-	708	
96	FN011384	Grand Island	22.6	-	-	12,709	-	12,709	-	-	562	-	562	
97	FN006457	GREENBUSH	12.5	-	-	-	2,185	2,185	-	-	-	175	175	
98	FN011442	New Greenwic	20.0	-	-	3,252	-	3,252	-	-	163	-	163	
99	FN011527	GROOMS	29.7	-	-	38,360	9,397	47,757	-	-	1,292	316	1,608	
100	FN002374	HAGUE	4.0	-	-	-	1,733	1,733	-	-	-	433	433	
101	FN011445	Hague	17.6	-	-	31,659	-	31,659	-	-	1,799	-	1,799	
102	FN011353	Hemstreet	12.5	-	-	1,992	-	1,992	-	-	159	-	159	
103	FN014119	Indian Lake	12.0	-	-	2,963	-	2,963	-	-	247	-	247	
104	FN011417	Inman	14.0	-	-	-	17,646	17,646	-	-	-	1,260	1,260	
105	FN010667	68 ELMWOOD	2.2	-	-	-	784	784	-	-	-	356	356	
106	FN011010	Karner	17.5	-	-	35,419	19,970	55,389	-	-	2,024	1,141	3,165	
107	FN011605	Kenmore Station	2.0	-	-	4,200	-	4,200	-	-	2,100	-	2,100	
108	FN005761	Lakeville	10.0	-	-	21,645	16,309	37,954	-	-	2,164	1,631	3,795	
109	FN011371	LASHER	11.0	-	-	-	7,293	7,293	-	-	-	663	663	
110	FN011411	Latham	7.5	-	-	30,152	-	30,152	-	-	4,020	-	4,020	
111	FN011974	Liberty Street	6.3	-	-	15,876	10,324	26,201	-	-	2,540	1,652	4,192	

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		CCR Rates=>							
						8.21%	8.44%	8.06%	14.13%
		Annual Cost \$000s Using ECCR per Capacity Added MW							
Line	Reference	Station	Capacity Added MW	In-Service Year	T_Station	T_Line	D_Station	D_Line	Sum
(A)	(A1)	(B)	(F)		(E-TS)	(E-TL)	(E-DS)	(E-DL)	(E)
					(D-TS)*ECCR	(D-TL)*ECCR	(D-DS)*ECCR	(D-DL)*ECCR	
75									
76	FN012062	Bridgeport	22.0	2031	-	-	-	73	73
77	FN012061	Bridgeport	25.0	2031	-	-	74	-	74
78	FN012057	East Molloy	22.0	2031	-	-	-	81	81
79	FN012055	East Molloy	25.0	2031	-	-	72	-	72
80	FN012048	BATAVIA STAT	40.0	2031	-	-	-	48	48
81	FN012041	BATAVIA STAT	40.0	2031	-	-	46	-	46
82	FN014033	Everett	15.0	2036	9	-	8	24	42
83	FN013818	64 STATION 64	4.6	2030	-	-	-	31	31
84	FN005770	Fayette St	41.5	2031	-	-	80	80	160
85	FN000459	FIREHOUSE	10.0	2029	-	-	-	29	29
86	FN011347	FIREHOUSE	15.0	2036	-	-	18	-	18
87	FN006171	Florida	2.0	2028	-	-	-	25	25
88	FN014455	FRENCH MOUNTAIN	5.0	2027	-	-	-	10	10
89	FN013397	Geneseo	6.8	2036	-	-	115	-	115
90	FN013415	Geneseo	1.4	2036	-	-	-	1,302	1,302
91	FN000195A	Gilbert Mills	15.0	2030	-	-	73	-	73
92	FN011476	Gilmantown	10.0	2031	-	-	44	-	44
93	FN011422	GLOVERSVILLE	15.0	2035	-	-	161	-	161
94	FN011970	GRANBY CENT	32.9	2034	-	-	-	147	147
95	FN002240	Grand Island	15.0	2033	-	-	57	-	57
96	FN011384	Grand Island	22.6	2036	-	-	45	-	45
97	FN006457	GREENBUSH	12.5	2028	-	-	-	25	25
98	FN011442	New Greenwic	20.0	2036	-	-	13	-	13
99	FN011527	GROOMS	29.7	2036	-	-	104	45	149
100	FN002374	HAGUE	4.0	2027	-	-	-	61	61
101	FN011445	Hague	17.6	2036	-	-	145	-	145
102	FN011353	Hemstreet	12.5	2036	-	-	13	-	13
103	FN014119	Indian Lake	12.0	2036	-	-	20	-	20
104	FN011417	Inman	14.0	2032	-	-	-	178	178
105	FN010667	68 ELMWOOD	2.2	2030	-	-	-	50	50
106	FN011010	Karner	17.5	2031	-	-	163	161	324
107	FN011605	Kenmore Station	2.0	2034	-	-	169	-	169
108	FN005761	Lakeville	10.0	2027	-	-	174	230	405
109	FN011371	LASHER	11.0	2036	-	-	-	94	94
110	FN011411	Latham	7.5	2036	-	-	324	-	324
111	FN011974	Liberty Street	6.3	2031	-	-	205	233	438

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Line	Reference	Station	Capacity Added MW	In-Service Year	Rationale	Annual Inflation=> 102.1%										
						Marginal Cost \$000s in Each Year										
						2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
	(A)	(A1)	(B)	(F)	(F-1)	(F26)	(F27)	(F28)	(F29)	(F30)	(F31)	(F32)	(F33)	(F34)	(F35)	(F36)
75																
76	FN012062	Bridgeport	22.0	2031	Cap	66	67	68	70	71	73	74	76	78	79	81
77	FN012061	Bridgeport	25.0	2031	Cap	67	68	70	71	73	74	76	77	79	81	82
78	FN012057	East Molloy	22.0	2031	Cap	73	75	76	78	79	81	83	84	86	88	90
79	FN012055	East Molloy	25.0	2031	Cap	65	66	67	69	70	72	73	75	76	78	79
80	FN012048	BATAVIA STAT	40.0	2031	Cap	43	44	45	46	47	48	49	50	51	52	53
81	FN012041	BATAVIA STAT	40.0	2031	Cap	41	42	43	44	45	46	47	48	49	50	51
82	FN014033	Everett	15.0	2036	MVD	34	34	35	36	37	37	38	39	40	41	42
83	FN013818	64 STATION 64	4.6	2030	Cap	29	29	30	31	31	32	33	33	34	35	35
84	FN005770	Fayette St	41.5	2031	MVD	144	147	150	153	156	160	163	167	170	174	177
85	FN000459	FIREHOUSE	10.0	2029	Cap	28	28	29	29	30	31	31	32	33	33	34
86	FN011347	FIREHOUSE	15.0	2036	MVD	15	15	15	16	16	16	17	17	17	18	18
87	FN006171	Florida	2.0	2028	Cap	24	24	25	25	26	27	27	28	28	29	29
88	FN014455	FRENCH MOUNTAIN	5.0	2027	MVD	10	10	10	10	11	11	11	11	11	12	12
89	FN013397	Geneseo	6.8	2036	MVD	93	95	97	99	102	104	106	108	110	113	115
90	FN013415	Geneseo	1.4	2036	MVD	1,058	1,080	1,103	1,126	1,149	1,174	1,198	1,223	1,249	1,275	1,302
91	FN000195A	Gilbert Mills	15.0	2030	Cap	68	69	70	72	73	75	77	78	80	81	83
92	FN011476	Gilmantown	10.0	2031	MVD	39	40	41	42	43	44	45	46	47	47	48
93	FN011422	GLOVERSVILLE	15.0	2035	MVD	134	137	140	143	146	149	152	155	158	161	165
94	FN011970	GRANBY CENT	32.9	2034	MVD	124	127	130	132	135	138	141	144	147	150	153
95	FN002240	Grand Island	15.0	2033	MVD	49	50	51	53	54	55	56	57	58	60	61
96	FN011384	Grand Island	22.6	2036	MVD	37	38	38	39	40	41	42	43	43	44	45
97	FN006457	GREENBUSH	12.5	2028	MVD	24	24	25	25	26	26	27	27	28	29	29
98	FN011442	New Greenwic	20.0	2036	MVD	11	11	11	11	12	12	12	12	13	13	13
99	FN011527	GROOMS	29.7	2036	MVD	121	123	126	129	131	134	137	140	143	146	149
100	FN002374	HAGUE	4.0	2027	Cap	60	61	62	64	65	67	68	69	71	72	74
101	FN011445	Hague	17.6	2036	MVD	118	120	123	125	128	131	133	136	139	142	145
102	FN011353	Hemstreet	12.5	2036	MVD	10	11	11	11	11	12	12	12	12	13	13
103	FN014119	Indian Lake	12.0	2036	MVD	16	17	17	17	18	18	18	19	19	19	20
104	FN011417	Inman	14.0	2032	MVD	157	161	164	167	171	174	178	182	186	190	194
105	FN010667	68 ELMWOOD	2.2	2030	Cap	46	47	48	49	50	51	52	54	55	56	57
106	FN011010	Karner	17.5	2031	MVD	292	298	305	311	318	324	331	338	345	352	360
107	FN011605	Kenmore Statio	2.0	2034	Cap	143	146	149	153	156	159	162	166	169	173	176
108	FN005761	Lakeville	10.0	2027	Cap	397	405	413	422	431	440	449	459	468	478	488
109	FN011371	LASHER	11.0	2036	MVD	76	78	79	81	83	84	86	88	90	92	94
110	FN011411	Latham	7.5	2036	MVD	263	269	274	280	286	292	298	304	311	317	324
111	FN011974	Liberty Street	6.3	2031	Cap	395	403	412	420	429	438	447	457	466	476	486

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Line	Reference	Station	Capital Spending \$000s													Sum
			Capacity Added MW	Prior to 2026 CapEx	FY26 Capex	FY27 Capex	FY28 Capex	FY29 Capex	FY30 Capex	FY31 Capex	FY32 Capex	FY33 Capex	FY34 Capex	FY35 Capex	FY36 Capex	
			(B)	(C26X)	(C26)	(C27)	(C28)	(C29)	(C30)	(C31)	(C32)	(C33)	(C34)	(C35)	(C36)	(C-Sum)
112	FN013411	Livonia	8.8	-	-	-	-	-	-	-	180	1,491	862	1,365	10,256	14,154
113	FN013414	37 HUDSON A	5.0	-	-	-	-	-	-	-	-	150	2,335	2,694	4,501	9,680
114	FN011857	Lowville	5.0	-	-	-	-	-	-	-	-	-	1,089	2,198	2,080	5,367
115	FN010006	LYNDONVILLE	5.0	-	-	-	-	-	-	35	346	1,040	1,386	495	-	3,302
116	FN011424	Mayfield	14.5	-	-	-	-	-	-	-	-	-	-	105	1,397	1,502
117	FN011534	McClellan	5.3	-	-	-	-	122	1,617	583	1,442	9,579	9,579	5,794	-	28,716
118	FN011344	Mexico	20.0	-	-	-	-	149	4,358	5,746	4,519	1,782	6,300	16,673	6,388	45,915
119	FN011382	Middleburgh	19.4	-	-	-	-	100	1,330	480	1,187	7,881	7,881	4,767	-	23,626
120	FN012928	Middleville	5.2	-	-	-	-	-	1,292	3,952	5,946	2,596	1,018	-	-	14,805
121	FN012193	Delameter	2.0	-	6,137	333	333	-	-	-	-	-	-	-	-	6,803
122	FN011965	Clintion Stator	13.5	-	-	-	-	499	2,140	2,053	5,385	9,267	357	-	-	19,702
123	FN011560	North Leroy	5.0	-	-	-	-	-	-	-	1,500	4,125	2,391	1,218	-	9,234
124	FN011393	Nassau	13.0	-	-	-	-	-	109	1,295	8,602	8,602	5,255	1,976	-	25,839
125	FN011296	New Cuba Stat	12.5	-	-	-	-	-	-	105	3,520	1,055	3,259	10,707	11,935	30,581
126	FN012315	NEW KRUMKIL	60.0	2,180	1,757	4,433	9,115	11,210	13,158	12,518	4,350	600	50	-	-	59,370
127	FN011311	New Livingstor	12.5	-	-	-	-	-	-	134	3,964	1,419	4,543	14,631	15,296	39,987
128	FN010052	Middleport	7.0	-	-	-	-	30	644	2,540	4,950	3,465	248	-	-	11,877
129	FN011103	NEWTONVILLE	38.7	2,489	1,317	4,197	7,578	6,601	8,797	3,868	2,223	-	-	-	-	37,072
130	FN011426	Northville Stati	12.5	-	-	-	-	110	1,466	529	1,308	8,689	8,689	5,255	-	26,047
131	FN011416	Ogdenbrook	24.6	-	-	-	-	-	-	-	-	148	1,965	709	1,982	4,804
132	FN012130	Otten	0.3	-	-	-	-	-	-	-	-	192	739	2,944	188	4,063
133	FN011443	OTTEN	0.5	-	-	-	-	-	-	-	676	1,980	1,980	1,980	1,560	8,176
134	FN012945	Paloma	20.0	-	-	-	-	-	-	-	-	-	-	-	9	9
135	FN011395	Partridge	15.0	-	-	-	-	110	1,466	529	1,308	8,689	8,689	5,255	-	26,047
136	FN012618	Peat	22.0	-	-	-	-	-	-	128	1,059	613	5,100	5,737	3,060	15,697
137	FN012004	PINEBUSH	0.7	-	-	-	-	-	-	-	-	328	1,262	1,468	-	3,058
138	FN011397	Pinebush	32.6	-	-	-	-	-	-	110	1,466	529	1,479	10,739	10,739	25,064
139	FN002263	Port Henry	2.5	53	-	686	-	-	-	-	-	-	-	-	-	739
140	FN011433	Port Henry	14.5	-	-	-	-	105	872	504	798	2,901	2,804	291	-	8,275
141	FN013957	Pottersville	13.0	-	-	-	20	1,370	656	1,732	4,427	758	798	2,901	2,804	15,467
142	FN011942	Raquette Lake	0.5	110	180	-	-	-	-	-	-	-	-	-	-	290
143	FN012721	North Chautau	4.0	-	-	-	-	-	-	-	-	100	1,330	1,342	760	3,532
144	FN000126	RIVERSIDE	5.0	518	-	-	-	15	15	5,635	3,600	3,000	-	-	-	12,783
145	FN011854	Rome Substati	5.0	-	-	-	-	-	-	-	69	267	307	-	-	644
146	FN011852	Rome Substati	5.0	-	-	-	-	990	2,624	0	-	-	-	-	-	3,614
147	FN011853	Rome Substati	5.0	-	-	-	-	390	2,000	1,250	-	-	-	-	-	3,640
148	FN011856	Rome Substati	5.0	-	-	-	-	-	-	-	69	267	307	-	-	644

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Line	Reference	Station	Capacity Added MW	Capital Spending \$000s					Capital \$000s per Capacity Added MW					E
				T_Station	T_Line	D_Station	D_Line	Sum	T_Station	T_Line	D_Station	D_Line	Sum	
				(C-TS)	(C-TL)	(C-DS)	(C-DL)	(C)	(D-TS)	(D-TL)	(D-DS)	(D-DL)	(D)	
				(C-TS)/(B)	(C-TL)/(B)	(C-DS)/(B)	(C-DL)/(B)		(D-TS)/(B)	(D-TL)/(B)	(D-DS)/(B)	(D-DL)/(B)		
112	FN013411	Livonia	8.8	-	-	14,154	-	14,154	-	-	1,618	-	1,618	
113	FN013414	37 HUDSON A	5.0	-	-	9,680	-	9,680	-	-	1,936	-	1,936	
114	FN011857	Lowville	5.0	-	-	-	5,367	5,367	-	-	-	1,073	1,073	
115	FN010006	LYNDONVILLE	5.0	-	-	3,302	-	3,302	-	-	660	-	660	
116	FN011424	Mayfield	14.5	-	-	1,502	-	1,502	-	-	104	-	104	
117	FN011534	McClellan	5.3	-	-	28,716	-	28,716	-	-	5,418	-	5,418	
118	FN011344	Mexico	20.0	-	-	-	45,915	45,915	-	-	-	2,296	2,296	
119	FN011382	Middleburgh	19.4	-	-	23,626	-	23,626	-	-	1,218	-	1,218	
120	FN012928	Middleville	5.2	-	-	-	14,805	14,805	-	-	-	2,847	2,847	
121	FN012193	Delameter	2.0	-	-	-	6,803	6,803	-	-	-	3,402	3,402	
122	FN011965	Clinton Stator	13.5	-	-	16,038	3,664	19,702	-	-	1,188	271	1,459	
123	FN011560	North Leroy	5.0	-	-	-	9,234	9,234	-	-	-	1,847	1,847	
124	FN011393	Nassau	13.0	-	-	25,839	-	25,839	-	-	1,988	-	1,988	
125	FN011296	New Cuba Stat	12.5	-	-	21,782	8,799	30,581	-	-	1,743	704	2,446	
126	FN012315	NEW KRUMKIL	60.0	-	-	24,914	34,456	59,370	-	-	415	574	989	
127	FN011311	New Livingstor	12.5	-	-	27,251	12,736	39,987	-	-	2,180	1,019	3,199	
128	FN010052	Middleport	7.0	-	-	11,877	-	11,877	-	-	1,697	-	1,697	
129	FN011103	NEWTONVILLE	38.7	5,546	-	16,421	15,105	37,072	143	-	424	390	957	
130	FN011426	Northville Stati	12.5	-	-	26,047	-	26,047	-	-	2,084	-	2,084	
131	FN011416	Ogdenbrook	24.6	-	-	4,804	-	4,804	-	-	195	-	195	
132	FN012130	Otten	0.3	-	-	4,063	-	4,063	-	-	12,697	-	12,697	
133	FN011443	OTTEN	0.5	-	-	-	8,176	8,176	-	-	-	16,353	16,353	
134	FN012945	Paloma	20.0	-	-	-	9	9	-	-	-	0	0	
135	FN011395	Partridge	15.0	-	-	26,047	-	26,047	-	-	1,736	-	1,736	
136	FN012618	Peat	22.0	-	-	-	15,697	15,697	-	-	-	714	714	
137	FN012004	PINEBUSH	0.7	-	-	-	3,058	3,058	-	-	-	4,705	4,705	
138	FN011397	Pinebush	32.6	-	-	25,064	-	25,064	-	-	769	-	769	
139	FN002263	Port Henry	2.5	-	-	-	739	739	-	-	-	296	296	
140	FN011433	Port Henry	14.5	-	-	8,275	-	8,275	-	-	571	-	571	
141	FN013957	Pottersville	13.0	-	-	9,154	6,313	15,467	-	-	704	486	1,190	
142	FN011942	Raquette Lake	0.5	-	-	290	-	290	-	-	579	-	579	
143	FN012721	North Chautau	4.0	-	-	3,532	-	3,532	-	-	883	-	883	
144	FN000126	RIVERSIDE	5.0	-	-	-	12,783	12,783	-	-	-	2,557	2,557	
145	FN011854	Rome Substati	5.0	-	-	-	644	644	-	-	-	129	129	
146	FN011852	Rome Substati	5.0	-	-	-	3,614	3,614	-	-	-	723	723	
147	FN011853	Rome Substati	5.0	-	-	-	3,640	3,640	-	-	-	728	728	
148	FN011856	Rome Substati	5.0	-	-	-	644	644	-	-	-	129	129	

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CCR Rates=>					8.21%	8.44%	8.06%	14.13%			
					Annual Cost \$000s Using ECCR per Capacity Added MW						
Line	Reference	Station	Capacity Added MW	In-Service Year	T_Station	T_Line	D_Station	D_Line	Sum		
	(A)	(A1)	(B)	(F)	(E-TS)	(E-TL)	(E-DS)	(E-DL)	(E)		
					(D-TS)*ECCR	(D-TL)*ECCR	(D-DS)*ECCR	(D-DL)*ECCR			
112	FN013411	Livonia	8.8	2036	-	-	130	-	130		
113	FN013414	37 HUDSON A\	5.0	2036	-	-	156	-	156		
114	FN011857	Lowville	5.0	2036	-	-	-	152	152		
115	FN010006	LYNDONVILLE	5.0	2035	-	-	53	-	53		
116	FN011424	Mayfield	14.5	2036	-	-	8	-	8		
117	FN011534	McClellan	5.3	2035	-	-	437	-	437		
118	FN011344	Mexico	20.0	2036	-	-	-	324	324		
119	FN011382	Middleburgh	19.4	2035	-	-	98	-	98		
120	FN012928	Middleville	5.2	2034	-	-	-	402	402		
121	FN012193	Delameter	2.0	2028	-	-	-	481	481		
122	FN011965	Clinton Stator	13.5	2034	-	-	96	38	134		
123	FN011560	North Leroy	5.0	2035	-	-	-	261	261		
124	FN011393	Nassau	13.0	2035	-	-	160	-	160		
125	FN011296	New Cuba Stat	12.5	2036	-	-	140	99	240		
126	FN012315	NEW KRUMKIL	60.0	2034	-	-	33	81	115		
127	FN011311	New Livingstor	12.5	2036	-	-	176	144	320		
128	FN010052	Middleport	7.0	2034	-	-	137	-	137		
129	FN011103	NEWTONVILLE	38.7	2032	12	-	34	55	101		
130	FN011426	Northville Stati	12.5	2035	-	-	168	-	168		
131	FN011416	Ogdenbrook	24.6	2036	-	-	16	-	16		
132	FN012130	Otten	0.3	2036	-	-	1,023	-	1,023		
133	FN011443	OTTEN	0.5	2036	-	-	-	2,311	2,311		
134	FN012945	Paloma	20.0	2036	-	-	-	0	0		
135	FN011395	Partridge	15.0	2035	-	-	140	-	140		
136	FN012618	Peat	22.0	2036	-	-	-	101	101		
137	FN012004	PINEBUSH	0.7	2035	-	-	-	665	665		
138	FN011397	Pinebush	32.6	2036	-	-	62	-	62		
139	FN002263	Port Henry	2.5	2027	-	-	-	42	42		
140	FN011433	Port Henry	14.5	2035	-	-	46	-	46		
141	FN013957	Pottersville	13.0	2036	-	-	57	69	125		
142	FN011942	Raquette Lake	0.5	2026	-	-	47	-	47		
143	FN012721	North Chautau	4.0	2036	-	-	71	-	71		
144	FN000126	RIVERSIDE	5.0	2033	-	-	-	361	361		
145	FN011854	Rome Substati	5.0	2034	-	-	-	18	18		
146	FN011852	Rome Substati	5.0	2031	-	-	-	102	102		
147	FN011853	Rome Substati	5.0	2031	-	-	-	103	103		
148	FN011856	Rome Substati	5.0	2034	-	-	-	18	18		

Exhibit 1

Niagara Mohawk Power Corporation d/b/a National Grid
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						Annual Inflation=> 102.1%										
						Marginal Cost \$000s in Each Year										
Line	Reference	Station	Capacity Added MW	In-Service Year	Rationale	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
	(A)	(A1)	(B)	(F)	(F-1)	(F26)	(F27)	(F28)	(F29)	(F30)	(F31)	(F32)	(F33)	(F34)	(F35)	(F36)
112	FN013411	Livonia	8.8	2036	MVD	106	108	110	113	115	117	120	122	125	128	130
113	FN013414	37 HUDSON A\	5.0	2036	MVD	127	129	132	135	138	141	144	147	150	153	156
114	FN011857	Lowville	5.0	2036	Cap	123	126	128	131	134	137	140	142	145	149	152
115	FN010006	LYNDONVILLE	5.0	2035	Cap	44	45	46	47	48	49	50	51	52	53	54
116	FN011424	Mayfield	14.5	2036	MVD	7	7	7	7	7	8	8	8	8	8	8
117	FN011534	McClellan	5.3	2035	MVD	362	370	378	385	394	402	410	419	428	437	446
118	FN011344	Mexico	20.0	2036	MVD	264	269	275	280	286	292	298	305	311	318	324
119	FN011382	Middleburgh	19.4	2035	MVD	81	83	85	87	88	90	92	94	96	98	100
120	FN012928	Middleville	5.2	2034	MVD	341	348	355	363	370	378	386	394	402	411	419
121	FN012193	Delameter	2.0	2028	Cap	461	471	481	491	501	512	522	533	544	556	568
122	FN011965	Clintion Stator	13.5	2034	MVD	114	116	118	121	123	126	129	131	134	137	140
123	FN011560	North Leroy	5.0	2035	Cap	216	221	226	230	235	240	245	250	256	261	266
124	FN011393	Nassau	13.0	2035	MVD	133	136	138	141	144	147	151	154	157	160	164
125	FN011296	New Cuba Stat	12.5	2036	MVD	195	199	203	207	212	216	221	225	230	235	240
126	FN012315	NEW KRUMKIL	60.0	2034	Cap	97	99	101	103	105	108	110	112	115	117	119
127	FN011311	New Livingstor	12.5	2036	Cap	260	265	271	276	282	288	294	300	307	313	320
128	FN010052	Middleport	7.0	2034	Cap	116	118	121	123	126	128	131	134	137	140	143
129	FN011103	NEWTONVILLE	38.7	2032	MVD	89	91	93	95	97	99	101	103	105	108	110
130	FN011426	Northville Stati	12.5	2035	MVD	139	142	145	148	151	155	158	161	164	168	171
131	FN011416	Ogdenbrook	24.6	2036	MVD	13	13	13	14	14	14	14	15	15	15	16
132	FN012130	Otten	0.3	2036	MVD	831	849	867	885	903	922	942	961	982	1,002	1,023
133	FN011443	OTTEN	0.5	2036	MVD	1,877	1,916	1,957	1,998	2,040	2,082	2,126	2,171	2,216	2,263	2,311
134	FN012945	Paloma	20.0	2036	Cap	0	0	0	0	0	0	0	0	0	0	0
135	FN011395	Partridge	15.0	2035	MVD	116	119	121	124	126	129	131	134	137	140	143
136	FN012618	Peat	22.0	2036	Cap	82	84	85	87	89	91	93	95	97	99	101
137	FN012004	PINEBUSH	0.7	2035	MVD	551	563	575	587	599	612	625	638	651	665	679
138	FN011397	Pinebush	32.6	2036	MVD	50	51	52	54	55	56	57	58	59	61	62
139	FN002263	Port Henry	2.5	2027	Cap	41	42	43	44	44	45	46	47	48	49	50
140	FN011433	Port Henry	14.5	2035	MVD	38	39	40	41	41	42	43	44	45	46	47
141	FN013957	Pottersville	13.0	2036	MVD	102	104	106	108	111	113	115	118	120	123	125
142	FN011942	Raquette Lake	0.5	2026	MVD	47	48	49	50	51	52	53	54	55	56	57
143	FN012721	North Chautau	4.0	2036	Cap	58	59	60	62	63	64	65	67	68	70	71
144	FN000126	RIVERSIDE	5.0	2033	MVD	312	319	326	332	339	347	354	361	369	377	384
145	FN011854	Rome Substati	5.0	2034	Cap	15	16	16	16	17	17	17	18	18	19	19
146	FN011852	Rome Substati	5.0	2031	Cap	92	94	96	98	100	102	104	106	109	111	113
147	FN011853	Rome Substati	5.0	2031	Cap	93	95	97	99	101	103	105	107	109	112	114
148	FN011856	Rome Substati	5.0	2034	Cap	15	16	16	16	17	17	17	18	18	19	19

**Niagara Mohawk Power Corporation d/b/a National Grid
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				Capital Spending \$000s												
Line	Reference	Station	Capacity Added MW	Prior to 2026 CapEx	FY26 Capex	FY27 Capex	FY28 Capex	FY29 Capex	FY30 Capex	FY31 Capex	FY32 Capex	FY33 Capex	FY34 Capex	FY35 Capex	FY36 Capex	Sum
	(A)	(A1)	(B)	(C26X)	(C26)	(C27)	(C28)	(C29)	(C30)	(C31)	(C32)	(C33)	(C34)	(C35)	(C36)	(C-Sum)
149	FN001348	Rotterdam	13.0	2,980	1,238	510	-	-	-	-	-	-	-	-	-	4,728
150	FN014168	RUSSELL RD	2.0	-	236	-	-	-	-	-	-	-	-	-	-	236
151	FN013424A	South Washing	5.0	-	-	-	-	-	-	-	396	1,523	6,066	387	-	8,372
152	FN011355A	Schenevus	3.0	-	-	-	-	84	1,506	828	82	-	-	-	-	2,500
153	FN011399	Schodack	17.6	-	-	-	-	-	-	-	109	1,464	10,632	10,632	6,496	29,333
154	FN011465	SCHROON LAK	4.8	234	294	149	-	-	-	-	-	-	-	-	-	677
155	FN011466	Scofield	29.5	-	-	50	472	-	-	-	-	-	-	-	-	522
156	FN002211	Scotia	9.1	2	-	10	-	-	-	-	15	188	225	9	-	450
157	FN001881	SELKIRK	2.5	73	438	-	-	-	-	-	-	-	-	-	-	511
158	FN006212	Sharon	2.1	7	-	-	-	1,391	-	-	-	-	-	-	-	1,398
159	FN006224	Sharon	2.0	113	-	56	756	-	-	-	-	-	-	-	-	925
160	FN013868	Shawnee Rd St	17.6	-	160	877	1,814	3,068	3,355	-	-	-	-	-	-	9,275
161	FN011715	Smith Bridge S	25.0	2,029	1,976	4,730	7,441	427	-	-	-	-	-	-	-	16,604
162	FN005814	EDEN CENTER	11.0	12,645	5,355	9,669	3,572	6	-	-	-	-	-	-	-	31,247
163	FN003350	NORTH COLLIN	5.6	5,714	665	-	-	-	-	-	-	-	-	-	-	6,379
164	FN011436	South Street	7.5	-	-	-	-	105	1,397	504	1,246	8,275	8,275	5,005	-	24,806
165	FN010876	Station 140	10.0	1,444	1,796	5,914	11,599	8,065	8	-	-	-	-	-	-	28,825
166	FN006255	Station 3012	9.0	31,194	10,875	3,000	-	-	-	-	-	-	-	-	-	45,069
167	FN005886	Station 61	35.0	1,063	200	200	1,500	3,523	6,188	10,218	320	-	-	-	-	23,211
168	FN011383	Summit	2.4	-	-	-	-	95	1,258	366	1,096	7,390	7,390	4,795	-	22,390
169	FN011069	Swaggertown	23.4	476	175	536	1,952	4,184	6,534	9,139	6,388	2,948	-	-	-	32,332
170	FN011562	Swann Rd	5.0	-	-	-	-	-	-	-	-	743	1,584	743	-	3,069
171	FN012826	78 FASSETT ST	5.0	-	-	-	-	-	-	-	-	417	2,951	4,432	4,095	11,896
172	FN005852	TULLER HILL	6.0	32	170	169	-	-	-	-	-	-	-	-	-	371
173	FN011404	UNIONVILLE	2.0	-	-	135	487	520	500	7,420	621	487	-	-	-	10,170
174	FN011406	UNIONVILLE	7.5	-	-	-	-	-	-	-	-	-	155	2,063	745	2,963
175	FN011310	214 Station	23.6	-	-	-	-	-	-	-	-	-	-	-	1,134	1,134
176	FN012943	Paloma	20.0	-	-	-	-	-	-	-	-	-	128	1,059	613	1,800
177	FN006357	VAIL MILLS	4.0	1,603	496	-	-	-	-	-	-	-	-	-	-	2,099
178	FN006234	VAIL MILLS	16.0	-	-	25	250	-	-	-	-	-	-	-	-	275
179	FN011427	VAIL MILLS	15.0	-	-	-	-	-	-	-	-	-	-	110	1,466	1,577
180	FN011996	Valkin	57.6	-	510	1,190	4,900	950	-	-	-	-	-	-	-	7,550
181	FN013976	Van Hoesen	48.2	-	-	-	-	620	4,867	6,673	7,140	11,673	11,673	5,730	-	48,376
182	FN011400	Voorheesville	15.0	-	-	-	-	110	1,466	529	1,479	10,739	10,739	6,496	-	31,559
183	FN006517	CHAUTAUQUA	4.0	-	-	50	525	-	-	-	-	-	-	-	-	575
184	FN012599	Walesville	14.0	-	-	-	-	-	-	-	4,803	1,074	5,888	5,968	2,656	20,390
185	FN002225	Warrensburg	0.5	-	15	1,184	-	-	-	-	-	-	-	-	-	1,199

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Line	Reference	Station	Capacity Added MW	Capital Spending \$000s					Capital \$000s per Capacity Added MW					E
				T_Station	T_Line	D_Station	D_Line	Sum	T_Station	T_Line	D_Station	D_Line	Sum	
				(C-TS)	(C-TL)	(C-DS)	(C-DL)	(C)	(D-TS)	(D-TL)	(D-DS)	(D-DL)	(D)	
				(C-TS)/(B)	(C-TL)/(B)	(C-DS)/(B)	(C-DL)/(B)		(D-TS)/(B)	(D-TL)/(B)	(D-DS)/(B)	(D-DL)/(B)		
149	FN001348	Rotterdam	13.0	-	-	-	4,728	4,728	-	-	-	364	364	
150	FN014168	RUSSELL RD	2.0	-	-	-	236	236	-	-	-	118	118	
151	FN013424A	South Washing	5.0	-	-	-	8,372	8,372	-	-	-	1,674	1,674	
152	FN011355A	Schenevus	3.0	-	-	2,500	-	2,500	-	-	833	-	833	
153	FN011399	Schodack	17.6	-	-	29,333	-	29,333	-	-	1,667	-	1,667	
154	FN011465	SCHROON LAK	4.8	-	-	-	677	677	-	-	-	141	141	
155	FN011466	Scofield	29.5	-	-	522	-	522	-	-	18	-	18	
156	FN002211	Scotia	9.1	-	-	450	-	450	-	-	49	-	49	
157	FN001881	SELKIRK	2.5	-	-	-	511	511	-	-	-	204	204	
158	FN006212	Sharon	2.1	-	-	-	1,398	1,398	-	-	-	678	678	
159	FN006224	Sharon	2.0	-	-	-	925	925	-	-	-	471	471	
160	FN013868	Shawnee Rd St	17.6	-	-	9,275	-	9,275	-	-	527	-	527	
161	FN011715	Smith Bridge S	25.0	-	-	9,572	7,032	16,604	-	-	383	281	664	
162	FN005814	EDEN CENTER	11.0	-	-	26,058	5,188	31,247	-	-	2,369	472	2,841	
163	FN003350	NORTH COLLIN	5.6	-	-	-	6,379	6,379	-	-	-	1,139	1,139	
164	FN011436	South Street	7.5	-	-	24,806	-	24,806	-	-	3,308	-	3,308	
165	FN010876	Station 140	10.0	-	-	28,825	-	28,825	-	-	2,882	-	2,882	
166	FN006255	Station 3012	9.0	-	-	27,114	17,955	45,069	-	-	3,013	1,995	5,008	
167	FN005886	Station 61	35.0	-	-	23,211	-	23,211	-	-	663	-	663	
168	FN011383	Summit	2.4	-	-	22,390	-	22,390	-	-	9,408	-	9,408	
169	FN011069	Swaggertown	23.4	-	-	11,289	21,043	32,332	-	-	482	899	1,382	
170	FN011562	Swann Rd	5.0	-	-	-	3,069	3,069	-	-	-	614	614	
171	FN012826	78 FASSETT ST	5.0	-	-	-	11,896	11,896	-	-	-	2,379	2,379	
172	FN005852	TULLER HILL	6.0	-	-	-	371	371	-	-	-	62	62	
173	FN011404	UNIONVILLE	2.0	-	-	-	10,170	10,170	-	-	-	5,085	5,085	
174	FN011406	UNIONVILLE	7.5	-	-	2,963	-	2,963	-	-	395	-	395	
175	FN011310	214 Station	23.6	-	1,000	134	-	1,134	-	42	6	-	48	
176	FN012943	Paloma	20.0	-	-	1,800	-	1,800	-	-	90	-	90	
177	FN006357	VAIL MILLS	4.0	-	-	-	2,099	2,099	-	-	-	525	525	
178	FN006234	VAIL MILLS	16.0	-	-	-	275	275	-	-	-	17	17	
179	FN011427	VAIL MILLS	15.0	-	-	1,577	-	1,577	-	-	105	-	105	
180	FN011996	Valkin	57.6	-	-	4,740	2,810	7,550	-	-	82	49	131	
181	FN013976	Van Hoesen	48.2	-	-	17,127	31,249	48,376	-	-	355	648	1,004	
182	FN011400	Voorheesville	15.0	-	-	31,559	-	31,559	-	-	2,104	-	2,104	
183	FN006517	CHAUTAUQUA	4.0	-	-	-	575	575	-	-	-	144	144	
184	FN012599	Walesville	14.0	-	-	-	20,390	20,390	-	-	-	1,456	1,456	
185	FN002225	Warrensburg	0.5	-	-	-	1,199	1,199	-	-	-	2,399	2,399	

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		CCR Rates=>							
						8.21%	8.44%	8.06%	14.13%
		Annual Cost \$000s Using ECCR per Capacity Added MW							
Line	Reference	Station	Capacity Added MW	In-Service Year	T_Station	T_Line	D_Station	D_Line	Sum
(A)	(A1)	(B)	(F)		(E-TS)	(E-TL)	(E-DS)	(E-DL)	(E)
					(D-TS)*ECCR	(D-TL)*ECCR	(D-DS)*ECCR	(D-DL)*ECCR	
149	FN001348	Rotterdam	13.0	2027	-	-	-	51	51
150	FN014168	RUSSELL RD	2.0	2026	-	-	-	17	17
151	FN013424A	South Washing	5.0	2035	-	-	-	237	237
152	FN011355A	Schenevus	3.0	2032	-	-	67	-	67
153	FN011399	Schodack	17.6	2036	-	-	134	-	134
154	FN011465	SCHROON LAK	4.8	2027	-	-	-	20	20
155	FN011466	Scotfield	29.5	2028	-	-	1	-	1
156	FN002211	Scotia	9.1	2035	-	-	4	-	4
157	FN001881	SELKIRK	2.5	2026	-	-	-	29	29
158	FN006212	Sharon	2.1	2029	-	-	-	96	96
159	FN006224	Sharon	2.0	2028	-	-	-	67	67
160	FN013868	Shawnee Rd St	17.6	2030	-	-	42	-	42
161	FN011715	Smith Bridge S	25.0	2029	-	-	31	40	71
162	FN005814	EDEN CENTER	11.0	2029	-	-	191	67	258
163	FN003350	NORTH COLLIN	5.6	2026	-	-	-	161	161
164	FN011436	South Street	7.5	2035	-	-	267	-	267
165	FN010876	Station 140	10.0	2030	-	-	232	-	232
166	FN006255	Station 3012	9.0	2027	-	-	243	282	525
167	FN005886	Station 61	35.0	2032	-	-	53	-	53
168	FN011383	Summit	2.4	2035	-	-	758	-	758
169	FN011069	Swaggertown	23.4	2033	-	-	39	127	166
170	FN011562	Swann Rd	5.0	2035	-	-	-	87	87
171	FN012826	78 FASSETT ST	5.0	2036	-	-	-	336	336
172	FN005852	TULLER HILL	6.0	2027	-	-	-	9	9
173	FN011404	UNIONVILLE	2.0	2033	-	-	-	718	718
174	FN011406	UNIONVILLE	7.5	2036	-	-	32	-	32
175	FN011310	214 Station	23.6	2036	-	4	0	-	4
176	FN012943	Paloma	20.0	2036	-	-	7	-	7
177	FN006357	VAIL MILLS	4.0	2026	-	-	-	74	74
178	FN006234	VAIL MILLS	16.0	2028	-	-	-	2	2
179	FN011427	VAIL MILLS	15.0	2036	-	-	8	-	8
180	FN011996	Valkin	57.6	2029	-	-	7	7	14
181	FN013976	Van Hoesen	48.2	2035	-	-	29	92	120
182	FN011400	Voorheesville	15.0	2035	-	-	170	-	170
183	FN006517	CHAUTAUQUA	4.0	2028	-	-	-	20	20
184	FN012599	Walesville	14.0	2036	-	-	-	206	206
185	FN002225	Warrensburg	0.5	2027	-	-	-	339	339

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Line	Reference	Station	Capacity Added MW	In-Service Year	Rationale	Annual Inflation=> 102.1%										
						Marginal Cost \$000s in Each Year										
						2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
	(A)	(A1)	(B)	(F)	(F-1)	(F26)	(F27)	(F28)	(F29)	(F30)	(F31)	(F32)	(F33)	(F34)	(F35)	(F36)
149	FN001348	Rotterdam	13.0	2027	MVD	50	51	52	54	55	56	57	58	59	61	62
150	FN014168	RUSSELL RD	2.0	2026	Cap	17	17	17	18	18	18	19	19	20	20	21
151	FN013424A	South Washing	5.0	2035	MVD	196	200	205	209	213	218	222	227	232	237	242
152	FN011355A	Schenevus	3.0	2032	MVD	59	61	62	63	64	66	67	69	70	71	73
153	FN011399	Schodack	17.6	2036	MVD	109	111	114	116	119	121	124	126	129	132	134
154	FN011465	SCHROON LAK	4.8	2027	MVD	20	20	20	21	21	22	22	23	23	24	24
155	FN011466	Scofield	29.5	2028	MVD	1	1	1	1	1	2	2	2	2	2	2
156	FN002211	Scotia	9.1	2035	MVD	3	3	3	4	4	4	4	4	4	4	4
157	FN001881	SELKIRK	2.5	2026	Cap	29	29	30	31	31	32	33	33	34	35	36
158	FN006212	Sharon	2.1	2029	Cap	90	92	94	96	98	100	102	104	106	109	111
159	FN006224	Sharon	2.0	2028	Cap	64	65	67	68	69	71	72	74	75	77	79
160	FN013868	Shawnee Rd St	17.6	2030	MVD	39	40	41	42	42	43	44	45	46	47	48
161	FN011715	Smith Bridge S	25.0	2029	MVD	66	68	69	71	72	74	75	77	78	80	82
162	FN005814	EDEN CENTER	11.0	2029	Cap	242	247	252	258	263	268	274	280	286	292	298
163	FN003350	NORTH COLLIN	5.6	2026	MVD	161	164	168	171	175	179	182	186	190	194	198
164	FN011436	South Street	7.5	2035	MVD	221	226	230	235	240	245	250	256	261	267	272
165	FN010876	Station 140	10.0	2030	MVD	214	218	223	228	232	237	242	247	252	258	263
166	FN006255	Station 3012	9.0	2027	Cap	514	525	536	547	558	570	582	594	607	620	633
167	FN005886	Station 61	35.0	2032	MVD	47	48	49	50	51	52	53	55	56	57	58
168	FN011383	Summit	2.4	2035	MVD	629	642	656	669	683	698	712	727	743	758	774
169	FN011069	Swaggertown	23.4	2033	MVD	143	146	150	153	156	159	163	166	169	173	177
170	FN011562	Swann Rd	5.0	2035	Cap	72	73	75	77	78	80	81	83	85	87	89
171	FN012826	78 FASSETT ST	5.0	2036	MVD	273	279	285	291	297	303	309	316	322	329	336
172	FN005852	TULLER HILL	6.0	2027	MVD	9	9	9	9	9	9	10	10	10	10	11
173	FN011404	UNIONVILLE	2.0	2033	MVD	621	634	648	661	675	689	704	718	734	749	765
174	FN011406	UNIONVILLE	7.5	2036	MVD	26	26	27	28	28	29	29	30	31	31	32
175	FN011310	214 Station	23.6	2036	Cap	3	3	3	3	4	4	4	4	4	4	4
176	FN012943	Paloma	20.0	2036	Cap	6	6	6	6	6	7	7	7	7	7	7
177	FN006357	VAIL MILLS	4.0	2026	Cap	74	76	77	79	81	82	84	86	88	89	91
178	FN006234	VAIL MILLS	16.0	2028	Cap	2	2	2	2	3	3	3	3	3	3	3
179	FN011427	VAIL MILLS	15.0	2036	MVD	7	7	7	7	7	8	8	8	8	8	8
180	FN011996	Valkin	57.6	2029	Cap	13	13	13	14	14	14	14	15	15	15	16
181	FN013976	Van Hoesen	48.2	2035	Cap	100	102	104	106	108	111	113	115	118	120	123
182	FN011400	Voorheesville	15.0	2035	MVD	141	144	147	150	153	156	159	163	166	170	173
183	FN006517	CHAUTAUQUA	4.0	2028	Cap	19	20	20	21	21	22	22	23	23	23	24
184	FN012599	Walesville	14.0	2036	MVD	167	171	174	178	182	185	189	193	197	202	206
185	FN002225	Warrensburg	0.5	2027	Cap	332	339	346	353	361	368	376	384	392	400	409

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Capital Spending \$000s																
Line	Reference	Station	Capacity Added MW	Prior to 2026 CapEx	FY26 Capex	FY27 Capex	FY28 Capex	FY29 Capex	FY30 Capex	FY31 Capex	FY32 Capex	FY33 Capex	FY34 Capex	FY35 Capex	FY36 Capex	Sum
	(A)	(A1)	(B)	(C26X)	(C26)	(C27)	(C28)	(C29)	(C30)	(C31)	(C32)	(C33)	(C34)	(C35)	(C36)	(C-Sum)
186	FN011538	Watt	5.8	-	-	-	-	-	-	-	-	-	-	1,626	7,405	9,031
187	FN011539	WEAVER ST	4.1	-	-	-	-	20	2,000	2,000	2,122	3,617	2,583	1,442	9,579	23,363
188	FN011423	Wells	3.4	-	-	-	-	105	1,397	504	1,246	8,275	8,275	5,005	-	24,806
189	FN012598	Whitesboro	12.0	-	-	-	-	-	-	-	-	2,628	10,108	15,320	322	28,378
190	FN011388	WOLF RD.	3.0	-	-	-	137	525	4,100	1,755	-	-	-	-	-	6,516
191																
192	FN010073	Transm Net	14.0	6,286	13,101	13,979	21,791	11,093	487	-	-	-	-	-	-	66,738
193	FN011214	Transm Net	105.0	22,074	19,765	26,032	17,789	7,973	-	-	-	-	-	-	-	93,633
194	FN010083	Transm Net	100.0	12,446	1,645	1,428	7,499	22,071	56,418	28,145	-	-	-	-	-	129,651
195	FN008736	Transm Net	20.0	788	959	1,479	260	480	1,116	7,855	3,585	-	-	-	-	16,523
196	FN008276	Transm Net	1,650.0	790,120	335,213	584,478	587,301	517,455	271,502	2,911	540	3,877	35,120	35,120	38,867	3,202,505
197	FN011526	Transm Net	52.1	-	-	-	-	-	-	-	-	-	-	104	2,397	2,501
198	FN008017	Transm Net	28.0	143	-	-	-	-	110	330	480	7,121	7,859	-	-	16,043
199	FN008359	Transm Net	800.0	80,083	29,940	64,455	70,183	44,340	12,571	-	-	-	-	-	-	301,571
200	FN008347	Transm Net	380.0	34,496	19,424	14,915	4,187	17	18	-	-	-	-	-	-	73,057
201	FN008061	Transm Net	33.0	-	-	-	-	-	-	-	-	-	-	-	450	450
202	FN013189	Transm Net	20.0	-	-	-	-	-	98	1,960	6,860	882	-	-	-	9,800
203	FN013188	Transm Net	34.0	-	-	-	-	-	-	-	98	882	-	-	-	980
204	FN008471	Transm Net	16.0	20,102	1,446	1,038	142	-	-	-	-	-	-	-	-	22,728
205	FN012042	Transm Net	40.0	-	120	220	830	4,570	4,650	500	-	-	-	-	-	10,890
206	FN012047	Transm Net	40.0	-	120	220	890	5,380	1,470	500	-	-	-	-	-	8,580
207	FN012044	Transm Net	40.0	-	120	220	1,070	3,750	4,500	750	-	-	-	-	-	10,410
208	FN012050	Transm Net	40.0	-	120	220	740	3,580	1,020	500	-	-	-	-	-	6,180
209	FN012039	Transm Net	40.0	-	120	175	950	2,850	2,100	500	-	-	-	-	-	6,695
210	FN008333	Transm Net	18.0	127	231	-	-	-	-	-	-	-	-	-	-	359
211	FN010064	Transm Net	75.0	26,931	13,205	11,212	928	-	-	-	-	-	-	-	-	52,276
212	FN008052	Transm Net	160.0	1,296	250	500	500	5,000	20,000	4,295	-	-	-	-	-	31,841
213																
214	FN010080	Transm Net	20.0	128,202	36,501	13,284	-	-	-	-	-	-	-	-	-	177,987
215	FN011215	Transm Net	10.0	7,471	-	-	-	-	250	3,506	5,634	4,900	-	-	-	21,761
216	FN010078	Transm Net	25.0	11,533	6,066	2,241	-	-	-	-	-	-	-	-	-	19,840
217	FN010094	Transm Net	130.0	10,974	5,685	4,350	4,500	24,226	39,461	41,666	53,386	53,761	49,056	27,946	-	315,010
218	FN011642	Transm Net	550.0	214,519	71,737	185,671	138,394	85,282	27,854	481	-	-	-	-	105	724,043
219	FN011630	Transm Net	40.0	-	-	-	-	-	-	-	110	1,466	529	1,479	10,739	14,323
220	FN010084	Transm Net	5.0	6,009	1,375	775	645	3,170	15,508	20,514	31,069	27,052	450	-	-	106,567
221	FN008253	Transm Net	312.0	-	-	50	470	680	6,250	15,000	39,250	39,250	37,950	34,140	-	173,040
222	FN008254	Transm Net	312.0	-	-	50	470	680	6,810	15,000	40,000	40,000	40,000	41,540	18,355	202,905

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				Capital Spending \$000s					Capital \$000s per Capacity Added MW					
Line	Reference	Station	Capacity Added MW	T_Station	T_Line	D_Station	D_Line	Sum	T_Station	T_Line	D_Station	D_Line	Sum	
	(A)	(A1)	(B)	(C-TS)	(C-TL)	(C-DS)	(C-DL)	(C)	(D-TS)	(D-TL)	(D-DS)	(D-DL)	(D)	
									(C-TS)/(B)	(C-TL)/(B)	(C-DS)/(B)	(C-DL)/(B)		
186	FN011538	Watt	5.8	-	-	1,739	7,292	9,031	-	-	300	1,257	1,557	
187	FN011539	WEAVER ST	4.1	-	-	13,343	10,020	23,363	-	-	3,254	2,444	5,698	
188	FN011423	Wells	3.4	-	-	24,806	-	24,806	-	-	7,211	-	7,211	
189	FN012598	Whitesboro	12.0	-	-	-	28,378	28,378	-	-	-	2,365	2,365	
190	FN011388	WOLF RD.	3.0	-	-	-	6,516	6,516	-	-	-	2,172	2,172	
191														
192	FN010073	Transm Net	14.0	2,955	63,783	-	-	66,738	211	4,556	-	-	4,767	
193	FN011214	Transm Net	105.0	6,554	87,079	-	-	93,633	62	829	-	-	892	
194	FN010083	Transm Net	100.0	20,374	109,277	-	-	129,651	204	1,093	-	-	1,297	
195	FN008736	Transm Net	20.0	16,523	-	-	-	16,523	826	-	-	-	826	
196	FN008276	Transm Net	1,650.0	1,258,925	1,943,580	-	-	3,202,505	763	1,178	-	-	1,941	
197	FN011526	Transm Net	52.1	-	1,000	1,501	-	2,501	-	19	29	-	48	
198	FN008017	Transm Net	28.0	-	16,043	-	-	16,043	-	573	-	-	573	
199	FN008359	Transm Net	800.0	4,481	297,091	-	-	301,571	6	371	-	-	377	
200	FN008347	Transm Net	380.0	1,416	71,641	-	-	73,057	4	189	-	-	192	
201	FN008061	Transm Net	33.0	-	450	-	-	450	-	14	-	-	14	
202	FN013189	Transm Net	20.0	9,800	-	-	-	9,800	490	-	-	-	490	
203	FN013188	Transm Net	34.0	-	980	-	-	980	-	29	-	-	29	
204	FN008471	Transm Net	16.0	22,728	-	-	-	22,728	1,420	-	-	-	1,420	
205	FN012042	Transm Net	40.0	-	10,890	-	-	10,890	-	272	-	-	272	
206	FN012047	Transm Net	40.0	-	8,580	-	-	8,580	-	215	-	-	215	
207	FN012044	Transm Net	40.0	-	10,410	-	-	10,410	-	260	-	-	260	
208	FN012050	Transm Net	40.0	-	6,180	-	-	6,180	-	155	-	-	155	
209	FN012039	Transm Net	40.0	-	6,695	-	-	6,695	-	167	-	-	167	
210	FN008333	Transm Net	18.0	-	359	-	-	359	-	20	-	-	20	
211	FN010064	Transm Net	75.0	48,377	3,899	-	-	52,276	645	52	-	-	697	
212	FN008052	Transm Net	160.0	-	31,841	-	-	31,841	-	199	-	-	199	
213														
214	FN010080	Transm Net	20.0	149,826	13,733	-	14,428	177,987	7,491	687	-	721	8,899	
215	FN011215	Transm Net	10.0	21,761	-	-	-	21,761	2,176	-	-	-	2,176	
216	FN010078	Transm Net	25.0	19,840	-	-	-	19,840	794	-	-	-	794	
217	FN010094	Transm Net	130.0	125,706	24,660	-	164,644	315,010	967	190	-	1,266	2,423	
218	FN011642	Transm Net	550.0	274,761	449,282	-	-	724,043	500	817	-	-	1,316	
219	FN011630	Transm Net	40.0	14,323	-	-	-	14,323	358	-	-	-	358	
220	FN010084	Transm Net	5.0	64,916	41,651	-	-	106,567	12,983	8,330	-	-	21,313	
221	FN008253	Transm Net	312.0	-	173,040	-	-	173,040	-	555	-	-	555	
222	FN008254	Transm Net	312.0	-	202,905	-	-	202,905	-	650	-	-	650	

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CCR Rates=>					8.21%	8.44%	8.06%	14.13%		
					Annual Cost \$000s Using ECCR per Capacity Added MW					
Line	Reference	Station	Capacity Added MW	In-Service Year	T_Station	T_Line	D_Station	D_Line	Sum	
		(A)	(A1)	(B)	(F)	(E-TS)	(E-TL)	(E-DS)	(E-DL)	(E)
					(D-TS)*ECCR	(D-TL)*ECCR	(D-DS)*ECCR	(D-DL)*ECCR		
186	FN011538	Watt	5.8	2036	-	-	24	178	202	
187	FN011539	WEAVER ST	4.1	2036	-	-	262	345	608	
188	FN011423	Wells	3.4	2035	-	-	581	-	581	
189	FN012598	Whitesboro	12.0	2036	-	-	-	334	334	
190	FN011388	WOLF RD.	3.0	2031	-	-	-	307	307	
191										
192	FN010073	Transm Net	14.0	2030	17	385	-	-	402	
193	FN011214	Transm Net	105.0	2029	5	70	-	-	75	
194	FN010083	Transm Net	100.0	2031	17	92	-	-	109	
195	FN008736	Transm Net	20.0	2032	68	-	-	-	68	
196	FN008276	Transm Net	1,650.0	2036	63	99	-	-	162	
197	FN011526	Transm Net	52.1	2036	-	2	2	-	4	
198	FN008017	Transm Net	28.0	2034	-	48	-	-	48	
199	FN008359	Transm Net	800.0	2030	0	31	-	-	32	
200	FN008347	Transm Net	380.0	2030	0	16	-	-	16	
201	FN008061	Transm Net	33.0	2036	-	1	-	-	1	
202	FN013189	Transm Net	20.0	2033	40	-	-	-	40	
203	FN013188	Transm Net	34.0	2033	-	2	-	-	2	
204	FN008471	Transm Net	16.0	2028	117	-	-	-	117	
205	FN012042	Transm Net	40.0	2031	-	23	-	-	23	
206	FN012047	Transm Net	40.0	2031	-	18	-	-	18	
207	FN012044	Transm Net	40.0	2031	-	22	-	-	22	
208	FN012050	Transm Net	40.0	2031	-	13	-	-	13	
209	FN012039	Transm Net	40.0	2031	-	14	-	-	14	
210	FN008333	Transm Net	18.0	2026	-	2	-	-	2	
211	FN010064	Transm Net	75.0	2028	53	4	-	-	57	
212	FN008052	Transm Net	160.0	2031	-	17	-	-	17	
213										
214	FN010080	Transm Net	20.0	2027	615	58	-	102	775	
215	FN011215	Transm Net	10.0	2033	179	-	-	-	179	
216	FN010078	Transm Net	25.0	2027	65	-	-	-	65	
217	FN010094	Transm Net	130.0	2035	79	16	-	179	274	
218	FN011642	Transm Net	550.0	2036	41	69	-	-	110	
219	FN011630	Transm Net	40.0	2036	29	-	-	-	29	
220	FN010084	Transm Net	5.0	2034	1,065	703	-	-	1,769	
221	FN008253	Transm Net	312.0	2035	-	47	-	-	47	
222	FN008254	Transm Net	312.0	2036	-	55	-	-	55	

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Line	Reference	Station	Capacity Added MW	In-Service Year	Rationale	Annual Inflation=> 102.1%										
						Marginal Cost \$000s in Each Year										
						2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
	(A)	(A1)	(B)	(F)	(F-1)	(F26)	(F27)	(F28)	(F29)	(F30)	(F31)	(F32)	(F33)	(F34)	(F35)	(F36)
186	FN011538	Watt	5.8	2036	MVD	164	167	171	174	178	182	186	190	194	198	202
187	FN011539	WEAVER ST	4.1	2036	MVD	494	504	515	525	536	548	559	571	583	595	608
188	FN011423	Wells	3.4	2035	MVD	482	492	502	513	524	535	546	557	569	581	593
189	FN012598	Whitesboro	12.0	2036	MVD	271	277	283	289	295	301	307	314	321	327	334
190	FN011388	WOLF RD.	3.0	2031	MVD	277	282	288	294	301	307	313	320	327	333	341
191																
192	FN010073	Transm Net	14.0	2030	Cap	370	378	386	394	402	410	419	428	437	446	455
193	FN011214	Transm Net	105.0	2029	MVT	71	72	74	75	77	78	80	82	83	85	87
194	FN010083	Transm Net	100.0	2031	MVT	98	100	102	105	107	109	111	114	116	118	121
195	FN008736	Transm Net	20.0	2032	MVT	60	61	62	64	65	66	68	69	71	72	74
196	FN008276	Transm Net	1,650.0	2036	MVT	132	134	137	140	143	146	149	152	155	159	162
197	FN011526	Transm Net	52.1	2036	Cap	3	3	3	3	3	4	4	4	4	4	4
198	FN008017	Transm Net	28.0	2034	MVT	41	42	43	44	45	45	46	47	48	49	50
199	FN008359	Transm Net	800.0	2030	MVT	29	30	31	31	32	32	33	34	35	35	36
200	FN008347	Transm Net	380.0	2030	MVT	15	15	16	16	16	17	17	17	18	18	18
201	FN008061	Transm Net	33.0	2036	Cap	1	1	1	1	1	1	1	1	1	1	1
202	FN013189	Transm Net	20.0	2033	Cap	35	35	36	37	38	39	39	40	41	42	43
203	FN013188	Transm Net	34.0	2033	Cap	2	2	2	2	2	2	2	2	2	3	3
204	FN008471	Transm Net	16.0	2028	MVT	112	114	117	119	122	124	127	129	132	135	138
205	FN012042	Transm Net	40.0	2031	Cap	21	21	22	22	23	23	23	24	24	25	25
206	FN012047	Transm Net	40.0	2031	Cap	16	17	17	17	18	18	18	19	19	20	20
207	FN012044	Transm Net	40.0	2031	Cap	20	20	21	21	22	22	22	23	23	24	24
208	FN012050	Transm Net	40.0	2031	Cap	12	12	12	13	13	13	13	14	14	14	14
209	FN012039	Transm Net	40.0	2031	Cap	13	13	13	14	14	14	14	15	15	15	16
210	FN008333	Transm Net	18.0	2026	MVT	2	2	2	2	2	2	2	2	2	2	2
211	FN010064	Transm Net	75.0	2028	MVT	55	56	57	59	60	61	62	64	65	66	68
212	FN008052	Transm Net	160.0	2031	Cap	15	15	16	16	16	17	17	18	18	18	19
213																
214	FN010080	Transm Net	20.0	2027	MVT	759	775	791	807	824	842	859	877	896	915	934
215	FN011215	Transm Net	10.0	2033	MVT	154	158	161	164	168	171	175	179	182	186	190
216	FN010078	Transm Net	25.0	2027	MVT	64	65	66	68	69	71	72	74	75	77	79
217	FN010094	Transm Net	130.0	2035	Cap	228	232	237	242	247	252	258	263	269	274	280
218	FN011642	Transm Net	550.0	2036	MVT	89	91	93	95	97	99	101	103	105	108	110
219	FN011630	Transm Net	40.0	2036	Cap	24	24	25	25	26	26	27	28	28	29	29
220	FN010084	Transm Net	5.0	2034	MVT	1,498	1,529	1,561	1,594	1,627	1,662	1,697	1,732	1,769	1,806	1,844
221	FN008253	Transm Net	312.0	2035	MVT	39	40	40	41	42	43	44	45	46	47	48
222	FN008254	Transm Net	312.0	2036	MVT	45	46	46	47	48	49	51	52	53	54	55

**Niagara Mohawk Power Corporation d/b/a National Grid
Marginal Cost Study Case 19-E-0283 and Case 15-E-0751
Capital Spending, Capital Cost per MW and Marginal Cost BY SUBSTATION**

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**Niagara Mohawk Power Corporation d/b/a National Grid
Marginal Cost Study Case 19-E-0283 and Case 15-E-0751
Capital Spending, Capital Cost per MW and Marginal Cost BY SUBSTATION**

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Niagara Mohawk Power Corporation d/b/a National Grid
Marginal Cost Study Case 19-E-0283 and Case 15-E-0751
Capital Spending, Capital Cost per MW and Marginal Cost BY SUBSTATION

						Annual Inflation=>	102.1%										
						Marginal Cost \$000s in Each Year											
Line	Reference	Station	Capacity Added MW	In-Service Year	Rationale	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	
	(A)	(A1)	(B)	(F)	(F-1)	(F26)	(F27)	(F28)	(F29)	(F30)	(F31)	(F32)	(F33)	(F34)	(F35)	(F36)	
223	FN008453	Transm Net	200.0	2028	MVT	7	7	7	8	8	8	8	8	8	9	9	
224	FN013571	Transm Net	1,100.0	2036	Cap	9	9	9	9	10	10	10	10	10	11	11	
225	FN013182	Transm Net	844.0	2036	Cap	9	9	10	10	10	10	11	11	11	11	11	
226	FN013318	Transm Net	104.0	2036	MVT	1	1	1	1	1	1	2	2	2	2	2	
227	FN008063	Transm Net	40.0	2027	Cap	6	6	7	7	7	7	7	7	8	8	8	
228	FN010255	Transm Net	24.0	2036	MVT	10	10	10	10	10	11	11	11	11	12	12	
229	FN008472	Transm Net	10.0	2029	MVT	28	28	29	29	30	31	31	32	33	33	34	
230	FN008116	Transm Net	30.0	2036	MVT	374	382	390	398	407	415	424	433	442	451	461	
231	FN008374	Transm Net	1,000.0	2027	MVT	77	78	80	82	83	85	87	89	91	93	95	
232	FN008262	Transm Net	97.0	2036	MVT	43	44	45	46	47	48	49	50	51	52	53	
233	FN008260	Transm Net	40.0	2036	MVT	1	1	1	1	1	1	1	1	1	1	1	
234	FN008683	Transm Net	10.0	2033	MVT	360	367	375	383	391	399	408	416	425	434	443	
235	FN013316	Transm Net	11.0	2033	Cap	65	66	68	69	71	72	74	75	77	78	80	
236	FN011646	Transm Net	10.0	2036	MVT	42	43	44	45	46	47	48	49	50	51	52	
237	FN013525	Transm Net	10.0	2031	MVT	138	141	144	147	150	153	156	159	163	166	170	
238	FN011289	Transm Net	25.0	2036	Cap	8	8	8	8	8	9	9	9	9	9	10	
239	FN011396	Transm Net	25.0	2036	Cap	102	104	106	108	110	113	115	117	120	122	125	
240	FN013572	Transm Net	200.0	2032	Cap	57	58	59	61	62	63	64	66	67	69	70	
241	FN010101	Transm Net	100.0	2026	MVT	202	206	210	215	219	224	228	233	238	243	248	
242																	
243																	
244																	
245	Sum		11,532.5			71.524	73.026	74.559	76.125	77.724	79.356	81.022	82.724	84.461	86.235	88.046	
246																	
247	Capacity Added				11,533	142	1,178	370	242	1,258	891	391	195	265	816	5,787	
248	Discount Factor to 2026					1.0000	1.0210	1.0424	1.0643	1.0867	1.1095	1.1328	1.1566	1.1809	1.2057	1.2310	
249	Total Marginal cost of Capacity					10,150	85,995	27,577	18,396	97,743	70,686	31,657	16,115	22,348	70,391	509,500	
250	Capacity Weighted Discounted Marginal Cost					10,150	84,226	26,454	17,285	89,946	63,710	27,946	13,933	18,925	58,383	413,892	
251	All-Year Weighted Average Marginal Annual Cost per MW Added					71.524											
252																	

Exhibit 2
Page 1 of 1

Exhibit 2

Niagara Mohawk Power Corporation d/b/a National Grid
Marginal Cost Study Case 19-E-0283 and Case 15-E-0751
Economic Carrying Charge Rates

Line

1	ECCR Exhibits	Exhibit Reference
2	Economic Carrying Charge Rates	Exhibit 2
3	Transmission Stations Economic Carrying Charge Rate	Exhibit 2-TS
4	Transmission Lines Economic Carrying Charge Rate	Exhibit 2-TL
5	Distribution Stations Economic Carrying Charge Rate	Exhibit 2-DS
6	Distribution Lines Economic Carrying Charge Rate	Exhibit 2-DL
7	O&M Costs	Exhibit 2-OM
8	Other Taxes Applicable to Plant	Exhibit 2-Tax

10 **ECCR Inputs**

11	Account Title	Account	Weighting (from Sch 5A)	Book Life	Salvage Value	Economic Carrying Charge Rate
12	Transmission Stations			47.6	(7%)	8.21% T_Station
13	Transmission Lines			65.8	(39%)	8.44% T_Line
14						
15	Distribution Stations	362		61.55	(15%)	8.06% D_Station
16	Distribution Lines	362-367		56.7	(24%)	14.13% D_Line
17	(includes Transformers)					

Annual Economic Carrying Charge Rate Parameters

20		Cost of Capital	O&M Expense	Insurance	Property Tax		
21	Applied to==>	Rate Base	Gross plant / Inflated	Gross plant / Inflated	Net Plant		Inflation Annual Rate
22	Transmission Stations	6.87%	1.33%	0.10%	2.02%	2.09%	1.0210
23	Transmission Lines	6.87%	2.09%	0.10%	2.02%	2.09%	1.0210
24							
25	Distribution Stations	6.87%	1.59%	0.10%	2.02%	#DIV/0!	1.0210
26	Distribution Lines	6.87%	7.49%	0.10%	2.02%	7.49%	1.0210

Other Factors

29	General Inflation (from 12/31/22 to 3/31/25)	
30	Annual Rate	2.1000%
31	Annual Inflator	102.1000%
32	WACC	6.87%
33	Wtd Equity	4.56%

Exhibit 2-TS

Niagara Mohawk Power Corporation d/b/a National Grid
Marginal Cost Study Case 19-E-0283 and Case 15-E-0751
Transmission Stations Economic Carrying Charge Rate

Line	Transmission Stations			
1				
2	Original Cost			Federal Tax
3	Original Cost \$	<i>Cost</i>	\$100.00	FIT Basis \$ <i>FIT_Basis</i> \$100.00
4	Depreciable life years	<i>Depr_Life</i>	47.60	FIT depreciation yrs <i>FIT_Life</i> 20
5	Salvage %	<i>Salvage</i>	(6.77%)	FIT rate <i>FIT_Rate</i> 21.00%
6	Depreciable basis	<i>DeprBasis</i>	\$106.77	FIT Gross-up <i>FIT_Mult</i> 26.58%
7	Annual depreciation	<i>AnnualDepr</i>	\$2.24	FIT DDB Rate <i>FDB_Rate</i> 150%
8	Year in service	<i>Start_Yr</i>	2025	FIT DDB % <i>FDBpct</i> 7.50%
9	Depr Year 1	<i>D_Yr1</i>	100%	FIT Method <i>FIT_DDB</i> TRUE
10				FIT Year 1 <i>F_Yr1</i> 50%
11				
12	Annual Costs			State Tax
13	O&M	<i>OM_pct</i>	1.33% Gross plant / inflated	SIT Basis \$ <i>SIT_Basis</i> \$100.00
14	Property tax	<i>Prop_pct</i>	2.02% Net plant	SIT depreciation yrs <i>SIT_Life</i> 20
15	Insurance	<i>Insur_pct</i>	0.10% Gross plant / inflated	SIT rate <i>SIT_Rate</i> 7.25%
16	Inflation rate	<i>Inflation</i>	2.10% 102.10%	SIT Gross-up <i>SIT_Mult</i> 7.82%
17				SIT DDB Rate <i>SDB_Rate</i> 200%
18	Cost of Capital			SIT DDB % <i>SDBpct</i> 10.00%
19	Wtd Avg Cost of Capital	<i>WACC</i>	6.87%	SIT Method <i>SIT_DDB</i> FALSE
20	Wtd Return on Equity	<i>WEqu</i>	4.56%	SIT Year 1 <i>S_Yr1</i> 50%
21				
22				
23	NPV- Revenue Req	\$152.44	NPV- Levelized Charge	\$174.89
24	NPV- Plant	\$1,430.32	Inflation Adjustment	5.38%
25	Economic Carrying Charge Rate	8.21% (ECCR)		0.021
26				

**Niagara Mohawk Power Corporation d/b/a National Grid
Marginal Cost Study Case 19-E-0283 and Case 15-E-0751
Transmission Stations Economic Carrying Charge Rate**

Line	Transmission Stations														
27	Year	<i>rYear</i>	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
28	Year Number	<i>rYearNum</i>	1	2	3	4	5	6	7	8	9	10	11	12	13
29	<i>ECCR Model continues through 2085=></i>														
30	Original Cost	<i>rCost</i>	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00		100.00
31	Depreciation expense	<i>rDepExp</i>	2.24	2.24	2.24	2.24	2.24	2.24	2.24	2.24	2.24	2.24	2.24	2.24	2.24
32	Accum. depreciation	<i>rAccumDep</i>	2.24	4.49	6.73	8.97	11.22	13.46	15.70	17.95	20.19	22.43	24.68	26.92	29.16
33	Net plant	<i>rNetPlant</i>	97.76	95.51	93.27	91.03	88.78	86.54	84.30	82.05	79.81	77.57	75.32	73.08	70.84
34	Inflation Factor	<i>rInflation</i>	1.0000	1.0210	1.0424	1.0643	1.0867	1.1095	1.1328	1.1566	1.1809	1.2057	1.2310	1.2568	1.2832
35	Levelized Charge	<i>rLevel</i>	8.21	8.38	8.55	8.73	8.92	9.10	9.30	9.49	9.69	9.89	10.10	10.31	10.53
36															
37	Rate Base														
38	Original Cost		100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00
39	Accum. depreciation		(2.24)	(4.49)	(6.73)	(8.97)	(11.22)	(13.46)	(15.70)	(17.95)	(20.19)	(22.43)	(24.68)	(26.92)	(29.16)
40	ADIT- Federal		(0.32)	(1.36)	(2.29)	(3.12)	(3.85)	(4.49)	(5.04)	(5.52)	(5.99)	(6.45)	(6.92)	(7.38)	(7.85)
41	ADIT- State		(0.02)	(0.22)	(0.42)	(0.62)	(0.82)	(1.02)	(1.22)	(1.42)	(1.62)	(1.82)	(2.02)	(2.22)	(2.42)
42	Rate Base	<i>rRateBase</i>	97.42	93.93	90.56	87.29	84.12	81.04	78.04	75.12	72.21	69.30	66.39	63.48	60.57
43															
44	Return on Rate Base	<i>rReturn</i>	6.69	6.45	6.22	6.00	5.78	5.57	5.36	5.16	4.96	4.76	4.56	4.36	4.16
45	Return on Equity	<i>rROE</i>	4.44	4.28	4.13	3.98	3.84	3.70	3.56	3.43	3.29	3.16	3.03	2.89	2.76
46															
47	Revenue Requirement														
48	Return on Rate Base		6.69	6.45	6.22	6.00	5.78	5.57	5.36	5.16	4.96	4.76	4.56	4.36	4.16
49	Depreciation expense		2.24	2.24	2.24	2.24	2.24	2.24	2.24	2.24	2.24	2.24	2.24	2.24	2.24
50	FIT- Total		1.18	1.14	1.10	1.06	1.02	0.98	0.95	0.91	0.88	0.84	0.80	0.77	0.73
51	SIT- Total		0.35	0.33	0.32	0.31	0.30	0.29	0.28	0.27	0.26	0.25	0.24	0.23	0.22
52	O&M		1.33	1.36	1.39	1.42	1.44	1.48	1.51	1.54	1.57	1.60	1.64	1.67	1.71
53	Property tax		1.97	1.93	1.88	1.84	1.79	1.74	1.70	1.65	1.61	1.56	1.52	1.47	1.43
54	Insurance		0.10	0.10	0.10	0.11	0.11	0.11	0.11	0.12	0.12	0.12	0.12	0.13	0.13
55	Revenue Requirement	<i>rRevReq</i>	13.86	13.56	13.26	12.97	12.69	12.41	12.15	11.89	11.63	11.38	11.12	10.87	10.62
56															

Exhibit 2-TS

Niagara Mohawk Power Corporation d/b/a National Grid
Marginal Cost Study Case 19-E-0283 and Case 15-E-0751
Transmission Stations Economic Carrying Charge Rate

Line	Transmission Stations		2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
57	Year	<i>rYear</i>													
58	Year Number	<i>rYearNum</i>	1	2	3	4	5	6	7	8	9	10	11	12	13
59	FIT														
60	Return on Equity		4.44	4.28	4.13	3.98	3.84	3.70	3.56	3.43	3.29	3.16	3.03	2.89	2.76
61	Depreciation expense		2.24	2.24	2.24	2.24	2.24	2.24	2.24	2.24	2.24	2.24	2.24	2.24	2.24
62	SIT Current		0.33	0.12	0.11	0.10	0.08	0.07	0.06	0.05	0.04	0.03	0.02	0.01	0.00
63	FIT Depr Allowance		(3.75)	(7.22)	(6.68)	(6.18)	(5.71)	(5.28)	(4.89)	(4.52)	(4.46)	(4.46)	(4.46)	(4.46)	(4.46)
64	FIT Taxable Income	<i>rFIT_Income</i>	3.26	(0.57)	(0.20)	0.14	0.45	0.73	0.98	1.20	1.12	0.97	0.83	0.69	0.54
65	ECCR Model continues through 2085=>														
66	FIT Current	<i>rFIT_Curr</i>	0.87	(0.15)	(0.05)	0.04	0.12	0.19	0.26	0.32	0.30	0.26	0.22	0.18	0.14
67	FIT Total	<i>rFIT_Total</i>	1.18	1.14	1.10	1.06	1.02	0.98	0.95	0.91	0.88	0.84	0.80	0.77	0.73
68	FIT Depreciation Allowance														
70	FIT Deprec SL	<i>rFIT_SL</i>	2.50	5.00	5.00	5.00	5.00	5.00	5.00	5.00	5.00	5.00	5.00	5.00	5.00
71	FIT Deprec DDB	<i>rFIT_DDB</i>	3.75	7.22	6.68	6.18	5.71	5.28	4.89	4.52	4.46	4.46	4.46	4.46	4.46
72	FIT Deprec Allow	<i>rFITDep</i>	3.75	7.22	6.68	6.18	5.71	5.28	4.89	4.52	4.46	4.46	4.46	4.46	4.46
73	FIT Basis														
74	FIT Basis	<i>rFITBasis</i>	100.00	96.25	89.03	82.35	76.18	70.46	65.18	60.29	55.77	51.31	46.85	42.38	37.92
75	FIT Deprec DDB Bal														
76	FIT Deprec DDB Bal	<i>rFIT_DDB_Bal</i>	100.00	96.25	89.03	82.35	76.18	70.46	65.18	60.29	55.77	51.31	46.85	42.38	37.92
77	FIT Remaining Years	<i>rFIT_RemY</i>	20.50	19.50	18.50	17.50	16.50	15.50	14.50	13.50	12.50	11.50	10.50	9.50	8.50
78	FIT Deferred														
79	FIT Deferred	<i>rFIT_Defd</i>	0.32	1.04	0.93	0.83	0.73	0.64	0.56	0.48	0.47	0.47	0.47	0.47	0.47
80	FIT ADIT	<i>rFIT_ADIT</i>	0.32	1.36	2.29	3.12	3.85	4.49	5.04	5.52	5.99	6.45	6.92	7.38	7.85
81	SIT														
82	Return on Equity		4.44	4.28	4.13	3.98	3.84	3.70	3.56	3.43	3.29	3.16	3.03	2.89	2.76
83	Depreciation expense		2.24	2.24	2.24	2.24	2.24	2.24	2.24	2.24	2.24	2.24	2.24	2.24	2.24
84	SIT Depr Allowance		(2.50)	(5.00)	(5.00)	(5.00)	(5.00)	(5.00)	(5.00)	(5.00)	(5.00)	(5.00)	(5.00)	(5.00)	(5.00)
85	SIT Taxable Income	<i>rSIT_Income</i>	4.19	1.53	1.37	1.22	1.08	0.94	0.80	0.67	0.54	0.40	0.27	0.14	0.01
86	SIT Current														
87	SIT Current	<i>rSIT_Curr</i>	0.33	0.12	0.11	0.10	0.08	0.07	0.06	0.05	0.04	0.03	0.02	0.01	0.00
88	SIT Total	<i>rSIT_Total</i>	0.35	0.33	0.32	0.31	0.30	0.29	0.28	0.27	0.26	0.25	0.24	0.23	0.22
89	SIT Depreciation Allowance														
90	SIT Deprec SL	<i>rSIT_SL</i>	2.50	5.00	5.00	5.00	5.00	5.00	5.00	5.00	5.00	5.00	5.00	5.00	5.00
91	SIT Deprec DDB	<i>rSIT_DDB</i>	5.00	9.50	8.55	7.70	6.93	6.23	5.61	5.05	4.54	4.09	3.68	3.49	3.49
92	SIT Deprec Allow	<i>rSITDep</i>	2.50	5.00	5.00	5.00	5.00	5.00	5.00	5.00	5.00	5.00	5.00	5.00	5.00
93	SIT Basis														
94	SIT Basis	<i>rSITBasis</i>	100.00	97.50	92.50	87.50	82.50	77.50	72.50	67.50	62.50	57.50	52.50	47.50	42.50
95	SIT Deprec DDB Bal														
96	SIT Deprec DDB Bal	<i>rSIT_DDB_Bal</i>	100.00	95.00	85.50	76.95	69.26	62.33	56.10	50.49	45.44	40.89	36.80	33.12	29.64
97	SIT Remaining Years	<i>rSIT_RemY</i>	20.50	19.50	18.50	17.50	16.50	15.50	14.50	13.50	12.50	11.50	10.50	9.50	8.50
98	SIT Deferred														
99	SIT Deferred	<i>rSIT_Defd</i>	0.02	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20
100	SIT ADIT	<i>rSIT_ADIT</i>	0.02	0.22	0.42	0.62	0.82	1.02	1.22	1.42	1.62	1.82	2.02	2.22	2.42
101	SIT Basis														
102	SIT Basis	<i>rSITBasis</i>	100.00	97.50	92.50	87.50	82.50	77.50	72.50	67.50	62.50	57.50	52.50	47.50	42.50
103	SIT Deprec DDB Bal														
104	SIT Deprec DDB Bal	<i>rSIT_DDB_Bal</i>	100.00	95.00	85.50	76.95	69.26	62.33	56.10	50.49	45.44	40.89	36.80	33.12	29.64
105	SIT Remaining Years	<i>rSIT_RemY</i>	20.50	19.50	18.50	17.50	16.50	15.50	14.50	13.50	12.50	11.50	10.50	9.50	8.50
106	SIT Deferred														
107	SIT Deferred	<i>rSIT_Defd</i>	0.02	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20
108	SIT ADIT	<i>rSIT_ADIT</i>	0.02	0.22	0.42	0.62	0.82	1.02	1.22	1.42	1.62	1.82	2.02	2.22	2.42

Exhibit 2-TL
Niagara Mohawk Power Corporation d/b/a National Grid
Marginal Cost Study Case 19-E-0283 and Case 15-E-0751
Transmission Lines Economic Carrying Charge Rate

Line	Transmission Lines					
1						
2	Original Cost		Federal Tax			
3	Original Cost \$	Cost	\$100.00	FIT Basis \$	FIT_Basis	\$100.00
4	Depreciable life years	Depr_Life	65.75	FIT depreciation yrs	FIT_Life	20
5	Salvage %	Salvage	(38.85%)	FIT rate	FIT_Rate	21.00%
6	Depreciable basis	DeprBasis	\$138.85	FIT Gross-up	FIT_Mult	26.58%
7	Annual depreciation	AnnualDepr	\$2.11	FIT DDB Rate	FDB_Rate	150%
8	Year in service	Start_Yr	2025	FIT DDB %	FDBpct	7.50%
9	Depr Year 1	D_Yr1	100%	FIT Method	FIT_DDB	TRUE
10				FIT Year 1	F_Yr1	50%
11						
12	Annual Costs		Applied to	State Tax		
13	O&M	OM_pct	2.09% Gross plant / inflated	SIT Basis \$	SIT_Basis	\$100.00
14	Property tax	Prop_pct	2.02% Net plant	SIT depreciation yrs	SIT_Life	20
15	Insurance	Insur_pct	0.10% Gross plant / inflated	SIT rate	SIT_Rate	7.25%
16	Inflation rate	Inflation	2.10% 102.10%	SIT Gross-up	SIT_Mult	7.82%
17				SIT DDB Rate	SDB_Rate	200%
18	Cost of Capital			SIT DDB %	SDBpct	10.00%
19	Wtd Avg Cost of Capital	WACC	6.87%	SIT Method	SIT_DDB	FALSE
20	Wtd Return on Equity	WEqu	4.56%	SIT Year 1	S_Yr1	50%
21						
22						
23	NPV- Revenue Req	\$168.19	NPV- Levelized Charge	\$188.13		
24	NPV- Plant	\$1,430.32	Inflation Adjustment	5.02%		
25	Economic Carrying Charge Rate	8.44% (ECCR)				
26						

**Niagara Mohawk Power Corporation d/b/a National Grid
Marginal Cost Study Case 19-E-0283 and Case 15-E-0751
Transmission Lines Economic Carrying Charge Rate**

Line	Transmission Lines														
27	Year	rYear	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
28	Year Number	rYearNum	1	2	3	4	5	6	7	8	9	10	11	12	13
29	ECCR Model continues through 2085=>														
30	Original Cost	rCost	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00		100.00
31	Depreciation expense	rDepExp	2.11	2.11	2.11	2.11	2.11	2.11	2.11	2.11	2.11	2.11	2.11		2.11
32	Accum. depreciation	rAccumDep	2.11	4.22	6.34	8.45	10.56	12.67	14.78	16.89	19.01	21.12	23.23	25.34	27.45
33	Net plant	rNetPlant	97.89	95.78	93.66	91.55	89.44	87.33	85.22	83.11	80.99	78.88	76.77	74.66	72.55
34	Inflation Factor	rInflation	1.0000	1.0210	1.0424	1.0643	1.0867	1.1095	1.1328	1.1566	1.1809	1.2057	1.2310	1.2568	1.2832
35	Levelized Charge	rLevel	8.44	8.62	8.80	8.98	9.17	9.37	9.56	9.76	9.97	10.18	10.39	10.61	10.83
36															
37	Rate Base														
38	Original Cost		100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00		100.00
39	Accum. depreciation		(2.11)	(4.22)	(6.34)	(8.45)	(10.56)	(12.67)	(14.78)	(16.89)	(19.01)	(21.12)	(23.23)	(25.34)	(27.45)
40	ADIT- Federal		(0.34)	(1.42)	(2.38)	(3.23)	(3.99)	(4.65)	(5.23)	(5.74)	(6.23)	(6.73)	(7.22)	(7.71)	(8.21)
41	ADIT- State		(0.03)	(0.24)	(0.45)	(0.66)	(0.87)	(1.08)	(1.28)	(1.49)	(1.70)	(1.91)	(2.12)	(2.33)	(2.54)
42	Rate Base	rRateBase	97.52	94.12	90.84	87.67	84.59	81.60	78.70	75.87	73.06	70.24	67.43	64.61	61.80
43															
44	Return on Rate Base	rReturn	6.70	6.47	6.24	6.02	5.81	5.61	5.41	5.21	5.02	4.83	4.63	4.44	4.25
45	Return on Equity	rROE	4.45	4.29	4.14	4.00	3.86	3.72	3.59	3.46	3.33	3.20	3.07	2.95	2.82
46															
47	Revenue Requirement														
48	Return on Rate Base		6.70	6.47	6.24	6.02	5.81	5.61	5.41	5.21	5.02	4.83	4.63	4.44	4.25
49	Depreciation expense		2.11	2.11	2.11	2.11	2.11	2.11	2.11	2.11	2.11	2.11	2.11	2.11	2.11
50	FIT- Total		1.18	1.14	1.10	1.06	1.03	0.99	0.95	0.92	0.89	0.85	0.82	0.78	0.75
51	SIT- Total		0.35	0.34	0.32	0.31	0.30	0.29	0.28	0.27	0.26	0.25	0.24	0.23	0.22
52	O&M		2.09	2.14	2.18	2.23	2.27	2.32	2.37	2.42	2.47	2.52	2.58	2.63	2.69
53	Property tax		1.97	1.93	1.89	1.85	1.80	1.76	1.72	1.68	1.63	1.59	1.55	1.51	1.46
54	Insurance		0.10	0.10	0.10	0.11	0.11	0.11	0.11	0.12	0.12	0.12	0.12	0.13	0.13
55	Revenue Requirement	rRevReq	14.51	14.22	13.95	13.69	13.44	13.19	12.96	12.73	12.50	12.27	12.05	11.83	11.60
56															

**Niagara Mohawk Power Corporation d/b/a National Grid
Marginal Cost Study Case 19-E-0283 and Case 15-E-0751
Transmission Lines Economic Carrying Charge Rate**

Line	Transmission Lines														
57	Year	<i>rYear</i>	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
58	Year Number	<i>rYearNum</i>	1	2	3	4	5	6	7	8	9	10	11	12	13
59	FIT		<i>ECCR Model continues through 2085=></i>												
60	Return on Equity		4.45	4.29	4.14	4.00	3.86	3.72	3.59	3.46	3.33	3.20	3.07	2.95	2.82
61	Depreciation expense		2.11	2.11	2.11	2.11	2.11	2.11	2.11	2.11	2.11	2.11	2.11	2.11	2.11
62	SIT Current		0.32	0.11	0.10	0.09	0.08	0.07	0.05	0.04	0.03	0.02	0.01	0.00	(0.01)
63	FIT Depr Allowance		(3.75)	(7.22)	(6.68)	(6.18)	(5.71)	(5.28)	(4.89)	(4.52)	(4.46)	(4.46)	(4.46)	(4.46)	(4.46)
64	FIT Taxable Income	<i>rFIT_Income</i>	3.13	(0.71)	(0.33)	0.02	0.33	0.61	0.87	1.09	1.02	0.88	0.74	0.60	0.46
65															
66	FIT Current	<i>rFIT_Curr</i>	0.83	(0.19)	(0.09)	0.01	0.09	0.16	0.23	0.29	0.27	0.23	0.20	0.16	0.12
67	FIT Total	<i>rFIT_Total</i>	1.18	1.14	1.10	1.06	1.03	0.99	0.95	0.92	0.89	0.85	0.82	0.78	0.75
68															
69	FIT Depreciation Allowance														
70	FIT Deprec SL	<i>rFIT_SL</i>	2.50	5.00	5.00	5.00	5.00	5.00	5.00	5.00	5.00	5.00	5.00	5.00	5.00
71	FIT Deprec DDB	<i>rFIT_DDB</i>	3.75	7.22	6.68	6.18	5.71	5.28	4.89	4.52	4.46	4.46	4.46	4.46	4.46
72	FIT Deprec Allow	<i>rFITDep</i>	3.75	7.22	6.68	6.18	5.71	5.28	4.89	4.52	4.46	4.46	4.46	4.46	4.46
73															
74	FIT Basis	<i>rFITBasis</i>	100.00	96.25	89.03	82.35	76.18	70.46	65.18	60.29	55.77	51.31	46.85	42.38	33.46
75															
76	FIT Deprec DDB Bal	<i>rFIT_DDB_Bal</i>	100.00	96.25	89.03	82.35	76.18	70.46	65.18	60.29	55.77	51.31	46.85	42.38	33.46
77	FIT Remaining Years	<i>rFIT_RemY</i>	20.50	19.50	18.50	17.50	16.50	15.50	14.50	13.50	12.50	11.50	10.50	9.50	7.50
78															
79	FIT Deferred	<i>rFIT_Defd</i>	0.34	1.07	0.96	0.85	0.76	0.67	0.58	0.51	0.49	0.49	0.49	0.49	0.49
80	FIT ADIT	<i>rFIT_ADIT</i>	0.34	1.42	2.38	3.23	3.99	4.65	5.23	5.74	6.23	6.73	7.22	7.71	8.21
81															
82	SIT														
83	Return on Equity		4.45	4.29	4.14	4.00	3.86	3.72	3.59	3.46	3.33	3.20	3.07	2.95	2.82
84	Depreciation expense		2.11	2.11	2.11	2.11	2.11	2.11	2.11	2.11	2.11	2.11	2.11	2.11	2.11
85	SIT Depr Allowance		(2.50)	(5.00)	(5.00)	(5.00)	(5.00)	(5.00)	(5.00)	(5.00)	(5.00)	(5.00)	(5.00)	(5.00)	(5.00)
86	SIT Taxable Income	<i>rSIT_Income</i>	4.06	1.40	1.25	1.11	0.97	0.83	0.70	0.57	0.44	0.31	0.19	0.06	(0.07)
87															
88	SIT Current	<i>rSIT_Curr</i>	0.32	0.11	0.10	0.09	0.08	0.07	0.05	0.04	0.03	0.02	0.01	0.00	(0.01)
89	SIT Total	<i>rSIT_Total</i>	0.35	0.34	0.32	0.31	0.30	0.29	0.28	0.27	0.26	0.25	0.24	0.23	0.22
90															
91	SIT Depreciation Allowance														
92	SIT Deprec SL	<i>rSIT_SL</i>	2.50	5.00	5.00	5.00	5.00	5.00	5.00	5.00	5.00	5.00	5.00	5.00	5.00
93	SIT Deprec DDB	<i>rSIT_DDB</i>	5.00	9.50	8.55	7.70	6.93	6.23	5.61	5.05	4.54	4.09	3.68	3.49	3.49
94	SIT Deprec Allow	<i>rSITDep</i>	2.50	5.00	5.00	5.00	5.00	5.00	5.00	5.00	5.00	5.00	5.00	5.00	5.00
95															
96	SIT Basis	<i>rSITBasis</i>	100.00	97.50	92.50	87.50	82.50	77.50	72.50	67.50	62.50	57.50	52.50	47.50	37.50
97															
98	SIT Deprec DDB Bal	<i>rSIT_DDB_Bal</i>	100.00	95.00	85.50	76.95	69.26	62.33	56.10	50.49	45.44	40.89	36.80	33.12	26.15
99	SIT Remaining Years	<i>rSIT_RemY</i>	20.50	19.50	18.50	17.50	16.50	15.50	14.50	13.50	12.50	11.50	10.50	9.50	7.50
100															
101	SIT Deferred	<i>rSIT_Defd</i>	0.03	0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.21
102	SIT ADIT	<i>rSIT_ADIT</i>	0.03	0.24	0.45	0.66	0.87	1.08	1.28	1.49	1.70	1.91	2.12	2.33	2.54
103															

Exhibit 2-DS **Niagara Mohawk Power Corporation d/b/a National Grid**
Marginal Cost Study Case 19-E-0283 and Case 15-E-0751
Distribution Stations Economic Carrying Charge Rate

Line	Distribution Stations			
1				
2	Original Cost			Federal Tax
3	Original Cost \$	Cost	\$100.00	FIT Basis \$ FIT_Basis \$100.00
4	Depreciable life years	Depr_Life	61.55	FIT depreciation yrs FIT_Life 20
5	Salvage %	Salvage	(15.03%)	FIT rate FIT_Rate 21.00%
6	Depreciable basis	DeprBasis	\$115.03	FIT Gross-up FIT_Mult 26.58%
7	Annual depreciation	AnnualDepr	\$1.87	FIT DDB Rate FDB_Rate 150%
8	Year in service	Start_Yr	2025	FIT DDB % FDBpct 7.50%
9	Depr Year 1	D_Yr1	100%	FIT Method FIT_DDB TRUE
10				FIT Year 1 F_Yr1 50%
11				
12	Annual Costs		Applied to	State Tax
13	O&M	OM_pct	1.59% Gross plant / inflated	SIT Basis \$ SIT_Basis \$100.00
14	Property tax	Prop_pct	2.02% Net plant	SIT depreciation yrs SIT_Life 20
15	Insurance	Insur_pct	0.10% Gross plant / inflated	SIT rate SIT_Rate 7.25%
16	Inflation rate	Inflation	2.10% 102.10%	SIT Gross-up SIT_Mult 7.82%
17				SIT DDB Rate SDB_Rate 200%
18	Cost of Capital			SIT DDB % SDBpct 10.00%
19	Wtd Avg Cost of Capital	WACC	6.87%	SIT Method SIT_DDB FALSE
20	Wtd Return on Equity	WEqu	4.56%	SIT Year 1 S_Yr1 50%
21				
22				
23	NPV- Revenue Req	\$158.79	NPV- Levelized Charge	\$181.09
24	NPV- Plant	\$1,430.32	Inflation Adjustment	5.08%
25	Economic Carrying Charge Rate	8.06% (ECCR)		
26				

Line	Distribution Stations														
27	Year	<i>rYear</i>	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
28	Year Number	<i>rYearNum</i>	1	2	3	4	5	6	7	8	9	10	11	12	13
29	<i>ECCR Model continues through 2085=></i>														
30	Original Cost	<i>rCost</i>	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00		100.00
31	Depreciation expense	<i>rDepExp</i>	1.87	1.87	1.87	1.87	1.87	1.87	1.87	1.87	1.87	1.87	1.87	1.87	1.87
32	Accum. depreciation	<i>rAccumDep</i>	1.87	3.74	5.61	7.48	9.34	11.21	13.08	14.95	16.82	18.69	20.56	22.43	24.30
33	Net plant	<i>rNetPlant</i>	98.13	96.26	94.39	92.52	90.66	88.79	86.92	85.05	83.18	81.31	79.44	77.57	75.70
34	Inflation Factor	<i>rInflation</i>	1.0000	1.0210	1.0424	1.0643	1.0867	1.1095	1.1328	1.1566	1.1809	1.2057	1.2310	1.2568	1.2832
35	Levelized Charge	<i>rLevel</i>	8.06	8.23	8.40	8.58	8.76	8.94	9.13	9.32	9.52	9.72	9.92	10.13	10.34
36															
37	<u>Rate Base</u>														
38	Original Cost		100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00
39	Accum. depreciation		(1.87)	(3.74)	(5.61)	(7.48)	(9.34)	(11.21)	(13.08)	(14.95)	(16.82)	(18.69)	(20.56)	(22.43)	(24.30)
40	ADIT- Federal		(0.40)	(1.52)	(2.53)	(3.43)	(4.24)	(4.96)	(5.59)	(6.15)	(6.69)	(7.24)	(7.78)	(8.33)	(8.87)
41	ADIT- State		(0.05)	(0.27)	(0.50)	(0.73)	(0.95)	(1.18)	(1.41)	(1.63)	(1.86)	(2.09)	(2.32)	(2.54)	(2.77)
42	Rate Base	<i>rRateBase</i>	97.69	94.47	91.37	88.36	85.46	82.65	79.92	77.27	74.62	71.98	69.34	66.70	64.06
43															
44	Return on Rate Base	<i>rReturn</i>	6.71	6.49	6.28	6.07	5.87	5.68	5.49	5.31	5.13	4.95	4.76	4.58	4.40
45	Return on Equity	<i>rROE</i>	4.45	4.31	4.17	4.03	3.90	3.77	3.64	3.52	3.40	3.28	3.16	3.04	2.92
46															
47	<u>Revenue Requirement</u>														
48	Return on Rate Base		6.71	6.49	6.28	6.07	5.87	5.68	5.49	5.31	5.13	4.95	4.76	4.58	4.40
49	Depreciation expense		1.87	1.87	1.87	1.87	1.87	1.87	1.87	1.87	1.87	1.87	1.87	1.87	1.87
50	FIT- Total		1.18	1.15	1.11	1.07	1.04	1.00	0.97	0.94	0.90	0.87	0.84	0.81	0.78
51	SIT- Total		0.35	0.34	0.33	0.31	0.30	0.29	0.28	0.28	0.27	0.26	0.25	0.24	0.23
52	O&M		1.59	1.62	1.65	1.69	1.72	1.76	1.80	1.83	1.87	1.91	1.95	1.99	2.03
53	Property tax		1.98	1.94	1.90	1.87	1.83	1.79	1.75	1.71	1.68	1.64	1.60	1.56	1.53
54	Insurance		0.10	0.10	0.10	0.11	0.11	0.11	0.11	0.12	0.12	0.12	0.12	0.13	0.13
55	Revenue Requirement	<i>rRevReq</i>	13.78	13.50	13.24	12.99	12.74	12.50	12.27	12.05	11.83	11.62	11.40	11.18	10.96
56															

Line	Distribution Stations															
57	Year	rYear	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	
58	Year Number	rYearNum	1	2	3	4	5	6	7	8	9	10	11	12	13	
59	FIT		ECCR Model continues through 2085=>													
60	Return on Equity		4.45	4.31	4.17	4.03	3.90	3.77	3.64	3.52	3.40	3.28	3.16	3.04	2.92	
61	Depreciation expense		1.87	1.87	1.87	1.87	1.87	1.87	1.87	1.87	1.87	1.87	1.87	1.87	1.87	
62	SIT Current		0.30	0.09	0.08	0.07	0.06	0.05	0.04	0.03	0.02	0.01	0.00	(0.01)	(0.02)	
63	FIT Depr Allowance		(3.75)	(7.22)	(6.68)	(6.18)	(5.71)	(5.28)	(4.89)	(4.52)	(4.46)	(4.46)	(4.46)	(4.46)	(4.46)	
64	FIT Taxable Income	rFIT_Income	2.87	(0.95)	(0.56)	(0.21)	0.11	0.40	0.66	0.90	0.83	0.70	0.57	0.44	0.31	
65																
66	FIT Current	rFIT_Curr	0.76	(0.25)	(0.15)	(0.06)	0.03	0.11	0.18	0.24	0.22	0.19	0.15	0.12	0.08	
67	FIT Total	rFIT_Total	1.18	1.15	1.11	1.07	1.04	1.00	0.97	0.94	0.90	0.87	0.84	0.81	0.78	
68																
69	FIT Depreciation Allowance															
70	FIT Deprec SL	rFIT_SL	2.50	5.00	5.00	5.00	5.00	5.00	5.00	5.00	5.00	5.00	5.00	5.00	5.00	
71	FIT Deprec DDB	rFIT_DDB	3.75	7.22	6.68	6.18	5.71	5.28	4.89	4.52	4.46	4.46	4.46	4.46	4.46	
72	FIT Deprec Allow	rFITDep	3.75	7.22	6.68	6.18	5.71	5.28	4.89	4.52	4.46	4.46	4.46	4.46	4.46	
73																
74	FIT Basis	rFITBasis	100.00	96.25	89.03	82.35	76.18	70.46	65.18	60.29	55.77	51.31	46.85	42.38	37.92	
75																
76	FIT Deprec DDB Bal	rFIT_DDB_Bal	100.00	96.25	89.03	82.35	76.18	70.46	65.18	60.29	55.77	51.31	46.85	42.38	37.92	
77	FIT Remaining Years	rFIT_RemY	20.50	19.50	18.50	17.50	16.50	15.50	14.50	13.50	12.50	11.50	10.50	9.50	8.50	
78																
79	FIT Deferred	rFIT_Defd	0.40	1.12	1.01	0.90	0.81	0.72	0.63	0.56	0.54	0.54	0.54	0.54	0.54	
80	FIT ADIT	rFIT_ADIT	0.40	1.52	2.53	3.43	4.24	4.96	5.59	6.15	6.69	7.24	7.78	8.33	8.87	
81																
82	SIT															
83	Return on Equity		4.45	4.31	4.17	4.03	3.90	3.77	3.64	3.52	3.40	3.28	3.16	3.04	2.92	
84	Depreciation expense		1.87	1.87	1.87	1.87	1.87	1.87	1.87	1.87	1.87	1.87	1.87	1.87	1.87	
85	SIT Depr Allowance		(2.50)	(5.00)	(5.00)	(5.00)	(5.00)	(5.00)	(5.00)	(5.00)	(5.00)	(5.00)	(5.00)	(5.00)	(5.00)	
86	SIT Taxable Income	rSIT_Income	3.82	1.18	1.04	0.90	0.77	0.64	0.51	0.39	0.27	0.15	0.03	(0.09)	(0.21)	
87																
88	SIT Current	rSIT_Curr	0.30	0.09	0.08	0.07	0.06	0.05	0.04	0.03	0.02	0.01	0.00	(0.01)	(0.02)	
89	SIT Total	rSIT_Total	0.35	0.34	0.33	0.31	0.30	0.29	0.28	0.28	0.27	0.26	0.25	0.24	0.23	
90																
91	SIT Depreciation Allowance															
92	SIT Deprec SL	rSIT_SL	2.50	5.00	5.00	5.00	5.00	5.00	5.00	5.00	5.00	5.00	5.00	5.00	5.00	
93	SIT Deprec DDB	rSIT_DDB	5.00	9.50	8.55	7.70	6.93	6.23	5.61	5.05	4.54	4.09	3.68	3.49	3.49	
94	SIT Deprec Allow	rSITDep	2.50	5.00	5.00	5.00	5.00	5.00	5.00	5.00	5.00	5.00	5.00	5.00	5.00	
95																
96	SIT Basis	rSITBasis	100.00	97.50	92.50	87.50	82.50	77.50	72.50	67.50	62.50	57.50	52.50	47.50	42.50	
97																
98	SIT Deprec DDB Bal	rSIT_DDB_Bal	100.00	95.00	85.50	76.95	69.26	62.33	56.10	50.49	45.44	40.89	36.80	33.12	29.64	
99	SIT Remaining Years	rSIT_RemY	20.50	19.50	18.50	17.50	16.50	15.50	14.50	13.50	12.50	11.50	10.50	9.50	8.50	
100																
101	SIT Deferred	rSIT_Defd	0.05	0.23	0.23	0.23	0.23	0.23	0.23	0.23	0.23	0.23	0.23	0.23	0.23	
102	SIT ADIT	rSIT_ADIT	0.05	0.27	0.50	0.73	0.95	1.18	1.41	1.63	1.86	2.09	2.32	2.54	2.77	
103																

Exhibit 2-DL

Niagara Mohawk Power Corporation d/b/a National Grid
Marginal Cost Study Case 19-E-0283 and Case 15-E-0751
Distribution Lines Economic Carrying Charge Rate

Line	Distribution Lines			
1				
2	Original Cost			Federal Tax
3	Original Cost \$	Cost	\$100.00	FIT Basis \$ FIT_Basis \$100.00
4	Depreciable life years	Depr_Life	56.69	FIT depreciation yrs FIT_Life 20
5	Salvage %	Salvage	(24.46%)	FIT rate FIT_Rate 21.00%
6	Depreciable basis	DeprBasis	\$124.46	FIT Gross-up FIT_Mult 26.58%
7	Annual depreciation	AnnualDepr	\$2.20	FIT DDB Rate FDB_Rate 150%
8	Year in service	Start_Yr	2025	FIT DDB % FDBpct 7.50%
9	Depr Year 1	D_Yr1	100%	FIT Method FIT_DDB TRUE
10				FIT Year 1 F_Yr1 50%
11				
12	Annual Costs	Applied to		State Tax
13	O&M	OM_pct	7.49% Gross plant / inflated	SIT Basis \$ SIT_Basis \$100.00
14	Property tax	Prop_pct	2.02% Net plant	SIT depreciation yrs SIT_Life 20
15	Insurance	Insur_pct	0.10% Gross plant / inflated	SIT rate SIT_Rate 7.25%
16	Inflation rate	Inflation	2.10% 102.10%	SIT Gross-up SIT_Mult 7.82%
17				SIT DDB Rate SDB_Rate 200%
18	Cost of Capital			
19	Wtd Avg Cost of Capital	WACC	6.87%	SIT DDB % SDBpct 10.00%
20	Wtd Return on Equity	WEqu	4.56%	SIT Method SIT_DDB FALSE
21				
22				
23	NPV- Revenue Req	\$273.96	NPV- Levelized Charge	\$288.43
24	NPV- Plant	\$1,430.32	Inflation Adjustment	5.16%
25	Economic Carrying Charge Rate	14.13% (ECCR)		
26				

**Niagara Mohawk Power Corporation d/b/a National Grid
Marginal Cost Study Case 19-E-0283 and Case 15-E-0751
Distribution Lines Economic Carrying Charge Rate**

Line	Distribution Lines														
27	Year	<i>rYear</i>	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
28	Year Number	<i>rYearNum</i>	1	2	3	4	5	6	7	8	9	10	11	12	13
29	<i>ECCR Model continues through 2085=></i>														
30	Original Cost	<i>rCost</i>	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00		100.00
31	Depreciation expense	<i>rDepExp</i>	2.20	2.20	2.20	2.20	2.20	2.20	2.20	2.20	2.20	2.20	2.20	2.20	2.20
32	Accum. depreciation	<i>rAccumDep</i>	2.20	4.39	6.59	8.78	10.98	13.17	15.37	17.56	19.76	21.95	24.15	26.35	28.54
33	Net plant	<i>rNetPlant</i>	97.80	95.61	93.41	91.22	89.02	86.83	84.63	82.44	80.24	78.05	75.85	73.65	71.46
34	Inflation Factor	<i>rInflation</i>	1.0000	1.0210	1.0424	1.0643	1.0867	1.1095	1.1328	1.1566	1.1809	1.2057	1.2310	1.2568	1.2832
35	Levelized Charge	<i>rLevel</i>	14.13	14.43	14.73	15.04	15.35	15.68	16.01	16.34	16.68	17.04	17.39	17.76	18.13
36															
37	Rate Base														
38	Original Cost		100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00
39	Accum. depreciation		(2.20)	(4.39)	(6.59)	(8.78)	(10.98)	(13.17)	(15.37)	(17.56)	(19.76)	(21.95)	(24.15)	(26.35)	(28.54)
40	ADIT- Federal		(0.33)	(1.38)	(2.32)	(3.16)	(3.90)	(4.55)	(5.11)	(5.60)	(6.08)	(6.55)	(7.03)	(7.50)	(7.98)
41	ADIT- State		(0.02)	(0.23)	(0.43)	(0.63)	(0.84)	(1.04)	(1.24)	(1.45)	(1.65)	(1.85)	(2.06)	(2.26)	(2.46)
42	Rate Base	<i>rRateBase</i>	97.46	94.00	90.66	87.43	84.29	81.24	78.28	75.39	72.52	69.64	66.77	63.89	61.02
43															
44	Return on Rate Base	<i>rReturn</i>	6.70	6.46	6.23	6.01	5.79	5.58	5.38	5.18	4.98	4.78	4.59	4.39	4.19
45	Return on Equity	<i>rROE</i>	4.44	4.29	4.13	3.99	3.84	3.70	3.57	3.44	3.31	3.18	3.04	2.91	2.78
46															
47	Revenue Requirement														
48	Return on Rate Base		6.70	6.46	6.23	6.01	5.79	5.58	5.38	5.18	4.98	4.78	4.59	4.39	4.19
49	Depreciation expense		2.20	2.20	2.20	2.20	2.20	2.20	2.20	2.20	2.20	2.20	2.20	2.20	2.20
50	FIT- Total		1.18	1.14	1.10	1.06	1.02	0.98	0.95	0.91	0.88	0.84	0.81	0.77	0.74
51	SIT- Total		0.35	0.34	0.32	0.31	0.30	0.29	0.28	0.27	0.26	0.25	0.24	0.23	0.22
52	O&M		7.49	7.65	7.81	7.97	8.14	8.31	8.48	8.66	8.84	9.03	9.22	9.41	9.61
53	Property tax		1.97	1.93	1.88	1.84	1.79	1.75	1.71	1.66	1.62	1.57	1.53	1.48	1.44
54	Insurance		0.10	0.10	0.10	0.11	0.11	0.11	0.11	0.12	0.12	0.12	0.12	0.13	0.13
55	Revenue Requirement	<i>rRevReq</i>	19.98	19.80	19.64	19.49	19.35	19.22	19.10	19.00	18.89	18.79	18.70	18.61	18.52
56															

**Niagara Mohawk Power Corporation d/b/a National Grid
Marginal Cost Study Case 19-E-0283 and Case 15-E-0751
Distribution Lines Economic Carrying Charge Rate**

Line	Distribution Lines														
57	Year	<i>rYear</i>	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
58	Year Number	<i>rYearNum</i>	1	2	3	4	5	6	7	8	9	10	11	12	13
59	FIT														
60	Return on Equity		4.44	4.29	4.13	3.99	3.84	3.70	3.57	3.44	3.31	3.18	3.04	2.91	2.78
61	Depreciation expense		2.20	2.20	2.20	2.20	2.20	2.20	2.20	2.20	2.20	2.20	2.20	2.20	2.20
62	SIT Current		0.32	0.12	0.10	0.09	0.08	0.07	0.06	0.05	0.04	0.03	0.02	0.01	(0.00)
63	FIT Depr Allowance		(3.75)	(7.22)	(6.68)	(6.18)	(5.71)	(5.28)	(4.89)	(4.52)	(4.46)	(4.46)	(4.46)	(4.46)	(4.46)
64	FIT Taxable Income	<i>rFIT_Income</i>	3.21	(0.62)	(0.24)	0.10	0.41	0.69	0.94	1.16	1.08	0.94	0.80	0.66	0.51
65	ECCR Model continues through 2085=>														
66	FIT Current	<i>rFIT_Curr</i>	0.85	(0.17)	(0.06)	0.03	0.11	0.18	0.25	0.31	0.29	0.25	0.21	0.17	0.14
67	FIT Total	<i>rFIT_Total</i>	1.18	1.14	1.10	1.06	1.02	0.98	0.95	0.91	0.88	0.84	0.81	0.77	0.74
68	FIT Depreciation Allowance														
70	FIT Deprec SL	<i>rFIT_SL</i>	2.50	5.00	5.00	5.00	5.00	5.00	5.00	5.00	5.00	5.00	5.00	5.00	5.00
71	FIT Deprec DDB	<i>rFIT_DDB</i>	3.75	7.22	6.68	6.18	5.71	5.28	4.89	4.52	4.46	4.46	4.46	4.46	4.46
72	FIT Deprec Allow	<i>rFITDep</i>	3.75	7.22	6.68	6.18	5.71	5.28	4.89	4.52	4.46	4.46	4.46	4.46	4.46
73															
74	FIT Basis	<i>rFITBasis</i>	100.00	96.25	89.03	82.35	76.18	70.46	65.18	60.29	55.77	51.31	46.85	42.38	37.92
75															
76	FIT Deprec DDB Bal	<i>rFIT_DDB_Bal</i>	100.00	96.25	89.03	82.35	76.18	70.46	65.18	60.29	55.77	51.31	46.85	42.38	37.92
77	FIT Remaining Years	<i>rFIT_RemY</i>	20.50	19.50	18.50	17.50	16.50	15.50	14.50	13.50	12.50	11.50	10.50	9.50	8.50
78															
79	FIT Deferred	<i>rFIT_Defd</i>	0.33	1.05	0.94	0.84	0.74	0.65	0.57	0.49	0.48	0.48	0.48	0.48	0.48
80	FIT ADIT	<i>rFIT_ADIT</i>	0.33	1.38	2.32	3.16	3.90	4.55	5.11	5.60	6.08	6.55	7.03	7.50	7.98
81															
82	SIT														
83	Return on Equity		4.44	4.29	4.13	3.99	3.84	3.70	3.57	3.44	3.31	3.18	3.04	2.91	2.78
84	Depreciation expense		2.20	2.20	2.20	2.20	2.20	2.20	2.20	2.20	2.20	2.20	2.20	2.20	2.20
85	SIT Depr Allowance		(2.50)	(5.00)	(5.00)	(5.00)	(5.00)	(5.00)	(5.00)	(5.00)	(5.00)	(5.00)	(5.00)	(5.00)	(5.00)
86	SIT Taxable Income	<i>rSIT_Income</i>	4.14	1.48	1.33	1.18	1.04	0.90	0.76	0.63	0.50	0.37	0.24	0.11	(0.02)
87															
88	SIT Current	<i>rSIT_Curr</i>	0.32	0.12	0.10	0.09	0.08	0.07	0.06	0.05	0.04	0.03	0.02	0.01	(0.00)
89	SIT Total	<i>rSIT_Total</i>	0.35	0.34	0.32	0.31	0.30	0.29	0.28	0.27	0.26	0.25	0.24	0.23	0.22
90															
91	SIT Depreciation Allowance														
92	SIT Deprec SL	<i>rSIT_SL</i>	2.50	5.00	5.00	5.00	5.00	5.00	5.00	5.00	5.00	5.00	5.00	5.00	5.00
93	SIT Deprec DDB	<i>rSIT_DDB</i>	5.00	9.50	8.55	7.70	6.93	6.23	5.61	5.05	4.54	4.09	3.68	3.49	3.49
94	SIT Deprec Allow	<i>rSITDep</i>	2.50	5.00	5.00	5.00	5.00	5.00	5.00	5.00	5.00	5.00	5.00	5.00	5.00
95															
96	SIT Basis	<i>rSITBasis</i>	100.00	97.50	92.50	87.50	82.50	77.50	72.50	67.50	62.50	57.50	52.50	47.50	42.50
97															
98	SIT Deprec DDB Bal	<i>rSIT_DDB_Bal</i>	100.00	95.00	85.50	76.95	69.26	62.33	56.10	50.49	45.44	40.89	36.80	33.12	29.64
99	SIT Remaining Years	<i>rSIT_RemY</i>	20.50	19.50	18.50	17.50	16.50	15.50	14.50	13.50	12.50	11.50	10.50	9.50	8.50
100															
101	SIT Deferred	<i>rSIT_Defd</i>	0.02	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20
102	SIT ADIT	<i>rSIT_ADIT</i>	0.02	0.23	0.43	0.63	0.84	1.04	1.24	1.45	1.65	1.85	2.06	2.26	2.46
103															

Exhibit 2-OM

Niagara Mohawk Power Corporation d/b/a National Grid
Marginal Cost Study Case 19-E-0283 and Case 15-E-0751
O&M Costs

Line	Account Description	Account No.	Total	Transmission Stations	Transmission Lines	Distribution Lines	Distribution Stations	Labor
1	COST VALUES			2,092,351,836	2,830,523,772	4,888,595,116	0	
2	Source			Historical	Historical	Historical	Historical	
3								
4	Transmission O&M	580	88,154,657	37,468,052	50,686,605			35.58%
5	Station Expenses	582	6,397,001				6,397,001	48.68%
6	Overhead Line Expenses	583	13,904,973			13,904,973		64.57%
7	Underground Line Expenses	584	10,172,080			10,172,080		7.63%
8	Maint of Structures	591	1,488,279				1,488,279	50.46%
9	Maintenance of Station Equipment	592	7,748,302				7,748,302	63.89%
10	Maintenance of Overhead Lines	593	325,349,104			276,106,568		36.41%
11	Maintenance of Underground Lines	594	11,550,806			11,550,806		35.99%
12								
13	Total - OPER. AND MAINT. EXP.	500-599	1,971,747	37,468,052	50,686,605	311,734,428	15,633,582	
14								
15	Labor Content	172,546,444	154,618,669	13,332,439	18,036,061	114,434,891	8,815,279	
16	Total Labor costs		370,439,970	370,439,970	370,439,970	370,439,970	370,439,970	
17	% of Total Labor in items above			3.60%	4.87%	30.89%	2.38%	
18	Total Labor-related costs	300,077	175,826,752	175,826,752	175,826,752	175,826,752	175,826,752	
19	Applicable Labor-related costs			6,328,149	8,560,691	54,315,724	4,184,111	
20								
21	Total Costs			43,796,201	59,247,296	366,050,152	19,817,693	
22								
23	O&M Rates as % of cost			2.09%	2.09%	7.49%	#DIV/0!	
24								
25	<u>Allocation of O&M to Plant Components</u>							
26	Poles, Towers and Fixtures	364	1,674,539,922					
27	Overhead Conductors and Devices	365	1,900,659,887	85%				
28	Services	369	637,623,017	15%				
29	Total		<u>4,212,822,826</u>					

Exhibit 2-Tax

Niagara Mohawk Power Company (Electric) dba National Grid
Marginal Class Study (\$000s) Pursuant to Order in Cases 15-E-0751, 19-E-0283
Other Taxes Applicable to Plant

Exhibit 2-Tax
Page 1 of 1

Line	Account Description	Account No.	Balance (\$000s)
1	C. TRANSMISSION PLANT		
2	Transmission Plant	350	4,922,875,608
3	Subtotal - TRANSMISSION PLANT	350-359	4,922,875,608
4			
5	D. DISTRIBUTION PLANT		
6	Land and Land Rights	360	77,051,653
7	Structures and Improvements	361	66,104,088
8	Station Equipment	362	1,249,810,809
9			
10	Poles, Towers and Fixtures	364	1,674,539,922
11	Overhead Conductors and Devices	365	1,900,659,887
12	Underground Conduit	366	338,352,972
13	Underground Conductors & Devices	367	975,042,335
14	Line Transformers	368	1,340,938,405
15	Services	369	637,623,017
16	Meters	370	409,302,497
17	Street Lighting & Signal Systems	373	198,865,681
18	All Other	374	
19	Total Distribution Plant	360-373	8,868,291,266
20			
21	TOTAL TRANSMISSION & DISTRIBUTION PLANT		13,791,166,874
22			
23	II. DEPRECIATION RESERVE		
24	Transmission Plant	108.5	793,858,929
25	Distribution- Land, Land Rights, Substations,	108.5	283,874,602
26	Distribution- PTF / OH / UG	108.5	1,483,657,135
27	Distribution- Line Transformers	108.5	354,984,116
28	Distribution- Services	108.5	303,908,930
29	Distribution- Meters	108.5	68,876,436
30	Distribution- Lighting	108.5	66,409,075
31	Total Depreciation Reserve	108	3,355,569,224
32	Net Plant		10,435,597,650
33			
34	Net Plant Summary		
35	Net Services Plant		333,714,087
36	Net Meter Plant		340,426,061
37	Net All Other Plant		9,761,457,502
38	Net Plant for Tax Bases		10,435,597,650
39			
40	General Taxes		
41	Municipal taxes	408.3	194,316,532
42	Other taxes	408	2,485,723
43	Subtotal - General Taxes		196,802,255
44	Net All Other Plant		9,761,457,502
45			
46	Other Taxes Applicable to Plant		2.016%
47			