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June 30, 2023

VIA ELECTRONIC DELIVERY

Honorable Michelle L. Phillips
Secretary
New York State Public Service Commission
Three Empire State Plaza, 19th Floor
Albany, New York 12223-1350

**RE: Case 14-M-0101 – Proceeding on Motion of the Commission in Regard to
Reforming the Energy Vision**

Case 16-M-0411 – In the Matter of Distributed System Implementation Plans

**NIAGARA MOHAWK POWER CORPORATION d/b/a NATIONAL GRID
– 2023 DISTRIBUTED SYSTEM IMPLEMENTATION PLAN (“DSIP”)
UPDATE**

Dear Secretary Phillips:

Niagara Mohawk Power Corporation d/b/a National Grid (“National Grid” or the “Company”) hereby submits its 2023 DSIP Update in accordance with the Commission’s April 20, 2016 *Order Adopting Distributed System Implementation Plan Guidance* in Cases 14-M-0101 and 16-M-0411 directing the Company to file an individual DSIP on a biennial basis.¹

Please direct any questions regarding this filing to:

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¹ Two extensions of six months each were granted that extended the filing date of the DSIP update from June 30, 2022 to June 30, 2023.

Hon. Michelle L. Phillips, Secretary
Cases 14-M-0101/16-M-0411 – National Grid 2023 DSIP Update
June 30, 2023
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Thank you.

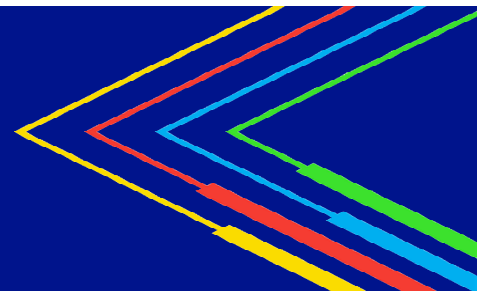
Respectfully submitted,

/s/ Janet M. Audunson

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

Case 16-M-0411
DSIP Proceeding
June 30, 2023



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Acronyms

3V0:	Zero-Sequence Voltage
ACE-NY:	Alliance for Clean Energy New York
ADMS:	Advanced Distribution Management System
AMI:	Advanced Metering Infrastructure
API:	Application Programming Interface
ARI:	Active Resource Integration
ATWG:	Advanced Technology Working Group
ASHP:	Air Source Heat Pump
BCA:	Benefit-Cost Analysis
BE:	Beneficial Electrification
BTM:	Behind-the-meter
Btuh:	British Thermal Unit per Hour
CARIS:	Congestion Assessment and Resource Integration Study
C&I:	Commercial and Industrial
CDG:	Community Distributed Generation
ccASHP:	Cold Climate Air Source Heat Pump
CDG:	Community Distributed Generation
CEATI:	Centre for Energy Advancement through Technological Innovation Inc.
CEI:	Customer Energy Integration
CEMP:	Customer Energy Management Platform
CESIR:	Coordinated Electric System Interconnection Review
CGPP:	Coordinated Grid Planning Process
CIP:	Capital Investment Plan
CLCPA:	Climate Leadership and Community Protection Act
CO2:	Carbon dioxide
Commission:	New York State Public Service Commission
Company:	Niagara Mohawk Power Corporation d/b/a National Grid
CSRP:	Commercial System Relief Program
CSS:	Customer Service System
CVR:	Conservation Voltage Reduction
CY:	Calendar Year
DAC:	Disadvantaged Community
DAF:	Data Access Framework
DCFC:	Direct Current Fast Charger
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
DLRP:	Distribution Load Relief Program
DMS:	Distribution Management System
DNI:	Distributed Network Infrastructure

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
DWDM:	Dense Wave Division Multiplexing
EDA:	U.S. Economic Development Administration
EE:	Energy Efficiency
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
ESS:	Energy Storage System
EV:	Electric Vehicle
EVCS:	Electric Vehicle Charging Station
EVSE:	Electric Vehicle Supply Equipment
FAN:	Field Area Network
FERC:	Federal Energy Regulatory Commission
FLISR:	Fault Location, Isolation, and Service Restoration
FY:	Fiscal Year
GBC:	Green Button Connect
GHG:	Greenhouse Gas
GIS:	Geographic Information System
GPU:	Graphic Processing Unit
GSHP:	Ground Source Heat Pump
GW:	Gigawatt
HC:	Hosting Capacity
HCA:	Hosting Capacity Analysis
HMI:	Human-Machine Interface
HP:	Heat Pump
HPWH:	Heat Pump Water Heater
ICAP:	Installed Capacity
ICE:	Interruption Cost Estimate
IEEE:	Institute of Electrical and Electronics Engineers
IEDR:	Integrated Energy Data Resource
IIJA:	Infrastructure Investment and Jobs Act
IOAP:	Interconnection Online Application Portal

IOU:	Investor-Owned Utility
IPV:	Initial Public Version
IPWG:	Interconnection Policy Working Group
IRA:	Inflation Reduction Act
ISO:	Independent System Operator
ISO-NE:	Independent System Operator – New England
ISS:	Intelligent Substation
IT:	Information Technology
ITC:	Investment Tax Credits
ITWG:	Interconnection Technical Working Group
JMC:	Joint Management Committee
kV:	Kilovolt
kW:	Kilowatt
kWh:	Kilowatt hour
LBMP:	Locational-Based Marginal Price
LDV:	Light Duty Vehicle
LED:	Light-emitting diode
LMI:	Low- to moderate-income
LSRV:	Locational System Relief Value
LTC:	Load Tap Changer
L1:	Level 1
L2:	Level 2
M&C:	Monitoring and Control
MADC:	Marginal Avoided Distribution Capacity
MCOS:	Marginal Cost of Service
MDIWG:	Market Design and Integration Working Group
MDMS:	Meter Data Management Services
MHDV:	Medium-Heavy Duty Vehicle
MMBtu:	Metric Million British Thermal Unit
MOU:	Memorandum of Understanding
MPLS-TP:	Multiprotocol Label Switching – Transport Profile
MRP:	Make-Ready Program
MTC:	Market Transition Credit
M&V:	Measurement and Verification
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
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
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
OT:	Operational Technology
PCC:	Point of Common Coupling
POC:	Proof of Concept
PPI:	Per-Plug Incentive
PV:	Photovoltaic
QA/QC:	Quality Assurance/Quality Control
REC:	Renewable Energy Certificate
REV:	Reforming the Energy Vision
RFP:	Request for Proposal
RTO:	Regional Transmission Operator
RTU:	Remote terminal unit
SAInt:	Scenario Analysis Interface for Energy Systems
SCADA:	Supervisory Control and Data Acquisition
SD-WAN:	Software-defined wide-area network
SEEP:	System Energy Efficiency Plan
SME:	Subject matter expert
SONET:	Synchronous Optical Network
SPOC:	Single Point of Contact
Sub-T:	Sub-transmission
Telco:	Telecommunications Companies
T&D:	Transmission and distribution
TBtu:	Trillion British thermal unit
TVP:	Time-varying pricing
UCG:	Utility Coordination Group
UL:	Underwriters Laboratories
UPA:	Utility Partners of America
VAR:	Volt-Amp Reactive
VDER:	Value of Distributed Energy Resource
VTou:	Voluntary Time-of-Use
VVO:	Volt-VAR Optimization
WWHP:	Water-to-Water Heat Pump
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 2023 Distributed System Implementation Plan (“DSIP”) Update¹ following the framework provided by the New York State Public Service Commission’s (“Commission”) Reforming the Energy Vision (“REV”) Proceeding² and advancing the objectives of the New York State Climate Leadership and Community Protection Act (“CLCPA”).³

In 2019, New York State passed the nation-leading CLCPA to achieve 100% zero-emission electricity by 2040 and 85% emission reductions below 1990 levels by 2050 which envisions that:

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

As a Distributed System Platform (“DSP”) provider, National Grid is a key partner to New York (“NY”) state in enabling this future. National Grid’s vision is to be at the heart of a clean, fair, and affordable energy future with a focus on safety, finding a better way and making it happen to deliver efficiently for customers. National Grid is committed to the achievement of CLCPA emission reduction goals, as reflected in the 2022 release of National Grid’s Northeast Clean Energy Vision⁴ to fully eliminate fossil fuels from both the Company’s gas and electric systems, enabling all homes and businesses that National Grid serves to meet their energy needs without the use of fossil fuels by 2050. In this 2023 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 CLCPA.

To deliver on National Grid’s vision and the goals of the CLCPA, 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

¹ DSIP Updates have been traditionally filed every two years. The Commission granted two six-month extensions for the 2022 DSIP Update, resulting in a due date of June 30, 2023 for this DSIP Update.

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

³ The CLCPA is available at <https://www.nysenate.gov/legislation/bills/2019/s6599>

⁴ Report and more information available at <https://www.nationalgrid.com/us/fossilfree>

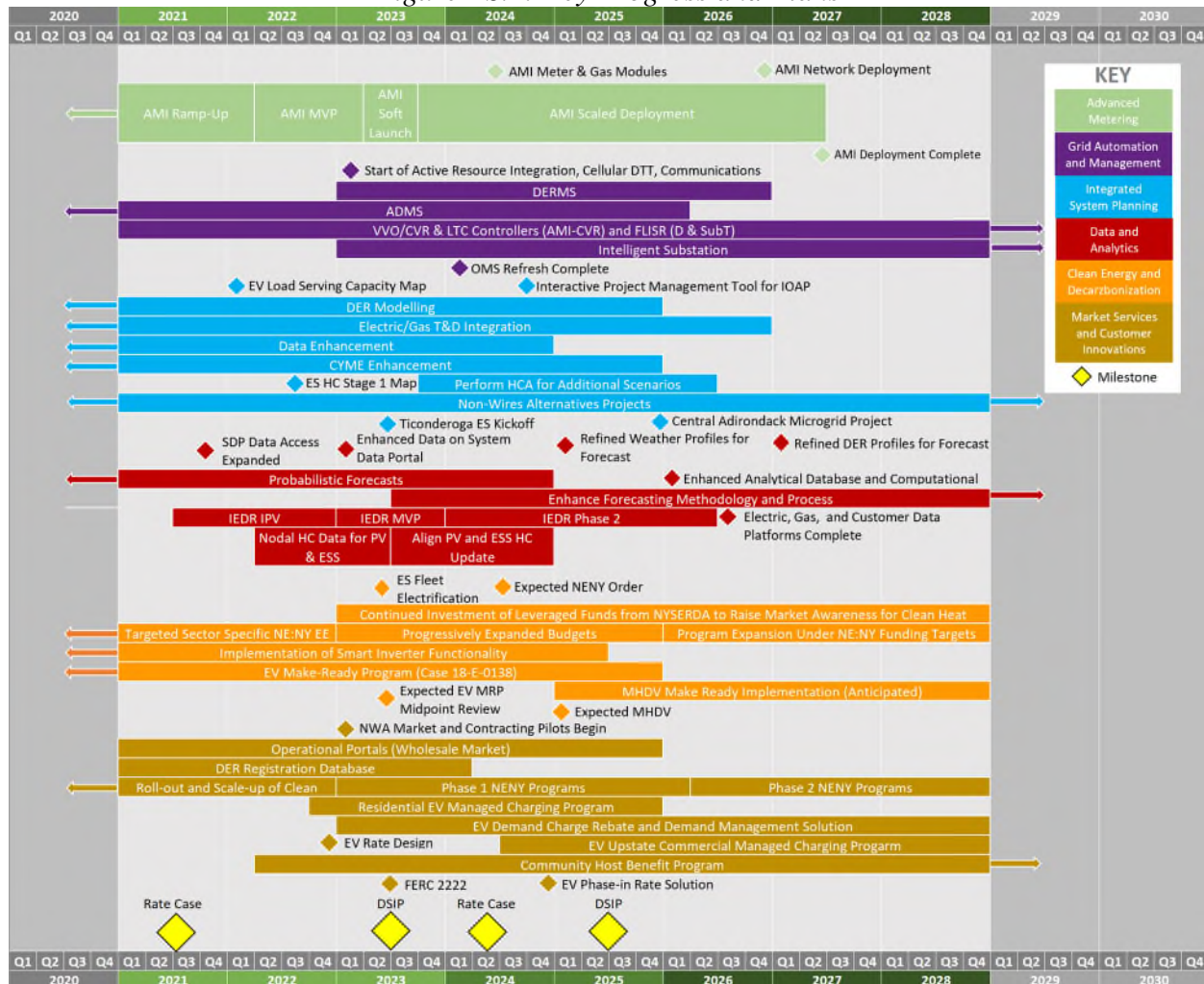
directed in the Commission’s REV Track One Order.⁵ In this role, the Company continuously seeks opportunities to incorporate services that enable third-party providers of distributed energy resources (“DER”) to deliver value to both customers and the electric system.

The Company’s progress and plans presented in this document exemplify how National Grid has embraced its role as DSP provider. Figure ES.1 below depicts key progress made to date as well as the Company’s current plans through 2028. Some of the major investment areas the Company is proposing include: ESS projects, such as through the Non-Wires Alternatives (“NWA”) program; development of Distributed Energy Resource Management System (“DERMS”) capabilities, such as short-term forecasting and tools for DER/Aggregator wholesale market participation; acceleration of the Fault Location Isolation and Service Restoration (“FLISR”) program to enhance reliability; and the deployment of Advanced Metering Infrastructure (“AMI”) to aid greater customer interactions and awareness of their energy supplies. Implementation of the activities set forth in this five-year plan are dependent on future rate case review and approval. National Grid’s current Three-Year Rate Plan⁶ is in effect through June 30, 2024. The proposal also contains provisions that apply a stay-out period immediately following the rate plan through March 2025. The Company is currently anticipating filing a new rate case with the Commission in Spring 2024.

⁵ REV Proceeding, Order Adopting Regulatory Policy Framework and Implementation Plan (issued February 26, 2015) (“REV Track One Order”).

⁶ 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”).

Figure ES.1: Key Progress and Plans



National Grid's 2023 DSIP Update

This 2023 DSIP Update provides detailed information about National Grid's planned DSP implementation over the coming five-year period ending in 2028.

In this DSIP Update the Company will:

- Report on DSP actions and progress since the 2020 DSIP Update;⁷
- Describe plans for developing and implementing necessary tools, policies, processes and resources to achieve the next five-year plan;
- Identify and describe how DER developers 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;

⁷ 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 – 2020 Distributed System Implementation Plan ("DSIP") Update (filed June 30, 2020).

- Provide useful links and citations to information and live data so stakeholders have access to the latest information; and
- Describe upcoming new programs, projects, and procurements to enable greater levels of DER.

Development of this 2023 DSIP Update has benefited from a collaborative process with the Joint Utilities of New York,⁸ Department of Public Service (“DPS”) Staff, and numerous other stakeholders. The Joint Utilities work collaboratively to progress the 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 DPS Proposed DSIP Guidance Update⁹ and maintain consistency with previous DSIP Updates. Each of the topical sections represented in Table ES.1 includes a discussion on context and progress made since the 2020 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 2023 DSIP Update.

⁸ The Joint Utilities of New York are Central Hudson Gas & Electric Corporation, Consolidated Edison Company of New York, Inc., New York State Electric & Gas Corporation, Niagara Mohawk Corporation d/b/a National Grid, Orange & Rockland Utilities, Inc., and Rochester Gas and Electric Corporation (“Joint Utilities”).

⁹ DSIP Proceeding, DPS Staff Whitepaper - Proposed Commission Guidance for the Electric Utilities’ DSIP Update Filings (filed January 10, 2023).

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

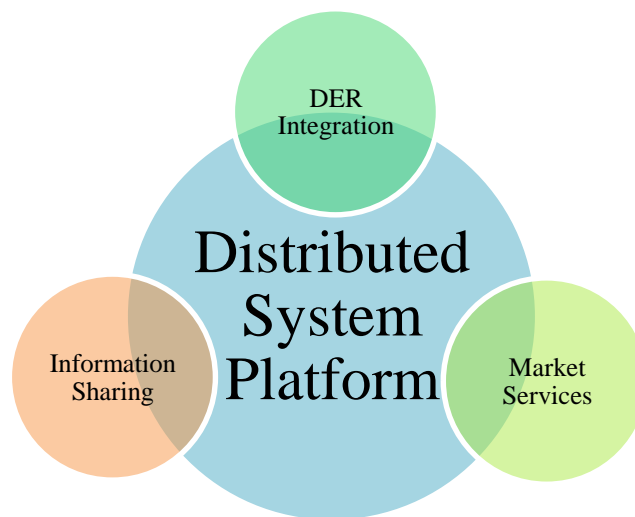
As the energy landscape evolves, so will National Grid's DSIP. There are multiple efforts and regulatory proceedings underway that may influence the implementation of this plan. For a list of regulatory proceedings that may influence the path forward, please refer to Appendix A. Throughout this evolution 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. The integrated implementation timelines found in each topical section of this document, as well as in Figure ES.1, reflect National Grid's current view of its DSIP and includes related regulatory filings and orders that may impact its plans. The inclusion of regulatory milestones in the timelines is meant only to provide a holistic view of important factors that may impact the Company's DSIP, not as an assurance that those milestones will materialize in line with the timeline provided.

1 Progressing the Distributed System Platform

Summary: National Grid's Vision Remains Consistent While DSP Functions Are Evolving

National Grid's vision is to facilitate the development of DERs through the three core DSP functions of DER integration, market services, and information sharing, so that our ongoing investments in grid technologies, advanced planning, and grid operations methods can empower communities and customers to actively manage their energy needs and participate in the marketplace, and the state can achieve its policy goals.

Figure 1.1: DSP Functions



While that overall vision remains the same since the last DSIP, there have been changes in state and federal policy that will impact the way the Company performs the core DSP functions. Accordingly, those changes have been incorporated into National Grid's vision.

This kind of adjustment has been a continuous process for National Grid. Starting with REV and through subsequent state policy initiatives – particularly the CLCPA – the Commission has been advancing an evolving set of goals for New York's energy future that include enhancements to system efficiency, reliability and resilience, market animation, utility business models, customer empowerment, and greenhouse gas ("GHG") emissions reduction.

Areas of Greater Focus in Updated 2023 Vision

- DER Integration: Integration of planning processes with the bulk power system.
- Information Sharing: Expansion through the Integrated Energy Data Resource (“IEDR”) and Data Access Framework (“DAF”) into a statewide effort.
- Market Services: FERC Order 2222 implementation opens new channels for DER value.
- Meeting State Goals: Greater focus on electrification and identification of enabling investments.

These areas of greater focus reflect new or expanded initiatives which are aligned with the three core DSP functions of:

- DER integration
- Market services
- Information sharing

The fourth area of greater focus reflects the Company’s commitment to enabling achievement of the broader policy goals of the CLCPA, and particularly, facilitating efficient electrification through investment to enable technology and utility capacities.

By integrating planning processes, expanding information sharing, implementing Federal Energy Regulatory Commission (“FERC”) Order 2222,¹⁰ and aligning DSP enablement with the Coordinated Grid Planning Process (“CGPP”), the Company aims to create new channels for DER value and identify investments that facilitate efficient electrification in line with state goals under the CLCPA. These initiatives will play a crucial role in meeting the State’s energy objectives and improving the sustainability of the communities National Grid serves.

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 system while continually evolving our planning process to preserve system safety and reliability and to maximize DER benefits for both customers and the electric grid.

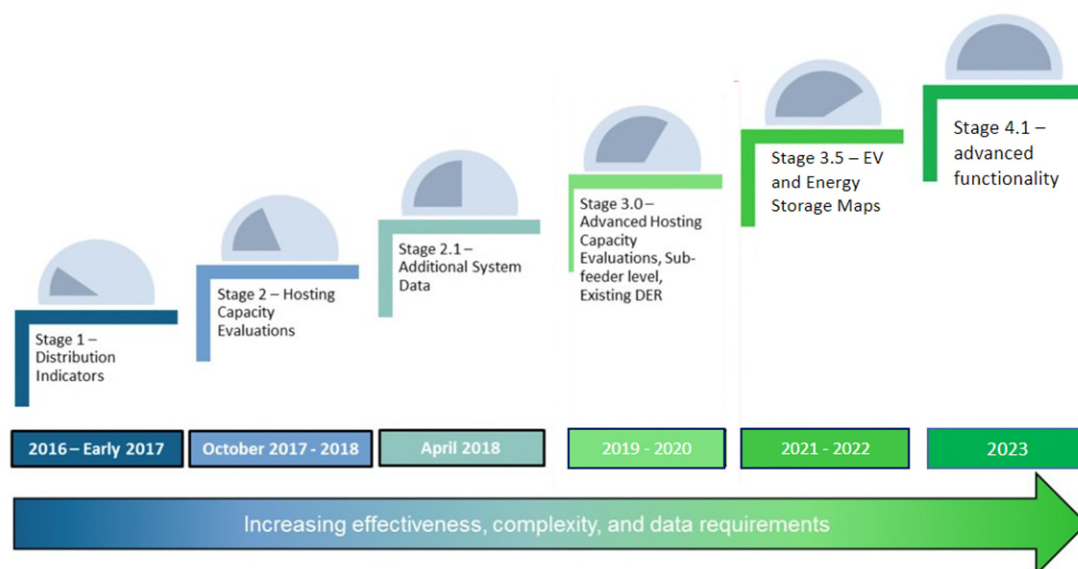
Accomplishments Since the Last DSIP

The Joint Utilities have continued to make progress on implementing the initiatives outlined in the DER Roadmap released in 2020. 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.

¹⁰ FERC Order 2222 (“FERC 2222”) requires Regional Transmission Operators (“RTOs”) and Independent System Operators (“ISOs”) to allow DER aggregators to participate directly in wholesale markets, thereby establishing a new category of market participants. The New York Independent System Operator (“NYISO”) will be implementing their FERC approved 2020 DER Participation Model in Q3 2023 with expectations to implement all of FERC 2222 by Q4 2026.

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,” worked with the other Joint Utilities to develop a smart inverter roadmap released earlier in 2023 that includes bulk power support and voltage support smart inverter settings and developed and proposed ESS metering architectures for various technology configurations. The Company has also progressed through the planned stages of the Hosting Capacity (“HC”) Roadmap shown below to achieve ever greater functionality and insight for DER developers to help them make efficient decisions that maximize system benefits.

Figure 1.2: Hosting Capacity Roadmap



National Grid published the first iteration of the Storage HC maps in spring 2022 which show 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 HC maps to further provide sub-feeder level information, nodal constraints (criteria violations), New York Standardized Interconnection Requirements (“NY-SIR”) Cost-Sharing 2.0 projects, and distributed generation (“DG”) connected since National Grid’s last HC refresh. The Storage HC maps are refreshed annually.

The Company has also shared updated solar photovoltaic (“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 HC 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.

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 Act¹¹ 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 while maintaining the State's electric grid reliability. The fulfilment of CLCPA objectives will require the deployment of emissions-free generation capacity at an unprecedented scale, as well as battery ESS and other advanced technologies. To support the optimal deployment of these investments and with the goal of delivering an electric system capable of meeting New York's clean energy objectives, the Joint Utilities continue to develop and refine integrated planning processes to identify and construct local transmission and distribution ("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 the 2023 DSIP Update is greater integration of distribution-level planning processes with the bulk system. The initial phases of this work were described in the Joint Utilities' CGPP, which explained how the Joint 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 DSIP 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 this function as a DSP now incorporates an understanding that DER will be integrated in this 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 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 monitoring and control ("M&C") and operational system requirements, developing new monitoring parameters, and coordinating with the New York Independent System Operator

¹¹ Available at <https://www.nysenate.gov/legislation/bills/2023/S373>

(“NYISO”) to define operational coordination processes needed to facilitate DER wholesale market participation.

Table 1.1: DER Integration Actions and Results

Actions	Results
National Grid expanded deployment or demonstration of foundational communications and operations infrastructure: AMI, sensors, Distribution System Supervisory Control and Data Acquisition (“DSCADA”), Distribution Automation, Advanced Distribution Management System (“ADMS”)	Facilitates improved network performance and increased DER integration.
The Joint Utilities held stakeholder sessions to enhance hosting capacity map functionality. National Grid released updated HC solar PV maps sharing information such as sub-feeder level HC data and nodal constraints. National Grid published an Energy Storage System HC map with the same level of granularity.	Stakeholder sessions allow for third-party input into the prioritization of the hosting capacity map enhancements in both the near and long-term. HC maps provide stakeholders with additional detailed information to create a more streamlined DER interconnection process and improve beneficial, cost-efficient siting of storage and solar PV.
National Grid led the Interconnection Policy Working Group’s (“IPWG”) Cost-Sharing 2.0 proposal as a joint filing with industry.	Approved in April of 2022, Cost-Sharing 2.0 introduces a pro rata concept where distributed generation interconnecting projects pay for the hosting capacity that they use from an upgrade, rather than charging full costs to the first mover that triggers an upgrade.
National Grid collaborated with members of industry on a “Comprehensive CESIR Analysis Evaluation Initiative”	Better stakeholder understanding of how to help projects pass successfully through the CESIR process, and a re-examination of the voltage flicker calculation which is anticipated to result in an increase in projects passing the CESIR Screen H Limit.
The Joint Utilities collaborated with the Electric Power Research Institute (“EPRI”) to make significant progress on understanding effective grounding practices and policies for DER.	Improved interconnection study capabilities and safety measures which will enhance project success.

Actions	Results
The Joint Utilities developed and proposed storage metering architectures for various technology configurations to serve as a guide for developers.	→ Gives developers a better sense of the metering configurations that could be used for their projects.
The Joint Utilities developed and released bulk power system support and voltage support settings/ setpoints for smart inverters, as part of the Phase 1 activity of the Joint Utilities Smart Inverter Roadmap.	→ After January 1, 2023, inverter-based DER projects installed in New York State will be equipped with Institute of Electrical and Electronics Engineers (“IEEE”) 1547-2018 compliant and Underwriters Laboratories (“UL”) 1741- SB certified inverters. These inverters offer advanced functionality, including voltage and frequency disturbance ride-through and the ability to specify both voltage – reactive power and voltage – active power setpoints (among other functionalities). Such inverters will aid integration of more DER with the grid while ensuring safety and reliability.
The Joint Utilities developed a monitoring requirements document to describe the key monitoring parameters and points required from inverter-based resources.	→ Advances the Joint Utilities’ goal of potentially using smart inverters as a low – cost monitoring solution, decreasing system and developer costs.
The Joint Utilities updated matrix of common infrastructure upgrade costs.	→ Provides additional insight to DER developers as to estimated costs of infrastructure upgrades. The updated DER technical guidance/ requirement matrix and cost matrix provide indicative estimates of various scopes of work and the relevant costs associated with the interconnection of DER on an individual company basis to help aid integration of more DER to the grid while ensuring safety and reliability.
National Grid collaborated on updates to the NY-SIR.	→ Provides stakeholders with latest guidance on UL 1741-SB certified inverters and will aid in improving the efficiency of the interconnection process.

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, the Company emphasized the need to achieve more uniform information access across the New York utilities. The Joint Utilities have made progress in recent years toward that objective through the inception of the IEDR. National Grid is a key stakeholder in the IEDR and supports its development. The Company has worked collaboratively with stakeholders to develop and shape the overall 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 and will help to inform 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 the New York State Energy Research and Development Authority (“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 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 New York’s electric grid and is committed to ensuring that the IEDR achieves its full potential.

Table 1.2: Information Sharing Actions and Results

Actions	Results
National Grid updated HC maps to Stage 4.1 which includes nodal hosting capacity results per violation criteria, change in DG since last update, and Cost-Sharing 2.0 projects.	→ Improved data access and granularity to increase value of data driven by stakeholder and developer feedback along with expanded applicability for additional stakeholders (i.e., ESS providers).
The Joint Utilities identified and filed data set omission analyses points that were not addressed in the Commission’s DAF	→ Awaiting Commission action.

Actions	Results
<p>Order.¹² Additional Commission filings by the Joint Utilities included a DAF alternative ID proposal, current data access use, a Customer Consent Plan, a Data Access Implementation Plan, recommended enhancements to cybersecurity and privacy protections, modifications request to Data Security Agreement (“DSA”) self-attestation (“SA”) requirements coupled with implementation of a governance review process for SA updates, and a petition in response to the Commission’s IEDR Order¹³ and DAF Order¹⁴ seeking clarity on consent and access to protected customer data.</p>	
<p>The Joint Utilities filed a Green Button Connect (“GBC”) User Agreement and Onboarding Process with the Commission.</p>	<p>→ No Commission action taken.</p>
<p>Each of the Joint Utilities shaped IEDR use cases, including the IPV, and provided non-confidential (i.e., public) data transfers.</p>	<p>→ Responded to stakeholder requests to provide useful information that relate to the highest-priority use cases.</p>
<p>Each of the Joint Utilities have filed quarterly IEDR reports with the Commission since Q4 2021.</p>	<p>→ Provide transparency in the Joint Utilities’ role in the IEDR process, investments, and progress.</p>
<p>Joint Utilities collaboration with NYSEDA, DPS Staff, and stakeholders on IEDR development and implementation.</p>	<p>→ Achieved an IEDR IPV that meets stakeholder and market needs as efficiently and effectively as possible.</p>
<p>National Grid Filed annual reports with the Commission regarding electric vehicle (“EV”) Make-ready Program and Direct</p>	<p>→ Illustrates how the make-ready efforts progress state EV adoption goals.</p>

¹² Case 20-M-0082, *Proceeding on Motion of the Commission Regarding Strategic Use of Energy Related Data* (“IEDR Proceeding”), Order Adopting Data Access Framework and Establishing Further Process (issued April 15, 2021) (“DAF Order”).

¹³ IEDR Proceeding, Order Implementing an Integrated Energy Data Resource (issued February 11, 2021) (“IEDR Order”).

¹⁴ IEDR Proceeding, *supra*, note 12.

Actions	Results
Current Fast Charger (“DCFC”) Per-Plug Incentive (“PPI”).	
National Grid completed HC map refreshes.	→ Maps reflect more current conditions.
The Joint Utilities provide updated monthly Cost-Sharing 2.0 information.	→ Providing stakeholders cost sharing information (substation, type of upgrade, amount of capacity added, cost, and timeline of upgrades) to facilitate additional DER integration.

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.

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 has been working with the NYISO to develop and support the launch of the DER Market Participation Model. National Grid has updated processes and systems to prepare for market launch, including refining the exchange of information related to registration, enrollment, operational coordination, and data exchanges providing input on draft NYISO manual revisions and resolving process concerns related to Q2 2023 market launch. The Company has also been actively coordinating with stakeholders along the way. For example, a 2022 stakeholder session with DER community

members focused on necessary telemetry requirements for safe and reliable operation of the distributed grid.

With this progress underway as a step toward full FERC 2222 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.

Table 1.3: Market Services Actions and Key Results

Actions	Results
National Grid identified and developed non-wires opportunities.	Developing projects and portfolios of DER solutions that provide value to customers; streamlining the non-wires solicitation process across the Joint Utilities; more projects give opportunities to support/improve system reliability.
National Grid worked closely with the 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 providing input on draft NYISO manual revisions, and resolving process concerns.	Provides opportunity for DER to access value for both distribution-level services and wholesale market to potentially reduce wholesale prices through increased competition.
National Grid coordinated with stakeholders on NYISO DER Market Participation including telemetry requirements.	Enables DER to access more value through wholesale markets while preserving system safety and reliability. Identified the need for lower cost solutions to be developed in near future.
National Grid expanded implementation of advanced customer programs for demand-side management (EE, demand response ("DR")).	Allows for greater DER market participation and increases DSP flexibility to meet system needs.
National Grid continued implementation of nine compensation programs: Volumetric Net Energy Metering ("NEM"), Monetary	Provides expanded set of market signals to DER about the locational and temporal

Actions	Results
Net Metering NEM, Remote Net Metering, Remote Crediting, Net Crediting, VDER Phase One NEM, VDER Phase One NEM with Customer Benefit Contribution, Phase One VDER Value Stack, and Phase Two VDER Value Stack.	value of operation and a wider array of compensation avenues.
National Grid made significant progress toward automation of crediting and billing of community distributed generation (“CDG”) projects.	→ Supports the widespread adoption of CDG projects and provides timely and accurate billing and compensation for DGs and retail customers. From 2020-2022, the number of CDG project hosts in NY has more than doubled.
National Grid engaged in the DPS Market Design and Integration Working Group (“MDIWG”).	→ Charting out potential paths forward to enable a New York energy marketplace that achieves clean energy deployment, customer empowerment, and cost savings while providing grid level, distribution level, and edge level products and services.
National Grid released ESS hosting capacity maps.	→ Provides an additional tool for ESS developers for market-driven site identification.
National Grid implemented utility EV programs for light duty vehicles (“LDV”) Make-Ready Program (“MRP”), medium-heavy duty vehicles (“MHDV”) Pilot, Transit Authority Pilot, DCFC PPI Program, and Residential Managed Charging.	→ Remove barriers to EV adoption via make-ready incentives, operating incentives, technical assistance and fleet advisory services, and ongoing stakeholder coordination.

Greater Focus on Electrification and Identification of Enabling Investments to Continue Progress on Clean Energy Goals Through Enhanced DSP Capabilities

Vision for Achieving Clean Energy Goals

The Company’s vision also includes an understanding that National Grid and the other New York utilities that function as DSPs have a critical role to play in achieving state policy goals – particularly for GHG emissions reduction – by making enabling investments and delivering programs that help customers decarbonize their overall energy usage through DERs.

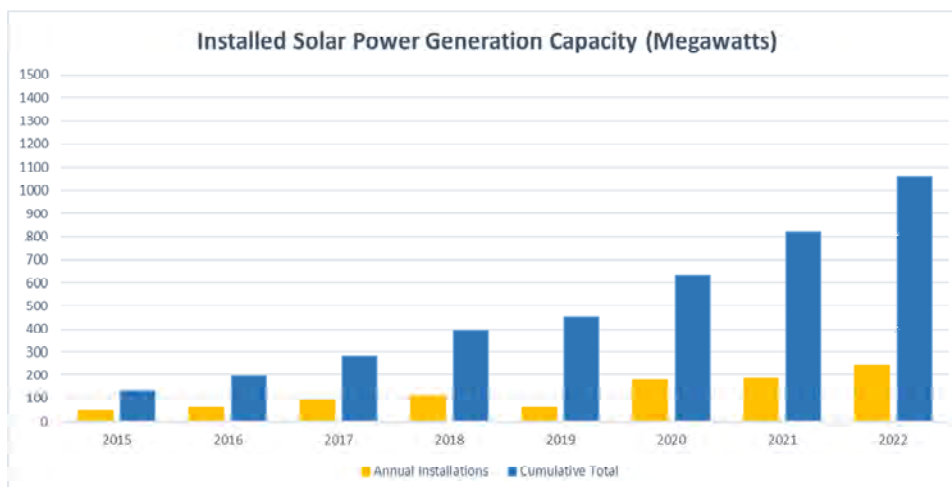
Accomplishments Since the Last DSIP

In the 2020 DSIP, National Grid considered how recent developments in New York’s clean energy policy would foster adaptations in its own vision for the future. As State policy emphasized greater decarbonization through larger-scale resources such as offshore wind and utility-scale solar and

demand shifts toward electrification – as called for in the CLCPA – the Company detailed how it had incorporated new approaches to the core aspects of the DSP that would enable these changes.

National Grid also showed how these kinds of actions were paying off in growing DER deployment. Those investments and the Company’s continued collaborative work with stakeholders have continued to pay dividends. There has been a significant step forward in the deployment of distributed solar PV, with a nearly 50% increase in the amount of solar PV installed or in development on the distribution system in National Grid’s service territory between the end of 2020 and December 2022. As shown in Figure 1.3 below, the cumulative installed solar power generation in 2022 reached over one gigawatt (“GW”), which is nearly double the amount installed in 2020. The annual installations of solar power generation (megawatts) continue to increase year over year.

Figure 1.3: Installed Solar Power Generation Capacity (Megawatts) in National Grid’s Service Territory



While the growth of distributed solar PV is promising, there is still a lot of work to be done to achieve the CLCPA goal of 10,000 megawatts (“MW”) or more from solar projects under 5 MW by 2030. Further investments will be needed to manage the increase in distribution-level solar PV and enhance flexibility to operate an increasingly dynamic distribution system.

In addition, by December 31, 2022, the cumulative ESS capacity interconnection in National Grid’s service territory reached 79 MW.

Since the Joint Utilities’ EV MRP launched in 2020, New York has also made significant progress in increasing the adoption of EVs. The state has seen a record increase in the number of EVs sold, bringing the total number on the road in 2022 to approximately 120,000. Meanwhile, the number of charging stations in the state increased to more than 10,000 in 2021, including Level Two chargers and DCFC equipment.

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

Recent years have brought an even greater state policy focus on electrification and the utilities' role in enabling a broader transition, particularly in transportation. National Grid has added a commensurate focus to its vision on the investments and program elements that it can deliver.

The Joint Utilities' planning, forecasting, and strategic investments remain instrumental in facilitating the development of electric infrastructure to accommodate an increased deployment of EVs. The EV MRP is currently supporting the development of electric infrastructure and equipment necessary to accommodate an increased deployment of EVs within New York State by reducing the upfront costs of building charging stations for EVs. The Joint Utilities also continue to work with stakeholders on advancing a highly flexible framework that will help facilitate the achievement of the LDV MRP goals.

It is also notable that the Company, along with the other Joint Utilities, is championing an equitable transition to electrified transportation by supporting investment in EV infrastructure to provide access to EV charging facilities in disadvantaged communities meeting the criteria established by the Climate Action Council's Climate Justice Working group¹⁵ (communities that bear burdens of negative public health effects, environmental pollution, impacts of climate change, and possess certain socioeconomic criteria or comprise high concentrations of low- and moderate-income households). Of New York State's \$701 million EV MRP budget, \$206 million directly benefits disadvantaged communities.

In addition to investments, the Joint Utilities are in the process of addressing other important aspects of transportation electrification. Developing EV charging load management, particularly residential managed charging, is central to maintaining reliability and controlling costs as EV adoption scales up. Rate design is another tool to both encourage EV adoption and manage charging loads. The Joint Utilities are exploring rate designs that send price signals to customers indicating charging times for efficient grid operation and also seek to mitigate the impact of demand charges for low load factor charging stations that can impact the cost effectiveness of EV charging for customers.

National Grid is committed to using markets to procure new energy products at lower costs to customers than the alternatives. This is an important element in achieving the State's clean energy goals at least cost for customers.

¹⁵ Map of disadvantaged communities and other documents related to the criteria *available at* <https://climate.ny.gov/resources/disadvantaged-communities-criteria/>

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, and 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 grid of the future. 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 has made a series of 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. However, 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
DER Asset Data	<ul style="list-style-type: none"> • 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	<ul style="list-style-type: none"> • 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	<ul style="list-style-type: none"> • 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.
Feeder Level Forecast w/ DER Scenario Considerations	<ul style="list-style-type: none"> • Feeder-specific electric load forecasts • Contribution of load from different DERs (EV, solar PV, ESS, heat pumps (“HP”), etc.) • Contribution of load from different DER scenarios (e.g., EV managed charging, high adoption of HP, 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, enables consistency in results since they are rooted in the

same source data system, and it 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 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 to improve the accuracy and precision of their analysis results. National Grid has worked to deploy a newer version of the CYME software that adds several enhancements with respect to modeling specific devices and their operational characteristics. However, leveraging the new software features required integration of utility data sets not previously captured or utilized, so development of novel data integration processes was necessary. Many of the processes developed utilize the Application Programming Interface ("API") available within the CYME software. The CYME API has allowed the Company to develop automated processes capable of performing bulk data integrations while requiring minimal direct user input.

In addition to leveraging the CYME API to automate data integration and analysis processes, automation of otherwise manual planning activities has proved to save engineers' time while also establishing standard practices for repetitive tasks which promotes accuracy and output quality. For example, National Grid uses software scripts to automate and simplify the extraction of the OSIsoft® PI Historian data for system data and to auto-scrub the detailed forecasts to check for internal inconsistencies. Automation can improve both internal and external processes. For example, the Company 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 NY-SIR process, which speeds up the time to complete DG interconnection studies while increasing efficiency for interconnection planning engineers.

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 3.2 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 nodal HCA data was fully released as part of Stage 4.0 HCA in April 2023. 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 chapter of this 2023 DSIP Update.

Significant investment has been made in developing and deploying the Company's ADMS which similarly requires the integration of many utility data sets. The effort to implement an ADMS has led to greater scrutiny of utility data systems since the data sources used for an ADMS are used to operate the electric grid in real-time rather than just for system planning. This has resulted in numerous Company initiatives to centralize data systems, clean source data sets, and develop

standards for data governance which has in turn resulted in benefits realized throughout the business including integrated planning. Phase 1 of the ADMS implementation which focused on integrating electric system models and power flow capabilities into the platform has been completed. Phase 1 enables ADMS to be utilized for real-time operations like automated switching as a result of FLISR.

Implementation of the Company's ADMS provides the systems and framework necessary to support other important efforts such as FERC Order 2222. FERC Order 2222 enables DERs to participate alongside traditional resources in the regional organized wholesale markets through aggregations to meet minimum size requirements. Implementation of FERC Order 2222 will enhance the network planning process by providing visibility on the edge of the grid. In 2022, the NYISO filed the response to FERC Order 2222 and a timeline to meet all the order requirements. The NYISO DER Aggregation ("DERA") Model will be live in August 2023 with enrollment beginning in April 2023. National Grid's DERACONNECT tool will facilitate distribution planners in better coordinating and planning for DER applications and participation with automated day-ahead load flow analysis which will rely heavily on the Company's ADMS.

In conjunction with capital infrastructure investments, National Grid continues to explore various flexibility solutions to address system capacity needs. A part of the Company'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 ("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 specific area planning need could be partially addressed by an NWA (e.g., hybrid wires and NWA solution). One example of this is National Grid's Watertown NWA project where the NWA is supporting system capacity needs in the area in conjunction with other capital investment to address asset condition needs. On an annual basis and as part of its Auto-DLM program discussed in Section 2.7 of this 2023 DSIP Update, the Company 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. 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 Active Resource Integration ("ARI") pilot, which is also a part of the Company's overall DERMS and digitalization strategy. The Company is currently implementing a solution that can actively manage generation from front-of-meter, distribution system connected, solar PV facilities being served from its Peterboro substation to defer the need to replace its substation transformer to mitigate backfeed overload risk. As the Company monitors the performance and reliability of this solution through the pilot, this concept of flexible interconnection could be used as a tool to accelerate interconnection of renewable distributed generation by improving utilization of existing system capacity. As system capacity becomes more heavily saturated with distributed generation and at higher levels of system utilization, additional system capacity buildout through capital investment will be paramount.

As part of implementing these flexibility solutions, National Grid is also investigating the required DER management capabilities through its DERMS investment in order to operationalize planned flexibility solutions to ensure the benefits are realized and system reliability is maintained. In some cases, these solutions will rely on awareness of real-time system conditions and take actions to mitigate system violations such as overloading distribution system assets. For other details regarding the Company's current and future DERMS investigation and implementation efforts, see Section 2.3 of this 2023 DSIP Update.

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 electric heat pumps 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 into 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 gas and electric network planning engineers to engage in combined modelling of the electric and gas networks and coordinated controls between them. Although the Company is in the early stages of implementing SAIInt, several use cases have already been identified for integrated planning of both the gas and electric systems. For example, modeling the Company's gas and electric networks in a single tool allows planners to assess the potential feasibility and cost implications of targeting segments of the gas network for full electrification. Additionally, SAIInt will facilitate more robust system modeling by integrating the electric distribution, Sub-T, and transmission network models into a single tool rather than modeling independently as it has traditionally been done. Successful integration of T&D electric models as well as gas models will require collaboration between the Company and encoord to develop import functionality for CYME and Siemens PSS®E modeling software used to model the electric distribution and transmission system respectively, and for the Synergi Gas modeling software used to model the gas system, to be compatible with SAIInt's data architecture.

In addition to investigating the electric system impacts resulting from the electrification of heat, National Grid is also assessing grid impacts as a result of the electrification of transportation. In September 2021, the Company released a case study with Hitachi Energy examining the electrification of "clusters" of commercial fleets in one area of National Grid's service territory. That study considered the load impacts of full depot electrification (100% MHDVs as EVs). National Grid has continued partnerships to evaluate how these impacts will scale with varying levels of EV penetration – and which portions of National Grid's system (distribution feeder, substation, transmission system) are impacted. For Phase 2 of the partnership, the Company focused on the impacts of depot electrification in one "heavy trucking district" in National Grid's service territory. This study considers multiple scenarios for EV adoption and grid constraints, which allow insights to be applied more broadly. Results of these studies indicate that grid impacts could materialize at relatively low levels of adoption, and solutions (which would be specific to each community) should begin to be evaluated soon in order to be ready for future load growth.

The Company is also investigating the impacts of climate change on its electric infrastructure as directed by the Commission in its June 16, 2022 *Order Initiating Proceeding*.¹⁶ Deep dive groups consisting of distribution planning and standards, emergency planning, operations, worker safety, civil substation design, electric substation operation and maintenance, transmission planning and standards, and electric forecasting have been established and are all assessing potential change(s) to processes, standards, and/or procedures. The Climate Change Vulnerability Study will evaluate how the Company's infrastructure, design specifications, and procedures are vulnerable to the impacts of climate change as outlined in newly available climate change weather projections from Columbia University. The results of the study will be addressed in the Climate Vulnerability and Resiliency Plan and identify how these vulnerabilities will be mitigated. The incorporation of this new climate change data and the changes to work practices that result from this deep dive analysis will be folded into regular integrated planning processes such that the impacts of climate change continue to be assessed as part of ongoing system planning.

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.

Data Enhancements

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 2023 DSIP Update. Granular AMI data will improve load and DER forecasts, enhancing both planning and operations. However, leveraging AMI data will require new tools and processes. The Company plans to procure and deploy the CYME Gateway which is a software system solution capable of facilitating the integration of vast AMI datasets 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 where the CYME Gateway will be leveraged to ease the data integrations.

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, 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 2023 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 to roll them out across

¹⁶ Case 22-E-0222, *Proceeding on Motion of the Commission Concerning Electric Utility Climate Vulnerability Studies and Plans*, Order Initiating Proceeding (issued June 16, 2022).

its service territory. The Commission’s May 14, 2020 Transmission Planning Order¹⁷ issued pursuant to the Accelerated Renewable Energy Growth and Community Benefit Act highlights the need to conduct integrated planning to help meet CLCPA goals. The Company will be working with the Joint Utilities to file process proposals and rate making topics per the requirements of the Transmission Planning Order.

The electric power system 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 its Asset Management 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 NY Distribution and Transmission organizations. Understanding maturity in the Asset Management space will ensure the Company provides the best efficiencies in regard to costs for customers, increasing safety and improving the reliability of the grid.

Advanced Forecasting

The Company 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.

Software Planning Tools & Studies

As discussed in the current progress section above, National Grid has made much progress with its ADMS implementation with plans to continue expanding its functionality in the future. As ADMS models are further refined, additional capabilities will be unlocked. Specifically, Phase 2 of the ADMS implementation focuses on enhancing integrations with the Company’s Outage Management System (“OMS”) which will facilitate outage, call, and crew management activities and allow the Company to eventually retire its existing OMS. The new ADMS and OMS integration will enable additional digital products such as new power outage reporting tools. Integration of system modeling, grid monitoring equipment, and robust outage information will

¹⁷ Case 20-E-0197, *Proceeding on Motion of the Commission to Implement Transmission Planning Pursuant to the Accelerated Renewable Energy Growth and Community Benefit Act* (“Transmission Planning Proceeding”), Order on Transmission Planning Pursuant to the Accelerated Renewable Energy Growth and Community Benefit Act (issued May 14, 2020) (“Transmission Planning Order”).

enable planning engineers to better assess system performance, resiliency, and reliability metrics which serves as a critical input to integrated planning processes. Additional information related to the ADMS implementation roadmap can be found in Section 2.3, Grid Operations, of this 2023 DSIP Update.

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. 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. Once CYME, 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 generation, storage, transmission, and distribution assets. For instance, SAInt can analyze flexibility and storage sources at the interface between the electricity and gas networks, optimize investments in power to gas facilities, and identify opportunities to substitute gas to electric conversions for leak prone pipe replacements.

SAInt can be used to plan, model, and compare potential paths toward a decarbonized future, considering both the role of fossil-free gas and renewable generation. In addition to helping plan the location and sizing of electrolyzers and the injection and blending of hydrogen into natural gas networks, SAInt can assess the impact of decarbonization on the electric network. SAInt can model the electricity generation of wind and solar facilities, the value of ESS and demand response, and overall power system operations under high renewable penetrations. Additionally, SAInt also helps model for a resilient and reliable system by analyzing the impact of electric and gas network contingencies on security of supply and quantifying the impact of disruptions or extreme events on interconnected electricity and gas networks. In parallel with identifying new use cases for SAInt, National Grid plans to focus on developing new processes that leverage SAInt's robust API to facilitate future system-wide analyses with the goal of SAInt being used for regular business planning activities necessary to progress National Grid's fossil-free vision.

The Company plans to continue its analysis work as directed by the Commission in Case 22-E-0222¹⁸ to assess the impact of climate change on the electric grid, and National Grid's standards and processes. National Grid plans to complete its Climate Change Vulnerability Study by September 2023 with the subsequent Climate Change Resiliency Plan to be completed by November 2023. The Company plans to refresh the climate change study every five years with new climate data.

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 CYME 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.

¹⁸ Proceeding on Motion of the Commission Concerning Electric Utility Climate Vulnerability Studies and Plans, *supra*, note 16.

FLISR Acceleration

FLISR is a centralized control scheme that is used to reduce outage impacts on National Grid's distribution and Sub-T circuits. The Company is monitoring system performance and working through a FLISR Acceleration study which focuses on deploying FLISR across the NY service territory at an increased rate to reduce outage impacts for more customers on the system. Currently about 4% of customers are connected to distribution circuits with automated restoration schemes such as FLISR. The acceleration plan would look to deploy FLISR to achieve a goal of about 60% of customers connected to FLISR circuits by the conclusion of Fiscal Year ("FY") 2030. The impacted number of customers was determined by reviewing eligible circuits across the Company's service territory and setting a goal of approximately two-thirds of the total 13.2 kilovolt ("kV") feeders and about one-half of the Company's total Sub-T circuits to have FLISR schemes installed on them.

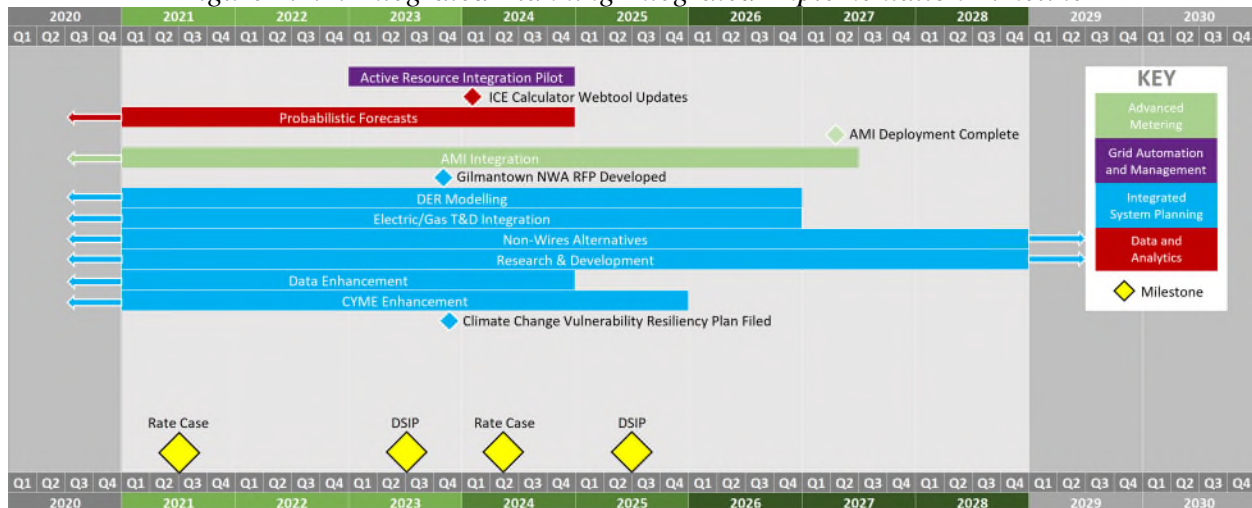
NWA Procurement Platform

Piclo Flex platform is a pilot for the procurement team to release NWA Requests for Proposal ("RFP") in 2023. The pilot is an online-based procurement platform that is tailored towards NWA procurement and offers flexibility in offering a more granular detail to display technical parameters to market participants. Benefits of rolling out NWA opportunities on this platform include new marketing procedures for opportunities of NWA deferrals with ancillary support needs and creates a market-based platform to procure flexibility services. For more information on NWA procurement and NWA opportunities, please refer to the Beneficial Locations of DER and Non-Wires Alternatives Section of this 2023 DSIP Update.

Interruption Cost Estimate ("ICE") Calculator Tool

The ICE Calculator is an electric reliability planning tool developed by Lawrence Berkeley National Laboratory and Nexant, Inc. 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. National Grid currently uses the ICE Calculator to determine the benefits and perform BCA for reliability and resiliency programs such as 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. National Grid's participation, which includes surveys of National Grid residential and commercial customers as well as the same customer groups of National Grid's affiliate in Massachusetts, 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 2024 and will provide a higher level of granularity and accuracy. The ICE Calculator is available at <https://icecalculator.com/home>.

Figure 2.1.1: Integrated Planning Integrated Implementation Timeline



Risks and Mitigations

Table 2.1.2: Risks and Mitigations for Integrated Planning

Risk	Mitigation
Potential delays in SAInt implementation due to difficulty integrating existing electric distribution and transmission system models with existing gas system models	National Grid is actively collaborating with encoord, the developing company of SAInt, to create model conversion tools capable of converting existing system models, in CYME, PSS®E, and Synergi formats, into SAInt's input format.
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. Additionally, the Company is focusing development efforts on leveraging existing software API functionality to facilitate bulk manipulation and data integrations.
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 centralized repository, data audits can be performed to identify discrepancies and build data governance practices.

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 2023 DSIP Update work in concert with the statewide CGPP. The “Initial CGPP Framework” filed in Case 20-E-0197¹⁹ reflects the Joint Utilities’ recognition of the planning and investment needed in the coming years to support achievement of the objectives of New York’s CLCPA and related statutes. 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 and solution development stages.

During initial forecasting, following development of zonal forecasts and assumptions for load and generation, the Joint Utilities will apply 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). 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.

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 station bank through NY-SIR Cost Sharing 2.0 since the planners identifying Cost Sharing 2.0 opportunities would be leveraging the same DER forecast as used in the CGPP.

¹⁹ Transmission Planning Proceeding, Joint Utilities’ Coordinated Grid Planning Process Proposal (filed December 27, 2022) (“Initial CGPP Framework”).

Stakeholder Interface

As indicated in the title of this chapter, 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, the Interconnection Technical Working Group ("ITWG"), and the Interconnection Policy Working Group ("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 stakeholder feedback to further expand and/or refine the deliverable.

2.2 Advanced Forecasting

Context and Background

Electric load forecasts are a fundamental component of utility operation and planning activities. The increasing penetrations of demand side management technologies, DERs, and new load from electrification require utilities to evolve their forecasting methodologies and processes to take these impacts into account. This section of the DSIP focuses on long-term forecasting. For a discussion of short-term forecasting, please refer to Section 2.3, Grid Operations, of the 2023 DSIP Update.

Currently, National Grid performs long-term load forecasting that considers the baseload²⁰ growth and impacts from DER, including EE, solar PV, EVs, ESS, and demand response. The forecasts are provided at the system level for National Grid and the NYISO load zones. The forecasts are also provided at the feeder level. Detailed discussions on the forecasting methodologies and process are provided in National Grid Electric Peak (MW) Report (“System Report”)²¹ and the National Grid Electric Peak (MW) Feeder-level Forecast Report (“Feeder Report”).²²

In its 2020 DSIP filing, National Grid outlined the plan to continue enhancing its forecasting methodologies for DER technologies and probabilistic load forecasting. Since then, the Company has implemented the following enhancements:

1. Introducing new DER technologies

Electric heat pumps

In the 2021 forecasting cycle, National Grid incorporated electric heat pumps into the load forecasting process.

Medium- and heavy-duty EVs and electric buses

Since the 2021 forecasting cycle, National Grid started to incorporate medium-duty and heavy-duty EVs and electric buses into its system and the NYISO zonal level forecasting. Please refer to the Distributed Energy Resources (DERs) section in the System Report for detailed discussions.

2. Enhancing DER forecasting methodologies

Light-duty EV charging profile

²⁰ Baseload is defined as load before DER impacts.

²¹ Available at

<https://systemdataportal.nationalgrid.com/NY/documents/Peak%20Load%20Forecast%20Report.pdf>, Rev. 1 (April 6, 2023).

²² Available at

<https://systemdataportal.nationalgrid.com/NY/documents/Peak%20Feeder%20Level%20Load%20Forecast.pdf>, dated December 2022

National Grid enhanced its LDV EV profiles to reflect impacts on charging load from temperature, EV types, at-home vs. public charging, etc. Please refer to the light-duty Electric Vehicles section of the Feeder Report for detailed discussions.

Electric heat pumps

In the 2022 forecasting cycle, National Grid further enhanced the methods of modeling load impacts from electric heat pumps from the following perspectives:

- Electric heat pumps are differentiated into full and partial use cases. Specific load impact profiles were developed for each to better capture their different characteristics. Please refer to the Distributed Energy Resources (DERs) section in the System Report for detailed discussions.
- National Grid leveraged fuel sources information from US Census Data for identifying likely electric heat pump adopters at a more granular geographical resolution. Please refer to the Electric Heat Pumps section of the Feeder Report for detailed discussions.

Non-rooftop solar PV penetration analysis

National Grid enhanced its methodology in land parcel analysis for non-rooftop solar PV forecasting. This methodology leveraged multiple levels of GIS information to better capture local land availability and suitability information. Please refer to the Non-Rooftop Solar-Photovoltaic section of the Feeder Report for detailed discussions.

3. Enhancing overall load forecasting process

Alignments among different layers of the forecasts

National Grid took a holistic method to align the system, regional, and feeder-level forecasting assumptions and processes. In general, the system and regional level forecasts take into account State DER policies and State and regional economic outlook. These forecasts serve as a high-level guideline for developing feeder-level forecasting. Please refer to the System Report and the Feeder Report for detailed discussions.

More comprehensive forecasting scenarios

National Grid continued refining its DER scenario development to reflect up-to-date State policy and market studies. These include aligning to the most recent CLCPA policy goals and leveraging market studies from national labs and industry-leading vendors.

Since its 2020 forecasting cycle, in addition to the normal and extreme weather scenarios, National Grid has incorporated climate change weather scenarios in its system load forecasting process. These scenarios help inform the uncertainties under climate change. Please refer to the Climate Scenarios section of the System Report for detailed discussions.

In the 2022 forecasting cycle, National Grid introduced a managed charging scenario for analyzing light-duty EV charging impacts.

Since the 2020 forecasting cycle, National Grid developed likelihoods for DER cases by leveraging subject matter expert (“SME”) input. Please refer to the DER Scenarios section of the System Report for detailed discussions.

Table 2.2.1: Summary of Forecasting Enhancements and Inclusion in System- and Feeder-Level Forecast

Category	Enhancement Description	System	Feeder
Electric Heat Pumps	Introduce base case scenario	✓	✓
Electric Heat Pumps	Introduce full and partial use-cases	✓	✓
Electric Heat Pumps	Using census data for adoption analysis		✓
Electric Vehicles	Introduce medium- and heavy-duty EVs and electric buses	✓	
Electric Vehicles	Introduce impacts on charging load from temperature, EV types, at-home vs. public charging for light-duty EVs	✓	✓
Electric Vehicles	Introduce managed charging scenario	✓	✓
Solar PV	Use multiple-level GIS information for land parcel analysis		✓
DER Scenario	Develop DER scenarios reflecting up-to-date State policies and market studies	✓	✓
DER Scenario	Introduce likelihood for DER cases and scenarios	✓	
Climate Scenario	Introduce climate change weather scenarios	✓	
Forecasting Process	Bring in alignments among forecasts at different levels to provide holistic view	✓	✓

Implementation Plan, Schedule, and Investments

Current Progress

At the system level, the forecasts are provided for the Company and the NYISO load zones. These forecasts are based on econometric models that use normal and extreme weather assumptions along with county-level economic projections from Moody's Analytics, a leading economic forecasting firm. The impact of EE, solar PV, EVs, electric heat pumps, ESS, and demand response is factored into the forecasts. A detailed explanation of the forecasting methodologies is provided in the Forecast Methodology section of the System Report.

The feeder-level forecasting process takes system-level load growth and DER projection as inputs. It then leverages regional-specific factors such as demographic information, land availability, etc. to allocate the system-level forecasts to the feeder level. Detailed discussion of the forecasting methodologies is provided in the Feeder Report.

The forecasts are provided under 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 System Report. The forecasts include seasonal peaks and hourly profiles for baseload and each DER component, giving system planners and DER developers granular insights.

Future Implementation and Planning

National Grid is committed to continually improving its load and DER forecasting methodologies and practices. For example, the Company has plans to explore building, customer, and end-use levels of information for refining load profile of DER technologies.

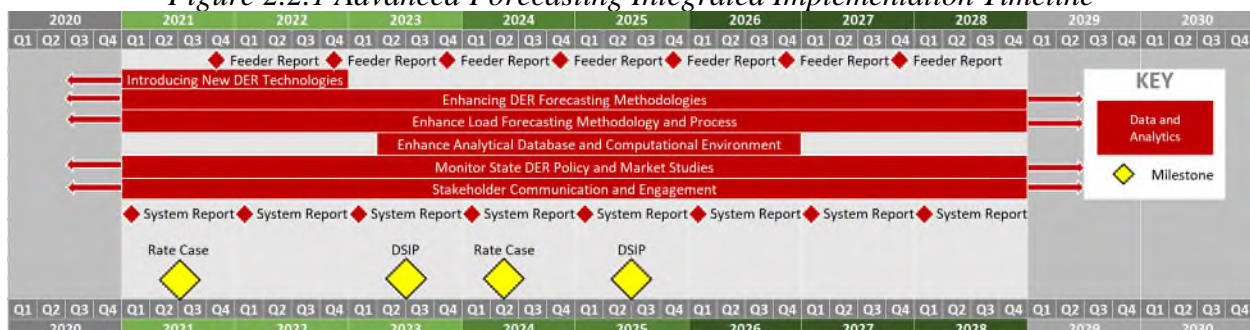
The Company also plans to further explore probabilistic forecasting techniques to better account for uncertainties in weather, economy, and DER technology. For example, National Grid intends to develop weather scenarios and their probabilities by leveraging more granular weather information, more comprehensive weather cases, and using quantitative measures to assist the decision-making process on weather scenario development. The Company is also considering aligning weather scenarios for load and DER forecasting as applicable. For example, when the performance of a DER technology is impacted by weather in some way (e.g., electric heat pump performance under different temperature conditions), the weather scenario being used to inform the DER technology's performance is expected to align with the one being used for informing baseload forecasting. The Company will also continue refining DER scenarios for load forecasting by keeping up to date with state policies and market studies.

The Company also plans to enhance its forecasting process and environment such as introducing version control tools and establishing cloud computing environment. These will help improve the work efficiencies and thereby allow more efforts to be focused on improving the forecasting methodologies.

National Grid will also continue participating in the Joint Utility Load and DER forecasting sub-group workshops to communicate with other utilities on forecasting methods and best practices.

The goal of National Grid's load and DER forecasting and analysis initiatives is to continue to enhance the accuracy of its point forecasts and the reliability, sharpness, and resolution of its probabilistic load forecasting.

Figure 2.2.1 Advanced Forecasting Integrated Implementation Timeline



Risks and Mitigations

Table 2.2.2: Risks and Mitigations for Advanced Forecasting

Risk	Mitigation
Availability and quality of data at more granular level	The Company will continue to put efforts to explore alternative and additional data sources.
Cost of managing and accessing more granular data	The Company will enhance its centralized database to meet analytical needs.
The increasing size and variety of data being used for forecasting require a more powerful computational environment and centralized control system.	The Company will continue investing in its analytical environment, including cloud computing and version control system.
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 to presenting the results to stakeholders, and for stakeholders to fully interpret and smoothly incorporate the forecast in their analyses.	The Company will continue forming the discussions and feedback loop 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.	The Company will continue exploring and evaluating up-to-date policies and studies to ensure the forecasts provide up-to-date views on uncertainties.

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 The System Report.

- EE: the forecast incorporates the New Efficiency: New York order (NE:NY Order) EE goals
- Solar PV: for the near-term, the forecasts are based on historical trend, subject matter experts' outlook, and projects in the queue. The CLCPA goals of 6,000 MW installed nameplate capacity by 2025 and 10,000 MW by 2030 provide guidance for the middle and long-term forecasts.
- Electric Heat Pumps: while the CLCPA did not establish formal goals for heat pump adoption, the forecast assumes the same growth in electric heat pump adoption as in CLCPA scenario three.
- Electric Vehicles: the forecasts for the sales share of EVs are based on the California Clean Car II and the California Clean Truck rules, which also align with the CLCPA.

- Energy Storage: the forecast adopted the CLCPA 1,500 MW installed nameplate capacity by 2025 and 3,000 MW by 2030 policy goal. National Grid is aware of the updated CLCPA policy goal of 6,000 MW installed nameplate capacity by 2030 CLCPA and plans to evaluate this new goal in its future forecasting cycle.

Stakeholder Interface

Forecasting is an essential step in the distribution system planning process. Load forecasts are inputs for base case development, summer preparedness, annual planning, area studies, 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 need or the studies which underpin the beneficial locations of DER.

National Grid provides forecasts at different geographical and temporal granularity levels and under multiple weather and DER scenarios, which give DER developers insights on system capacity and opportunities and risks of developing DER projects. The forecast reports and forecasted load profiles per feeder are published on National Grid's System Data Portal. Additionally, the forecast is utilized as an input to the hosting capacity analysis process to infer future minimum load values. The results of the hosting capacity analysis are also shared on the Company's System Data Portal and help inform the developer community of the capacity for the electric system to support different DERs.

2.3 Grid Operations

Context and Background

The Grid Operations update provides updates on a broad variety of activities. There have been many developments in distribution connected wholesale and retail market areas and developments in grid modernization in support of federal and state orders and goals. As a result, and much like National Grid’s 2020 DSIP Update filing, there are several key topical areas in this section which include, but are not limited to, transmission node mapping, operational coordination and communications, and short-term forecasting.

Grid Modernization includes the hardware and software associated with managing the grid, notably AMI, ADMS, DSCADA, and OMS. Grid modernization technologies increase distribution system automation capabilities which enable programs such as Volt-VAR Optimization (“VVO”)/Conservation Voltage Reduction (“CVR”) and FLISR.

The NYISO filed a tariff with FERC in July 2019, which was approved in January 2020, to enable DER to participate in NYISO wholesale markets. Following this filing, FERC issued Order 2222 providing guidance on DER/Aggregator wholesale market participation. The NYISO filed the response to FERC 2222 and a timeline to meet the Order requirements. The Joint Utilities has been involved in stakeholder meetings to help shape the structure and timing of functions required to enable the supporting market and grid operations.

While the expansion of wholesale markets has driven many changes, National Grid has also advanced its Distribution Automation Programs which include VVO, CVR, and FLISR. In support of the Grid and Market Operation Distribution Automation Programs, the Company has made steps toward advancing Information Technology (“IT”) networks and infrastructure to support developing programs and their data and security needs.

DPS Staff has also worked with stakeholders to evaluate the potential need of a retail market mechanism, beyond retail tariffs, to bolster DER products and services that may create value for all stakeholders. The MDIWG effort was started in 2019 and will culminate with a report of the findings. MDIWG is looking at longer term solutions that may benefit the State while meeting the State’s clean energy goals.

Implementation Plan, Schedule, and Investments

Current Progress

In 2021 the Company developed a Distributed System Operator (“DSO”) (known as DSP provider in NY) and DERMS roadmaps. These roadmaps were developed to better plan development of new DSO capabilities with a direct path to customer value and associated DERMS technology

advancements that enable DSO activities. Both roadmaps promote the ultimate goal of integrating DERs into the grid to achieve the State's clean energy goals.

The Company is incorporating a digital approach into its development of the capabilities identified in the DSO and DERMS roadmaps. For instance, National Grid has developed DERACONnect, a project that includes a DER Wholesale Market Registration Database and an Operational Portal, through its digital process. Digital is a way of working that employs an iterative approach in multidisciplinary teams, ensuring project success through early feedback. Digital is re-imagined operations and processes enabled by technology and agile ways of working to deliver on key outcomes. National Grid employs the agile project management framework which utilizes an iterative approach that includes frequent and continuous releases, with feedback incorporated throughout. The focus is on early involvement of the stakeholders with constant improvement of the product and processes. This ensures the delivery of well-designed and thoroughly tested products that match a customer's needs.

DSO Operational Coordination and Communications/Preparation for NYISO DER Participation
National Grid and the Joint Utilities, along with the NYISO, are preparing for go-live of the NYISO DER Participation Model in Q3 2023 and NYISO anticipated changes required to meet FERC 2222 implementation in 2026. As National Grid developed workflows, enhancements in applications and processes were identified as required to support this integration effort. Some of these include Short Term Operational Forecasting, Distribution Outage coordination, a DER registration database, and the use of operational portals to electronically exchange information between internal organizations and external stakeholders. These items are described in more detail below. Since the last DSIP Update, National Grid has undertaken significant steps in preparation to support the NYISO DER Wholesale Market Integration effort, especially regarding grid operations. This is due to the potential impacts of loading distribution elements and the desire to secure the distribution system before real-time operations. This will alleviate real-time challenges to distribution system operators and help to create a safe, reliable system and optimize system usage, creating value for all stakeholders.

- **NYISO Transmission Node Development:** National Grid and the NYISO have defined Aggregator Transmission Nodes to assist electric system modeling for the wholesale market and transmission grid operations. These nodes can be found on the NYISO websites. These nodes are subject to change annually due to system changes in load, resources, or topology.
- **Short-Term Operational Forecasting:** Distribution grid operations will require a more robust ability to forecast customer load and DER resources to ascertain forecasted system loading for proactive mitigation of operational risks. This becomes increasingly important due to the growing integration of DER to meet state and federal renewable goals.
- **Operational Portal:** DERACONnect was designed to be an operational portal where important operational data could be exchanged between the Aggregators and the DSO. Initially DERACONnect will receive DER Day-Ahead Operating Plans for distribution utility evaluations. DERACONnect will also act as a DER Registration Database for the DSO.

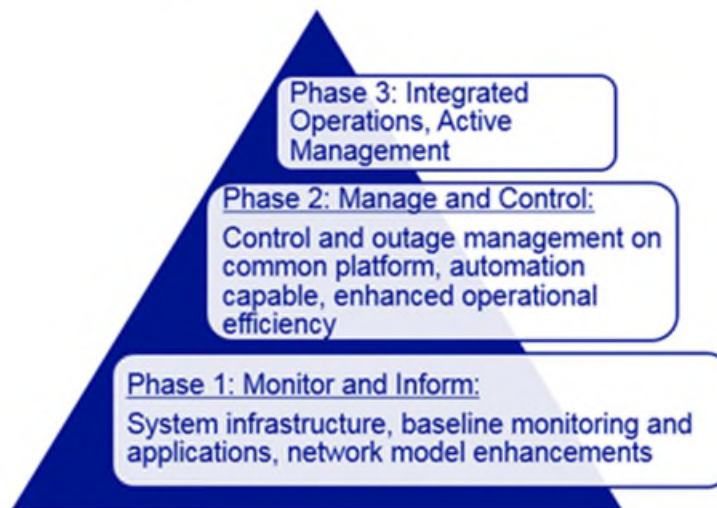
- **Communication of Distribution Outage Plans:** The DSO will be providing relevant outage information to DERs and Aggregators to help them optimize their resources and minimize re-dispatch. This in turn will reduce financial risk and help DERs and Aggregators to optimize the use of the distribution system while delivering energy products and services to the grid. These outage plans are communicated through an outage planning application called iTOA® via e-mail.
- **DER Wholesale Market Registration Database:** This database, developed as part of DERACONnect, provides granular information to National Grid organizations for operations, planning, customer service, and billing and settlement. The application will be integrated with several existing and new National Grid systems to provide the DSO with a holistic view of DER Operational and Market information. Some of the functionality of this new application includes:
 - Relationship between DER and contracted Aggregator
 - DER and Aggregator operational information as well as contact information
 - DER interconnection details
- **Grid Operations Procedure:** DER/Aggregator communications and coordination. These procedures are dependent on the NYISO tariffs and manuals which are still in the process of review and approval by stakeholders. National Grid will continue to revise and develop these documents using good utility practice and lessons learned.

ADMS Enhancements

ADMS is a control room-based hardware and software solution that allows for greater visibility, situational awareness, and optimization of the electric distribution grid. As noted in the 2020 DSIP, National Grid developed a phased approach for rolling out its ADMS, including implementing Distribution Management System (“DMS”) advanced applications and upgrading the existing OMS as a module of the ADMS. The ADMS project will implement a distribution-specific SCADA system, DSCADA, dedicated to the management and control of the distribution. The resulting DSCADA system will be integrated with the DMS applications and OMS on a common operations platform.

To date, the Company has accomplished Phase 1 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 human-machine interface (“HMI”) and enabled a system monitoring functionality
- 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
 - Simulated Live Connectivity

Figure 2.3.1 Phases of ADMS Implementation

Monitoring and Control

Through the feeder monitor deployment program, National Grid has increased the number of distribution feeders with interval monitoring from line sensors or station remote terminal units (“RTU”) to approximately 91%. This gives engineering and system operators the necessary visibility to make better informed decisions while the Company continues to work through installing station-based RTUs to connect equipment and meters to the Company’s Energy Management System (“EMS”). Since the last DSIP, National Grid has standardized utilizing common midline devices to get more data into EMS. Mid-line devices such as reclosers were targeted to have communications packages installed across the Company’s service territory to enhance the data available to engineers and system operators. More recently switched capacitors and voltage regulators have been included in newly installed receiving communications packages to enhance visibility. Control of distribution resources will become paramount as penetration increases and the Company continues to evaluate low-cost options for monitoring and control.

Energy Management System

The EMS was refreshed in the first half of 2020. This was part of a scheduled refresh of hardware and updates to software to prevent the system from becoming bespoke. An upgrade to EMS, called Equipment Outage scheduler, was made. This add-on to the existing EMS system allows operators and coordinators to pre-define outages within a study case to be used / saved off. Users can activate outages from a list of all the pre-defined outages. This removes the need for the user to go to the one-line diagrams and set the device status, which improves the Operator interface.

Distribution Automation (VVO/CVR and FLISR)

National Grid has deployed VVO/CVR schemes to thirteen substations and sixty-four associated feeders. These schemes are part of a centralized platform that manages the equipment based on real-time conditions to maintain an improved voltage profile, reduce system losses, and improve hosting capacity:

- Total Number of Distribution Circuits in 2022 = 2,013
- Number of Distribution Circuits that Employ VVO in 2022 = 41

- Number of Distribution Circuits that Employ VVO by the end of FY²³ 2023 = 60
- Total Number of Customers on Distribution Circuits with VVO Deployed= 73,796

The Company is working to complete updates on one of its Clifton Park Demand Reduction REV Demonstration Project schemes after lessons learned from the expansion of the VVO/CVR program and through data collected via Measurement and Verification (“M&V”) processes.

National Grid has also expanded the FLISR deployment program to include distribution circuits along with Sub-T lines. The Company has deployed three new Sub-T FLISR schemes with several under construction. There are also ten active Distribution FLISR Schemes with several more in construction phases. 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 for more customers on the system. Currently about 4% of customers are connected to distribution circuits with automated restoration schemes such as FLISR.

IT Network – Software-Defined Wide Area Network (“SD-WAN”)

National Grid has initiated investigating the use of SD-WAN communication technology for use in National Grid’s Operational Technology (“OT”) business. This investigation will include performing a Proof of Concept (“POC”) on the technology through collaboration with a demand-response or generation customer that participates in the NYISO wholesale market. A successful POC will prove that SD-WAN can pass customer data and NYISO base points between the customer, National Grid’s Critical Network Infrastructure, and the NYISO while meeting NYISO’s telemetry latency requirements and National Grid’s cyber security requirements. National Grid’s intent is to own and operate the SD-WAN with the system controller in the Company’s central control center.

Long-term benefits that National Grid hopes to realize from this technology are: offering a lower cost communication solution to the Company’s customers, improved scalability through use of open standard internet-based medium, quicker installation time for customers, and leveraging software-defined network management of the system.

Dual Participation/East Pulaski Power Marketer Integration

National Grid is working on a NWA demonstration project using its East Pulaski Battery ESS facility installed under the Commission’s 2018 Energy Storage Order.²⁴ National Grid has enrolled the ESS in the NYISO Wholesale Market and has contracted with a Power Marketer to facilitate wholesale market participation. The purpose of this demonstration project is to more fully understand the coordination required while a resource is engaged in dual participation (NWA and wholesale market sales) as well as understand the ability to coordinate products and services between retail and wholesale programs while maintaining the primary goals of distribution system safety and reliability.

²³ National Grid’s fiscal year is April 1 to March 31.

²⁴ Case 18-E-0130, *In the Matter of the Deployment of Energy Storage Deployment Program* (“Energy Storage Proceeding”), Order Establishing Energy Storage Goal and Deployment Policy (issued December 13, 2018) (“2018 Energy Storage Order”).

NWA

National Grid has deployed or is in the process of deploying NWA projects that meet the suitability criteria required for NWA consideration. NWA opportunities are options to defer more costly capital improvements for a set time period. NWA projects are intended to meet load relief and reliability requirements as part of the planning criteria. National Grid currently has a set of NWA projects at various stages of operation and construction.

- East Pulaski: National Grid is strengthening asset monitoring and maintenance operations, and has plans, with vendor support, to improve the ESS availability going forward. These deficiencies have caused operational difficulties and, in some cases, required the ESS project to be taken out of service, unfortunately resulting in significant delays in bidding the ESS into the NYISO wholesale market. Further details on the East Pulaski ESS can be found in Section 2.4, Energy Storage Integration.
- North Troy: The North Troy ESS was out of service previously for cybersecurity remediation and is currently out of service for additional work needed to re-establish SCADA communications with National Grid and remote communications with the ESS vendor to facilitate operations and maintenance support. Further details on the North Troy ESS can be found in Section 2.4, Energy Storage Integration.
- Pine Grove: The completed NWA solution deploys two grid-tied 5 MW solar PV projects, each paired with 5 MW / 20 megawatt hours (“MWh”) lithium-ion battery ESS. The Pine Grove NWA solution is operational with the dispatch season expected in the summer. Further details on the Pine Grove NWA project can be found in Section 2.13, Beneficial Locations for DERs and Non-Wires Alternatives.
- Watertown: The NWA solution under construction is a solar PV and battery ESS installation that will meet the 5.7 MW / 40 MWh need. The NWA solution is expected to be in-service in 2023. Further details on the Watertown NWA project can be found in Section 2.13, Beneficial Locations for DERs and Non-Wires Alternatives.
- Energy Storage Order: The Company continues to review system needs for projects to comply with the requirements of the Energy Storage Order.

Communications

Essential to monitoring and control 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 filing National Grid has deployed operational telecom projects to support and expand connectivity across the power system.

- To support increased bandwidth needs of operational systems Dense Wave Division Multiplexing (“DWDM”) technology has been deployed to 6 substations.
- The legacy end-of-life Synchronous Optical Network (“SONET”) technology, which runs National Grid’s fiber optic network, is in the process of being replaced with Multiprotocol

Label Switching – Transport Profile (“MPLS-TP”). A thorough evaluation of solutions has been completed and the vendor selected for this next generation communication system. To help support the development of standards and support workforce training, a lab has been established where the first node was installed in 2022.

- A centralized network operation center was established to provide 24/7 monitoring of networking devices. Initial Minimum Viable Product (“MVP”) is monitoring approximately 6,000 public cellular devices providing services to intelligent pole-mounted distribution devices.
- Across the state, telecommunication companies are discontinuing analog circuits (i.e., Digital Signal 0 (“DS0”)) and converting from copper to fiber. So far, 13 substations and dozens of other operational circuits have been migrated from the phased out DS0 services.
- Dark fiber has been secured to expand National Grid’s fiber optic network by hundreds of miles, connecting or improving communications with over 100 locations.
- To help manage the Company’s communications networks, National Grid has begun deployment of the Telecom Operations Management System which is a telecom asset management and design tool.

Cyber Security

National Grid continues to implement risk-focused and customer-centric cybersecurity approaches for all Grid Modernization initiatives. Most recently, identity and access management and privileged access management were deployed as part of the current phase of the ADMS implementation to ensure control systems are secured against improper access and privilege escalation attacks.

National Grid has also implemented standardized capabilities for better security monitoring and secure access to operational technology (“OT”) networks and environments. This includes deployment of an Intrusion Detection System solution and privileged access workstations to access OT systems. These capabilities are now a standard part of any new initiatives that implement such networks or systems, including those in scope of the Grid Modernization program.

Additionally, 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 in accordance with National Grid adapted industry standards and regulatory obligations.

Demand Response Management System

Since 2020, there have not been many changes to the demand response management system (part of DERMS). It continues to be used to operate the Commercial System Relief Program (“CSR”), demand response program.

Future Implementation and Planning

A number of items discussed in this section reflect further refinement and automation as part of post-market go live and grid modernization. Part of these efforts will focus on further functionality and integration to gain efficiencies and will help to evolve grid and market operations.

DSO and DERMS

Going forward the Company will continue to update the roadmap, track progress, and pivot as necessary based on changes in the industry. Additionally, National Grid will continue to implement DERMS and associated DSO capabilities, primarily via a digital approach.

DSO Operational Coordination and Communications/Preparation for NYISO DER Participation

The DSO will further evolve DSO / NYISO communications and coordination with ADMS data feeds from forecasting tools, distribution outage information, and resource schedules. While these processes will require some manual intervention, these functions will be automated to support safe and reliable operations moving forward in a high-penetration DER system.

- **Short-Term Operational Forecasting:** National Grid understands the importance of accurate short-term forecasting to help optimize system usage and maintain safety and reliability. To that end, forecasting tools will continue to be enhanced as the applications available become more advanced. It is anticipated that premise-level forecasting tools for load and resources will provide better data for operational support. The level of forecasting is enabled by foundational investments, many of which are currently underway including additional distribution element metering, AMI deployment, and advanced historian applications (plant information systems).
- **Operational Portal:** Future upgrades to the Operational Portal may include communication of distribution outages to DERs and DER aggregators to enable them to consider impacts in scheduling resources. In addition, the application, DERACONnect, will continue to evolve and include integration with other existing and new applications to provide an autonomous and seamless HMI.
- **Communication of Distribution Outage Planning:** Once DERACONnect functionality and portal access has been established, National Grid will continue to monitor usage and integration with enhancements as necessary.
- **DER Registration Database:** Once DERACONnect functionality has been established, National Grid will continue to monitor usage and integration with enhancements as necessary.
- **Grid Operations Procedures:** Continue to evaluate changes from FERC 2222.

ADMS Enhancements

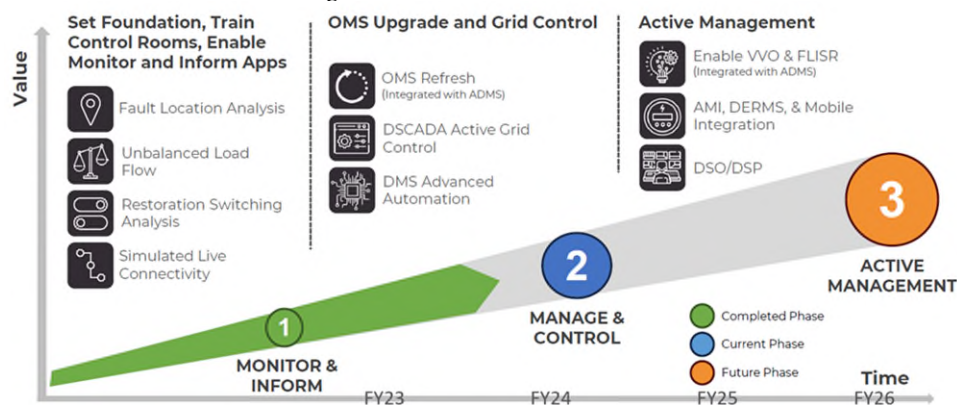
The ADMS project will be implemented using a phased approach, putting different modules and functionality into service over calendar year (“CY”) 2023 – CY 2026. As noted above, Phase 1 of ADMS has been completed. Continuous expansion of coverage and features are delivered into

production utilizing an agile or iterative delivery. In parallel, the Company is currently in the build and test stages of ADMS Phase 2 which will expand ADMS functionality for outage management, control, and automation on a common platform. OMS and related functionality will be incorporated into a common distribution model with the DMS applications. DSCADA will be built, implemented, and integrated with the ADMS platform. Together these three major modules integrated on a common platform will increase operational efficiencies and data sharing. The goal in-service date for the OMS integration into ADMS is late CY 2023-early CY 2024. DSCADA control capability will be delivered in CY 2025. Functionality delivered in Phase 2 includes:

- OMS refresh (with integration to DMS on a common connected network model)
- DSCADA control capability
- DMS Advanced Automation leveraging control

ADMS Phase 3 will 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 a 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.

Figure 2.3.2 ADMS Timeline



Monitoring and Control

The Feeder Monitor Program is expected to conclude in March 2024. This date reflects the end of deployment for line sensor technology on viable feeders. Enhancements to feeder monitoring and control for operational purposes will continue after the EMS-RTU program delivers station-based connectivity between SCADA and substation equipment and meters.

The Company expects new midline devices to be equipped with communications packages to enhance operator situational awareness visibility into the system and provide increased interval data for system planning and grid operation.

To successfully operate the grid of the future a hybrid decision-making approach is required where actions that require fast decisions but have limited impact on the broader grid can be made at the grid edge. In contrast, those actions that do impact the broader grid will be made via a master

centralized system and communicated out to the grid edge as needed. As such, National Grid is planning to deploy real-time monitoring, control, and intelligence at the grid edge that also bi-directionally communicates with centralized systems.

Distribution Automation

The Company plans to continue to monitor VVO/CVR schemes and conduct M&V on the initial deployments over the next few years. This data will then be used to update plans to deploy other schemes in the future. Since the last DSIP, National Grid has deployed new load tap changer (“LTC”) controllers at 24 substations. These LTC controllers will be linked to the ADMS to manage the voltage at feeder heads based on future AMI data. This is expected to act as a CVR scheme to lower the voltage at feeder heads so as to reduce energy demand and consumption for impacted customers.

The lessons learned during the initial rollout of FLISR to Sub-T and distribution feeders will be applied during a ramp up of deployment through a FLISR acceleration effort. This acceleration effort will affect both 15 kV and Sub-T circuits across the Company’s service territory with a goal of having about 60% of customers on FLISR circuits by the end of 2030. FLISR is also being paired with CLCPA-based projects to continue automating feeder ties and enabling the quick restoration of customers where possible.

As AMI is deployed across the service territory, National Grid plans to leverage the data available to enhance VVO/CVR schemes to use customer endpoint voltage to help make informed decisions on CVR levels and to provide opportunities for outage notifications for FLISR schemes via the Company’s ADMS platform.

Flexible Interconnections

National Grid is currently working on a project to operate a new flexible interconnection scheme for distribution-connected solar PV with testing planned in the 2023-2024 period. More details on this project can be found in Section 2.2, Integrated Planning.

Dual Participation

Dual participation continues to be evaluated, ensuring that resources do not get compensated twice for the same product or service while participating in both the wholesale and retail markets. FERC 2222 prohibits this form of market participation so as to ensure that customers are protected from overpaying. However, a resource can provide an NWA need in the retail market and participate in the wholesale market as long as participation in the retail and wholesale markets do not occur concurrently.

Communications

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.

- To support the growth of intelligent distribution assets the Company will continue to utilize Verizon Cellular Private IP network while building an AT&T First Net Cellular gateway

as part of the Company's communication and data network. This secondary carrier will help address coverage issues and provide redundancy in the data and communication network.

- Convert end-of-life SONET to MPLS-TP.
- Deployment of DWDM to increase network capabilities with 17 more nodes planned over the next 2 years.
- Migrate phased out telecommunication companies ("Telco") circuits which currently provide SCADA, teleprotection, and other critical services. There are over 800 circuits that need to be migrated in the next few years.
- Refresh New York Optical Ground Wire and All Dielectric Self-Supporting infrastructure as well as increased use of dark fiber (unlit fiber optic strands that are secured for exclusive use by the Company) with a total estimated growth of 100+ miles of new fiber optic infrastructure over the next 3 years.
- Support the expansion of National Grid 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 with broadband access while also connecting unconnected substations, grid automation devices, customer and DER RTU's, battery ESS, and other electrical assets which require communication, at a lower cost to all.
- Continue to populate the Telecom Operations Management System with existing and new asset data to support the growing and even more critical telecom network.

Cyber Security

In recognition of the strategic significance of the Grid Modernization program to National Grid and its customers, the Company will continue to invest in a robust cybersecurity plan to support the program's activities and build any necessary security capabilities. The plan includes security-by-design, expansion of security monitoring and incident response, building security capabilities for new technologies, and continuous remediation of risks and emergent vulnerabilities.

- Security-by-design: Ensuring 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.
- Expanding security monitoring and incident response: Security will continue to deploy the OT Intrusion Detection System and OT privileged access workstations 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 various Grid Modernization projects. Current reporting processes will be further enhanced to ensure National Grid holds 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.
- 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 to 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 pen testing and remediation to ensure they remain in a secure posture.

Advanced Meter Infrastructure

The DSO anticipates that AMI, once commissioned across the system, will provide some important functionality to grid operations. National Grid believes that the following functionality may be useful and will be evaluated for deployment:

- Ability to “ping” individual or groups of meters to ascertain grid connectivity;
- Ability to selectively shed and restore load as part of storm or blackout events; and
- Additional meter data for forecasting, and near real-time operational and planning data.

Digital Substation

The Digital Substation program will 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, IEC 61850 & 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, New York. In the next 5 years, 8 full digital substations will be deployed.

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 than conventional protection and control systems, reducing cabling and raceways.
- Digitalizes protection and control systems: Touch-screen HMI replace physical control switches reducing the size of control houses and enabling greater functionalities.
- Standardizes 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.

Substation Online Monitoring includes enhanced monitoring of substation assets such as transformers and circuit breaks using real-time data. In the next few years, substation online monitoring will be installed at IEC 61850 sites with a focus on transformers and circuit breakers over 115kV. Deployment of substation online monitoring is anticipated to deliver the following long-term goals:

- Enable Condition-Based Maintenance – Focus on assets at the highest risk of failure
- Optimize On-Site Requirements – Targeted visits based on asset condition
- Increased Equipment Availability and Reliability

Intelligent Substation (“ISS”)

This is a project that advances the ability of the OMS, ADMS, EMS and DERMS to scale to 100,000 points and beyond by building a small, scalable version of a DSO / Distributed Network Infrastructure (“DNI”) within the substation.

The ISS provides a deployable solution that incorporates Edge Compute graphic processing units (“GPUs”) for advanced Machine Learning security threat and detection mechanisms, as well as Digital Twin Capabilities, while simultaneously enabling Virtual Intelligent Electronics Devices and Software Defined Networking using localized autonomous control within a larger federated infrastructure. The ISS provides the foundational technology to provide scalable, deployable solutions that match the needs of the network as it grows in complexity.

The ISS informs the future of electric functional organization. It touches on all the components and functions within the DSO/DNI organization and will drive the direction of operations and organizational changes within the larger system. This project is deployed with various other POC projects to provide a guiding direction for future capability enhancements.

Figure 2.3.3 Future of Electric: Proof of Concept Projects



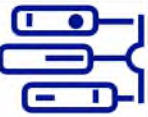



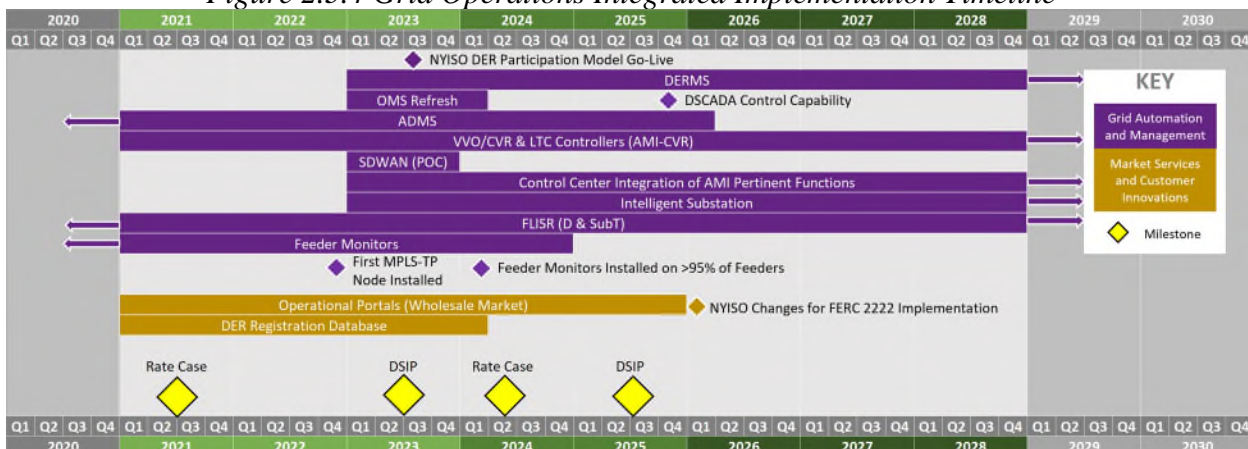
	NG2IN NationalGrid Next Generation Intelligent Network	SD-WAN	OT Bus	GIS NSE GIS Network State Engine (NSE)	Public API Server - ADMS	Intelligent Substation
						
Capabilities	Design, deploy and test an interoperable telecom infrastructure that uses both circuit and packet switched technologies using emerging high speed, low latency operational network requirements.	Deploy a minimal viable software defined networking technology for the OT infrastructure. Develop the SD control mechanisms that meet the needs of the future WAN.	Deploy a highly scalable, high-speed transport technology coupled with protocol converters that meets the needs of existing and future federated OT data interoperability.	Develop and deploy a real-time bi-directional data fusion network service engine for combining slow moving GIS data with fast moving measurements points.	Implement an API service front-end landing zone as part of the ADMS roadmap that unlocks bidirectional data access to the ADMS and OMS systems.	Install and test technology of strategic partners (Microsoft/ Intel) in the substation while developing the control, management, security and performance specs for this technology.
Outcomes	Provide a future proof modern telecom infrastructure that enables large-scale, low-cost networking.	Provides high velocity rollout of DE connectivity. Provides a means of connecting thousands of DE participants including Aggregators and Power Marketeers.	Provides an OT data communications capability that meets the needs of both end computing devices as well as traditional systems within the NG energy network.	Provides real time network insight and visibility to unlock fast data applications such as Digital Twin and Situational Awareness	Provides bi-directional, real-time connectivity, to the CNI to unlock emerging transactional / federated applications.	Provide an industry ref design for federated "data exchange" between the data center, cloud and network edge compute devices starting at the substation.

Figure 2.3.4 Grid Operations Integrated Implementation Timeline



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.

Risks and Mitigations

As DER penetration increases there is higher variability in resource outputs which produce risks on both 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. With increasing DER penetration there are also growing concerns over implementation of appropriate system protection schemes. There is also a risk with the speed at which wholesale and retail markets evolve and the ability of the Company and the NYISO to keep up with the associated changes required in grid operations to maintain a safe and reliable electric system. The implementation of FERC 2222, additional retail tariffs, and markets should be timed so as not to overload member systems with the need to develop, implement, and learn new operational technologies.

Table 2.3.1: Risks and Mitigations for Grid Operations

Risk	Mitigation
Higher variability in resource outputs due to DER penetration	Tools and automation for increased operator situational awareness
Speed of market and grid operational changes	Thoughtful implementation of FERC 2222 and additional retail tariffs

Integrated & Associated Stakeholder Value

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

The Grid Operations section of this DSIP mainly deals with preparing the grid to handle DER integration consistent with the timelines of the State's CLCPA goals and FERC 2222. The section also describes the many investments in grid modernization the Company considers good utility practices, stakeholder input in an effort to support evolving operations, and system safety and reliability. The Company has found stakeholder interaction valuable in providing and soliciting feedback and guidance on processes, programs, and applications under development.

The Company's goals are to maintain a safe and reliable system that optimizes the use of utility 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 state and federal goals and requirements. National Grid will continue to engage stakeholders, when appropriate to do so, to ensure proposed processes, procedures, and/or applications do not cause unintended problems.

2.4 Energy Storage Integration

Context and Background

As of December 31, 2022, the cumulative amount of ESS capacity interconnected in the Company's service territory is greater than 79 MW with a majority (greater than 95%) being ESS projects co-located with generation such as solar PV.

However, the interconnection and integration of ESS with the electric power system has and continues to evolve significantly. Across the industry, the value of ESS has been highlighted through numerous studies and the adoption of new policies. This also aligns with the anticipated amount of ESS needed to support state and federal goals continue to grow. In response to Governor Hochul's intention to double the state's 2030 energy storage goal deployment goal from 3 GW to 6 GW of storage by 2030, DPS Staff and NYSERDA jointly developed and filed New York's 6 GW Energy Storage Roadmap.²⁵ ESS is clearly contemplated to serve as a crucial part of energy decarbonization plans while also serving as another means to support electric reliability and resiliency.

National Grid agrees that ESS can play a major role in supporting decarbonization goals within New York. ESS can be used to support both electric supply and system infrastructure needs. The Company is particularly focused on how to advance the interconnection of ESS and how to utilize ESS to support the T&D systems. The Company is already implementing a number of ESS projects that seek to support system reliability through NWAs as well as in response to the 2018 Energy Storage Order to procure at least 10 MW of bulk power ESS. National Grid continues to make steps towards integrating ESS into its planning and operations by exploring additional opportunities and use cases to utilize ESS to support T&D system needs through studies and specific project proposals. The deployment of ESS can also support other state policies regarding transportation electrification and the deployment of renewable generation by helping to balance energy supply and demand to mitigate both bulk and local system constraints which may result in accelerated growth of these new sources of load and generation.

The following are having a significant impact in driving the increased deployment and integration of ESS in New York:

- Energy Storage Roadmap
- NYISO Energy Storage Resource Model and FERC 2222 compliance
- CLCPA goals
- Utility procurement of bulk ESS dispatch rights
- New York's Climate Action Council Scoping Plan

²⁵ Energy Storage Proceeding, New York State Department of Public Service and the 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 December 28, 2022) ("Energy Storage Roadmap").

- Federal Inflation Reduction Act (“IRA”) and Investment Tax Credits (“ITC”) for ESS

Implementation Plan, Schedule, and Investments

Current Progress

Current Company-owned Energy Storage Demonstration Projects

As part of the Commission’s March 9, 2017 *Order on Distributed System Implementation Plan Filings* directing utilities to deploy ESS projects on distribution substations or feeders at no fewer than two sites in order to increase hosting capacity and reduce peak load,²⁶ the Company has deployed utility-owned 2 MW / 3 MWh ESS projects at its East Pulaski and North Troy substations. Both projects have provided substantial learning in various project phases such as planning, development, deployment, and operation of ESS. Additionally, the East Pulaski ESS project is providing substantial wholesale dispatch and marketing learning. These projects have informed and will continue to inform current ESS projects such as Gilmantown, as well as plans for future ESS projects being pursued by National Grid.

East Pulaski

The East Pulaski ESS project has experienced technical challenges including inverter equipment failure and malfunctioning heating ventilation and air conditioning equipment. These challenges have caused operational difficulties and, in some cases, required the ESS project to be taken out of service, unfortunately resulting in significant delays in bidding the battery into the NYISO wholesale market. Although these issues have now been addressed, most recently the Company experienced software compatibility issues which has further delayed the ability to bid this ESS project into the NYISO wholesale market by a few additional months. National Grid is in the process of strengthening asset monitoring and maintenance plans with vendor support to improve the availability of the unit going forward. Learning from the Company’s experience operating this asset over the last several years, National Grid is actively looking to improve secure data accessibility of the system for National Grid and vendor support personnel that can enhance service response times and early identification of potential asset health concerns.

North Troy

The North Troy ESS was previously out of service for cybersecurity remediation and is currently out of service to allow for additional work needed to re-establish SCADA communications with National Grid, as well as remote communications with the ESS vendor to support unit operations and maintenance. Placing the ESS project back in service will require additional work to be completed by the Company’s telecommunications provider. Additionally, a cybersecurity penetration test will need to be performed prior to reconnecting the ESS project to the Company’s SCADA network and placing the unit back in service.

2018 Energy Storage Order Implementation

²⁶ REV Proceeding, Order on Distributed System Implementation Plan Filings (issued March 9, 2017), p. 30.

The Company has continued to progress its efforts in the deployment of ESS as directed by the 2018 Energy Storage Order to secure dispatch rights to at least 10 MW of bulk ESS projects and to expand its DLM procurement to provide new opportunities for ESS. To date, National Grid has issued RFPs on four potential third-party owned ESS projects under the 2018 Energy Storage Order. However, each of these projects have experienced challenges progressing to implementation. The Company continues to review opportunities that support the 2018 Energy Storage Order including in Auto-DLM procurements as described below.

Auto-DLM

Since the 2018 Energy Storage Order, the Company has launched three Auto-DLM procurement events in 2020 through 2022 with an aggregate load relief opportunity of more than 25 MW across all events. The Company's Auto-DLM program requirements are well suited to be met by the flexible dispatchability of ESS resources. National Grid has and will continue to design opportunities into procurement events so that resources can provide short-term load relief in areas with forecasted load growth prior to needing a long-term solution such as an NWA solution. Further, the Company will continue to seek opportunities where Auto-DLM resources could transition to being part of a potential NWA portfolio solution if the need for relief 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.

Energy Storage as NWA

The Company continues to pursue NWA opportunities through a competitive procurement process which is detailed in Section 2.13 of this 2023 DSIP Update. There have been thirteen competitive procurement events to solicit proposals for specific locations. A total of approximately sixty 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 battery ESS. Please see Section 2.13 for further details.
- Watertown: Watertown is a third party-owned NWA solution that is under construction. The completed NWA solution will deploy two grid-tied systems solar arrays, each paired a lithium-ion battery ESS to meet a 5.7 MW / 29 MWh need. Please see Section 2.13 for further details.
- Gilmantown: Gilmantown is a potential NWA solution that is currently in the planning stage. The Company anticipates that the NWA solution may deploy three separate ESS units to support the area fed by the radial Northville-Gilmantown Sub-T line. The combined ESS capacity is expected to be 6 MW / 18 MWh. Please see Section 2.13 for further details.

Interconnection of Storage

Since its 2020 DSIP, the Company has developed and published ESS hosting capacity maps that can help facilitate ESS developers to identify potential locations for ESS investment and deployment, which can be found at the below link and under the ESS Hosting Capacity tab, available at <https://systemdataportal.nationalgrid.com/NY/>

In collaboration with industry and DPS Staff, National Grid and the other Joint Utilities have formed an ESS sub-group of the ITWG to work through solutions that can better facilitate ESS interconnections and support multiple ESS use cases. National Grid, along with the other Joint Utilities, is a key participant in this ESS sub-group which is currently examining the interconnection process and study improvements including:

- Impact to ESS use cases
- Consideration of operational windows for ESS via specific time period for charge and discharge capabilities

Additionally, National Grid along with the other Joint Utilities developed and proposed ESS metering architectures for various system configurations such as DC-coupled ESS paired with solar PV systems. The goal of the proposal was to guide developers on potential metering configurations based on their ESS characteristics. As a result of collaboration between the Joint Utilities, industry, and DPS Staff, it was concluded that auxiliary metering may be necessary depending on purpose and use of the ESS but ultimately would not be required for the sole purpose of metering auxiliary loads.

The Company is also active in the discussions within the IPWG and ITWG to consider flexibility of ESS using static time-based operational restrictions with autonomous control or more dynamic operational restrictions utilizing future deployment of a utility DERMS.

As of December 31, 2022, the cumulative amount of ESS capacity interconnected in National Grid's service territory is greater than 79 MW with a majority (greater than 95%) being ESS projects co-located with generation such as solar PV versus standalone ESS projects.

External Collaboration

The Company continues to prioritize external collaboration to accelerate deployment of ESS and share learnings. Highlights in 2022 include efforts with the other 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 New York's 6 GW Energy Storage Roadmap proposed by NYSERDA and DPS Staff. Further, National Grid collaborated with the Joint Utilities and NYSERDA to advance the mission of the Advanced Technology Working Group ("ATWG") task force. These efforts will continue throughout 2023 and the Company is looking forward to working with stakeholders to shift from policy proposals to implementation. National Grid also provided a letter of support for the New Energy New York proposal led by the State University of New York ("SUNY") at Binghamton to the U.S. Economic Development Administration ("EDA") Build Back Better Regional Challenge with the aim of supporting economic recovery, development, and resilience in Upstate New York through the growth of an internationally competitive ESS industry cluster. This proposal was awarded \$63.7 million by the EDA in 2022 to support establishing a national hub for battery research and manufacturing in the Southern Tier and Finger Lakes region in New York. The Company has also engaged industry ESS manufacturers and developers to further understand evolving trends in ESS technologies, including significant interest and anticipated value in long-duration ESS chemistries and use cases required to support future T&D system needs.

Software and Studies

In the past, the Company has utilized various tools to plan the use of ESS supporting distribution needs and in particular for National Grid's analysis supporting its Bulk Dispatch Rights Procurement RFP. These tools include CYME's software application, Siemen's PSS®E software application, U.S. Department of Energy's ("DOE") Interruption Cost Estimate ("ICE") calculator, and EPRI's Storage Value Estimation Tool (StorageVET® now known as DER-VET™). The Company is currently investigating tools to expand its ability to plan the use of ESS, 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 on the Company's System Data Portal. Specifically, the ESS Hosting Capacity map, shared publicly on the NY System Data Portal, 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 Section 2.9, Hosting Capacity.

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

Forecasting Energy Storage

To capture the growing impact of ESS deployments connecting to the distribution system over the next several years, the Company understands the importance of accurately modeling the impact of ESS as an input to many business processes, including how it conducts integrated system planning. As of now, in its load forecasting process, National Grid considers ESS paired with solar PV and a peak shaving use case by assuming storage will discharge during typical peak hours in a day and charge during the hours when solar PV is expected to generate in the Niagara Mohawk Power Company Electric Peak (MW) Report (System Report).

Future Implementation and Planning

The Company has significant plans to continue the exploration, integration, and utilization of ESS on the distribution system.

Potential Study for Energy Storage to Support T&D (ATWG Energy Storage Task Force)

The Company serves as a member of the ATWG and is collaborating with NYSERDA and the other Joint Utilities to study the potential for ESS to be integrated with and support the needs of utility T&D systems, as recommended within the Energy Storage Roadmap filed with the Commission in December 2022. Not only is ESS anticipated to experience significant growth in deployment over the next few years and beyond 2030, but utility T&D systems are expected to see substantial load growth from greater levels of demand electrification. The Company is eager to explore, analyze, and incorporate findings from the potential study that could further drive cost-effective deployment of ESS to support T&D system needs. National Grid also anticipates further

investigation of the capabilities and potential uses of long-duration ESS through the scope of ATWG and the ESS potential study, with a focus on how long-duration ESS 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.²⁷ In 2023, the Company will lead a DOE-funded effort to study and write a regional plan for MHDV highway charging in New York, New Jersey, Pennsylvania, and New England 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 to address transmission grid constraints, including ESS.

Potential Energy Storage Project Under Consideration in Ticonderoga Area

Radial transmission supply and rugged terrain put the Ticonderoga area at risk of outages due to storms and other environmental factors while also making restoration more challenging. As a solution, the Company is evaluating and developing plans for ESS facilities to improve reliability and resiliency.

Expanding Capabilities in Developing and Operating Energy Storage Projects

The Company is evaluating appropriate steps to take in 2023 to accelerate internal readiness and expand capabilities in developing, procuring, operating, and maintaining ESS projects to deliver benefits to customers and support New York's ESS 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.

External Collaboration

Continued collaboration will be necessary to implement an eventual Energy Storage Roadmap 2.0 order from the Commission and develop implementation plans that can deliver 2030 ESS goals. The Company anticipates collaboration themes to include consideration of ESS expanded use cases and integration of storage into relevant regulator and planning processes. Collaboration with and outreach to communities that host ESS assets, while already important today, will become increasingly vital to ensure safe and reliable operation as more and larger scale ESS is deployed to support system needs and the state's CLCPA goal of 6 GW of ESS by 2030. As one example, the Company has plans to enhance its standard operating procedures training program for local and county level first responders to ensure access to training in order to safely identify and respond to incidents related to ESS.

Forecasting Energy Storage

At the system level, National Grid plans to continue refining ESS scenarios for forecasting by keeping up to date with state policies and market studies. The Company is considering solar PV coupled with ESS on the distribution system and thus is leveraging the land parcel analysis

²⁷ See, e.g., *Electric Highways: Accelerating and Optimizing Fast-Charging Deployment for Carbon-Free Transportation*, National Grid, CALSTART, RMI, Stable Auto, and Geotab (November 2022), available at ngrid.com/electric-highways-study (Electric Highways Study).

software tool developed by Gridtwin in identifying where to allocate the projected system level ESS. The Company will continue working with Gridtwin to refine the land parcel analysis to capture up-to-date regulations on land parcel analysis and incentives for developing solar PV and ESS projects. The Company is also actively evaluating and improving the process of using information in its DG interconnection database for more accurate classification of rooftop and ground-mounted solar PV projects connected and in the queue. This will help allocate the solar PV projects properly and thus will improve the allocation of storage projects coupled with solar PV. 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 storage profiles.

Energy Storage Integration into EE and DR

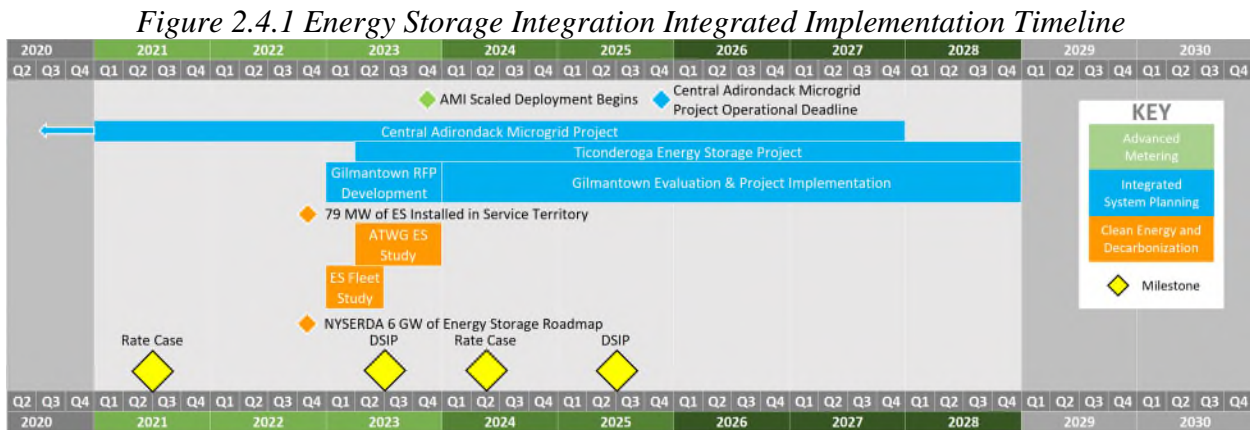
The Company is contributing to the Joint Utilities response to the NY Energy Storage Roadmap 2.0. National Grid is supportive of the proposed retail and residential storage goals and recognizes behind-the-meter (“BTM”) storage deployment will need to scale up in order to meet those goals. The Company supports utility involvement that can support market development. In the implementation process for the anticipated Commission Energy Storage Roadmap 2.0 Order, the utilities will work with NYSERDA and DPS Staff to evaluate how utilities can support BTM deployment, including whether new utility-run incentive programs are appropriate.

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 case for BTM storage and drive increased adoption of storage assets in New York. The Company sees an opportunity to maximize the value of residential storage systems, whether through existing DLM program offerings or through new DLM participation models designed for residential storage systems.

National Grid has begun its four-year deployment of AMI in 2023 (see Section 2.12, Advanced Metering Infrastructure, for more detail). AMI will further drive the customer value case for ESS, providing customers with granular energy usage data and improved opportunities to respond to load-reducing or load-shifting signals from existing DR programs, future DR programs, and/or future time-varying rates. 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 continues to monitor the potential impact smaller-scale storage will have once these resources are able to participate in wholesale markets through FERC 2222. One way the Company is encouraging more storage through aggregator participation is by posting NWA opportunities on Piclo Flex, a global marketplace provider for flexibility services. National Grid entered into a pilot agreement with Piclo Flex in 2022 whereby Piclo Flex is to deliver an independent marketplace that widens and streamlines participation for all types of DERs capable of providing flexibility services.²⁸

²⁸ See <https://www.piclo.energy/press-releases/piclo-and-national-grid-launch-new-marketplace-for-flexibility-services-in-new-york-state>



Risks and Mitigations

Table 2.4.1: Risks and Mitigations for Energy Storage Integration

Risk	Mitigation
Delays in returning East Pulaski and North Troy ESS projects back to service	Improved asset monitoring, IT, and maintenance plans working closely with ESS vendor and operations and maintenance ("O&M") provider
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
Shortage of resources within National Grid to support future implementation of ES	Develop and seek approval of plan addressing resource shortfalls in next rate case.
Opposition from communities to siting and permitting ESS projects	National Grid will develop a tailored Public Involvement Plan (PIP) for each proposed ESS project. The PIP will consider the specific community and impacted residents while utilizing public involvement techniques that will help inform the siting, permitting, construction, and operation and maintenance of the proposed ESS project. The PIP will also provide educational opportunities for community residents to better describe ESS technology and safety plans that will be in place. The PIP will be updated as community feedback is obtained.
Studies focused on ESS use cases do not result in new or feasible use cases	Refocus efforts on improving existing use cases for ESS and interconnection of ESS to help bolster ESS deployment in support of the CLCPA 6 GW by 2030 goal

Alignment with CLCPA Goals

The Company's implementation plans for advancing ESS align with the goals of the CLCPA and the expanded state goal to achieve 6 GW by 2030 in two ways: advancing the method to interconnect ESS onto the system and progressing how ESS can be integrated into serving the needs of the grid. These two implementation categories will facilitate increased deployment of ESS and drive the benefits that ESS can provide to offset other system needs and deliver value to customers.

As discussed above, numerous efforts are underway to improve the interconnection experience and feasibility of ESS through collaborative efforts in IPWG and ITWG. The Company's Energy Storage Hosting Capacity maps drive further data transparency that can aid ESS developers to efficiently site ESS facilities in areas that have available system capacity. National Grid's interconnection process for ESS continues to improve the data used for interconnection studies as well as investigate steps to more effectively study ESS. 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 ESS can charge and discharge at its maximum nameplate capability during all hours of the day and year. All of these efforts must be carefully harmonized in order to ensure they do not compromise system reliability or safety or result in unduly increasing customer costs.

Increased deployment of ESS can aid in furthering CLCPA goals if utilized effectively to support system needs. ESS 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 ESS integrated as transmission or distribution assets. Pine Grove and Watertown are early examples of how the Company has explored effective use of ESS to support grid needs. The Company continues to exercise its integrated planning process to identify additional opportunities where ESS could be utilized cost effectively as a grid asset. This use of ESS to support transmission needs is being investigated through National Grid's CLCPA efforts and through the ESS task force supported under the ATWG. The Company anticipates the outcome of the ATWG ESS potential study to also inform the CGPP in how to effectively utilize ESS as a solution to address T&D needs, similar to other technology solutions being investigated by ATWG such as dynamic line ratings and power flow control. The Company is also considering what ongoing resources (e.g., contract management, O&M, etc.) will be needed to support these ESS assets for the life cycle of supporting grid needs, whether the ESS assets are Company-owned or third party-owned.

Stakeholder Interface

National Grid continues to collaborate with the other Joint Utilities, as well as DPS Staff and NYSEERDA, particularly in support of state policy goals and programs such as the Energy Storage Roadmap targeting 6 GW of ESS deployment by 2030. The Company also engages the ESS 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 (“CEATI”). Information regarding ESS hosting capacity and NWA opportunities for ESS is also available on National Grid’s System Data Portal for stakeholders.

2.5 Electric Vehicle Integration

Context and Background

Transportation accounts for 40% of New York’s CO₂ emissions, the largest share of emissions in the state. This has resulted in a large number of policies, goals, and active proceedings to decarbonize transportation. New York’s commitment is to have 850,000 zero-emission vehicles (“ZEV”) on the road by the end of 2025, 100% light-duty ZEV sales by 2035, and 100% ZEV school buses by 2035, among other policy goals. With approximately 120,000 light-duty EVs on the road at the end of 2022, this is an ambitious goal that requires significant charging infrastructure to support these 850,000 EVs. National Grid agrees that EV adoption is critical to meeting these goals. The Company has aggressively supported transportation electrification by installing more than 3,000 charging stations at customer sites across its upstate NY territory. In 2023, the Company will launch a residential managed charging program for New York customers and initiate additional solutions to reduce the cost of EV charging, including programs for demand management technologies, demand charge reductions, and commercial managed charging.

The goal of utility transportation electrification programs is to deploy an EV charging network across New York State that could support 850,000 light-duty ZEVs, consistent with state goals. In September 2021, New York State Senate Bill 2758/Assembly Bill 4302 was signed into law that targets 100% of new light-duty vehicle sales to be ZEV 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% for model years 2025 and scaling to 100% by 2035. Over the longer term, this will help accelerate activity beyond the already ambitious 2025 goals from the 2013 ZEV MOU²⁹ and require greater investment in EV charging infrastructure. For the MHDV segment, the state has also adopted aggressive goals to transition to ZEVs. In July 2020, New York was a signatory to a Multi-State Memorandum of Understanding (“MOU”) which set a mutual goal among signatories to ensure that 100% of all new MHDV sales will be ZEVs by 2050 with an interim goal of 30% MHDV sales to be ZEV by 2030. These goals were amended in December 2021 when NY passed New York State Senate Bill S2758/Assembly Bill 4302 which amended the NYS environmental conservation law to include a goal that 100% of in-state sales of MHDV be zero-emission by 2045.

A high-level market overview of the NY EV landscape indicates nearly 120,000 registered LDVs were on the road at the end of 2022.³⁰ The Joint Utilities’ MRP investments have collectively contributed to more than 4,500 EV charging ports deployed in New York State since July 2020 (as

²⁹ In 2013, Governor Cuomo signed onto the Multi-State Zero Emissions Vehicle Memorandum of Understanding (ZEV MOU). For the eight states that are participating, the ZEV MOU establishes a collective goal of 3.3 million ZEVs on the road by 2025. New York State’s allocation of this goal is 850,000 ZEVs registered in New York State by 2025. The text of the ZEV MOU is *available at* the following link: <https://www.nescaum.org/documents/zev-mou-8-governors-signed-20131024.pdf>.

³⁰ See EvaluateNY analysis developed by Atlas Public Policy (August 2022), *available at* <https://atlaspolicy.com/evaluateny/>

of December 31, 2022). The Joint Utilities have also supported the MHDV segments via a MHDV pilot program, by providing assistance to the state’s public transit agencies in their electrification journeys, and through a fleet assessment services program.

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, electric vehicle supply equipment (“EVSE”) tax credits, and support for replacing heavy-duty vehicles. In addition, the Environmental Protection Agency’s Clean School Bus Program supports the procurement of electric school buses and associated charging equipment.

These policies and goals have resulted in several Commission proceedings focused on EVs, including:

- Case 18-E-0138 - addressing the light-duty EV make-ready programs, residential managed charging programs, and establishing the PPI program;
- Case 18-E-0206 – addressing modifications to the Company’s Voluntary Time-of-Use (“VTOU”) rate to better support residential customers who own EVs;
- Case 22-E-0236 – addressing modifications to the PPI program, commercial rate designs for EV charging sites, demand charge rebates, commercial managed charging programs, and load management technology incentives; and
- Case 23-E-0070 – addressing barriers to medium- and heavy-duty EV charging infrastructure.

Since the health and well-being of residents within disadvantaged communities (“DACs”) are disproportionately impacted by air and noise pollution from transportation and electrification can reduce the pollution exposure disparity, supporting electrification of vehicles that park or operate within DACs is a priority of the Joint Utilities. As noted in section 1 above, National Grid’s and other Joint Utilities’ EV programs have significant goals to bring equitable access to clean transportation for all, with substantial portions of the EV programs dedicated to DACs. Of New York State’s \$701 million EV MRP budget, \$206 million directly benefits DACs, and projects serving DACs receive an increased incentive from the EV MRPs. Future programs, described below, will continue to have this commitment for EV projects or drivers located in DACs and for MHDVs operating in or domiciled in DACs.

Implementation Plan, Schedule, and Investments

Current Progress

National Grid has supported the EV sector in several ways since the 2020 DSIP (i.e., DCFC PPI program and MRP) and will continue with the forthcoming Residential and Commercial Managed Charging Programs, and EV Rate Design programs.

DCFC PPI Program

National Grid has offered the DCFC PPI program since the Commission's February 7, 2019 *Order Establishing Framework for Direct Current Fast Charging Infrastructure Program*.³¹ The DC Fast Charger Order included funding for \$9 million of incentive funds for National Grid customers. According to National Grid's 2022 annual report, the Company received applications for fifty-eight plugs, with twenty-eight in service and thirty under construction as of December 31, 2022. The DCFC PPI program has paid approximately \$150,000 in incentives through March 2023. As of March 20, 2023, the program has stopped accepting new applications. Under the Commission's January 19, 2023 EV Rate Design Order,³² unused DCFC PPI program funds will be repurposed for the forthcoming Load Management Technologies Incentive Program as described below in EV Rate Design Programs.

EV Make-Ready Infrastructure Program

National Grid has made substantial progress in supporting the goals of the Commission's July 16, 2020 *Order Establishing Electric Vehicle Infrastructure Make-Ready Program and Other Programs* ("EV Make-Ready Order").³³ As of April 30, 2023, the Company has supported:

- LDV Make-Ready: National Grid make-ready funding has supported 2,150 EVSE ports (1,979 Level 2 ("L2") ports and 171 DCFC ports). This is in addition to the 1,403 EVSE ports in the Company's Phase 1 program, bringing the total support to 3,553 EV ports in National Grid's service territory.
- MHDV Make-Ready Pilot Program: The Company has supported MHDV customers through the fleet assessment services program, as well as one project enrolled in the program, and one project pending approval.
- Fleet Assessment Services: The Company has completed 74 assessments for fleet customers across its service territory, assessing more than 4,000 vehicles.
- Transit Authority Make-Ready Program: The Company has supported the two transit authorities in its service territory (Niagara Frontier Transportation Authority and Capital District Transportation Authority) in order to reach their state goals of 25% electrification by 2025.

Residential Managed Charging Program

The EV Charge Smart Plan is a new residential managed charging program for residential customers. The program provides customers with financial savings to easily charge their vehicle(s) within the convenience of their home through a smartphone app during off-peak hours, 11:00 p.m. to 7:00 a.m., when there is less strain on the grid and energy costs are lower. The program launched in June 2023 and is approved by the Commission through 2025. The Company will also offer installation support to customers looking to install EVSE that will enable participation in this program.

³¹ Case 18-E-0138, *Proceeding on Motion of the Commission Regarding Electric Vehicle Supply Equipment and Infrastructure* ("EVSE and Infrastructure Proceeding"), Order Establishing Framework for Direct Current Fast Charging Infrastructure Program (issued February 7, 2019) ("DC Fast Charger Order").

³² Case 22-E-0236, *Proceeding to Establish Alternatives to Traditional Demand-Based Rate Structures for Commercial Electric Vehicle Charging*, Order Establishing Framework for Alternatives to Traditional Demand-Based Rate Structures (issued January 19, 2023) ("EV Rate Design Order").

³³ EVSE and Infrastructure Proceeding, Order Establishing Electric Vehicle Infrastructure Make-Ready Program and Other Programs (issued July 16, 2020) ("EV Make-Ready Order").

The EV Charge Smart Plan offers flexible, subscription-based pricing tiers with a flat monthly fee for a certain amount of home EV charging kilowatt hours (“kWh”), saving up to 30% annually against standard rates:

Table 2.5.1: Charge Smart Plan Pricing

Subscription Pricing	Tier 1	Tier 2
EV Monthly Charge	\$20	\$30
Off-Peak Home EV Charging Allotment	225 kWh per month	365 kWh per month
Estimated annual miles of EV charging provided (at 2.9 kWh per mile)	7,700	12,500

EV Rate Design Programs

The EV Rate Design Order requires the Joint Utilities to take several actions which include two sets of actions termed ‘Immediate Solutions’ and ‘Near-term Solutions.’ The Immediate Solutions include a temporary Demand Charge Rebate, and a transition plan for the funds from the DCFC PPI program to a Load Management Technologies Incentive Program. The temporary Demand Charge Rebate program is a 50% demand charge discount on the EV load of commercial charging sites (both dedicated EV load and mixed load) which will last until the EV Phase-in rate described below. The Load Management Technologies Incentive Program will make use of the approximately \$8 million remaining in the National Grid DCFC PPI funds to incentivize load management technologies for commercial EV charging sites. These two “Immediate Solutions” programs have been filed with the Commission and are awaiting approval.

The EV Phase-in Rate is required to have time-of-use Energy Charge components paired with demand charges with several graduation levels of pricing based on the commercial customer’s load factor. Lower load factor customers, which are likely applicable to start-up charging stations, will be billed mainly with kWh charges and higher load factor customers will have a combination of kWh charges and demand charges. The concept behind the graduation approach is to phase customers to the standard demand-based rates as their EV usage factor increases. The Commercial Managed Charging Program is required to provide incentives for reductions in billed-kW and reductions in on-peak kWh consumption. These “Near-term Solutions” programs will be filed with the Commission in July 2023 with approval expected later in the year.

Future Implementation and Planning

National Grid’s EV programs will continue to support the EV sector in line with the programs outlined above, the Commission’s on-going proceedings, and upcoming offerings.

DCFC PPI Program

As per the EV Rate Design Order, the DCFC PPI Program funds are being redeployed to fund a new program to incentivize EV charging demand management technologies. The Joint Utilities are currently designing this program, which will provide incentives for on-site ESS, ESS integrated directly into charging equipment, and advanced load management technologies and software, among other eligible technologies. The deadline for new applications in the DCFC PPI Program, communicated to customers via the Joint Utilities website and each utility’s individual website,

was March 20, 2023. The combined DCFC PPI program and demand management technologies program funding will be deployed through February 28, 2026.

EV Make-Ready Infrastructure Program

The EV MRP is currently undergoing a midpoint review process. As part of this process, DPS Staff made several recommendations to modify the program, including:

- Increasing baseline costs to reflect actual average costs
- Increasing the statewide budget from \$701 million to \$1.1 billion while also updating plug goals
- Extending the deadline of the MRP beyond 2025 if plug goals are not met
- Creating a micro mobility MRP targeting disadvantaged communities
- Modifying the disadvantaged communities tier for L2 plugs based on premise-specific eligibility criteria for stations within multi-unit dwellings while adding curbside charging as an eligible use case
- Modifying the MHDV Pilot by increasing the budget, expanding eligibility to include the United States Environmental Protection Agency's Clean School Bus Program, and allowing customer-side incentives up to the 50% level for projects in disadvantaged communities

The Joint Utilities filed comments as part of this midpoint review process in May 2023. A Commission order adjusting the components of the EV MRP is expected in the fall of 2023. The program is expected to be continued through 2025 with the possibility of an extension beyond 2025.

EV Rate Design Programs

A Commission order is anticipated in the summer of 2023 for the Demand Charge Discount Program. A Commission order for the Demand Management Technologies program is anticipated in the fall of 2023. A Commission order for the Commercial Managed Charging Program is anticipated by year-end 2023.

As discussed above in the DCFC PPI section, the DCFC PPI Program funds are being redeployed to fund a new program to incentivize EV charging load management technologies. The Joint Utilities are currently designing this program, which will provide incentives for on-site ESS, ESS integrated directly into charging equipment, and advanced load management technologies and software, among other eligible technologies.

Medium- and Heavy-Duty EV Order

On April 20, 2023, the Commission initiated a proceeding to address the electrification needs of the State's medium- and heavy-duty EV sector.³⁴ The full scope of the proceeding is yet to be established, but it will focus on ensuring equitable investments for clean air and developing proactive planning approaches to ensure the grid infrastructure is prepared to enable the growing EV charging needs across New York State.

³⁴ Case 23-E-0070, *Proceeding on Motion of the Commission to Address Barriers to Medium- and Heavy-Duty Electric Vehicle Charging Infrastructure*, Order Instituting Proceeding and Soliciting Comments (issued April 20, 2023).

Risks and Mitigations

Table 2.5.3: Risks and Mitigations for Electric Vehicle Integration

Risk	Mitigation
Inflation and supply chain constraints	National Grid and the other Joint Utilities have routine market update calls with developers, trade allies, and market participants to understand the current market dynamics, including supply chain constraints and equipment pricing concerns.
Automaker development and production schedules	National Grid and the other Joint Utilities have various forums with automakers, through industry working groups, including Corporate EV Alliance, Edison Electric Institute, Alliance for Transportation Electrification, and EPRI. These working groups provide clarity and updates on 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 the EV programs accordingly.
Funding for MRP	The MRP is currently scheduled to have funding available through at least 2025, with a possible extension subject to Commission determination and order issue.
Market Disruption	Changes in the marketplace are always top of mind for the Joint Utilities and discussed at the routine Joint Utilities' coordination meetings.
Diminished Policy Support	The MRP is currently scheduled to have funding available through at least 2025, with a possible extension subject to Commission order. Any additional policy changes would be addressed through the routine Joint Utilities' coordination meetings.
Different needs between upstate and downstate customers	Several components of the MRP include differences for upstate and downstate customers. These differences are managed by each representative utility and communicated to relevant stakeholders as appropriate.

Risk	Mitigation
MHDV and Concentrated EV Charging may outpace grid infrastructure	The Commission’s <i>Order Instituting Proceeding and Soliciting Comments</i> regarding MHDV in Case 23-E-0070 will address this risk, with two recommended immediate action in two critical areas: (1) broad availability of compelling incentives for make-ready infrastructure and other charging-related costs to address financial challenges and encourage customer investment decisions, in combination with technical advisory services to assist customers to develop robust fleet electrification plans for the near-, medium-, and long-term, and (2) advanced planning and build-out of grid infrastructure so utilities are ready to serve customer electrification loads when needed.

Alignment with CLCPA Goals

National Grid’s EV programs support New York’s ambitious climate goals adopted in the CLCPA by focusing on the transportation sector as the largest source of CO2 emissions in New York. The Company is engaged across the multiple active EV proceedings to help enable a more holistic approach.

Ensuring equitable access to the benefits of clean transportation and meeting the State’s CLCPA goals will require decarbonizing all aspects of the transportation sector, including LDV and MHDV fleets. While the Company’s EV programs support EVs of all types (i.e., residential customers, commercial public charging, and fleet electrification), additional programs and incentives in the residential and commercial markets are needed to provide a holistic approach to enable widespread EV adoption and meet the State’s transportation emission reduction and broader CLCPA goals.

Integrated and Associated Stakeholder Value

National Grid and the Joint Utilities have many mechanisms to coordinate with stakeholders. In line with the structure outlined above, those mechanisms include:

EV Make-Ready Infrastructure Program

The MRP includes many venues for stakeholder coordination, including Mid-Point Review Technical Conferences, stakeholder comments, and the DPS Staff Whitepaper and Joint Utilities comments.

Residential Managed Charging Program

The residential managed charging program similarly has several areas of coordination, including the original proposal comment process, as well as the technical standards working group on submetering testing accuracy.

EV Rate Design Programs

The EV Rate Design programs will have many opportunities for stakeholder interaction, including public comment periods, technical conferences, as well as many utility-hosted feedback sessions.

In addition to the resources listed above, the Joint Utilities also coordinate weekly with DPS Staff, provide hosting capacity maps for developers, host a Joint Utilities website and approved contractor list, and a common fleet assessment services application, along with providing individual utility program websites, resources, and customer outreach and education.

2.6 Clean Heat

Context and Background

The NYS Clean Heat Program, which launched on April 1, 2020, provides customers, contractors, and other heat pump solution providers with a consistent experience and business environment throughout New York State. The NYS Clean Heat Program supports a consistent statewide heat pump program designed to achieve the State’s ambitious heat pump goals and build the market infrastructure for a low-carbon future.

The NYS Clean Heat Program includes initiatives to advance the adoption of efficient electric heat pump systems for space and water heating applications throughout New York State. The Joint Utilities provide incentives to support customer adoption of eligible heat pump technologies, 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 (“HPWH”), as well as their promotion and pricing by contractors and other heat pump solution providers. The Implementation Plan³⁵ and the two Program Manuals³⁶ provide details about the NYS Clean Heat Program, including incentive structures and levels, eligible technologies, program rules and processes, and information for participating contractors.³⁷

Recently, the Commission began the mid-cycle Interim Review of the New Efficiency: New York Order (“NE:NY Order”)³⁸ and is evaluating its effectiveness as well as looking for input on how to improve and modify this order for future years from a variety of stakeholders. The NE:NY EE goals are set to address energy savings in buildings and the industrial sector across all fuel sources. Since 2020, there has been an increasing focus on adapting the order to encourage more Beneficial Electrification (“BE”) for residents through the statewide Clean Heat Program. Several questions

³⁵ See Case 18-M-004, *In the Matter of a Comprehensive Energy Efficiency Initiative* (“New Efficiency: New York Proceeding” or “NE:NY Proceeding”), NYS Clean Heat: Statewide Heat Pump Program Implementation Plan (“Implementation Plan”) (initially filed on March 16, 2020 by the Joint Utilities and NYSEERDA (collectively, “Joint Efficiency Providers”) and most recently refiled as Version 2 by the Joint Efficiency Providers on July 1, 2021). The Joint Efficiency Providers’ work in coordinating development of the NYS Clean Heat Program began in 2019, following the issuance of the Commission’s Order Authorizing Accelerated Energy Efficiency Targets (issued December 13, 2018).

³⁶ NE:NY Proceeding, NYS Clean Heat: Statewide Heat Pump Program Manual (“Clean Heat Program Manual” or “Program Manual”) (initially filed by the Joint Efficiency Providers on March 16, 2020 and most recently filed as Version 2 by the Designated Utilities and NYSEERDA on March 1, 2023); NYS Clean Heat Con Edison Heat Pump Program Manual (initially filed on January 12, 2023 and most recently filed on March 1, 2023).

³⁷ Both the Implementation Plan and Program Manual are revisited, as necessary and with prior notice, on a separate schedule from The Clean Heat Annual Report.

³⁸ NE:NY Proceeding, Order Authorizing Utility Energy Efficiency and Building Electrification Portfolios through 2025 (issued January 16, 2020) (“NE:NY Order”).

were posed to the Joint Utilities to gain stakeholder feedback on how the State should go about meeting its aggressive goals. The Governor’s 2022 State of the State address supported the goal of two million electrified and electrification-ready homes by 2030. Modification to the NE:NY Order based on these recent changes is expected to be announced in early 2024.

In addition to the changes expected on a state-wide level, there have been significant updates on a national level to energy policy and standards. Two complementary acts were passed to advance BE initiatives nationwide. The Infrastructure Investment and Jobs Act (“IIJA”) and the IRA were passed to tackle widescale issues facing the nation. Each contained several provisions for BE work, including electrical infrastructure improvements in the IIJA that will help remove the barriers for buildings traditionally heated by fossil gasses in their transition to electrified heat through high-efficiency heat pumps. The IRA detailed provisions in the coming years to address the cost of heating electrification through broad incentives, credits, and rebates for building owners and residents.

In the background of this activity, National Grid continues to expand the already robust portfolio of Clean Heat incentives through the NYS Clean Heat Statewide Heat Pump Program Implementation Plan. The Implementation Plan is a key element of the State’s clean energy pathway and is designed to support customers in transitioning to energy-efficient electrified space and water heating technologies. The Implementation Plan describes the establishment and ongoing administration of the NYS Clean Heat Program by the Joint Efficiency Providers, in collaboration with NYSERDA, as part of the new statewide framework. The statewide framework is designed to provide contractors and other heat pump solution providers a consistent experience and business environment throughout NYS.

The Joint Efficiency Providers have implemented, are administering, and are 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 (“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 Joint Efficiency Providers monitor the extent to which NYS Clean Heat-incentivized heat pump systems displace or replace other heating fuels. The Joint Efficiency Providers continue to review the program’s progress and make adjustments to improve performance as appropriate.

Implementation Plan, Schedule, and Investments

A list of the Company’s clean heat programs as of this 2023 DSIP Update is provided below. A more complete description of National Grid’s programs can be found in the links below or within the Clean Heat Program Manual.³⁹

³⁹ NE:NY Proceeding, *supra*, note 41.

Table 2.6.1: National Grid Clean Heat Incentives

Category	Description	Incentive	Contractor Reward (from Incentive)
1	ccASHP: Partial Load Heating	\$500 / outdoor condenser unit	\$100 / outdoor condenser unit
2	ccASHP: Full Load Heating	\$1,000 / 10,000 British Thermal Unit per Hour (“Btuh”) of maximum heating capacity at Northeast Energy Efficiency Partnerships (“NEEP”) 5° F	\$500 / project
2a	ccASHP: Full Load Heating with Integrated Controls	\$1,200 / 10,000 Btuh of maximum heating capacity at NEEP 5° F	\$500 / project
2b	ccASHP: Full Load Heating with Decommissioning	\$1,400 / 10,000 Btuh of maximum heating capacity at NEEP 5° F	\$500 / project
3	GSHP: Full Load Heating	\$1,500 / 10,000 Btuh of full load heating capacity as certified by AHRI	\$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	N/A
5	HPWH (< 120 gallons of tank capacity)	\$700 / unit	N/A
6	Custom Hot Water Heating Applications	\$80 / MMBtu of annual energy savings	N/A
7	GSHP Desuperheater	\$100 / unit	N/A
8	Dedicated domestic hot water (“DHW”) Water-to-Water Heat Pump (“WWHP”)	\$900 / unit	N/A
9	Simultaneous Installation of Space Heating and Water Heating	\$250 / Additional bonus per combination installation	\$250 / project

Note: More information is *available* at <https://cleanheat.ny.gov/contractors/> as well as <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 to deliver building electrification solutions. Some of National Grid’s highlights since the launch of the Clean Heat Program are summarized below:

- Updated and improved the heat pump measures in the NY Technical Resource Manual
- Made Quality Assurance/Quality Control (“QA/QC”) process improvements including revising ASHP and GSHP checklists in coordination with stakeholders, revising the decommissioning checklist, and promoting 110 Clean Heat contractors to Full Status
- Improved application process cycle times through increased program staffing, improved communication with participants, and increased training opportunities for industry partners
- Agreed to add Heat Pump Water Heater midstream incentives to the Program Manual and began to deploy these programs.
- National Grid 2a— ccASHP full load heating with integrated controls and Category 2b— ccASHP with decommissioning
- National Grid introduced a bonus for priority electrification zip codes
- Commercial and Industrial (“C&I”) as a share of program savings rose from 0% in 2020 to 23% by 2022
- Scaled-up contractor network from 88 in 2020 to 323 in 2022

Table 2.6.2 below shows the current implementation of National Grid’s most recent Clean Heat Program goals resulting from the Commission’s Three-Year Rate Plan Order.⁴⁰

Table 2.6.2: National Grid’s Electric Clean Heat Savings Goal to 2025⁴¹

	2020	2021	2022	2023	2024	2025
Gross Savings Goal (MWh)	38,993	63,163	136,017	210,694	245,889	280,647

Future Implementation and Planning

National Grid continues to advance energy affordability by developing initiatives focused on energy solutions for low- to moderate-income (“LMI”) / DAC 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. National Grid will continue to focus on scaling up the program and identifying ways to simplify

⁴⁰ National Grid Electric and Gas 2020 Rate Case Proceeding, *supra*, note 6.

⁴¹ 2020-2022 values are actuals from the Company’s 2019-2022 Electric Clean Energy Dashboard Scorecard, *available at* <https://www.nyscda.ny.gov/About/Tracking-Progress/Clean-Energy-Dashboard/View-the-Dashboard> whereas the 2023-2025 values are targets from the NE:NY Order, NE-NY Proceeding, *supra*, note 43.

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. National Grid also plans to determine appropriate program structure where it can potentially tie into community- and utility-owned thermal energy networks.

Figure 2.6.1 Clean Heat Integrated Implementation Timeline



Risks and Mitigations

Table 2.6.3: Risks and Mitigations for Clean Heat Integration

Risk	Mitigation
Fundability – Does National Grid have enough funding secured to deliver the outcomes	NE:NY interim review will provide an opportunity to plan future funding
Uncertainty for EE program administration and targeted policy incentives for electric HP adoption e.g., regulatory approval of EE program administration jurisdiction and targeted electric heat pump (“EHP”) incentives with customer segment priority	Early engagement/outreach to clarify program administration and advocate for targeted incentives Engage with stakeholders early and often Co-create regulatory solutions (Joint advocacy)
Data gap exists for electric-only customer electric HP 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 electric HP 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 New York 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 New York achieve its energy and environmental goals under the CLCPA and has designed EE programs under NE:NY in a manner that is consistent with these net zero efforts. As part of its commitment to a clean energy future, National Grid announced in October of 2020 the “Net Zero by 2050” plan and updated Responsible Business Charter.⁴² In 2022, National Grid issued “Our Clean Energy Vision,”⁴³ which outlines a path forward for a fossil-free future for cleanly heating homes and businesses through four pillars: first, aggressively accelerating insulation and EE improvements to buildings; second, supporting cost-effective, targeted electrification on National Grid’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 electric heat pumps with their gas appliances; and, finally, eliminating fossil fuels from the Company’s existing gas network no later than 2050 by delivering renewable natural gas RNG and green hydrogen to customers.

Across every community served, 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 the clean energy investments in DACs in furtherance of the goals of the CLCPA. 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 the Company to help all customers benefit from EE and electrification.

Stakeholder Interface

As a statewide program Clean Heat has pre-established stakeholder interfaces to ensure consistency across New York. 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 effort discussions are planned and executed through National Grid’s participation in the Clean Heat Joint Utility Management Commission.

⁴² The Company’s “Net Zero by 2050” plan and updated Responsible Business Charter affirm National Grid’s commitment to: (i) reduce GHG emissions from direct operations by 80% by 2030, 90% by 2040, and to net zero by 2050; (ii) reduce GHG emissions from the gas the Company sells to customers by 20% 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 National Grid’s US operations and the energy delivered to customers.

⁴³ Available at <https://www.nationalgrid.com/us/fossilfree>

2.7 Energy Efficiency Integration and Innovation

Context and Background

National Grid recognizes that EE is the lowest-cost, zero-carbon energy resource option for its customers and the State, and that 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 in order to reduce system costs and provide enhanced customer savings. EE is one of the four pillars of the Company's vision of a fossil-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, continue to align with and support the 2025 statewide EE goal of 185 trillion British thermal units ("TBtu") of energy usage reductions at the customer level. New York's CLCPA is one of the most ambitious climate laws in the United States, requiring New York to reduce economy wide GHG emissions 40% from 1990 levels by 2030 and achieve net zero GHG emissions by 2050.

Recently, the Commission began the mid-cycle Interim Review of the NE:NY Order⁴⁴ and is evaluating its effectiveness as well as looking for input from a variety of stakeholders on how to improve and modify this order for future years. The NE:NY EE goals are set to address energy savings in buildings and the industrial sector across all fuel sources. Since 2020, there has been an increasing focus on adapting the order to encourage more home weatherization to facilitate BE for residents. Several questions were posed to the utilities in New York to gain stakeholder feedback on how the State should go about meeting its aggressive EE and BE goals. The Governor's 2022 State of the State address supported the goal of two million electrified and electrification-ready homes by 2030. Modification to the NE:NY Order based on these recent changes is expected to be announced in early 2024.

In addition to the changes expected on a state-wide level, there have been significant updates on a national level to energy policy and standards. Two complementary acts were passed to advance EE & BE initiatives nationwide. The IIJA and the IRA were passed to tackle widescale issues facing the nation. Each contained several provisions for EE & BE work, including electrical infrastructure improvements in the IIJA that will help remove the barriers for buildings traditionally heated by fossil gasses in their transition to electrified heat through high-efficiency heat pumps. The IRA detailed provisions in the coming years to address the cost of heating electrification through broad incentives, credits, and rebates for building owners and residents.

Due to several long-standing national initiatives to improve the efficiency of lighting choices, the federal government adopted new lighting standards effective in January of 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

⁴⁴ NE:NY Proceeding, *supra*, note 43.

a requirement of forty-five lumens per watt as per Energy Independence and Security Act guidelines. This effectively makes high-efficiency light-emitting diodes (“LEDs”) the baseline standard in all major retail stores, with the expectation that incandescent lamps will be phased out of production nationwide. As a result of this, lighting incentive programs are expected to be reduced starting in January of 2023 because there will be marginal improvements in bulb efficiency available to incentivize.

In the background of this activity, National Grid continues to expand the already robust portfolio of EE offerings in the annually filed System Energy Efficiency Plan (“SEEP”).⁴⁵ The SEEP is designed to support the progression of market-based solutions and the penetration of emerging and transformative technologies within the Company’s service territory in support of the Commission’s REV Proceeding, NE:NY Order, and the CLCPA. It provides detailed information on EE programs,⁴⁶ budgets, goals, and Evaluation, Measurement, and Verification (“EM&V”) strategies. The overall goal is to exceed the current energy savings targets while finding new opportunities to reduce implementation and administration costs. 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 the customer.

In addition to EE programs, National Grid currently operates DLM programs which were created in accordance with directives provided by the Commission in Case 14-E-0423.⁴⁷ The current DLM programs are comprised of the Distribution Load Relief Program (“DLRP”), Term-DLM, Auto-DLM, Commercial System Relief Program (“CSRP”), and the Direct Load Control (“DLC”) Program. The DLC program, which includes the **ConnectedSolutions** Program, was launched in 2016 by the Company. CSRP, Term- and Auto-DLM, and DLRP are primarily considered to be commercial and industrial 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, 2022 which includes an assessment of its DLM programs for the 2022 capability period and identifies changes planned for the 2023 capability period.⁴⁸

Table 2.7.1 below shows the current implementation of National Grid’s most recent SEEP in gross savings goals resulting from the Three-Year Rate Plan Order. The Company recovers all EE program costs through base rates, including those in its electric and gas SEEP.

⁴⁵ Case 18-M-0084, *In the Matter of a Comprehensive Energy Efficiency Initiative*, Niagara Mohawk Power Corporation d/b/a National Grid 2022 System Energy Efficiency Plan (filed September 30, 2022) (“SEEP”).

⁴⁶ See, e.g., <https://www.nationalgridus.com/Upstate-NY-Home/Energy-Saving-Programs/>

⁴⁷ Cases 14-E-0423 *et al.*, *Proceeding on Motion of the Commission to Develop Dynamic Load Management Programs* (“DLM Programs Proceeding”), Order Adopting Dynamic Load Management Filings with Modifications (issued June 18, 2015).

⁴⁸ DLM Programs Proceeding, Niagara Mohawk Power Corporation d/b/a National Grid Dynamic Load Management Programs Annual Report for 2022 Capability Period (filed November 15, 2022).

Table 2.7.1: National Grid's Electric EE Savings Goal to 2025⁴⁹

	2020	2021	2022	2023	2024	2025
Gross Savings Goal (MWh)	579,474	537,596	494,791	443,243	490,947	548,284

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 or within National Grid's filed SEEP.

Table 2.7.2: National Grid's Electric EE Programs

Note	Program	Fuel Types	Sector
1	Electric Demand Response	Electric	Residential
	Multifamily Direct Install	Electric & Gas	Residential
	Custom Incentive Program	Electric & Gas	C&I
	Behavioral Incentive Programs	Electric & Gas	Residential
	Electric C&I Retrofit	Electric	C&I
	Electric Small Business Services	Electric	C&I
	Small and Medium Business Managed Energy Program	Electric	C&I
	Electric Demand Response	Electric	C&I
	Portfolio Manager Data Uploads	Electric & Gas	Residential/C&I
2	Electric Products Program	Electric	Residential
3	Online Audit Program	Electric & Gas	Residential
4	Empower Referrals	Electric & Gas	Residential
5	Energy Affordability Program	Electric & Gas	Residential
6	E-commerce Market Place– (Residential & Small Business Services)	Electric & Gas	Residential/C&I
7	Tiered Incentive Structure	Electric & Gas	C&I
-	Heating Ventilation and Air Conditioning and Appliance Controls	Electric	C&I
-	Rebate as a Service aka Instant Rebates	Electric & Gas	Residential
-	Exploring LMI Housing Incentives	Electric & Gas	Residential
-	Streetlight LED	Electric	C&I

Note: More information is available at the below links:

- 1) <https://www.nationalgridus.com/Upstate-NY-Business/Energy-Saving-Programs/>

⁴⁹ *Supra*, note 46.

- 2) <https://www.nationalgridus.com/media/pdfs/resi-ways-to-save/ee7255-uny-electric-heat-and-products-application.pdf>
- 3) <https://energyassessment.nationalgridus.com/residential/start/>
- 4) <https://www.nyserda.ny.gov/All-Programs/Programs/EmPower-New-York>
- 5) <https://www.nationalgridus.com/Upstate-NY-Home/Bill-Help/Energy-Affordability-Program>
- 6) <https://marketplace.nationalgridus.com/>
- 7) <https://www.nationalgridus.com/Services-Rebates?r=10&page=1&customerType=For+Businesses&locations=Upstate+New+York>

Current Progress

National Grid's current EE program portfolio focuses on cost effectiveness and managing programs at the portfolio level by investing in successful, highly efficient programs 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 in order to increase market penetration and customer ease while also lowering costs.

To align with current goals for EE & BE at the state level, National Grid is developing a weatherization program for residential and C&I customers to reduce gas consumption and facilitate the transition to electrified heat with greater ease for customers. Modifications to lighting initiatives in the wake of the baseline changes at the federal level are currently the focus for the residential and multifamily teams as the impact in those sectors was greater than in the C&I space. The Market Rate EE team is currently evaluating alternative electrical saving technologies to adjust for the expected gap with lighting incentives being phased out soon. 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.

EM&V continues to be an integral part of the EE portfolios. Throughout the 2021-2023 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 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. National Grid continues to explore new evaluation methods that utilize automation, smart devices, and/or software solutions.

National Grid's relatively new DLM Programs, Term- and Auto-DLM, as well as the more established DLRP, CSRP, and the DLC Program, have continued to progress steadily and generally have experienced growth over the last three years with DLC, 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 Tariff. The Auto-DLM and DLRP programs have experienced challenges in securing bids for the Company's RFPs, but the Company continues to modify these programs in an effort to make them more appealing.

The CSRP is activated for peak-shaving needs when National Grid's electrical system exceeds 92% of the system-wide 95/5 peak forecast, as defined in the Company's 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 Results⁵⁰

Year	Total Participants (Direct and via Aggregator)	Contracted Curtailment (MWs)	Average Curtailment (MWs)	Events	Aggregators	Direct 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

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. The most recent RFP documents for Term-DLM and Auto-DLM are *available at* <https://www.nationalgridus.com/Upstate-NY-Business/RFP/Term-DLM-and-Auto-DLM-Program-Request-for-Proposals>

In December 2020, National Grid issued its first Term-DLM and Auto-DLM Program RFP,⁵¹ soliciting resources to begin participation in the 2021 or 2022 Vintage Years. One bid for the Term-DLM Program cleared cost-effectiveness. The accepted bid was an aggregation, awarded a contract for their full bid of 55 MW of load relief, beginning participation in the 2022 Vintage Year. No bids were received for the Auto-DLM program.

⁵⁰ The drop in participants count and contracted MW curtailment are due in part to side effects of the pandemic and participants from the prior season having moved into the Term-DLM program for the 2022 capability period.

⁵¹ See DLM Programs Proceeding, National Grid RFP for Resource Participation in Term-DLM and Auto-DLM Programs (filed December 2, 2020).

In October 2021, National Grid issued the 2021 Term-DLM and Auto-DLM Program RFP, soliciting resources to begin participation in the 2023 Vintage Year.⁵² Bids were received in January 2022, and for a second consecutive year no Auto-DLM bids were received, though three Term-DLM Program bids were received and ultimately cleared. These bidders were contracted for 15 MW, 2.6 MW, and 10 MW of load relief, and their participation will commence in the 2023 Vintage Year.

In 2022, the Term-DLM participants included a single aggregation of forty-one participants, contracted for 55 MW of curtailment. Term-DLM was activated seven times, coincident with CSRP activation with the exception of the event called 7/19/22. The single aggregation performed an average of 47.94 MW when called during the 2022 season.

The Auto-DLM Program has unfortunately been less successful, as over the three years of procurements National Grid has not received any Auto-DLM bids. 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) and added value tiers to the Auto-DLM locations to help bidders better understand the program.

The DLC Program is activated for system-critical situations or for peak shaving purposes. Through this program, National Grid is able to remotely adjust thermostat settings of participating customers with WiFi 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 demand response management system ("DRMS"). **ConnectedSolutions** is available to all residential and small commercial customers served at primary and secondary voltage levels. For **ConnectedSolutions** there is a one-time sign-up payment of \$30 and a \$20 yearly incentive that is payable in the second year of participation for the reduction of load during at least 80% of called event-hours.

At the end of the 2022 capability period, there were 19,259 thermostats enrolled in National Grid's **ConnectedSolutions** Program, now nearly four times larger than the last report. Thermostat enrollment increased by 3,662, 5,849, and 6,009 in 2020, 2021, and 2022 respectively. Enrollment is expected to grow in 2023 and beyond. For the 2020 through 2022 Capability Periods, **ConnectedSolutions** events were scheduled coincidentally with CSRP events. Average participation has remained steady at around 63% throughout each summer, regardless of the relative frequency of back-to-back event days. In 2020 there were three event days immediately followed by another event day, 2021 and 2022 both saw four 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 remained steady at 0.86 kW.

⁵² Cases 18-E-0130 *et al.*, *In the Matter of Energy Storage Deployment Program*, National Grid RFP for Resource Participation in Term-DLM and Auto-DLM Programs (filed October 28, 2022).

Demand Response Management System

In 2020 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. In 2022, National Grid conducted an RFP for these same services and awarded the contract to EnergyHub, the incumbent vendor.

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 EE's benefits. In addition to EE, the recent focus on Building Electrification through state and federal legislature 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, NWA projects, 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. Technologies like AMI and data sharing capabilities such as GBC will give National Grid and 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 the programs. These activities will be undertaken consistently with the principles and goals of REV, NE:NY and the CLCPA, and are supported by the Company's SEEP, which seek more flexibility in program delivery and management.

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 beneficial electrification projects. Recently, the Company has supported an initiative that supplies high efficiency lighting to local foodbanks as a means to provide efficiency measures to some of National Grid's most vulnerable customers. Also, as of 2022 National Grid has formally begun funding contributions towards NYSERDA's Empower NY program to further strengthen the Company's portfolio of LMI/DAC initiatives. As part of the overall plan to better serve LMI/DAC customers as per the CLCPA, the Company has future plans to coordinate with the statewide Clean Heat Program in the coming years.

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 on a system-wide basis based on customer demand. The Company's EE team works closely with the 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 to design targeted programs and add locations to existing targeted load relief programs such as Auto-DLM.

The Company continues to focus on positioning EE as a least-cost system resource. National Grid'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. To support and expand the continued benefits of EE, the Company expects that future SEEPs will include not only EE, but also describe coordination with other DR programs offered by National Grid, changes to rate design, and improvements to LMI programs. National Grid will continue to leverage EE programs to create customer value by contributing to lowering system operating and capital costs. 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 carbon mitigation, the Company expects customer savings goals to continue to increase beyond 2025. The next generation of National Grid's EE service offerings 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.

Figure 2.7.1 EE Integration and Innovation Integrated Implementation Timeline



Risks and Mitigations

Table 2.7.4: Risks and Mitigations for EE Integration and Innovation

Risk	Mitigation
Reduced funding as a result of NE:NY Interim Review	Assertive participation in Interim Review process to ensure utility funding levels are maintained, extended, or increased
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

Continued discussion between utilities, government agencies, and other stakeholders will help maximize the savings attained in New York 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 New York achieve its energy and environmental goals under the CLCPA and has designed EE programs under NE:NY in a manner that is consistent with these net zero efforts. As part of its commitment to a clean energy future, National Grid announced in October of 2020 the “Net Zero by 2050” plan and updated Responsible Business Charter.⁵³ In 2022, National Grid issued “Our Clean Energy Vision,”⁵⁴ 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 served, 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 New York achieve ranking in the top five most energy efficient states in the nation through existing EE and DR programs several years in a row, and these programs continue to grow. Under the state’s NE:NY transformation of utility EE programs, National Grid is committed to achieving nation-leading annual levels of efficiency savings by 2025.

The Company also has established internal processes to track and report on clean energy investments in DACs in furtherance of the goals of NY’s CLCPA. 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 the Company to help all customers benefit from EE and 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 the commercial DRMS and the 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

⁵³ The Company’s “Net Zero by 2050” plan and updated Responsible Business Charter affirm National Grid’s commitment to: (i) reduce GHG emissions from direct operations by 80% by 2030, 90% by 2040, and to net zero by 2050; (ii) reduce GHG emissions from the gas the Company sells to customers by 20% 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 National Grid’s US operations and the energy delivered to customers.

⁵⁴ Available at <https://www.nationalgrid.com/us/fossilfree>

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.

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 New York 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 New York’s clean energy goals.⁵⁵

Implementation Plan, Schedule, and Investments

Current Progress

System Data Portal

Since filing the DSIP in 2020, 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 its 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.

⁵⁵ Case 20-M-0082, *Proceeding on Motion of the Commission Regarding Strategic Use of Energy Related Data* (“IEDR Proceeding”), Order Implementing an Integrated Energy Data Resource (issued February 11, 2021) (“IEDR Order”).

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 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 Inventory showing the DG interconnection queue.	Assists with access to interconnection application portal and how to use the portal. Provides helpful links to the Joint Utilities site and the NY-SIR inventory 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 forecasted loading has been added.	The data provides information that helps DER developers understand potential system constraints that may impact future interconnections.
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.
EV Load-Serving Capacity	Provides overall load serving capacity on a per feeder basis for EV chargers.	The data provides information that helps customers understand how much capacity each feeder has for EV charging infrastructure.
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 nodal level as to the amount of ES DG capacity and load	Hosting Capacity gives the developer a relative indication of where interconnection costs may be higher or lower.

Portal Tab	Description / Data Provided	Stakeholder Utilization
	serving capacity that each feeder could accommodate at that node without requiring significant infrastructure upgrades	
Locational System Relief Value (“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 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.
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 explains what an NWA is, 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 (“ESEs”) 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 the DSIP update. The IEDR Program Team implemented the following use cases for the IEDR IPV which was released in Q1 of 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 site new DERs and monitor the state of DER development in New York.	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
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 a single map view with consistent data so that end users can site new DERs and monitor the state of DER development in NYS accurately.	3/31/2023

The IPV is *available* at <https://iedr.nyserda.ny.gov>.

Future Implementation and Planning

The Company will continue to enhance the system data it directly makes publicly available with specific improvements to HCA. National Grid plans on refreshing the analysis on the entire system and releasing an update to the PV Hosting Capacity map on October 1, 2023. A detailed plan for enhancing HCA is discussed in the Hosting Capacity section of this 2023 DSIP Update.

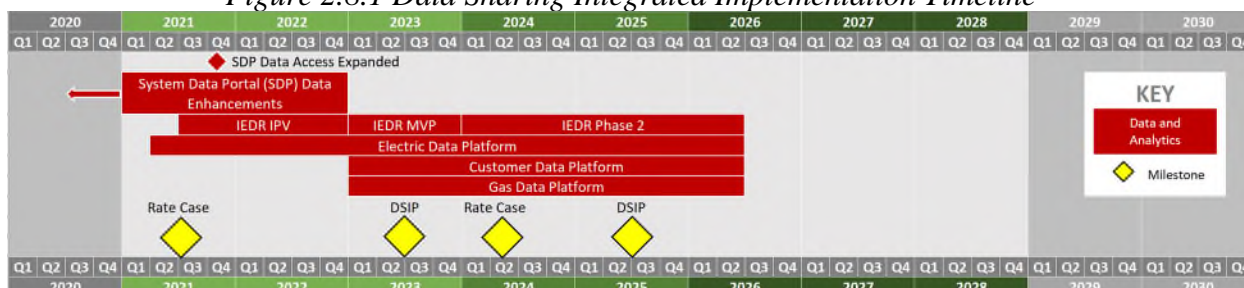
The IEDR program will publish data to support up to ten use cases by the end of CY 2023. The following use cases currently being considered for Phase 1:

- Find and Filter Rate Options Across NYS IOUs
- Efficient Access to Existing Customer Billing Data
- DER Siting
- Community Choice Aggregation
- Building Electrification Site Identification
- Accessible DER Interconnection (HC Map Enhancement)
- Whole Building Energy Consumption Analysis

Additional information in regard to the future implementation of IEDR can be found in the Appendix.

IEDR Phase 2 use cases are being refined in 2023 and will be part of IEDR's implementation plans that commit to approximately fifty IEDR use cases and a timeline of sixty months. IEDR Project status is on NYSEDA's website *available at* <https://www.nyserda.ny.gov/All-Programs/Integrated-Energy-Data-Resource-Program>. The IEDR platform is *available at* <https://iedr.nyserda.ny.gov>.

Figure 2.8.1 Data Sharing Integrated Implementation Timeline



Risks and Mitigations

Table 2.8.3: Risks and Mitigations for Data Sharing

Risk	Mitigation
Cybersecurity	National Grid is ensuring that the IEDR program team has proper cyber certification in place before data is shared with the team.
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.
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 New York State'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 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 their DER sites. National Grid's NWA

website also provides information for third parties that may be capable of using DER to solve grid constraints.

Stakeholder Interface

National Grid conducts periodic stakeholder sessions for various data sets made available on the Company's NY 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. Suggestions for improvements from stakeholders are regularly incorporated into roadmaps that outline a path for implementing future enhancements.

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.⁵⁶

To encourage efficient DER integration, National Grid provides estimates of its system's hosting capacity⁵⁷ for each radial distribution circuit within the Company's service territory, as it relates to different types of DERs (e.g., solar PV and 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 HCA maps through National Grid's System Data Portal *available at* <https://systemdataportal.nationalgrid.com/NY/>.

Implementation Plan, Schedule, and Investments

Current Progress

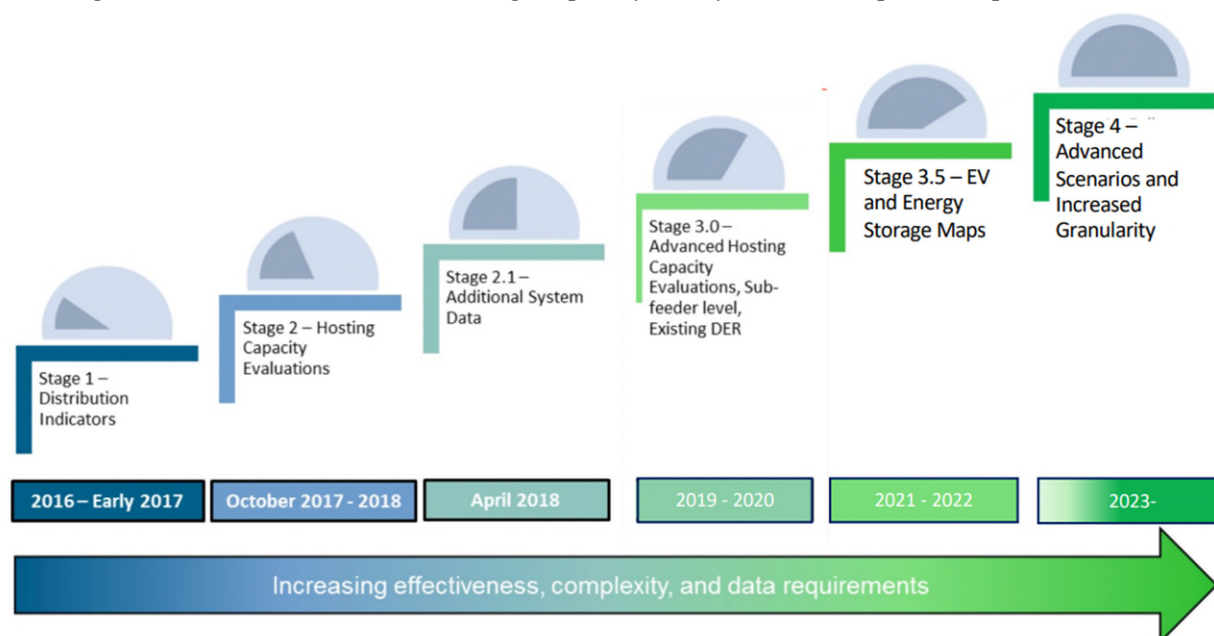
National Grid, in coordination with the other Joint Utilities, continues to progress hosting capacity efforts in stages as presented in Figure 2.9.1. The Company completed these stages by developing feeder models in CYMDIST distribution power flow software and using the DRIVE software tool developed by EPRI. The DRIVE tool is a capacity evaluation application used to determine the ability of a radial distribution feeder to host distributed energy resources without causing adverse impacts to the distribution system.

⁵⁶ 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, 2, *available at*

<http://www.epri.com/abstracts/Pages/ProductAbstract.aspx?ProductId=000000003002008848>

⁵⁷ *Available at* <https://systemdataportal.nationalgrid.com/NY/>

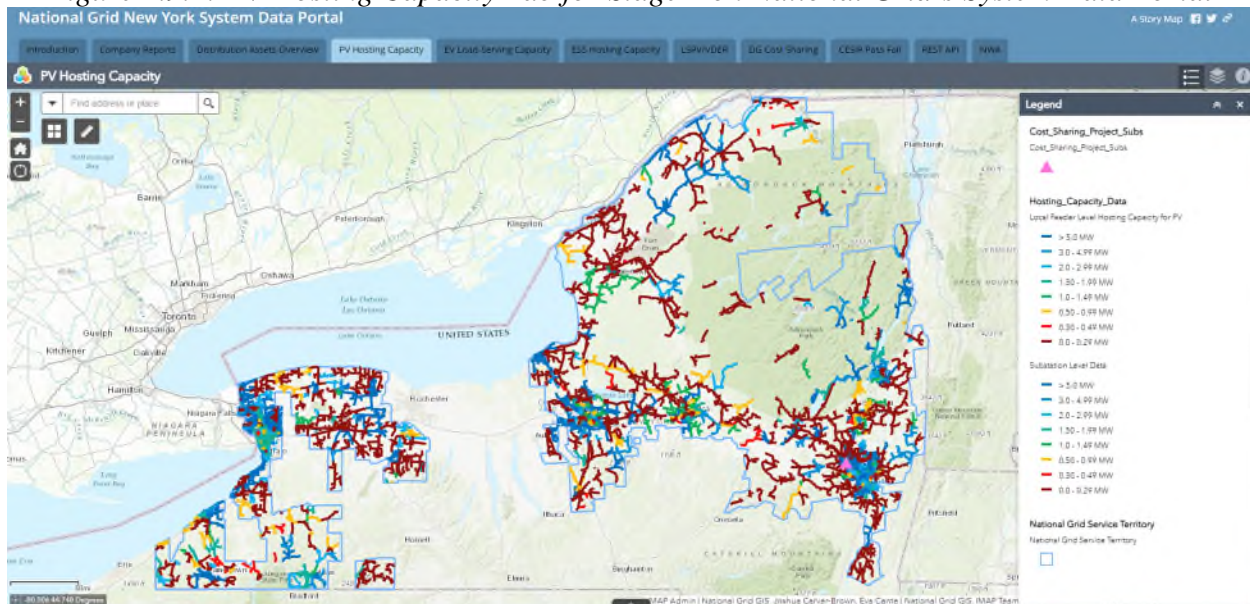
Figure 2.9.1: Joint Utilities Hosting Capacity Analysis Roadmap Development to Date



The Company has completed all stages up to and including Stage 4 with all results generated thus far being shared on National Grid’s System Data Portal. Discussions are ongoing related to a hosting capacity analysis roadmap beyond Stage 4. In Stage 1, several parameters, such as voltage class, feeder load level, station transformer fusing, level of interconnected DG, and substation zero-sequence voltage (“3V0”), were assessed and results were presented in a red zone map. Stage 2 evaluations met the Commission’s goals, including a system data update (Stage 2.1). Stage 2 and 2.1 analyses were carried out on a feeder level only, in which a maximum and a minimum hosting capacity value were provided for each feeder analyzed. Detailed Stage 3 evaluations provided sub-feeder level hosting capacity which incorporated existing installed DG into the modeling and analysis,⁵⁸ as well as the inclusion of additional system data during the Stage 3.1 release in April 2020. A depiction of the PV hosting capacity map can be seen below in Figure 2.9.2.

⁵⁸ This enhancement incorporates interconnected DG to date into the circuit models used for the HCA with a priority on solar PV (> 500 kW), which remains the DER technology with the most significant impacts on hosting capacity.

Figure 2.9.2: PV Hosting Capacity Tab for Stage 4 on National Grid's System Data Portal



Stage 3.5 involved the development of capacity maps for both EV and ESS, each of which have their own tab on the Company's System Data Portal, released in October 2020 and April 2022, respectively. Figures 2.9.3 and 2.9.4 below depict the EV and ESS capacity maps implemented as part of Stage 3.5.

Figure 2.9.3: ESS Hosting Capacity Tab for Stage 4 on National Grid's System Data Portal

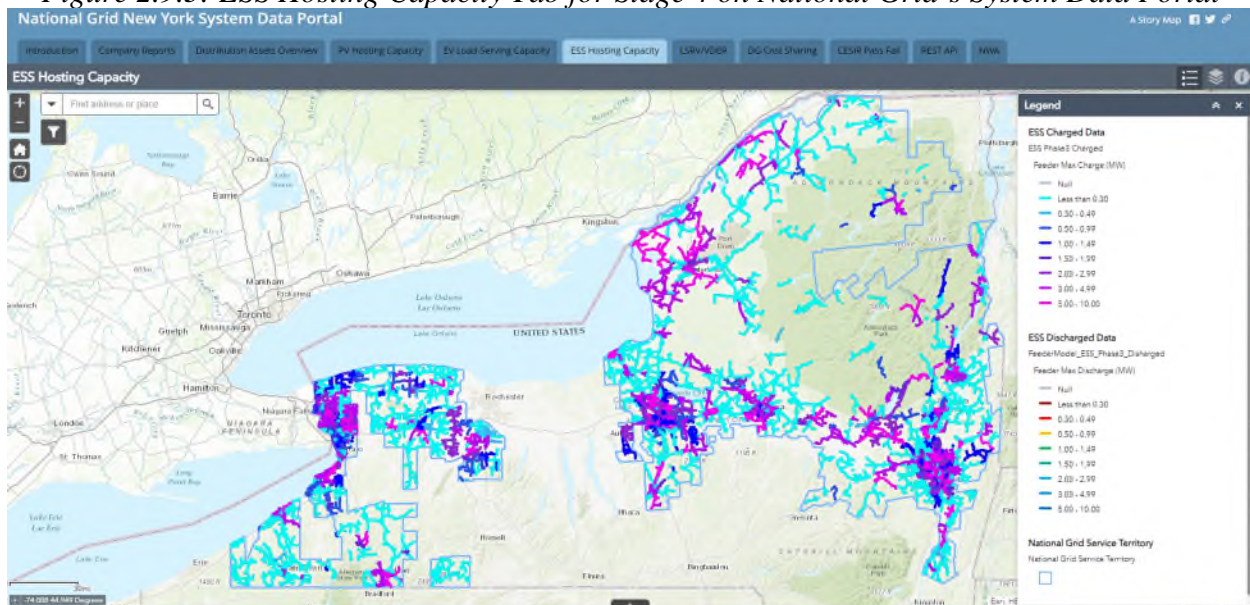
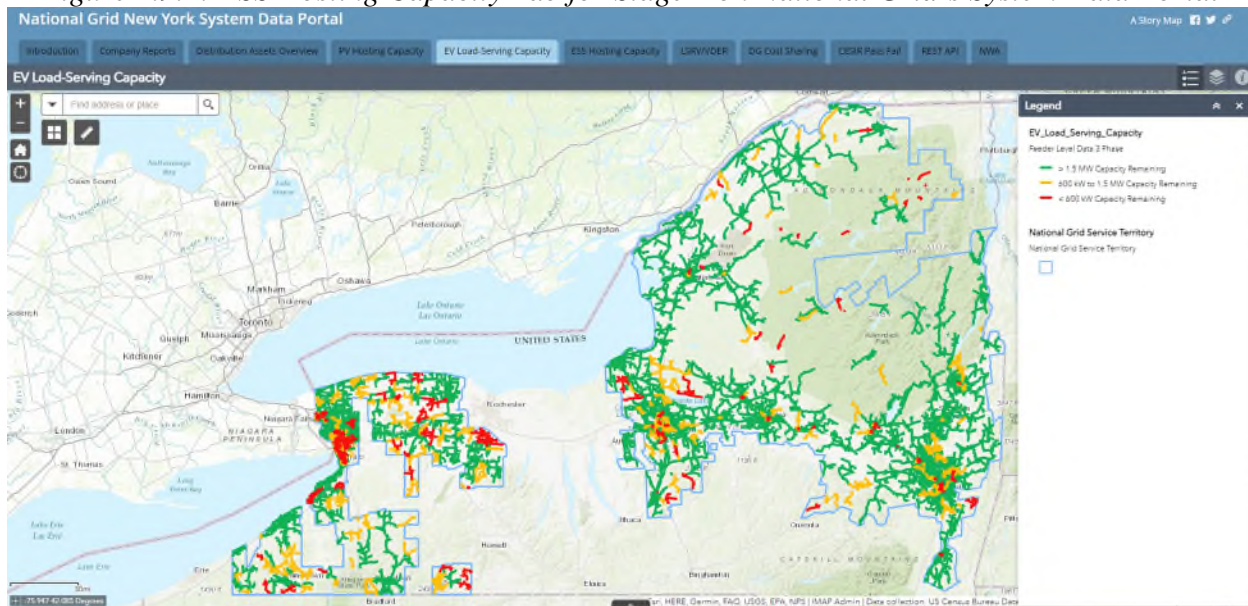


Figure 2.9.4: ESS Hosting Capacity Tab for Stage 4 on National Grid's System Data Portal



Stage 4 involved adding additional granularity to the PV and ESS hosting capacity maps specifically as they were of most interest to the DG developer community. Additional granularity 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. Sharing hosting capacity values as they relate to each evaluation criteria is useful to help understand what criteria is limiting the hosting capacity per individual line section which can then help users better understand what type(s) of violations are limiting hosting capacity in that area and what upgrades may be necessary to mitigate those violations. Figure 2.9.5 below shows an example of the primary (nodal) level popup available on the PV Hosting Capacity map.

Figure 2.9.5: National Grid Primary Level System Data

Primary Level Hosting Capacity

Primary ID	332644171
Feeder	36_40_12251
Base Voltage (kV)	13.20
Primary Hosting Capacity (MW)	1.70
Primary Over-Voltage (MW)	10.00
Primary Voltage Deviation (MW)	10.00
Primary Voltage Regulator Deviation (MW)	3
Thermal from Generation (MW)	1.70
Anti-Islanding (MW)	
Flicker Value (MW)	15.83

Improvements in System Data Portal performance have enabled National Grid to effectively share the nodal hosting capacity results, as generated by utilizing the EPRI DRIVE tool, without needing to merge similar nodes together with an associated color code and reducing the number of data points made available on the map. Sharing unique hosting capacity results per node allows for more location-specific information that better informs DG developers when they are trying to identify potential locations and submit DG applications. These improvements ultimately yield more applications that lead to successful interconnections.

Although the EV load serving capacity map represents each circuit's ability to support additional load at the overall feeder level as opposed to the nodal level on the PV and ESS maps, additional enhancements have been made to improve stakeholder value and engagement. For example, all data currently shared on National Grid's System Data Portal is now accessible via API which allows for more advanced users of the ArcGIS platform to integrate National Grid's map and data into their own maps or access the data programmatically.

In addition to the implementation of several new maps and API accessibility, National Grid has made considerable improvements to the quality of the data sources used to conduct HCA. Specifically, expansion of feeder and device monitoring programs allows for a more refined HCA that considers actual load conditions on each feeder as opposed to resorting to conservative assumptions. Improved integration with DER interconnection data sets also allows for specific hosting capacity data to be refreshed on a monthly and six-month cadence as opposed to a single annual update. The capacity of DG connected and DG In Queue per feeder are refreshed monthly, and any feeder with greater than 500 kW of connected DG since the last annual HCA update has a full HCA recalculation at the six-month interval. Although HCA values depicted on the maps are not necessarily real-time values, the additional fields and frequency of refreshes allow DER developers to understand how a feeder's hosting capacity may have changed since the last time it was calculated. Figure 2.9.6 below shows an example of the feeder level popup available on the PV Hosting Capacity map.

Figure 2.9.6: National Grid Feeder Level System Data

Local Feeder Level Hosting Capacity for PV

Feeder	36_40_12251
Substation/Bank Name	NORTH CREEK
Local Voltage (kV)	13.20
Local Maximum Hosting Capacity (MW)	4.90
Local Minimum Hosting Capacity (MW)	0.07
Anti-Islanding Hosting Capacity Limit (MW)	1.08
Feeder DG Connected (MW)	0.30
Feeder DG in Queue (MW)	5.00
Feeder DG Connected Since Last HCA Refresh Date (MW)	0.00
Feeder DG Connected/In Queue Refresh Date	1/29/2023
HCA Refresh Date	9/30/2022
Substation Backfeed Protection	No
NYISO Load Zone	F-4
Operating Company	National Grid
Notes	Station will need relay additions/modifications if DG Threshold is violated.

Substation level data is available in a second popup which contains information related to the substation bank that the selected feeder is connected to. Data available on the substation level popup includes the substation bank thermal capacity, the estimated 3V0 protection threshold as well as relevant DG data. Figure 2.9.7 below shows an example of the substation level popup information.

Figure 2.9.7: National Grid Substation Level System Data

Substation Level Data	
Substation/Bank Name	NORTH CREEK
Current Feeder Selection	36_40_12251
Substation/Bank Installed DG (MW)	0.51
Substation/Bank Queued DG (MW)	15.03
Total Substation/Bank Installed and Queued DG (MW)	15.54
Substation/Bank DG Connected Since Last HCA refresh (MW)	0.01
Substation Refresh Date	1/29/2023
Substation/Bank Peak (MW)	4.80
Substation/Bank Thermal Capacity (MW)	13.13
Substation Backfeed Protection	No
Estimated 3V0 Protection Threshold (MW)	0.00
HCA Refresh Date	9/30/2022
NYISO Load Zone	F-4
Operating Company	National Grid

With the introduction of Cost-Sharing 2.0 as adopted by the Commission in its July 16, 2021 *Order Approving Cost-Sharing Mechanism and Making Other Findings*,⁵⁹ National Grid has begun sharing relevant Cost-Sharing 2.0 projects on its Hosting Capacity maps as they relate to improving hosting capacity. Data currently shared includes the project location and cost as well as the associated future impacts to hosting capacity once the project is complete. Figure 2.9.8 below shows an example of the Cost-Sharing 2.0 popup.

⁵⁹ Case 20-E-0543, *Petition of Interconnection Policy Working Group Seeking a Cost-Sharing Amendment to the New York State Standardized Interconnection Requirements* (“IPWG Petition Seeking a Cost-Sharing Amendment to the NY-SIR”), Order Approving Cost-Sharing Mechanism and Making Other Findings (issued July 16, 2021).

*Figure 2.9.8: National Grid Cost-Sharing 2.0 Project Data***Cost Sharing Project Substation**

Substation	Chrisler Ave
Estimated Incremental Impact in HC Availability at Substation (MVA)	20 MVA
Estimated Cost (thousand of dollars)	4,228
Type of Project	CIP
Description	Convert Station to 13.2 kV

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 its System Data Portal. The System Data Portal is publicly accessible and provides users with an 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.

National Grid has also been actively engaged in the development of the IEDR platform with the other Joint Utilities. Part of the IEDR IPV includes hosting capacity data which will serve as a centralized platform where users can view all utilities' hosting capacity data on a single map rather than needing to visit each utility's individual hosting capacity platform. Further discussion of the IEDR and the data National Grid is sharing to support the effort can be found in Section 2.8, Data Sharing.

Future Implementation and Planning

National Grid will continue to enhance the hosting capacity maps. As the hosting capacity maps evolve, both the analysis and data requirements increase in complexity. National Grid is investigating opportunities to increase the update frequency of the HCA and associated datasets. Projects have been ongoing to implement and expand upon a centralized data repository that will be capable of serving as a single source of truth for utility data and facilitate integration with other processes including HCA. Maturing data management practices involved with HCA will facilitate the inclusion of additional data on the Company's System Data Portal and HCA that is relevant to developers. Data enhancements currently being investigated for incorporation include:

- Seasonal hosting capacity results based on operating characteristics of DER depending on the time of year
- Planned projects expected to impact hosting capacity in addition to Cost-Sharing 2.0 projects.
- Increase in refresh rate of data sets via frequent analysis updates where triggered based on a set of criteria such as change in connected DG, device rating update, network topology change, etc.

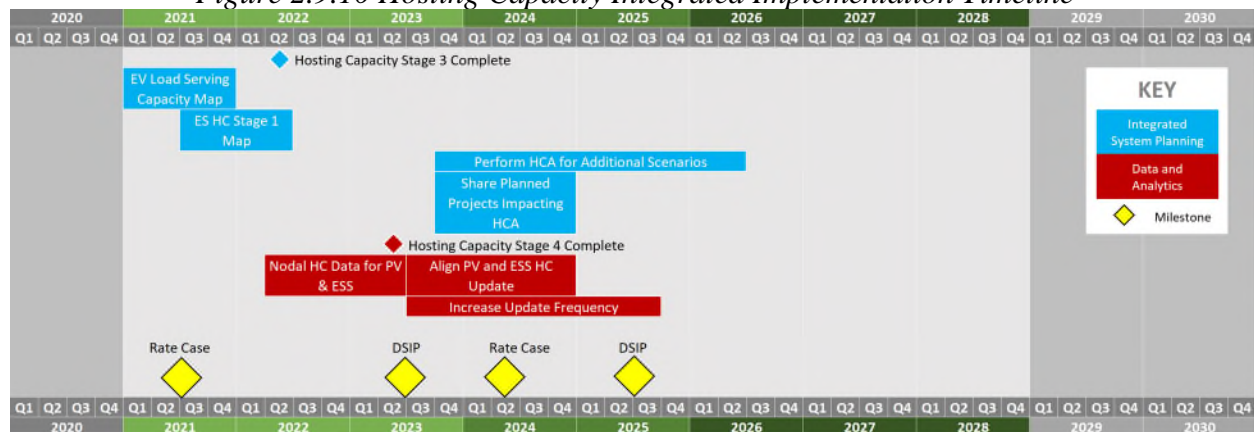
In addition to identification of these three near-term proposed enhancements, the Company, in collaboration with the Joint Utilities and stakeholders, plan to develop and update the longer-term road map (see Figure 2.9.9 below). As such, the Joint Utilities plan to hold at least two more stakeholder sessions in 2023. In consideration of the longer term roadmap it is important to note

that many enhancements require discussion in the interconnection forums before being considered for implementation in future hosting capacity maps. For example, the scenarios for which HCA will be evaluated must also align with expected operational scenarios. Also, all proposed enhancements need to take into consideration the data, software, costs, and resources required to enable them.

Figure 2.9.9 Joint Utilities Roadmap for HCA Stages



Figure 2.9.10 Hosting Capacity Integrated Implementation Timeline



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 puts 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.

Stakeholder Interface

Stakeholder engagement will be a critical input into shaping the HCA roadmap. The Company, along with the other Joint Utilities, will engage stakeholders to solicit their input on approaches and the value proposition for developers to further inform the continued expansion of the roadmap for hosting capacity. Stakeholder sessions are conducted as a collective of Joint Utilities' members on a periodic basis and when new enhancements are released to the hosting capacity maps in parallel across all member utilities. In conjunction with stakeholder engagement sessions, the Joint Utilities has focused on improving the documentation of the HCA process to promote transparency between utilities and stakeholders with respect to the inputs selected and assumptions made when performing HCA. The enablement of API functionality on the Company's System Data Portal adds significant value by allowing for direct integration of National Grid's hosting capacity map data into third-party websites where other useful data sets may be available (e.g., land availability, permitting restrictions, etc.).

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. The Joint Utilities have also put together supporting documents for developers to help with using the hosting capacity maps.

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 eight years. The Company currently maintains the following compensation programs:

- Volumetric Net Energy Metering ("NEM")
- Monetary NEM
- Remote Net Metering
- Remote Crediting
- Net Crediting
- VDER Phase 1 NEM
- VDER Phase 1 NEM with Customer Benefit Contribution
- Phase 1 VDER Value Stack
- Phase 2 VDER Value Stack

In addition to the nine existing programs, an additional two programs, volumetric net crediting and wholesale value stack are soon to be implemented, bringing the total to eleven individual compensation programs. It is important to note the tremendous level of complexity and the time and resources that are necessary to support each of these compensation programs from design, programming, and implementation to on-going IT and administrative maintenance. Furthermore, the complexity increases when considering the interaction between these and other non-DER related programs such as time-of-use and budget billing, as well as opting-in, opting-out, switching, and banking.

In response to changing policies and stakeholder feedback, there have been many changes in CDG billing and crediting since the last DSIP filing. The Commission first adopted the CDG program in 2015. There were numerous subsequent orders and modifications made to the CDG program through the end of 2019, culminating in the Commission's December 12, 2019 *Order Regarding Consolidated Billing for Community Distributed Generation*⁶⁰ which directed the Joint Utilities to implement Net Crediting as a consolidated billing option for all CDG projects, both existing and new.

Prior to this DSIP period, the Joint Utilities had each implemented changes to their retail programs to create the VDER Value Stack mechanism to compensate DERs based on when and where they provide electricity to the grid. The Value Stack compensation mechanism has been operating over

⁶⁰ Case 19-M-0463, *In the Matter of Consolidated Billing for Distributed Energy Resources* (Consolidated Billing Proceeding), Order Regarding Consolidated Billing for Community Distributed Generation (Consolidated Billing Order) (issued December 12, 2019).

the course of this DSIP period, compensating enrolled resources for their eligible contributions to: Energy Value, Capacity Value (“ICAP”), Environmental Value, Demand Reduction Value (“DRV”), and LSRV. Some resources also receive the added incentive of Market Transition Credit (“MTC”) and Community Credit, depending on their eligibility date. In particular, all of the Joint Utilities have been working toward automation of the Value Stack billing process in their respective customer service systems since late 2017 upon issue of the Commission’s September 14, 2017 *Order on Phase One Value of Distributed Energy Resources Implementation Proposals, Cost Mitigation Issues, and Related Matters*.⁶¹ This includes the programming of all aspects of Value Stack compensation, including the multifaceted calculations of each of the Value Stack components for onsite projects, Remote Net Metering (now Remote Crediting) projects, and CDG projects, as well as the details of transferring credits to subscribers and satellites, tracking each Value Stack component in customer banks, and compiling information for both host and satellite accounts.

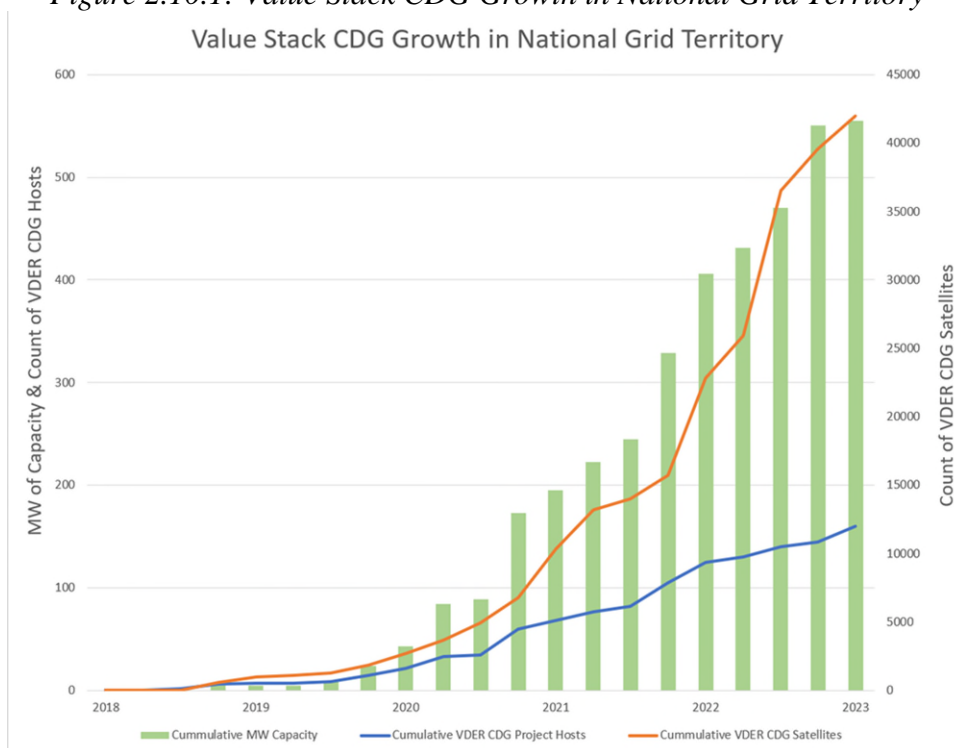
On October 31, 2022, National Grid filed an Implementation Plan detailing its progress toward automation of crediting and billing of CDG pursuant to Ordering Clause No. 2 of the Commission’s September 15, 2022 *Order Establishing Process Regarding Community Distributed Generation Billing*.⁶² The plan detailed the billing system constraints, the changes necessary to effectuate automated CDG billing, and the steps and timeline to achieve full automation of CDG billing.

Billing automation is necessary to support the widespread adoption of CDG projects in the Company’s service territory and provide timely and accurate billing for customers. From 2020-2022, the number of VDER CDG project hosts has approximately quadrupled as shown in the chart below. Similarly, the number of customers participating in VDER CDG as satellites has grown tenfold.

⁶¹ Case 15-E-0751, *In the Matter of the Value of Distributed Resources* (“VDER Proceeding”), Order on Phase One Value of Distributed Energy Resources Implementation Proposals, Cost Mitigation Issues, and Related Matters (issued September 14, 2017).

⁶² Case 19-E-0463, *In the Matter of Consolidated Billing for Distributed Energy Resources*, Order Establishing Process Regarding Community Distributed Generation Billing (issued September 15, 2022) (“Consolidated Billing Process Order”).

Figure 2.10.1: Value Stack CDG Growth in National Grid Territory



Implementation Plan, Schedule, and Investments

Current Progress

The Company was required to provide quarterly updates until automation efforts were completed pursuant to the Consolidated Billing Process Order. The first quarterly update was filed on December 30, 2022 and provided the progress on implementation. The Value Stack automation programming for the billing and crediting of Value Stack CDG and Net Crediting projects was deployed into the Customer Service System (“CSS”) in August 2022. National Grid has been diligently working to transition existing projects (prior to August 2022) into CSS automated billing using a phased approach one-by-one. At this time, all onsite, Remote Crediting and CDG/Net Crediting Value Stack projects have been transitioned into automation with completion of that aspect of the project in January 2023.

While the Company has automated the Value Stack CDG and Net Crediting billing and crediting, some reporting functionality remains to be tested and deployed in CSS. Monthly host reports are still created through a manual process and uploaded into the interconnection portal for customers to access. In addition, annual (or ad hoc) host bank distribution programming was pulled into a separate workstream of the automation project so as not to hinder the larger billing and crediting effort to apply credits to bills and is still being processed manually by the Company. Cancel/rebills of the host account will also be included in the last phase of Value Stack automation. The host reports and host bank distribution programming are anticipated to be fully automated and available to customers through the Company’s My Business Account web portal in July 2023.

Future Implementation and Planning

Future implementation efforts are underway for several different programs. Wholesale market developments to address FERC 2222, the host community benefit program, volumetric CDG Net Crediting, and the Expanded Solar for All program are anticipated to be deployed as further discussed below.

Wholesale Market Developments

The Joint Utilities have continued to interface with the NYISO as it prepares to launch its DER Market Participation Model which was accepted by FERC in April of 2020. The NYISO is on track to launch this new model in 2023. With FERC 2222 having been issued after FERC acceptance of the NYISO's initial DER market design, NYISO will launch a market in 2023 that is fully compliant with FERC 2222 and FERC Order 841⁶³ by 2026. The Joint Utilities' discussions with the NYISO have centered on the development of processes and hand offs between the NYISO and the utilities in enrolling, assessing, tracking, monitoring, and compensating DER aggregators participating in this new market. Over the course of discussions with the NYISO, each of the Joint Utilities have continued to evolve their own corresponding internal processes, including those related to compensation and billing systems administration. Each of the Joint Utilities have implemented the appropriate changes in their internal billing systems administration and are ready, from a process and technology standpoint, for the NYISO's market launch this year.

Each of the Joint Utilities have reviewed and identified retail tariff amendments that will be necessary to enable NYISO's 2023 market launch and its later implementation of a fully FERC 2222 and 841 compliant market. The utilities filed proposed retail tariff amendments in September of 2022 requesting Commission approval. The amendments preclude dual market participants from receiving duplicative compensation in both wholesale and retail markets concurrently. The Commission approved the utilities' respective tariff amendments as filed in its March 17, 2023 *Order Approving Tariff Modifications*⁶⁴ confirming a July 1, 2023 effective date. The NYISO has stated it expects DER aggregator registration to begin in Q2 2023 but DER aggregators are not expected to transact in the NYISO markets until approximately August 2023.

National Grid, along with the other IOUs in the State, plan to file Wholesale Distribution Service tariffs with FERC. The Wholesale Distribution Service tariff will facilitate the charging of distribution delivery service to stand-alone energy storage projects who charge their units for the purpose of selling discharged energy to the NYISO, and to charge exports rates for the use of the delivery system to deliver the discharged energy. The target date for the Wholesale Distribution Service tariff filings with FERC is anticipated to be the summer 2023. Moving forward, the Joint Utilities will continue to interface with the NYISO as it prepares for its 2026 market launch. In

⁶³ FERC Order 841 amends FERC's regulations to facilitate the participation of energy storage systems sized at 100 kW or larger in the capacity, energy, and ancillary service markets operated by RTOs and ISOs. FERC Order 841 is a necessary precursor order for FERC Order 2222. FERC Order 841 allows storage resources to operate in wholesale markets.

⁶⁴ Case 22-E-0549, *In the Matter of the Federal Energy Regulatory Commission (FERC) Order Nos. 2222 and 841, to Modify Rules Related to Distributed Energy Resources*, Order Approving Tariff Modifications (issued March 17, 2023).

parallel, the Joint Utilities will continue to assess and implement as appropriate any supporting utility compensation and billing practices to enable DER participation in the 2026 market launch.

Host Community Benefit Program

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 renewable owner of a 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 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 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*.⁶⁵ The Joint Utilities await approval by the Commission of the Implementation Plans and tariff leaves. National Grid currently has six major renewable energy facilities in its service territory totaling 1.3 GW of nameplate capacity. The earliest project is expected to achieve commercial operation in November 2024 with bill credits due to eligible residential customers in January 2025.

Net Crediting for Volumetric NEM CDG

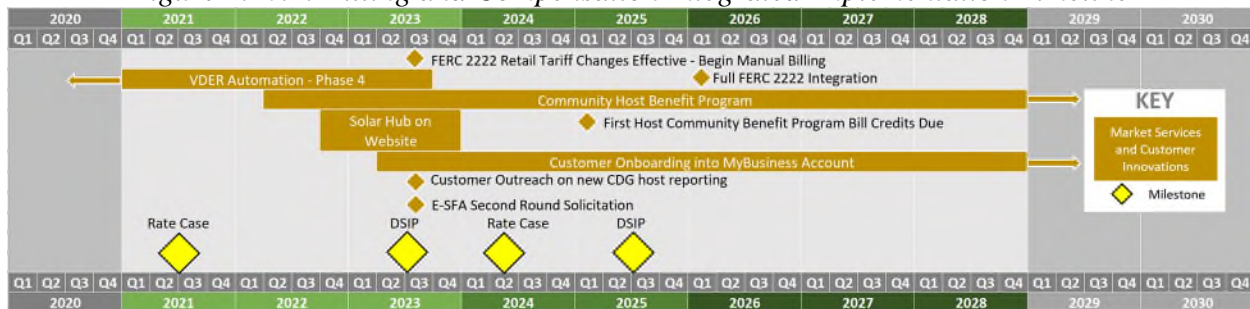
The Joint Utilities began offering Net Crediting for monetary Value Stack CDG customers in October 2020 thereby providing an alternate payment and crediting methodology for CDG Hosts and CDG Satellites that eliminated the need for a separate participation payment from the CDG Satellite to the CDG Host. The 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. The Joint Utilities are currently working with DPS Staff and stakeholders to develop an alternative Net Crediting program for these types of projects.

Expanded Solar for All

Expanded Solar for All is a DG billing program that provides a monthly solar credit for all income-eligible electric customers in National Grid's service territory (i.e., residential participants in the Company's Energy Affordability Program). In 2023, the Company, in collaboration with NYSEERDA, conducted a solicitation to procure 120 MW of solar projects to participate in the program. Bill credits will start flowing to eligible customers on December 1, 2023. A second-round solicitation will be conducted in early summer 2023. DPS Staff is working with the Joint Utilities on designing a statewide E-SFA program that would apply to all of the Joint Utilities.

⁶⁵ 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).

Figure 2.10.2: Billing and Compensation Integrated Implementation Timeline



Risk and Mitigation

The primary risk to timely implementation is the comparative challenge of making the complex changes to the Company's billing system that are often needed. 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.

The Company 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: Risk and Mitigation for Billing and Compensation

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	<ul style="list-style-type: none"> 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 New York 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% of benefits directed to underserved communities

By conceptualizing and advocating for programs such as Expanded Solar for All, the Company is contributing towards bringing the economic benefits of the clean energy transition to low income customers. The CDG Net Crediting program, initiated by the Company, has helped spur the CDG market by taking some of the financial risk off CDG developers. Offering credible, accurate and timely billing and crediting enables the distributed generation 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 so as to achieve desired policy outcomes. Since the last DSIP filing, the Company has hosted or participated in many stakeholder engagement sessions to continually provide information to customers and industry participants. This includes past and planned presentations, webinars, and workshops centered on various utility program topics such as Value Stack compensation, net crediting, and remote crediting. Collaboration between the Joint Utilities, NYISO, and stakeholders has been on-going to support the FERC 2222 implementation effort.

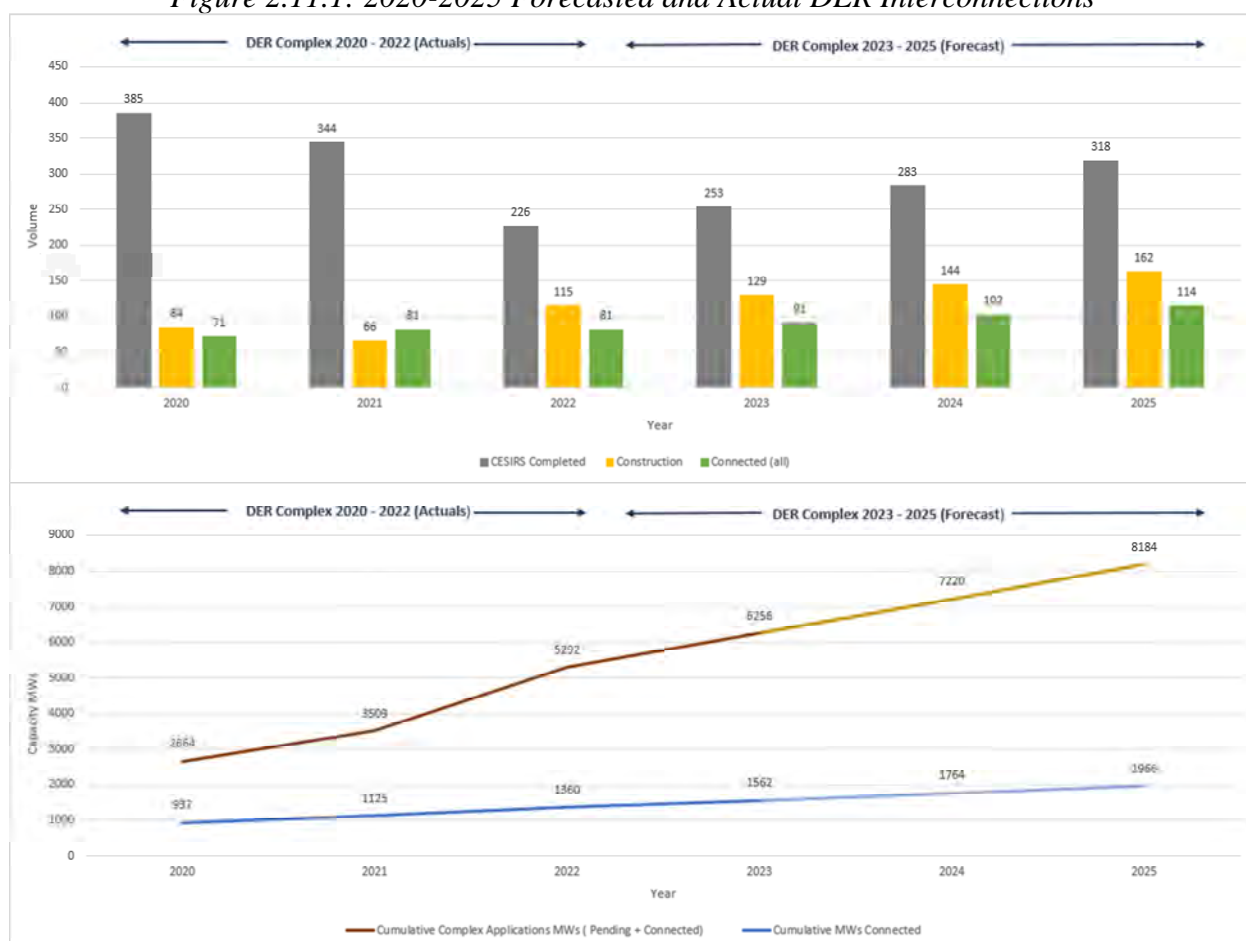
The Joint Utilities participate in monthly meetings with the CDG Billing and Crediting Working Group which are predominantly attended by DER developers and other industry trade associations (e.g., New York Solar Energy Industries Association (“NYSEIA”) and Coalition for Community Solar Access (“CCSA”)). These meetings are facilitated by NYSERDA and DPS Staff is typically in attendance. 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 modest metrics. DPS Staff is expected to issue a proposal for CDG billing and crediting performance metrics and associated NRAs during the second half of 2023.

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 are growing. In 2022, approximately 15% of the DER interconnected was front-of-the-meter ESS. To date, the ESS applications are primarily paired with solar PV.

Figure 2.11.1: 2020-2025 Forecasted and Actual DER Interconnections



In an effort 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 flicker, remote monitoring and control, battery ESS metering architectures, effective grounding, and smart inverter settings. The IPWG explores non-technical issues related to the processes and policies relevant to the interconnection of DER in New York. The IPWG has focused on cost sharing, non-emergency disconnects, the capital project queue, timing of estimates, and minor modifications to projects in queue. The Smart Inverter Working Group has been involved in the development of a Joint Utilities Smart Inverter roadmap. This effort has required research and analysis into the benefits and challenges smart inverters could have on the planning and operation of the grid.

Cost-Sharing 2.0

In 2017 and 2018, National Grid pursued REV demonstration projects to install 3V0 at six substations using a cost allocation methodology for increasing the pace and scale of interconnecting DG systems above 50 kW through upfront investments in common upgrades aimed at removing barriers for DG interconnection applicants. This was a successful demonstration that showed that a pro rata cost-sharing methodology, where developers pay a portion of the total upgrade costs based on the size of their project and the total hosting capacity enabled, could be successful in lieu of the traditional first mover cost. This pro rata concept was subsequently expanded into the Cost-Sharing 2.0 proposal.

National Grid initiated discussions at IPWG between DPS Staff, NYSERDA, 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 July 2021⁶⁶ and made part of the New York State Standardized Interconnection Requirements (“NY-SIR”) in April 2022. The Company posts monthly updates on qualifying upgrade project estimates and payments on the System Data Portal, *available at* <https://systemdataportal.nationalgrid.com/NY/>. 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.

Implementation Plan, Schedule, and Investments

Current Progress

Interconnection Process Working Group/ Interconnection Technical Working Group

In April 2022, National Grid and the other Joint Utilities, in collaboration with the ITWG, DPS Staff, EPRI, and Pterra Consulting, amended the voltage flicker calculation in the template CESIR. The collaboration efforts yielded a new calculation that is anticipated to increase the number of

⁶⁶ Case 20-E-0543, *Petition of Interconnection Policy Working Group Seeking a Cost-Sharing Amendment to the New York Standardized Interconnection Requirements*, Order Approving Cost-Sharing Mechanism and Making Other Findings (issued July 16, 2021).

DER interconnection applications passing the CESIR flicker analysis. The results of the new flicker calculation confirmed that the original analysis was conservative.

To improve transparency of upgrade costs, the IPWG proposed an update to the Construction Milestone checklist template to include an updated Upgrade Cost Estimate within ten business days after the utilities have completed their design work in the event of a significant change in work scope. This change has no impact on payments or the reconciliation process and was approved by the Commission in its April 21, 2023 *Order Modifying Standardized Interconnection Requirements*.⁶⁷

The IPWG proposed additional language for times when a utility requires DER disconnection for non-emergency purposes. This was in response to an industry request to provide more visibility if this was a planned outage or potentially a site-specific issue. The proposed language offers two business days advance notice to customer-generators for all required disconnections of their system to facilitate non-emergency utility work on the electric power system with an indication of anticipated duration. The proposed language was also approved in the NY-SIR Modification Order.

In collaboration with the ITWG, DPS Staff, industry, and the National Grid Salesforce-based web platform team, the Company published a guidance document on its DER application portal page indicating the effective date for the requirement for inverter-based resources to be certified to UL 1741 Supplement “B”. National Grid enforced an effective date of January 1, 2023, that required all new inverter-based resource applications to submit and provide proof of UL 1741 Supplement B certification. The enforcement of the certification was captured within the Salesforce system which is the primary repository for DER information including application documents required by the NY-SIR. The preliminary screen B for certification was updated within Salesforce to show supplement B certification requirements. Additionally, as part of National Grid’s unintentional islanding screening, DER customers have been required to provide evidence of the inverter active islanding detection methods. This information is used to calculate islanding risks associated with the DER in aggregate on an interconnecting circuit.

In December 2022, National Grid in collaboration with the other Joint Utilities, ITWG members, DPS Staff, and industry published a combined document outlining the individual utility-specific inverter specifications regarding new Bulk Power Ride-Through Settings and IEEE 1547-2018 control requirements. This published document provided critical insight to the DER developer community and industry as to the utility-specific functions and created a location to easily locate the setpoints. This published document was created as an extension to each of the Joint Utilities’ existing interconnection technical documentation in order to give the DER community the key data in a single location.

⁶⁷ Case 22-E-0173, *Petition of the IPWG/ITWG Members Seeking Certain Minor Amendments to the New York State Standardized Interconnection Requirements*, Order Modifying Standardized Interconnection Requirements (issued April 21, 2023) (“NY-SIR Modification Order”).

Process Improvements

In November 2022, National Grid deployed a new process to the witness testing and verification procedure for DER interconnections, reducing the resources required at the witness test from Engineering, Operations, and Customer representatives to just Operations. This collaborative effort outlined an efficient procedure to maximize the Company's engineering resources for engineering studies and construction management functions. The new witness test verifications decrease interconnection timelines by overcoming internal resource constraints associated with the large influx of DER studies and construction activities.

Additionally, National Grid has made significant improvements in sharing construction requirements for DER systems interconnecting to the Electric Power System ("EPS"). One of the key improvements is the development of an itemized checklist that is provided to all DER developers that outlines the critical construction requirements for DER systems to be able to safely and reliably interconnect to the EPS. This checklist encompasses construction guidelines and standards for customer systems from all relevant National Grid Electric System Bulletins ("ESBs") in a single document. The developer construction checklist is a manageable document that facilitates proper and efficient construction reviews while allowing a single exchange of communication between the customer and National Grid when identifying deficiencies and inaccuracies in customer construction design packages. This checklist is anticipated to streamline customer construction document reviews and provide the ability to enforce National Grid construction standards consistently across its service territory.

National Grid contractors play a key role in ensuring the changing needs of customers are met so as to enable the clean energy transition. To ensure the Company drives timely interconnections of DER, contractors are leveraged to support construction phase activities, ensuring no impact to the construction phase process or overall interconnection process.

As multiple internal stakeholder teams support the interconnection process for DER customers, National Grid convenes these teams for in-person and virtual roundtable discussions to identify ways to improve efficiency, transparency, internal communication, and the customer experience. Prompted by several years of high activity at year-end to support interconnections, the purpose of these discussions is to explore ways to smooth interconnection activity through the calendar year. While National Grid installed 38% more capacity (MWs) in 2022 than 2021, the interconnections in December decreased by 24% in 2022. These workshops will continue several times a year to continue to provide a forum for more process efficiency ideation.

In addition to recurring meetings as appropriate with DER customers, National Grid hosts longer virtual and in-person workshops to discuss barriers to interconnection, share technical briefs or ESB updates, and collaborate around shared learning to improve the interconnection process for both the customer and utility.

National Grid piloted a low-cost monitoring solution for DER customers to be used specifically for DER projects that do not require a point of common coupling ("PCC") recloser under the NY-SIR but still need monitoring. This was a customer-side solution for generating facilities sized under 500 kW. Initial piloted cases are in service currently. National Grid subsequently transitioned to pilot another form of low-cost monitoring solution that is expected to be more

reliable and achieve the required monitoring for DER systems under 500 kW or where a PCC recloser option is not applicable (e.g., DER paired with facility load). This low-cost monitor solution has been dubbed the “DER Gateway” which utilizes a Schweitzer Engineering Laboratories Real-Time Automation Controller which can be connected to the Company’s EMS network to provide SCADA and remote disconnect functionality. The DER Gateway is expected to provide low-cost solutions to smaller nameplate DER systems and meet the technical requirements needed for interconnection. To date, National Grid has installed the DER Gateway in a small number of locations, one of which includes a secondary-connected DER system behind an existing secondary service where the DER Gateway monitors the DER separate from the site load.

Improved Customer Experience

The Company’s customer organization continues to grow with an emphasis on process improvement to increase the focus on project management and account management activities, such as discussing key developers’ portfolios of proposed renewable energy projects to better inform National Grid’s forecasts for connected MWs. These discussions can dovetail with the account management objective to hold quarterly meetings with senior management from renewable energy development companies.

National Grid’s interconnection specifications, as published in the Company’s ESB No. 756, Requirements for Parallel Generation Connected to a National Grid owned EPS, were revised in January 2023 and are updated on an annual basis to ensure ongoing regulatory compliance and the implementation of best practices. The latest revision of the ESB incorporated key updates related to smart inverter control, setpoints, and performance requirements as dictated by IEEE Standard 1547-2018.

Customer Energy Integration (“CEI”) is evaluating an interactive project management tool to be adapted to the Company’s application portal. This tool would assist in decreasing cycle times through effective project management as it would be used by both the development community along with National Grid distributed generation groups in managing project schedules and milestones. The tool would also provide greater visibility of action items and responsible parties to both the Company and customers.

CEI is reviewing its organizational structure to best serve customers. The CEI organization includes the traditional complex project managers, while having specialists focused on expedited complex projects that have upgrades but do not impact the distribution and Sub-T system, hydro projects seeking a new standalone interconnection agreement and an anticipated growth in Vehicle-to-Grid projects. The appropriate structure will ensure skilled representatives are aligned based on the nuances of each customer’s project.

Future Implementation and Planning

The 2019 CLCPA goals provide clear direction to the New York energy industry on clean energy goals. These goals align with National Grid’s own sustainability objectives. National Grid’s footprint is ideal for complex DER interconnections, particularly solar PV. The Company has connected over 1 GW of distributed solar on the distribution and Sub-T systems through 2022

including 242 MW in 2022. National Grid also interconnected 44 MW of ESS in 2022. The Company continues to partner with DPS Staff, NYSERDA, the other Joint Utilities, and industry at IPWG and ITWG meetings and other venues to focus on solutions to continue driving momentum to interconnect renewable energy to meet the CLCPA goals.

Additionally, National Grid in collaboration with industry and the other Joint Utilities, have created an ESS sub-working group to explore and develop new means to evaluate, model, and interconnect battery ESS to the EPS. The focus of this sub-group is to identify barriers and develop technical solutions to mitigate interconnection constraints and cost-inhibitive factors related to increased DER penetration relative to battery ESS. One of the key barriers to interconnection is the constraints surrounding operational windows for the battery ESS and the ESS sub-working group is targeting improvements to the interconnection studies and progressing towards more specific operational windows besides worst-case studies.

The Energy Storage Roadmap provides clear direction to the New York energy industry on ESS where the goals align with National Grid's own sustainability objectives. National Grid and ITWG/IPWG members support the increasing ESS activity being experienced in the State. National Grid has been experiencing an increase in ESS applications, largely coupled with solar PV, and expect to continue to see a rising volume of ESS in the DG interconnection queue.

In addition to expanding pro rata cost sharing to market-driven projects, Cost-Sharing 2.0 created mechanisms for utility-driven upgrades, including proactive 3V0 and multi-value distribution projects. Multi-value distribution involves reviewing substation projects in the Company's CIP and offering developers an opportunity to contribute to substation project costs to upgrade a given substation project to a larger size so as to create additional hosting capacity. This can be a more affordable path to creating hosting capacity that favors DER development while upgrading assets that are due for work for other needs such as asset condition or reliability.

Clean Innovation Projects

National Grid kicked off a clean energy transformation pilot project called Distributed-Communications in 2021. The project includes three initiatives:

- Piloting cellular direct transfer trip for DER anti-islanding protection.
- Piloting SD-WAN as a lower-cost and scalable alternative to leased Telco-owned MPLS circuits between transmission operator control centers, the NYISO, and DER projects selling power to the wholesale market.
- Piloting communication protocols and grid-edge gateways available to the industry for communication between DERs and DERMS.

In 2022 National Grid selected and installed a cellular direct transfer trip solution in an engineering laboratory for testing. This solution is intended to support the increasing levels of DER interconnecting to the distribution system by offering a lower-cost, more scalable communication solution for direct transfer trip anti-islanding protection. To progress from the pilot stage to the implementation stage, the pilot must prove that cellular communications can be used to meet the anti-islanding requirements of IEEE 1547, while also demonstrating dependability and satisfying cyber security requirements. If adopted, two independent private cellular networks would need to be stood up internally with Verizon and AT&T First-Net. These networks would be dedicated to

this application. A recommendation report based on the effectiveness of the pilot is targeted for end of 2023.

In 2022, Distributed Communications kicked off an SD-WAN pilot project in partnership with National Grid's IT department. The pilot is targeted specifically towards aggregators operating that participate in the wholesale market in support of the launch of FERC 2222. National Grid is seeking collaboration with an existing aggregator for this pilot. National Grid expects the equipment to be installed and the pilot to be operating by end of 2023. The pilot seeks to leverage software-defined network management is to quickly provision and manage network devices for DER-related communications. Recognizing an increased need for external third-party communications over secured and scalable network, this will use 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 their aggregation point, the transmission operator control centers, and the NYISO. The ability to offer such a solution is being encouraged the NYISO as the existing leased Telco MPLS circuits used today are expensive and slow to install. If the pilot is successful, SD-WAN will be considered for other green energy applications in need, such as ARI (as covered in Section 2.1, Integrated Planning) and DER to DERMS communications.

Distributed Communication's third initiative is not as advanced as the others. National Grid has hired an engineering firm, QualityLogic, to assist in the evaluation of different communication protocols, interoperability, and requirements for grid edge gateways. Defining reliable and affordable dispatch communication requirements will inform DER dispatch and control for a more interactive grid. The Company plans to work with QualityLogic on setting up the necessary equipment in an engineering laboratory to facilitate the evaluation of different protocols and use cases. If this initiative yields positive results, implementation will support stakeholders by allowing the distribution system operator and DERMS roadmaps to be executed.

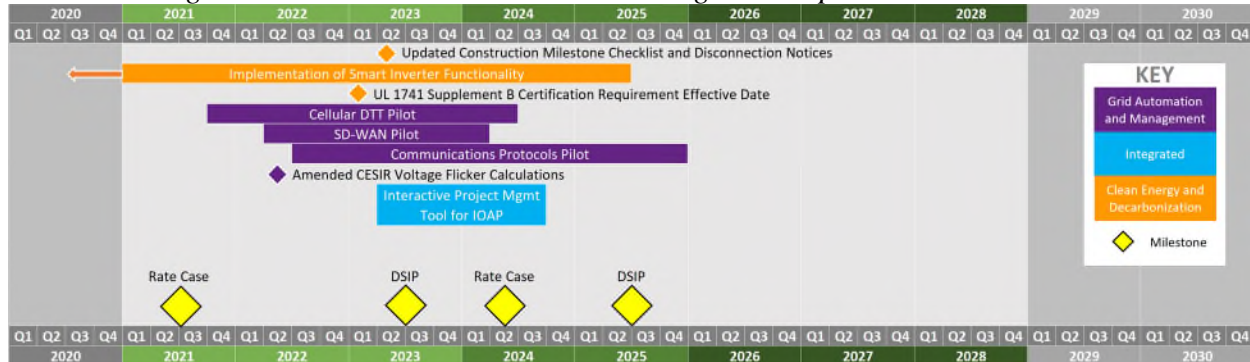
Solutions

The Company seeks creative solutions to interconnect DERs. For projects other than solar PV, National Grid has explored nighttime export options, where such projects generate when solar PV projects interconnected to the Company's EPS are not generating. This type of flexible interconnection can allow more wind, farm waste, or ESS projects on circuits that are saturated with solar PV.

National Grid actively participated in discussions on smart inverter functionality through the Joint Utilities' Smart Inverter Working Group. The Company, in collaboration with ITWG members, DPS Staff, industry, and the other Joint Utilities was a key contributor to identifying and publishing recommended unattended control functions such as Volt-Var and Volt-Watt control modes. National Grid is actively participating in discussions involving the next phase of the smart inverter roadmap where the Company will be a key contributor to identifying the advanced functions requirements and interactive settings for smart inverter functionality. National Grid will continue to work with key stakeholders to develop interactive settings for incorporation into the technical interconnection documents.

National Grid recognizes the need to evaluate and implement means to reduce interconnection timeline and costs. In addition to DER Customer workshops, the Company is assessing current internal process steps and durations to develop plans to decrease interconnections timelines in the short and long term. Decreasing study and construction periods allows more DERs to interconnect, aligning with the clean energy goals of both the state and National Grid. As mentioned earlier, ARI and Cost-Sharing 2.0 are methods to help mitigate the costs of interconnection. National Grid will work with the other Joint Utilities to collaboratively identify additional approaches and policies to manage the cost of DERs interconnecting to the distribution system.

Figure 2.11.2: DER Interconnections Integrated Implementation Timeline



Risk and Mitigation

The DER customer activity in the National Grid service territory has resulted in over 1.5 MW of DERs interconnected on the Company's distribution grid. Earlier interconnected projects often targeted locations that did not require costly utility infrastructure upgrades. As more projects enter the queue, more utility upgrades are required, leading to higher costs and interconnection times due to more substantial utility upgrades. This raises the risk of reduced interest by DER developers to site projects in the National Grid service territory. To mitigate this, the Company continues to champion policies and methods to facilitate interconnections, such as ARI and Cost-Sharing 2.0.

Table 2.11.1: 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 ARI and Cost-Sharing 2.0.

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 state's 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.

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 New York 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 the normal course of business.

Each stakeholder in the DER interconnection process is supporting the overall goal of meeting and exceeding New York's 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.

DER interconnections are 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. National Grid 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 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 involved in the process.

2.12 Advanced Metering Infrastructure

Context and Background

AMI, commonly referred to as smart meters, is foundational to New York’s energy future. AMI transforms the relationship between National Grid and its customers, providing access to new products and technology, while incentivizing customers to actively participate in energy markets, manage energy consumption, and control costs. Granular, time-series data from smart meters and other intelligent devices at customers’ premises enable advanced analytics, innovative rate designs, and customer engagement strategies that benefit both the customers and the grid.

From a grid perspective, smart meters provide monitoring and granular data, enhance grid operations, and provide additional control capabilities that are the foundation of a modern distribution system. Voltage sensing and measurement functions support increased system efficiency and enable improved outage detection and restoration processes. AMI capabilities also support DER measurement, monitoring, and control, which is essential for DER integration.

Since the 2020 DSIP Update filing, the Company has made significant progress in its journey towards AMI implementation. National Grid had previously filed a report on November 15, 2018, seeking implementation of AMI throughout National Grid’s electric and gas service territories (AMI Report).⁶⁸

On November 20, 2020, the Commission issued an order formally approving National Grid’s AMI plan with modifications (“AMI Order”).⁶⁹ The AMI Order 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. Additionally, National Grid’s Massachusetts affiliate received approval for 1.4 million electric AMI meters in the state of Massachusetts. Learnings from both Upstate New York and the Massachusetts AMI deployment will be utilized for the benefit of both service territories and their customers over the course of the meter roll-out across the two regions.

The below sections describe in more detail the actions the Company has taken since the issue of the AMI Order toward deployment and implementation, including engagement with stakeholders, plans for future implementation, and risks and mitigation. It will also outline how the

⁶⁸ Cases 17-E-0238 and 17-G-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”), Report of Niagara Mohawk Power Corporation d/b/a National Grid on the Proposed Implementation of Advanced Metering Infrastructure (filed November 15, 2018) (“AMI Report”).

⁶⁹ National Grid Electric and Gas 2017 Rate Case Proceeding, Order Authorizing Implementation of Advanced Metering Infrastructure with Modifications (issued November 20, 2020) (“AMI Order”).

transformational investment will enable benefits for customers and address operational needs while providing meaningful contributions toward the clean energy goals set forth in the CLCPA.

Implementation Plan, Schedule, and Investments

Current Progress

Regulatory Milestones

On November 15, 2018, the Company filed its AMI Report seeking implementation of AMI throughout National Grid's electric and gas service territories in UNY.⁷⁰ The AMI Report was a requirement in the rate order issued in the National Grid Electric and Gas 2017 Rate Case Proceeding. The AMI Report included National Grid's business case for implementing AMI (AMI Business Case), a BCA model, and a Customer Engagement Plan that discusses the Company's plans for customer outreach and education.

On November 20, 2020, the Commission issued the AMI Order⁷¹ formally approving National Grid's AMI plan with modifications.

On January 19, 2021, National Grid filed its AMI Benefits Implementation Plan⁷² in accordance with the AMI Order, with the intent to maximize the value of the AMI investment across benefits categories of avoided O&M costs, customer benefits, and avoided program costs.

On May 20, 2021, National Grid filed a revised Customer Engagement Plan,⁷³ as directed by the AMI Order, defining the Company's strategy for educating customers about smart meter technology, empowering and enabling them to derive the greatest value from the new functionality, and preparing employees to guide customers through the transformational journey.

The Company is now on a cadence of filing Semi-Annual Metrics Reports in accordance with the AMI Order, the latest of which was filed on May 31, 2023.⁷⁴

Deployment Milestones

Following the AMI Order, the Company launched its implementation efforts in June 2021. Since that time, the AMI team has been involved with extensive planning activities, process workshops, detailed design, and back-office system implementation. Dedicated National Grid AMI project resources have been onboarded and they have been working closely with both Landis+Gyr

⁷⁰ National Grid Electric and Gas 2017 Rate Case Proceeding, *supra*, note 68.

⁷¹ National Grid Electric and Gas 2017 Rate Case Proceeding, *supra*, note 69.

⁷² National Grid Electric and Gas 2017 Rate Case Proceeding, National Grid Advanced Metering Infrastructure (AMI) Benefits Implementation Plan (filed January 19, 2021) ("AMI Benefits Implementation Plan").

⁷³ National Grid Electric and Gas 2017 Rate Case Proceeding, National Grid Advanced Metering Infrastructure Customer Engagement Plan (filed May 20, 2021).

⁷⁴ National Grid Electric and Gas 2017 Rate Case Proceeding, National Grid Advanced Metering Infrastructure Semi-Annual Metrics Report (filed May 31, 2023).

(“L+G”), meter, module, field area network (“FAN”), and professional services vendor, and Ernst & Young, business integrator, after significant contracting efforts.

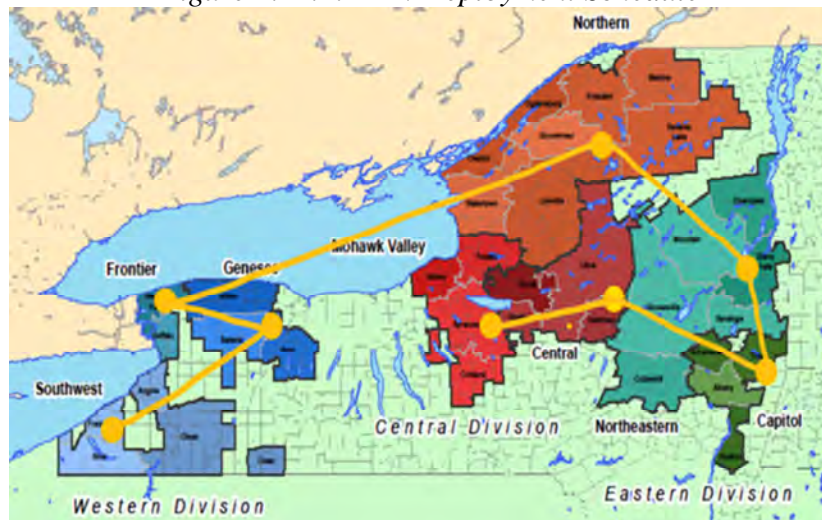
One year after kickoff and in alignment with the project’s agile methodology, National Grid successfully completed a small installation and demonstration of the AMI capabilities in June 2022. This demonstration was referred to as MVP and involved the installation of five Revelo 2S electric meters at the homes of volunteer customers, who also happen to be National Grid employees.

In addition to the five meters, field area network equipment was installed on nearby distribution poles in order to collect electric usage information and backhaul this data to National Grid. The specific meters installed had yet to receive Commission approval (which was subsequently obtained in October 2022), and thus a dual socket was utilized to maintain both automated meter reading and AMI readings. The dual sockets have since been removed and meters were replaced with the Commission-approved models. Since installation, the volunteer customers have successfully completed all consecutive billing cycles.

In December 2022, the AMI project team completed another significant contracting effort when they onboarded Utility Partners of America (“UPA”). UPA is a turnkey vendor who brings extensive experience with AMI deployments across the United States and will perform the vast majority of electric meter and gas module installations on behalf of National Grid. In addition to meter and module installations, UPA will provide scheduling support and reminder notifications, facility and inventory management, and integrated work order management services.

Field area network (“FAN”) deployment was successfully initiated in February 2023 in areas just south of the city of Syracuse and continues today in the Company’s Central Division. Prior to installation of the FAN devices, an initial desktop network design was provided by L+G and National Grid developed standards and work methods to be leveraged by overhead line resources conducting the installations. L+G has conducted extensive field surveys to help validate the proposed locations per the network design.

Additionally, National Grid has contracted with CHA Consulting, Inc. to perform the National Grid survey work and designs for make ready work and installation. The Company is intentionally building out the FAN well in advance of planned electric meter and gas module installations to provide the program with additional flexibility. The AMI team expects to complete FAN installation in CY 2025 whereas meter and module deployment will continue into 2027. The program is currently on track to meet this deployment schedule. Following is an illustration of the FAN deployment plan (subject to change) where National Grid directionally expects to progress deployment in the Central Division, move to the Eastern Division, and then complete FAN deployment in the Western Division.

Figure 2.12.1: FAN Deployment Schedule

In April 2023, the program initiated an electric-only “soft launch” in advance of mass deployment. Similar to the MVP, a soft launch is intended to demonstrate AMI capabilities while continuing to test and validate all of the end-to-end system integration and deployment processes that have been put into effect over the past several months. Soft launch involves the deployment of approximately 5,000 electric meters, whereby the program will ramp-up slowly toward steady state as the Company continues to test new capabilities and functionality. Soft launch was started with internal resources only, and National Grid is in the process of integrating UPA into the deployment mix.

In parallel with the above-described deployment activities, National Grid and L+G continue to work with the Commission to obtain regulatory approval for the various electric meters and gas modules needed to accommodate the upstate NY deployment. Multiple electric meter and gas module petitions have been submitted and as previously mentioned, the Commission approved L+G’s Revelo E360 metering line in October 2022. This metering line covers the entire population needed for soft launch, and approximately 94% of the electric meter installations required.

Support for Stakeholder Needs – A Collaborative Deployment Approach

National Grid’s agile and collaborative approach to AMI deployment has been critical to engaging customers and stakeholders. By starting small with the MVP demonstration and engaging customers early in the process, the Company has been able to learn as it goes, generating valuable insights along the way. Three examples highlight this approach:

First, the Company has proactively engaged communities prior to deployment via town all meetings in Albany, Buffalo, and Syracuse, generating insights to be used to build and design around real customer feedback. Responses from those town halls on how AMI could be helpful to customers included:

- “Saving money and energy. Money can always be saved for something else...”
- “The ability for the power company to spot and correct outages readily.”
- “It’s gotta be a huge help for knowing the power outage locations.”
- “It gives you a better handle on how you’re using your electricity, save you some money.”
- “I think knowledge is power and if I know what I’m using, I can have some control.”

- “If I can save money and reduce the stress on the electric grid, those are things that I would like to do.”

Second, in preparation for the installation process and Phase 1 of the customer journey, the Company conducted customer needs research within the Buffalo, Syracuse, and Albany regions. This research included three focus groups covering seventy-three National Grid customers and twenty-six in-depth interviews with customers representing four vulnerable population groups (Seniors, income eligible, medical hardship, and Spanish speakers). Overarching reactions to smart meters – including key benefits and concerns – were similar across customers groups with whom this research was conducted:

- Customers have very limited knowledge/awareness of smart meters but have an overall positive reaction to the technology when given a description.
- Customers have a desire for more control over their energy usage, although it is not something they think about on a daily basis.
- Benefits that resonate the most with customers include potential cost savings, real-time access to detailed usage information, usage alerts, and personalized recommendations. Benefits related to service and reliability, such as real-time outage notifications, are also very appealing.
- While customers had very positive reactions to the benefits of the technology, questions about cost to the customer, data privacy, and customers’ options did come up.

The general population focus groups leveraged dial-testing on how to communicate effectively with residential groups. For example, National Grid learned that messaging must remain centered on savings and how smart meters can help customers manage/lower their bills. In addition, the Company utilized its Customer Council Research Panel to test messaging concepts with 960 residential and sixty-two business customers.

The research with vulnerable populations explored reactions to installation processes and the customer’s option to opt out in greater depth. Customers found the installation processes to be straightforward and expected. The research confirmed that customers expect to be notified in advance, preferably via text and email reminders, and to be told how long their power will be disabled so that they can be prepared. Most customers are unlikely to opt out, even before learning about the fees associated with doing so but did expect clarity around the fees and reasoning behind the fees. The Company has incorporated these lessons into its communications plan and materials, including its Welcome Brochure.

As National Grid deploys smart meters across its service territory, it will conduct research with customers to continuously monitor the customer experience, customer’s awareness of smart meters, and their overall sentiments. In December 2022, the Company signed a contract with Escalent as its research vendor to conduct this tracking research with drafting of survey questionnaires underway.

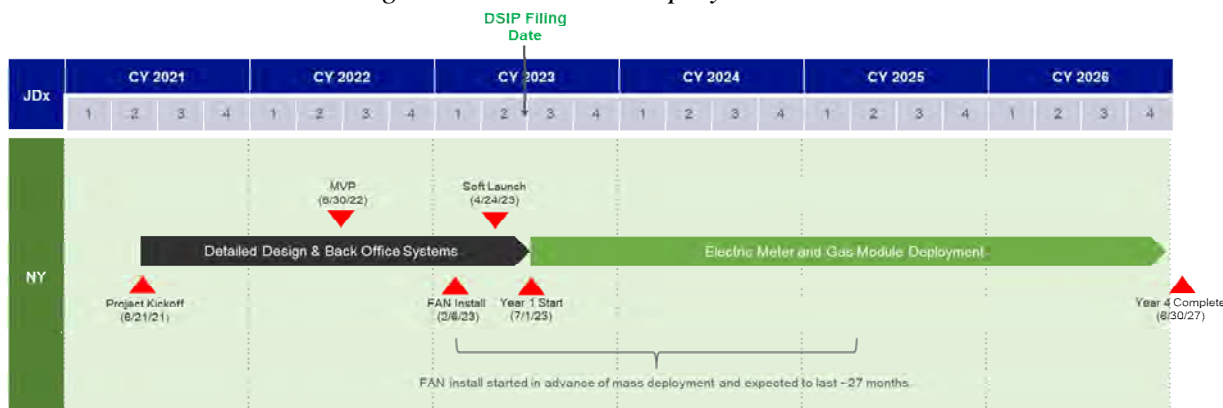
Third, National Grid constructed an “AMI Smart House” in 2022 to be a fully functioning house showcasing AMI technology at its Syracuse / Henry Clay Boulevard facility. The Smart House has been an important tool for showcasing AMI technologies, demonstrating smart home

integrations, testing new digital customer products, live simulations, trainings, and internal stakeholder engagements.

Future Implementation and Planning

As mentioned above, the Company has entered a soft launch period during which National Grid continues to test new functionality and ramp-up toward steady state. The expectation is that soft launch will provide valuable lessons learned and the ability to refine processes and capabilities. As processes and capabilities are refined, the Company will continue to scale deployment. Over the four years of planned electric meter and gas module deployment, National Grid has committed to deploying 20% of the endpoints in year one, 35% in years two and three respectively, and 10% in year four (see meter deployment timeline below).

Figure 2.12.2: Meter Deployment Timeline



Customer Benefits and Stakeholder Needs

With the deployment of AMI, customers will benefit from a significant improvement in visibility, control, choice, and convenience in their energy experience. AMI enables a modern customer experience by providing granular, time-variant energy price signals, which enables a reduction in energy consumption and usage shift from high-cost periods to lower cost periods, while also driving system savings.

That granular energy usage information will also provide more actionable information, enhanced energy management including energy usage alerts and personalization tools, enablement of smart-home devices, better access to outage information, remote connect and disconnect of services, access to third-party services, and eventually new and innovative pricing options that can help customers manage energy costs.

Time-Varying Pricing

AMI deployment enables National Grid to provide time-varying pricing ("TVP") to customers. In the AMI Business Case, the Company modeled TVP benefits to customers as savings derived from avoided supply costs. These savings may result from reduced energy consumption, or more likely, shifting usage from higher priced periods to lower-priced periods. TVP is a critical component of meeting the goals and objectives of the CLCPA in a cost-effective fashion.

The number of customers who participate in a TVP program are a key input in determining the actual magnitude of the associated benefits. Generally, more participants will yield higher benefits. For this reason, the Company's preference is to work with stakeholders and the Commission to ultimately propose an appropriate TVP package as a default (i.e., opt-out) rate. In general, opt-out rates have far higher participation than those that require an affirmative choice from customers to "opt-in." However, the Commission's AMI Order approved the Company's AMI deployment based on an opt-in scenario for TVP, which reflects savings based on costs related to electric supply. Thus, to deliver this benefit, the Company must propose and receive approval for an opt-in rate that generates benefits equal to those modeled in the AMI Business Case.

After the Company has completed the back-office systems work and associated training, it plans to propose an opt-in supply rate, or suite of TVP rates, that will produce benefits that equal or exceed those modeled in the opt-in TVP case. The Company is also currently evaluating opportunities to test out existing voluntary TVP rates in some of the earlier stages of AMI deployment to drive customer benefits and generate learnings for future TVP rate design.

Customer Engagement

Customer engagement will be critical to the success of AMI deployment. As detailed in the Company's customer engagement plan, its approach focuses on three phases.

First is customer awareness (Phase 1). In this phase, the Company will inform customers about smart meters and begin the conversation about how the technology can improve the customer energy experience. Second is deployment (Phase 2). As National Grid begins to deploy the AMI electric meters and gas modules, it will step up efforts to prepare customers for installation. This strategy involves a 90-60-30-day pre-deployment plan for communicating with customers and answering questions.

Third is empowerment and enablement (Phase 3). The next-generation capabilities of the AMI technology can open the door to myriad benefits for customers, such as enhanced access to energy usage data, high-usage alerts, personalized EE recommendations, remote service connections, and enhanced outage management. It also enables the Commission to consider and approve future innovative pricing programs (e.g., time-of-use rates). The third phase represents the Company's ongoing commitment to help customers realize the benefits.

National Grid intends to file an AMI Remote Re-establishment and Disconnection Fee which will represent at significantly lower cost to customers to reconnect service after being disconnected for non-payment, and for seasonal customers to reconnect and disconnect service, once the AMI remote connect/disconnect functionality is enabled. The Company plans to file a petition for approval of the new fee in the summer of 2023.

In regard to innovative rate designs, prior to full deployment of AMI, it is expected that the Commission will issue an order approving the Company's July 14, 2022 revised standby and buyback service rates filing⁷⁵ made in compliance with two March 16, 2022 Commission orders

⁷⁵ VDER Proceeding, National Grid Draft Tariff Leaves and Other Compliance Items (filed July 14, 2022).

(Orders”).⁷⁶ The Orders expand the Company’s standby service rate (SC-7), which is a demand based time-of-use rate, to become a fully opt-in rate for all customers. Other requirements include making the SC7 rates demand-based for mass market (parent SC1 and SC2 non-demand) customers (using a 60-minute integrated demand), introduction of a summer super-peak period, and the requirement that all SC7 customers be billed hourly supply rates if taking supply from National Grid. The Orders also establish buyback charges for customers selling energy to the Company under the SC6 tariff.

Figure 2.12.3: Customer Engagement Sample



AMI and Future DSP Evolution

AMI plays a foundational role in delivering DSP benefits to customers, such as enhanced demand response and EE programs, innovative rate structures, allowing customers to better manage electricity consumption and bills, and driving overall system efficiencies. Moreover, AMI will facilitate customer access to value-added products and services provided by third parties including DER providers and energy services companies.

AMI will enhance National Grid’s existing and future Distribution Automation Program, such as VVO and FLISR, and also allow for new programs to be developed. AMI data can be linked to existing VVO schemes to enable the centralized control to pull near real-time customer voltage data to more accurately control the voltage loops of the schemes. Using customer endpoint data in the VVO schemes is anticipated to improve the energy consumption reduction by approximately 1%.

As AMI meters can read and report usage data multiple times a day, they can act as end-of-line sensors to support centralized VVO control systems via integration with ADMS and meter data management services (“MDMS”). The VVO control systems can then make voltage and reactive power adjustments to optimize the distribution system voltage and power flows to reduce power consumption on the grid.

⁷⁶ VDER Proceeding, Order Establishing an Allocated Cost of Service Methodology for Standby and Buyback Service Rates and Energy Storage Contract Demand Charge Exemptions (issued March 16, 2022) and Order Directing Standby and Buyback Service Tariff Filings (issued March 16, 2022).

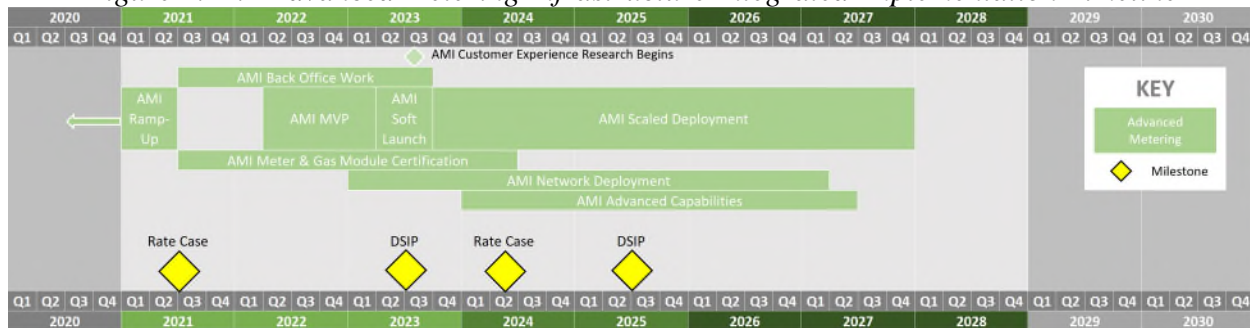
Through the integration of AMI voltage data with the VVO solution, additional voltage optimization can be achieved, resulting in additional efficiency and savings. Without this AMI integration the VVO must maintain a larger safety margin based on its very limited voltage reading feedback from the distribution system to ensure customer voltages are maintained with the ANSI C84.1 range. Having the AMI voltage readings at every customer premise located on the VVO scheme reduces the need for this safety margin.

The following table summarizes how AMI can help address key DSP-related planning and operations challenges:

Table 2.12.1: AMI Capabilities to Address Key Planning and Operations Challenges

Planning and Operations Challenges	AMI Solution / Improvement
Customer satisfaction to improve reliability	<ul style="list-style-type: none"> • Integration of AMI to ADMS-OMS to identify faulted devices quicker and verify customer power if restored
Inefficiencies in current work processes	<ul style="list-style-type: none"> • Track service transformer loading to prevent overloads • FLISR fault location identification and improved load transfers for quicker restoration
Need to improve DER grid integration	<ul style="list-style-type: none"> • Ingestion of AMI granular data into short-term forecasting algorithms to improve accuracy • Communications to BTM DERs via AMI to increase grid integration and market participation • Load disaggregation of BTM assets, including DERs for improved monitoring and to validate market performance
Lack of data granularity leads to conservatism, resulting in inefficient planning and operating the grid	<ul style="list-style-type: none"> • Use AMI data to better plan service transformer replacements • Integration of AMI voltage data into VVO algorithms to gain capacity and energy reduction benefits • Integration of AMI voltage data into voltage optimization algorithms to gain capacity and energy reduction benefits • Import AMI data into CYME model for improved planning model accuracy and into long-term forecasting algorithms to improve algorithm accuracy • Capture AMI data at sufficient granularity to identify customer power quality issues and reduce complaints

Figure 2.12.4 Advanced Metering Infrastructure Integrated Implementation Timeline



Risks and Mitigations

Table 2.12.2: Risks and Mitigations for Advanced Metering Infrastructure

Risk	Mitigation
Supply chain issues may impact an accelerated FAN deployment. (Soft launch AMI areas are not at risk as they are complete.)	Engaging vendors to advance procurement of materials to prevent scheduling delays. Escalated discussions in-flight with L+G. Watch item for all program assets and planning for increased lead time to assure to no program or budget delays.
Resource challenges arising around recruitment of staff and identification and availability of SMEs.	Continue to strategize on new ways to bring in quality resources. Dedicated recruitment lead/consultant in place to help navigate next six months' recruitment.
No funding currently available to implement DSP-AMI capabilities.	Considering proposals for upcoming rate case.
National Grid access to customer load disaggregation data to implement DSP-AMI capabilities will require Commission approval.	Seek Commission approval for access to load disaggregation data.
The L+G gas modules are not available for the start of scaled deployment thus requiring revisions of the current module strategy for National Grid AMI project.	Year One plan adjusted to pull forward electric-only deployments. Complete full impact assessment and share with key stakeholders before implementing additional contingency plans.

Alignment with CLCPA Goals

The Company believes that AMI deployment presents a once-in-a-generation opportunity to align key clean energy policy goals such as those set forth in the CLCPA with operational requirements, while delivering customer benefits through a modernized grid.

By investing in AMI, National Grid will be taking a key step toward achieving REV and CLCPA objectives. AMI supports implementation of the Energy Storage Roadmap and provides a cost-

effective solution for NEM successor tariffs' metering requirements. AMI will also improve the Company's DSP provider capabilities. In this role, the Company will construct, operate, and maintain highly integrated technology platforms, enhancing the incorporation of third-party owned DERs, which can include DR, EE, ESS, and DG. These technologies will be tightly integrated into the Company's distribution infrastructure.

When AMI meters have been deployed and the associated back-office infrastructure is in place, customers will have access to more granular usage data in near real-time. The frequency of the readings, combined with the granularity of the data, will enable customers to take control of their energy usage through EE, energy conservation, DR, and new pricing programs.

The pathway to achieving the goals set forth in the CLCPA requires a multi-faceted strategy that accelerates decarbonization of the electricity sector, electrification of the transportation sector, and the transformation of the heating sector through EE and electrification. AMI plays a critical role in all three of these areas.

First, by enabling energy insights, targeted EE, and DR, as well as time-varying rate structures, AMI is key to reducing peak load in furtherance of the CLCPA's GHG emission reduction goals (i.e., 40% reduction in GHG emissions from 1990 levels and 85% reduction in GHG emissions from 1990 levels). Likewise, the system information produced by AMI (e.g., identifying areas of high demand and lower voltage) can facilitate increased integration of DERs, such as solar PV, which will help reach the CLCPA's goal of installing 6,000 MW of solar generation by 2025.

Second, by facilitating the development of more cost-reflective rates for supply and delivery, AMI can play an important role in the adoption of EVs and electric heat pumps. Finally, the proposed implementation of AMI-compatible gas modules provides helpful insights into natural gas usage that can lead to reduced consumption and further aid in the adoption of electric heat pump technology. Overall, the customer and system insights provided by a foundational investment in AMI will put National Grid, its customers, and the State on a trajectory to meet the CLCPA's ambitious clean energy goals.

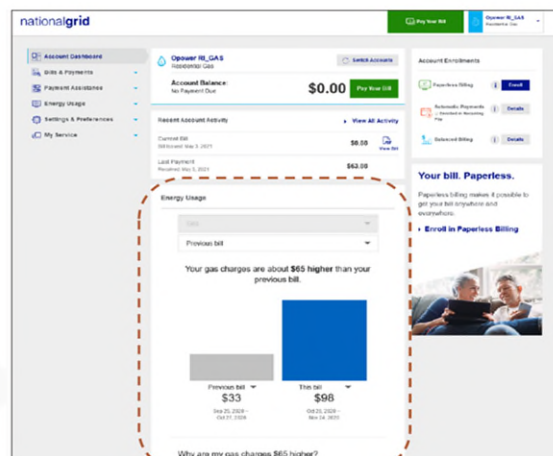
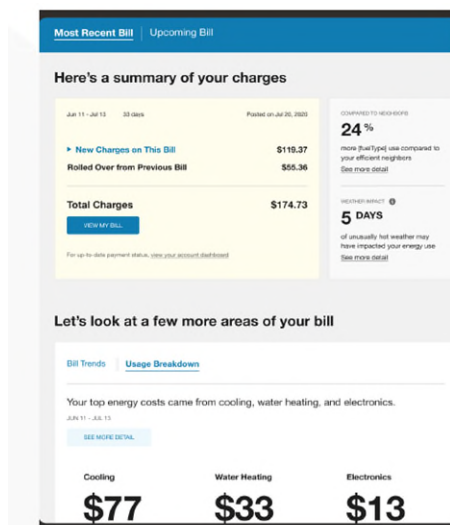
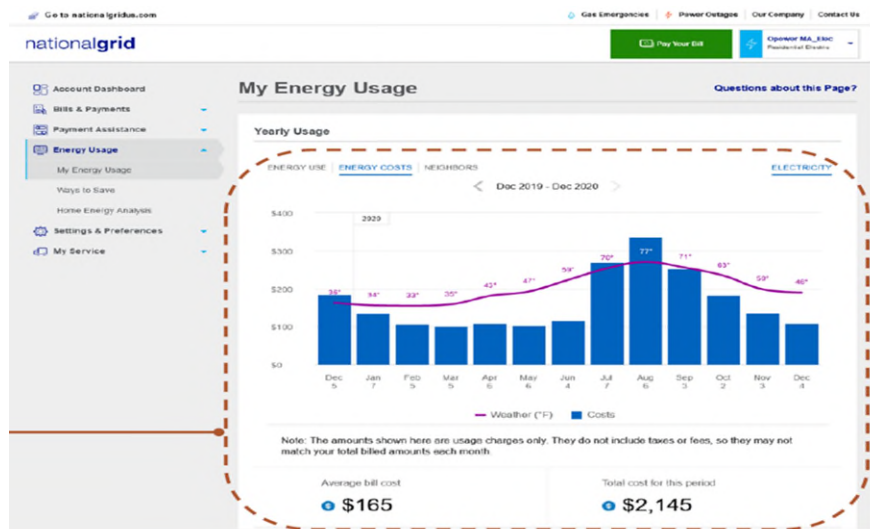
Load Disaggregation

The new AMI meters will be equipped with Sense load disaggregation technology, which when connected to a Home Area Network via WiFi can provide more granular appliance-level energy data for customers. Customers can also access high-level energy load disaggregation via the Customer Energy Management Portal ("CEMP") on the National Grid website. This same high-level load disaggregation will also be made available to the Company's customer service representatives for customers that wish to call into service centers with questions regarding their energy usage and bills.

Load disaggregation will provide significant customer benefits, including higher control and automation, improved energy management, and increased home awareness and reliability. For National Grid, the Sense integration enables a customer engagement platform that can drive better EE and peak demand management outcomes, as well as improved operational information that can lead to system management benefits and greater customer savings.

The CEMP website is now live. Below are screenshots of the CEMP website, which has an AMI data display available for AMI customers as an initial feature. Development of the CEMP website will continue under an iterative approach, with features available over time as the meters and back-end billing systems come online.

Figure 2.12.5: Sample CEMP Interfaces



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Figure 2.12.6: Sample Sense mobile platform

Stakeholder Interface

As described above, AMI is foundational to New York's energy future. It will enable customers to better manage energy consumption, control costs, and access new products and technology. The data generated by AMI meters provide basic and foundational information for seamlessly integrating DERs and modeling their behavior. AMI information will be able to support multiple DER use cases to include interconnection, forecasting, ESS integration, EV integration, hosting capacity, and NWAs.

National Grid's agile and collaborative approach to AMI deployment has been critical to engaging customers and stakeholders. By starting small with the MVP demonstration and engaging customers early in the process, the Company has been able to learn as it goes, generating valuable insights along the way via town halls, focus groups, and the build of the AMI Smart House to showcase AMI technologies and engage stakeholders. Looking forward, the Company plans to follow its Customer Engagement Plan throughout the three phases of AMI deployment: 1) marketing, education, and outreach; 2) deployment with a 90-60-30-day plan to engage customers when meters are being deployed; and 3) empowerment and enablement to assist customers with realizing the benefits AMI offers.

2.13 Beneficial Locations for DERs and Non-Wires Alternatives

Context and Background

The impacts of DERs vary greatly depending on where they are placed on the distribution system. National Grid endeavors to identify where DERs may provide benefits to the electric delivery system through its integrated planning process and shares that information on the System Data Portal. National Grid defines a beneficial location as a location where DER integration can reduce, delay, or eliminate the need for electric system upgrades, enhance reliability and/or increase efficiency of the electric system. There are multiple procurement and compensation mechanisms that rely on accurate assessment of beneficial locations. To date, National Grid 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 ESS dispatch rights and novel, targeted DLM programs). For more information regarding ESS programs, please refer to Section 2.4, Energy Storage Integration, and Section 2.7, Energy Efficiency Integration and Innovation. The beneficial locations associated with NWAs, LSRV, and bulk power ESS 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 DERs 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 average and peak demands, 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 website⁷⁷, 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 Commission's website, in addition to being available on National Grid's Ariba procurement system. DPS Staff and other stakeholders are regularly apprised of the status of potential NWA projects.

⁷⁷ Available at <https://www.nationalgridus.com/Business-Partners/Non-Wires-Alternatives/>

National Grid evaluates RFP responses to proposed NWA opportunities considering both economic and technical dimensions. The Commission’s BCA Framework Order,⁷⁸ explained in more depth in National Grid’s BCA Handbook,⁷⁹ 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	Project completion a minimum of eighteen months prior to the date of the system need
Cost Suitability	Greater than or equal to \$500K

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.

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 Chapter discusses National Grid’s current capabilities and multi-year roadmap. Beneficial locations are increasingly driving DER deployment as National Grid has completed twelve evaluations for NWA opportunities. The Company has taken many steps to implement and refine its NWA RFP process. To date, National Grid has issued twelve RFPs. The following table summarizes the RFPs released between the filing of 2020 DSIP update and the 2023 DSIP update that are still actively being pursued by the Company.

⁷⁸ REV Proceeding, Order Establishing the Benefit-Cost Analysis Framework (issued January 21, 2016) (“BCA Framework Order”).

⁷⁹ REV Proceeding, Niagara Mohawk Power Corporation d/b/a National Grid – Version 3.0 Benefit-Cost Analysis (“BCA”) Handbook (filed June 30, 2020).

Table 2.13.2: Status of National Grid's 2020-2023 NWA RFPs through Competitive Solicitation

Project Name	Status	Voltage Type	Estimated RFP Timing (CY)
Sawyer 11H Sub-T Line <i>Former Buffalo 23 kV</i>	Planner Review	Sub-T	RFP Closed
Rensselaer (Forbes Ave) New Substation & D-Line	Planner Review	Distribution / Sub-T	RFP Closed
Watertown New 115 / 13.2 kV Substation	Construction	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, the Company will continue to file the quarterly reports and implementation plans to provide updates. Additionally, the Pine Grove NWA project is complete and operational.

Rensselaer

On January 23, 2019, National Grid issued an RFP seeking proposals for a third party-owned NWA solution with no viable proposals received. On January 29, 2021, the Company released a second RFP again seeking proposals for a third party-owned NWA solution. Again, no viable proposals were received. National Grid is reassessing the need in the area and looking to potentially release an RFP for a utility-owned solution due to site control being an issue for third-party solutions.

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 had increased to a level at which it was projected to be overloaded to 100% (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 this NWA solution will be detailed in the Company's NWA quarterly reports.

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 had increased to a level at which it was projected to be overloaded to

100% (or higher) of its emergency rating (upon an outage of one of the two station transformer banks). The Company evaluated alternatives similar to that proposed for the Pine Grove NWA and a contract was executed with a third-party developer. The NWA solution under construction is a solar and battery installation that will meet the 5.7 MW / 40 MWh need. The NWA solution is expected to be in-service by Q1 2024.

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 had increased to a level at which it was projected to be overloaded to 100% (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 in order 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 battery ESS was 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 battery ESS. The Pine Grove NWA solution is operational with dispatch expected to commence in the summer 2023.

RFP Process Improvement and Lessons Learned

Throughout 2020 to 2023, RFPs were further improved by:

- Updating the RFP template so that bidders have a more clear understanding of the project such as clarifying technical needs.
- 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 investigate/pursue financing options prior to proposal submittal.
- Discussing contract structure and performance expectations in the RFP and evaluation process with the active bidders.
- Using of a standard template to provide a common format across all RFPs.
- Having the Company assume real property acquisition responsibility.
- Including 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.
- Including performance expectations and how they relate to the telemetry.
- Providing greater clarity for NWA contract terms and performance expectations for third-party ownership.
- Continuing improvements to the BCA tool to ensure NWA benefits are appropriately considered.

- Increasing collaboration between the Company's DR programs and EE programs.
- Drafting a process to dispatch third-party NWA assets that include battery ESS through a real time centralized dispatch protocol. This language will be added to future RFPs.

During the proposal review process, National Grid provides individual vendor and group updates through the procurement platform for both updates to individual bid status and questions and answers applicable to all bidders.

Vendor Stakeholder Procurement Platform

In 2022, National Grid embarked on a procurement pilot with a third-party vendor. During the pilot the procurement team will be using the Piclo Flex platform to release RFPs in 2023. 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 in lieu of using the Ariba system. 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. The Company is in the process of evaluating the use of an EE kicker for additional opportunities.

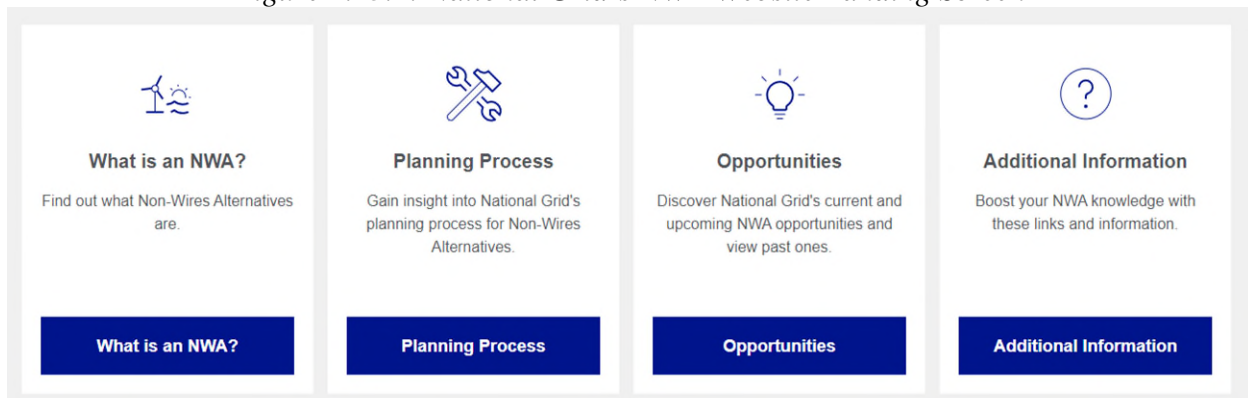
Contracting

The Company is working with a third-party consultant to revise the current NWA contract template. The goal of this effort is to decrease timelines associated with RFP development, evaluation, and contracting. The consultant will also offer feedback on the template from a non-utility perspective. Additionally, the contracted template update will provide vendors with more detail on the service requirements, potential liquidated damages, and liability requirements. This should enable bidders to provide more confident pricing when responding to an RFP.

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 landing screen shot is captured in Figure 2.13.1 and the website link is *available at* <https://www.nationalgridus.com/Business-Partners/Non-Wires-Alternatives/>.

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 Ariba procurement platform and enrollment instructions
- Links to the National Grid System Data Portal

The website content will be refreshed periodically with specific project information and other information beneficial to potential bidders. The Company has also established a new 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 generally monitors this NWA mailbox daily.

Land Inventory

In accordance with the Energy Storage Order, the Company continues to include information regarding suitable, unused, and undedicated land owned by National Grid 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 real 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 acquiring the National Grid land 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 real property to determine the fair market value.⁸⁰ This formal appraised value will be used in National Grid's BCA should the bidder elect to proceed with the lease or purchase of Company-owned land.

Interconnection Costs

In accordance with the 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

⁸⁰ The lease or sale of real property owned by the utility will require Commission approval under Public Service Law Section 70.

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, *available at* <https://www.nationalgridus.com/Business-Partners/Non-Wires-Alternatives/>.

Table 2.13.3: National Grid’s Planned NWA Projects

2023-2028 NWA Projects	Need Date	Estimated Solicitation Timing
Gilmantown	2027	2023

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.

Gilmantown

National Grid is looking to implement an NWA solution for the customers supplied by the Northville Gilmantown Sub-T line. The Company will be exploring storage solutions to mitigate the impact for the loss of the Sub-T 23 kV supply line that supplies the Gilmantown area. The feeders supplied from these stations have historically been on the worst performing feeder list. Outages experienced along this corridor impacts all substations and customers fed by the circuit (Wells, Charley Lake, Gilmantown Road). There are limited feeder ties and capacity and the “traditional” reliability solution is predicted to be expensive and have limitations on the scope of work that can be completed since this circuit travels through the Adirondack Park. The NWA solution may be located on the distribution system to island the substations fed by this circuit following a loss of supply contingency. The NWA team aims to release an ownership agnostic RFP to explore potential solutions in this area. The team will be leveraging lessons learned from Energy Storage Order implementation , as described in Section 2.4, Energy Storage Integration. Future NWAs will continuously be assessed as the Company makes updates to its capital plan to identify alternatives.

Improved RFPs

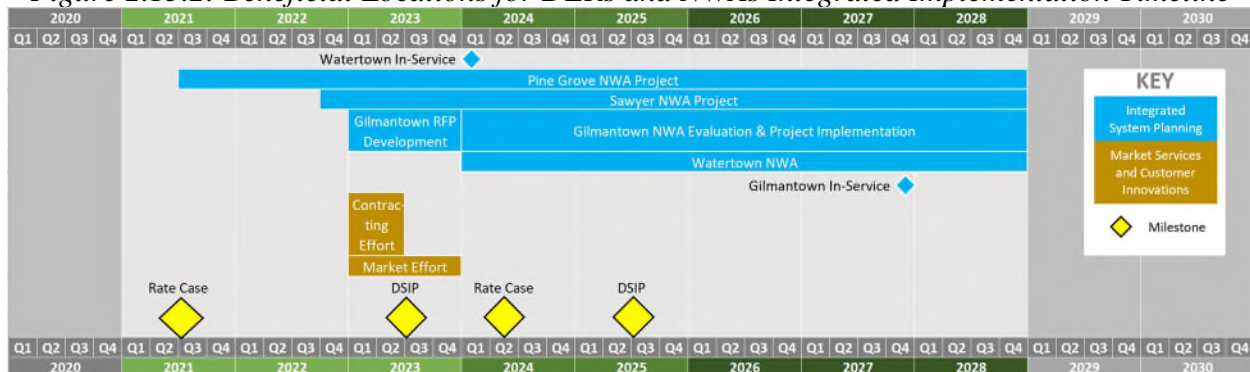
As described previously, National Grid will continue to improve the NWA RFPs and the associated information provided. Future RFPs will be revised thorough a continuous improvement effort including feedback from external stakeholders (e.g., vendors), internal stakeholders, and lessons learned.

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. The Company is working on an effort with a third-party consultant to optimize the standard contract and receive market feedback on contracting practices to better align with industry practices and reduce go-to-market and contract negotiating timelines.

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 2023 and beyond. The Company will also continue to work in conjunction with the Joint Utilities to incorporate lessons learned from the Joint Utilities group, 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.

Figure 2.13.2: Beneficial Locations for DERs and NWAs Integrated Implementation Timeline



Risks and Mitigations

Table 2.13.4: Risks and Mitigations for Beneficial Locations for DERs and NWAs

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
	Including performance expectations and how they relate to DERs in the RFP and discussing performance expectations in evaluation process with active bidders early in the process

Risk	Mitigation
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 a consultant to optimize the contract templates and contracting process to ease future negotiations.
Community Outreach: Opposition from communities to siting and permitting ESS projects	Current thinking on mitigation strategy suggests project-specific engagement plans that are tailored to host community concerns and needs; emphasizing the importance of early engagement, two-way communications, and transparency in site selection processes.

Alignment with CLCPA Goals

Identifying beneficial locations can inform economic deployment of DER, such as ESS and solar PV, 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 CLCPA has established bold clean energy goals that include specific quantities of storage, offshore wind, and solar. To the extent NWAs provide solutions that include ESS, solar, and/or other renewable generation, NWAs contribute to achieving CLCPA goals.

Integrated and Associated Stakeholder Value

Beneficial locations such as NWAs are both an input and an output to other processes described in this 2023 DSIP. In turn, National Grid incentivizes DER to site in beneficial locations through a number of mechanisms, including NWA solutions, DLM programs, and the LSRV portion of the VDER Value Stack tariff. NWA solutions provide more pathways to integrate DER into grid operations and rely on strong forecasting, integrated planning, and identification of beneficial locations sufficiently in advance of the need. Integrating NWAs into the distribution planning processes enables the identification of NWA investments by National Grid that could provide net benefits for customers above and beyond the traditional wires solution.

3 Other DSIP Information

3.1 DSIP Governance

DSIP Scope, Objectives and Participants

This 2023 DSIP Update serves as a core planning document, outlining National Grid's plans with respect to DER and EV integration, information sharing, and market services over the course of the next five years based on current Company and New York State 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 2023 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 2023 DSIP Update, National Grid anticipates filing its next electric and gas rate case around the spring of 2024.

DSIP Work Processes

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 REV Leadership Team that coordinates the activities of two subordinate Joint Utilities committees, the DSP Steering Committee and the Regulatory Policy Committee. These committees then coordinate multiple work teams that focus on the individual topics discussed in this 2023 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

Building on the structures established in 2016, 2018, and 2020, the Joint Utilities have collaborated effectively with stakeholders to enhance communication channels and inform this 2023 DSIP Update.

As part of the development of the 2023 DSIP Update, National Grid held a stakeholder session on June 5, 2023, to share the planned content for the update and solicit feedback and suggestions from stakeholders.

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

National Grid has not made any changes to either its “traditional MCOS” study or its “Enhanced MCOS” study since the 2020 DSIP Update. Both of those studies are examined and documented in other proceedings. In 2018 and 2019, National Grid filed its Enhanced MCOS, which it renamed the Marginal Avoided Distribution Capacity (“MADC”) study, to examine, on a substation basis, the quantity of traditional assets that DER could defer on a location-specific basis. The MADC study outputs include the location, quantity, value and need date for DER to defer a traditional infrastructure solution.

In the April 18, 2019 Value Stack Order, the Commission instituted a new proceeding to examine the enhanced MCOS studies the Joint Utilities filed in 2018, including National Grid’s MADC study.⁸¹ DPS Staff held a Stakeholder Forum on June 28, 2019, which was followed by a series of filings throughout 2019, including a refiling by each utility of its most recent enhanced MCOS study, individual utility responses to multiple rounds of information requests, Joint Utilities’ Comments filed on November 25, 2019, and Joint Utilities’ Reply Comments filed on December 13, 2019. In March 2023 DPS Staff filed a whitepaper on enhanced MCOS studies.⁸² Initial comments on the Staff whitepaper were due on June 20, 2023 with reply comments due on July 11, 2023. However, the Secretary granted an extension for initial and reply comments to July 20, 2023 and August 18, 2023, respectively.

As of the time of publication of this 2023 DSIP Update, National Grid is planning to file a rate case around Spring 2024 which will include an updated traditional MCOS study which will inform a limited set of ratemaking activities, notably the development of “marginal cost” rates for the Excelsior Jobs Program (the Empire Zone Rider program is fully expired as of March 2023).

⁸¹ VDER Proceeding, Order Regarding Value Stack Compensation (issued April 18, 2019).

⁸² Case 19-E-0283, *Proceeding on Motion of the Commission to Examine Utilities’ Marginal Cost of Service Studies*, Department of Public Service Staff Whitepaper Regarding Marginal Cost of Service Studies (filed March 27, 2023).

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 2020 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 New York, the Handbooks would establish methodologies based on common analytics and standardized assumptions, and would identify various sensitivities and synergies.⁸³

The BCA Framework Order required each utility to file its proposed BCA Handbook with its initial DSIP on June 30, 2016.⁸⁴ As required by the BCA Framework Order,⁸⁵ the Company'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 source included in the BCA Handbooks are provided in Appendix C of the BCA Framework Order. The 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, the Company's Version 2.0 and 3.0 BCA Handbook was developed in cooperation with the Joint Utilities and differs from the other utilities' BCA Handbooks only where necessary to accommodate distinctions between the service territories.

Similarly, Version 4.0, filed contemporaneously with this 2023 DSIP Update, provides utility-specific and statewide input assumptions and clarifying edits to Version 3.0.

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 2023 Version 4.0 BCA Handbook, and key assumptions are also shown in Table 3.3.1 below. Version 4.0 of the Company's BCA Handbook will be on the National Grid System Data Portal *available at* <https://systemdataportal.nationalgrid.com/NY/>.

⁸³ REV Proceeding, BCA Framework Order, p. 29.

⁸⁴ *Id.*, p. 31.

⁸⁵ *Id.*

Table 3.3.1: New York Assumptions for Version 4.0 of BCA Handbook

New York Assumptions	Source
Energy and Demand Forecast	NYISO: 2022 Load & Capacity Data ⁸⁶
Avoided Generation Capacity Cost	DPS Staff: ICAP Spreadsheet Model ⁸⁷
Locational Based Marginal Prices (“LBMP”)	NYISO: Congestion Assessment and Resource Integration Study (“CARIS”) Phase 2 ⁸⁸
Historical Ancillary Service Costs	NYISO: Markets & Operations Reports ⁸⁹
Wholesale Energy Market Price Impacts	DPS Staff: To be provided ⁹⁰
Allowance Prices (SO ₂ , and NO _x)	NYISO: CARIS Phase 2 ⁹¹
Renewable Energy Certificate (“REC”) Price	NYSERDA: Results of most recently completed RECs solicitation ⁹²
Net Marginal Damage Cost of Carbon	DPS Staff: To be provided

⁸⁶ The 2023 Load & Capacity Data Report is available at <https://www.nyiso.com/documents/20142/2226333/2023-Gold-Book-Public.pdf/c079fc6b-514f-b28d-60e2-256546600214> The 2023 Load & Capacity Data Report is available at <https://www.nyiso.com/documents/20142/2226333/2023-Gold-Book-Public.pdf/c079fc6b-514f-b28d-60e2-256546600214>

⁸⁷ REV Proceeding, Department of Public Service Staff 2022 ICAP Spreadsheet Model (filed October 3, 2022).

⁸⁸ 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) page, available at <https://www.nyiso.com/cspp>. <https://www.nyiso.com/cspp>. The direct link to the CARIS Phase 2 results are available at <https://www.nyiso.com/documents/20142/1407490/2018-CARIS-2-Hourly-LBMP.zip/80fac5d5-c95f-5d92-4beb-9b3f23cd2c1f>

⁸⁹ Historical ancillary service costs are available on the NYISO website at: <http://mis.nyiso.com/public/P-6Blist.htm>. The values to apply are described in Section 4.1.5. of the BCA Handbook.

⁹⁰ DPS Staff will perform the modeling and file the results with the Commission on or before July 1 of each year.

⁹¹ The NYISO publishes price assumptions for NO_x and SO_x. The most recent is the 2019 study, available at https://www.nyiso.com/documents/20142/7239276/03c+2019_CARIS_EmissionsForecastInformatio.pdf/a9ccb4fd-317f-b3fd-b475-112c54602430?version=1.0&t=1561031785776&download=true The NYISO publishes price assumptions for NO_x and SO_x. The most recent is the 2019 study, available at https://www.nyiso.com/documents/20142/7239276/03c+2019_CARIS_EmissionsForecastInformatio.pdf/a9ccb4fd-317f-b3fd-b475-112c54602430?version=1.0&t=1561031785776&download=true

⁹² The results of NYSERDA REC contract solicitations are available at <https://www.nyseda.ny.gov/All-Programs/Programs/Clean-Energy-Standard/Renewable-Generators-and-Developers/RES-Tier-One-Eligibility/Solicitations-for-Long-term-Contracts>. The weighted average contract price from the most recently completed solicitation is generally used.

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://ngus.force.com/s/>
- National Grid System Data Portal:
<https://ngrid.apps.esri.com/NGSysDataPortal/NY/index.html>
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 following its filing on June 30, 2023.)
- National Grid Customer Market Place:
<https://marketplace.nationalgridus.com/>
- National Grid New York Solar Market Place:
<https://www.nationalgridus.com/upstate-NY-Home/Ways-to-Save/Solar>
- National Grid Energy Savings Program:
<https://www.nationalgridus.com/Upstate-NY-Home/Energy-Saving-Programs/>
- National Grid **Connected**Solutions:
<https://www.nationalgridus.com/Upstate-NY-Home/Energy-Saving-Programs/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 Reforming the Energy Vision (REV) References with Links

- Joint Utilities of New York:
<http://jointutilitiesofny.org/>

- Joint Utilities of New York EV Readiness Framework:
<http://jointutilitiesofny.org/wp-content/uploads/2018/03/Joint-Utilities-of-New-York-EV-Readiness-Framework-Final-Draft-March-2018.pdf>
- Joint Utilities Resources:
<http://jointutilitiesofny.org/resources/>
- Utility Specific Non-Wires Alternatives Opportunities:
<http://jointutilitiesofny.org/utility-specific-pages/nwa-opportunities/>
- NY REV Homepage:
<https://rev.ny.gov/>
- REV Connect:
<https://nyrevconnect.com/>
- REV Connect Non-Wires Alternatives:
<https://nyrevconnect.com/non-wires-alternatives/>

Other References with Links

- New York State DPS search page:
<http://www3.dps.ny.gov/W/PSCWeb.nsf/All/FCFC9542CC5BE76085257FE300543D5E?OpenDocument>
- DER Integration Case 16-M-0412, Benefit Cost Analysis Handbook:
<http://documents.dps.ny.gov/public/MatterManagement/CaseMaster.aspx?MatterCaseNo=16-M-0412>
- 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:
<http://www3.dps.ny.gov/W/PSCWeb.nsf/All/DEF2BF0A236B946F85257F71006AC98E>
- 2015 New York State Energy Plan:
<https://energyplan.ny.gov/Plans/2015>
- New York's Clean Energy Jobs and Climate Agenda:
<https://www.governor.ny.gov/news/governor-cuomo-unveils-20th-proposal-2018-state-state-new-yorks-clean-energy-jobs-and-climate>
- NYISO Homepage: <http://www.nyiso.com/public/index.jsp>
- NYSERDA Homepage:
<https://www.nyserda.ny.gov/>
- NYSERDA: Electric Vehicle Programs:
<https://www.nyserda.ny.gov/Researchers-and-Policymakers/Electric-Vehicles/Electric-Vehicle-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:
- 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/xpls/icp.jsp?arnumber=7356399>.
- Energy.Gov: Green Button Open Energy Data:
<https://www.energy.gov/data/green-button>
- Multistate ZEV Task Force:
<https://www.zevstates.us/>.
- National Standard Practice Manual:
https://nationalefficiencyscreening.org/wp-content/uploads/2017/05/NSPM_May-2017_final.pdf

DSIP Related Proceedings and Efforts

- Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision (Case 14-M-0101)
- In the Matter of Distributed System Implementation Plans (Case 16-M-0411)
- In the Matter of the Value of Distributed Energy Resources (VDER Proceeding) (Case 15-E-0751)
- VDER Working Group Regarding Value Stack (Matter 17-01276)
- VDER Working Group Regarding Rate Design (Matter 17-01277)
- VDER Low Income Working Group Regarding Low and Moderate Income Customers (Matter 17-01278)
- Proceeding on Motion of the Commission Regarding Electric Vehicle Supply Equipment and Infrastructure (18-E-0138)
- In the Matter of Offshore Wind Energy (Case 18-E-0071)
- In the Matter of Energy Storage Deployment Program (Case 18-E-0130)

- In the Matter of Utility EE Programs (Case 15-M-0252)
- In the Matter of the Utility Energy Registry (Case 17-M-0315)
- Whole Building Energy Data Aggregation Standard (Cases 16-M-0411 and 14-M-0101)
- 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 Regulation and Oversight of Distributed Energy Resource Providers and Products (Case 15-M-0180)
- In the Matter of Proposed Amendments to the NY-SIR for Small Distributed Generators (Case 18-E-0018)
- 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 to Develop Dynamic Load Management Programs (Case 14-E-0423)
- Tariff Filing by Niagara Mohawk Power Corporation to Effectuate Dynamic Load Management Programs (Case 15-E-0189)
- 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)
- Petition of Interconnection Policy Working Group Seeking a Cost-Sharing Amendment to the New York Standardized Interconnection Requirements (Case 20-E-0543)
- 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)
- 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 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)

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.⁹³

1. The means and methods used for integrated distribution system planning?

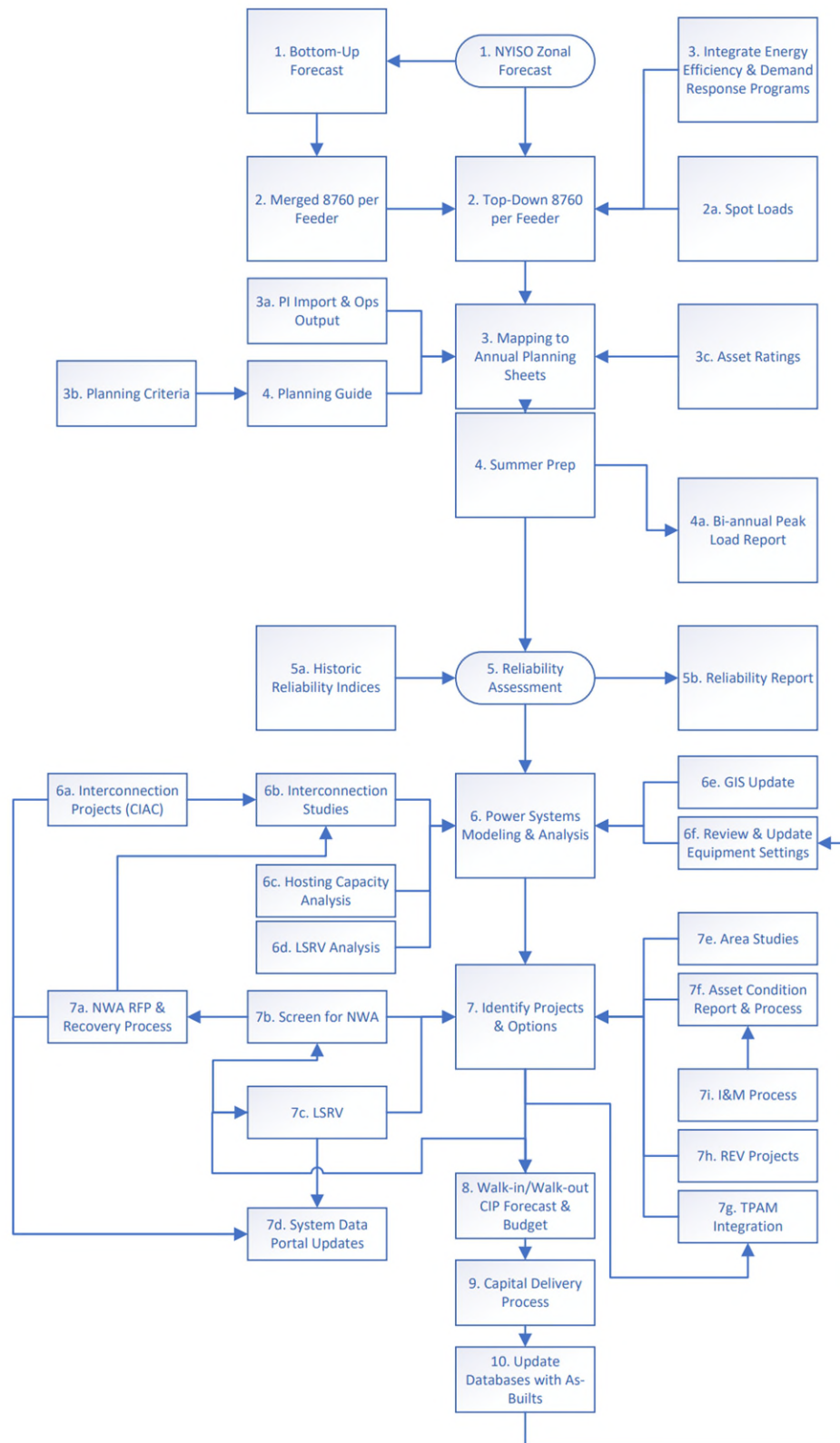
Today's integrated distribution planning process involves many different components and sub-processes, from forecast development through to project delivery.

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 described in this DSIP Update. 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 the today's integrated planning process that is ever evolving and expanding.

⁹³ DSIP Proceeding, *supra*, note 9, 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 tool box
 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 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. Hosting Capacity Analysis: 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-Transmission 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, LTC 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 Hosting Capacity Analysis. 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

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 15-year 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, with the first procurements in-service in 2021.

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.⁹⁴ 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 beneficial electrification, 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.

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 hosting capacity analysis, DER integration, distribution system automation, and various CEATI programs.

⁹⁴ *Supra*, note 21. Appendices D and E provide definitions and further details of adoption scenarios.

5.2 Advanced Forecasting

The following responds to DSP Staff's request to provide additional details to address National Grid's resources and capabilities to enable advanced electric system forecasting and provide the most current forecast results.⁹⁵

- 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 Portal 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 require forecasts at multiple geographical and temporal resolutions. As such, the forecasts are provided at the Company level, NYISO zonal level, and feeder levels. The forecasts are provided for seasonal peaks and for 8,760 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 Company level, NYISO zonal level, and feeder level long-term forecasts via the System Data Portal. The forecasts are issued on an annual basis, usually during the last quarter of each calendar year. Additionally, National Grid continues to assess stakeholder data needs through collaboration with the other 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 level, NYISO zonal level, and feeder level. Temporally, the forecasts are provided for seasonal peaks and for 8,760 profiles.

- 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, EHP, EV, solar PV, ESS, and DR.⁹⁶ The net load after DER impact is provided by adding up the impacts of these individual components. Please refer to the System Report for detailed discussions.

⁹⁵ DSIP Proceeding, *supra*, note 9, pp. 10-12.

⁹⁶ Forecasts are only at the system and NYISO zonal level.

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 weather and DER scenarios. The forecasting process has already incorporated multiple weather scenarios and their probabilities, as well as expanding the scenarios for DER technologies, including introducing emerging DER technologies and developing various cases for them as appropriate. SME inputs are leveraged to develop likelihoods for DER cases. Please refer to the System Report for detailed discussions on these topics.

National Grid plans to improve its probabilistic load forecasting from the following aspects, among others:

- Explore the method of developing weather scenarios and their probabilities by leveraging more granular weather information, more comprehensive weather cases, and using quantitative measures to assist the decision-making process.
- Explore economic scenarios in the peak load forecasting process.
- Align weather scenarios for load and DER forecasting as applicable.
- Continue refinement of DER scenarios for load forecasting.

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 System 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 as for stakeholders. A key application of forecast data is to integrate that data into planning processes. National Grid's planning processes leverage individual feeder-level detailed forecasts with base, low, and high DER probability levels in planning studies and regular engineering processes. These detailed forecasts allow planners to understand forecasted load growth with locational granularity while accounting for multiple possible loading scenarios to better inform planned upgrades and accommodate future DER projects.

9. Describe the utility's specific objectives, means, and methods for acquiring and managing the data needed for its advanced forecasting methodologies.

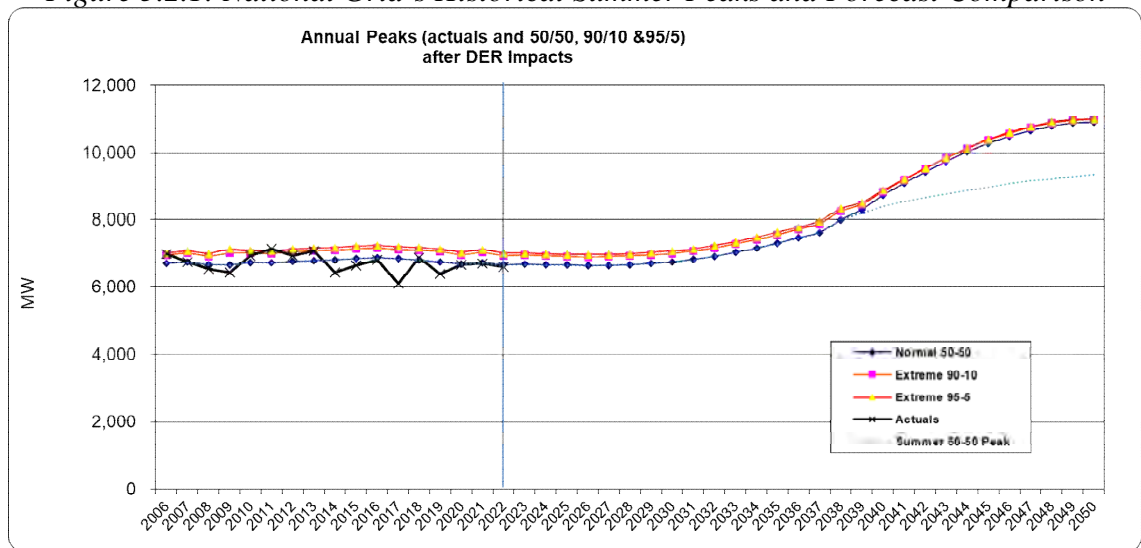
National Grid acquired data for load and DER forecasting through internal and external data sources. The System Report and the Feeder Report discuss the data being used for the load forecasting process and their sources.

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



For the system peak load forecast as shown in Figure 5.2.1 above, historical peak loads are compared to the forecasts under 50/50, 90/10, and 95/5 weather scenarios. System-level forecasts have generally been accurate within the 1% to 3% 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 exist 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 8,760 profiles at the substation level aid DER developers in evaluating impacts such as capacity constraints at peak or off-peak hours, 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.

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 the System 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 the Company's DER forecasts include but are not limited to the following:

- Information received from DG developers as part of interconnection applications
- Information received from EE and DR programs
- Information shared by market participants with the NYISO for its DER forecasting

15. Describe how the utility will inform its forecasting processes through best practices and lessons learned from other jurisdictions.

National Grid continues to enhance the forecasting process by leveraging best practices and lessons learned from other jurisdictions, other utilities, and industry groups, including the following venues:

- Joint Utilities Integrated Planning Working Group; DER and Load forecasting sub-group
- Independent System Operator – New England ("ISO-NE")
- Research conducted by national labs and federal agencies such as National Renewable Energy Laboratory ("NREL") for solar PV, and DOE for EV

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 on its existing methodologies or developing new methodologies to improve its forecast accuracy from the following aspects:

- The current hierarchical forecasting system leverages information at system-level, NYISO zonal level, feeder level, zip code level, and land parcel level information for modeling DER impacts. National Grid plans to further refine this hierarchy for each DER technology to identify the optimal level for analysis.
- National Grid 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 Laboratories, research institutes, and vendors.

17. Describe where CGPP forecast information can be found.

The Company's currently issued forecasts provide NYISO zonal and more granular feeder level forecasts as discussed in the System Report and the Feeder Report. Statewide CLCPA policy goals

were evaluated and considered in the current forecasts as discussed in the CLCPA alignment section.

As described in the Section 2.1, Integrated Planning, the CGPP aims to identify an optimal portfolio of solutions needed to achieve NY's CLCPA policy goals. It is broken into six stages that roughly follow the typical engineering process of: developing assumptions, identifying needs, developing solutions, and selecting an optimal portfolio of solutions. One of the most important assumptions for this study process is the load and generation forecast that will dictate the power flow modeling. In the first CGPP stage, stakeholder input will be leveraged to develop zonal level load and generation forecasts, ensuring each zone has forecasts for large-scale renewables, as well as DERs. Coordination is critical at this stage, such that the selected CGPP forecast(s) align with the utility's forecast, specifically that the distribution components for each distribution station forecast align. This alignment will enable distribution to be treated as an "input" to CGPP as opposed to requiring CGPP to develop incremental and novel policy-driven solutions while leveraging other processes looking at policy driven distribution upgrades such as Cost-Sharing 2.0.

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.⁹⁷

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.

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.

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:

⁹⁷ DSIP Proceeding, *supra*, note 9, pp. 12-13.

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 DSIP details current and future investments associated with parts c, d, e, and f 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 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. 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 its NWA projects such as the Pine Grove project. 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% 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.

Currently, the Company has sixty distribution feeders with centralized VVO/CVR schemes that utilize data from feeder monitors at the end of the circuit and actively control voltage and volt-amp reactive ("VAR") power flows using voltage regulators, LTCs at the substation transformer, and advanced switched-capacitors. To date, National Grid has also installed FLISR schemes on ten distribution feeders and three Sub-T circuits. These FLISR schemes utilize pole top reclosers/sectionalizers to restore unaffected portions of feeders/circuits using a centralized logic controller.

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% within the Company's service territory. The remaining 5% of feeders

and associated substations will get EMS installation projects where feasible to achieve greater than 99% 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% 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. VVO/CVR schemes will continue to be rolled out across the service territory to feasible 13.2 kV substations and their associated feeders beginning in FY 2026.

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 anticipates continuing deployment of VVO/CVR scheme devices in FY 2026 and activating them once the ADMS is ready to be the centralized controller for the associated devices. To deploy VVO/CVR, engineering performs a study to improve VAR flows using advanced switched-capacitors and then adding voltage regulators as necessary to maintain a tighter voltage profile. Once VAR and voltage correction equipment is located, the lowest voltage areas can then be determined, and feeder monitors are placed for the centralized system to have a three-phase end of line voltage reference point. The Company uses standard equipment for both FLISR and VVO/CVR allowing them to be adaptable and updatable.

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.

Benefits for deploying VVO/CVR are reduced peak demand and energy consumption, leading to improved system capacity and more efficient delivery of power to National Grid's customers. The equipment and centralized control also improve voltage profiles and VAR flows. This in turn also allows for improved hosting capacity DERs and other connections. The devices in VVO/CVR also provide additional monitoring points for engineering and control center operators.

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 1 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
- 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
 - Simulated Live Connectivity

f. Describe how ADMS capabilities will increase and improve over time.

National Grid is currently in the build and test stages of ADMS Phase 2 which will expand ADMS functionality for outage management, control, and automation on a common platform. OMS and related functionality will be incorporated into a common distribution model with the DMS applications. DSCADA will be built, implemented, and integrated with the ADMS platform. Together these three major modules integrated on a common platform will increase operational efficiencies and data sharing. The target in-service date for the OMS into ADMS is late CY 2023-early CY 2024 and for DSCADA control capability the target in-service date is CY 2025.

Functionality delivered in this phase includes:

- OMS refresh (with integration to DMS on common connected network model)
- DSCADA control capability
- DMS Advanced Automation leveraging control
- ADMS Phase 3 will 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 a 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 Commercial System Relief Program, Term-DLM, Auto-DLM, and Direct Load Control (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. 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 area such as DER registration, dispatch, edge control and short-term forecasting to support FERC 2222 and the Company's ARI project.

h. Describe how DERMS capabilities will increase and improve over time.

National Grid plans to continue evolving its current DERMS modules as well as introduce other DERMS modules to provide the Company with more comprehensive DER management capabilities that would provide benefits to customers and address customer needs and/or system benefits. This may include modules to improve DER interconnection experience, billing, forecasting and communications. As the number of DERMS modules and DER management capabilities expand, the Company is also looking towards a more comprehensive view on system architecture, data integration and interfaces across system modules as well as other enterprise systems such as ADMS.

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.⁹⁸

- 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.**

Please see the link to the latest NY-SIR interconnection queue for National Grid for projects below 5 MW, *available at* <https://dps.ny.gov/distributed-generation-information>.

Please also see the link to access NYISO's interconnection queue spreadsheet where National Grid is identified as "NM-NG" in column L of the spreadsheet, *available at* <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 with a signed letter of intent to proceed, projects under construction, or projects in operation:

Table 5.4.1: Current Energy Storage Projects

Project	East Pulaski
Description	2 MW / 3 MWh lithium-ion battery
Use Case	Distributed Peak Reduction, Reliability, Wholesale Market Participation (anticipated), Power Quality (anticipated)
Original Schedule	In service by December 31, 2018
Current Status	Online but not yet participating in the NYISO market
Lessons Learned to Date	Challenges with technical operation of the ESS may be mitigated by improved monitoring and maintenance plans.
Adjustment and Improvement Opportunities Identified to Date	Improve asset monitoring and maintenance plans with vendor support and improve secure

⁹⁸ DSIP Proceeding, *supra*, note 9, pp. 13-16.

Project	East Pulaski
	remote data accessibility to the ESS. Resolve software compatibility issues with bidding into the NYISO market.
Next Steps with Timeline and Deliverables	Conduct stakeholder webinar and file first annual report by September 29, 2023 with subsequent annual reports to be filed on the anniversary of the first annual report filing.

Project	North Troy
Description	2 MW / 3 MWh lithium-ion battery
Use Case	Distributed Peak Reduction, Wholesale Market Participation (potential future use case), Power Quality (potential future use case)
Original Schedule	Anticipated in service by December 31, 2018
Current Status	The ESS was placed in service in February 2020. Later in 2020, cybersecurity vulnerabilities were identified in vendor equipment that required the ESS to be taken offline for remediation. After remediation was completed in Q2 2022, additional work is ongoing to reconnect to National Grid communication network for operations and O&M support.
Lessons Learned to Date	Challenges with cybersecurity compliance and establishing remote access and monitoring for vendor support.
Adjustment and Improvements Opportunities Identified to Date	Incorporation of evolving cybersecurity requirements and external vendor/contractor support requiring remote access to the ESS
Next Steps with Timeline and Deliverables	Re-establish connection with National Grid communication network by end of 2023 and review health of asset prior to putting back in service.

Project	Pine Grove
Description	The completed NWA solution deploys two grid-tied 5 MW solar arrays, each paired with 5 MW / 20 MWh lithium-ion battery ESS. See NWA section for further details.
Use Case	NWA for reliability (substation N-1)
Original Schedule	Goal: Summer 2021 (Actual: Summer 2022)
Current Status	Operational
Lessons Learned to Date	See Section 2.13 for lessons learned

Project	Pine Grove
Adjustment & Improvements Opportunities Identified to Date	See Section 2.13 for process improvements
Next Steps with Timeline and Deliverables	M&V, BCA filing, quarterly report filings, and annual implementation plan filings

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 for details.
Use Case	NWA for reliability (substation N-1)
Original Schedule	Goal: In-Service by Q1 2024 ⁹⁹
Current Status	Under construction
Lessons Learned to Date	See Section 2.13 for lessons learned
Adjustment & Improvements Opportunities Identified to Date	See Section 2.13 for process improvements
Next Steps with Timeline and Deliverables	Interconnect and commission/test the system.

Project	Gilmantown
Description	Combined 6 MW and 18 MWh ¹⁰⁰ of ESSs
Use Case	Form a Microgrid for reliability
Original Schedule	Goal: Complete by Spring 2029 ¹⁰¹
Current Status	In planning
Lessons Learned to Date	See Section 2.13 for lessons learned
Adjustment & Improvements Opportunities Identified to Date	See Section 2.13 for process improvements
Next Steps with Timeline and Deliverables	Confirm sizing requirement and draft an RFP to go out to bid in CY 2023.

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.

ESS forecasts for the next five years are provided and discussed in the Niagara Mohawk Power Corporation 2023 to 2050 Electric Peak (MW) Forecast (Appendix C and D of the report). In its existing load forecasting process, National Grid considers storage paired with the type of solar PV that is interconnected to the Company's distribution system (in contrast to whereas those interconnected to the bulk power system as supply). The total forecasted amount aligns with the state's policy target as discussed in the Alignment with CLCPA Goals section under Advanced Forecasting. A peak-shaving profile is utilized to model the load impact that assumes storage

⁹⁹ In-service date is subject to change.

¹⁰⁰ Project size is subject to change.

¹⁰¹ Project schedule subject to change.

projects will discharge during typical peak hours in a peak day and charge during the hours when solar PV generates.

- 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**
 - 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 with a focus on the following use cases:

- 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 generator’s revenue.
- Power Quality – Flicker, harmonic filtering, voltage, and 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 a 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 provide a means to optimize and increase the utilization of a specific ESS to provide stacked benefits while considering the potentially increased cost of mobile ESS compared to stationary storage.

Further use cases specifically to support T&D system needs are being investigated by the ESS task force within the ATWG comprised of members of the Joint Utilities, EPRI, NY-BEST, NYSERDA and DPS Staff. The ATWG plans to conduct a study with a consultant to investigate grid support use cases of ESS based on experience across the ESS 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 ESS on the distribution system. The Company continues to advance its modeling capabilities within CYME's software application to model ESS and is exploring valuation estimation tools to model how ESS can support distribution system needs such as backup power support (e.g., microgrids).

The Company is also continuing its efforts to incorporate within its ADMS deployment means to improve visibility and modeling of ESS as part of its distribution system operations. There are ongoing 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.

For National Grid assets participating in the wholesale market, the Company has procured consultancy, training, and market operations services from a third-party marketer for its East Pulaski Battery ESS project. However, unplanned outages of the unit and software compatibility issues have delayed integration of the power marketer services.

- 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 ESS projects installed as directed in the Commission's 2017 DSIP Order¹⁰² and the existing and planned contracted NWA projects, EMS is/will be used to monitor the projects' input/output power and control the interconnecting circuit breakers. EMS is also used to monitor the input/output power and control the interconnecting PCC reclosers of third party-owned ESS resources.

In collaboration with the Joint Utilities, National Grid has and continues to examine monitoring and control requirements for smart inverters, which also impact how it determines the real-time status, behavior, and effect of ESS resources on the distribution system. The Joint Utilities have released their Phase 2 smart inverter roadmap requirements which have been incorporated into the Company's ESB 756B. The next phase will investigate how National Grid seeks to interact more dynamically with smart inverters, including inverter-based ESS resources in Phase 3 of the Joint Utilities' smart inverter roadmap.

As part of the Company's plans, National Grid intends to transition monitoring and control of these ESS resources to ADMS and is currently investigating whether scheduling and dispatch of Company-owned or contracted ESS resources supporting distribution system needs should be managed through ADMS, DERMS, or a combination of both.

- 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.**

Long-Term Forecast

In the current long-term load forecasting process, National Grid considers storage to be paired with solar PV and a peak-shaving use case by assuming the ESS discharges during typical peak hours in a day and charges during the hours when the solar PV is expected to generate. The assumptions for developing the ESS projection are discussed in the Niagara Mohawk Power Corporation Electric Peak (MW) Report.¹⁰³ ESS is assumed to discharge during likely peak hours for a duration of four to five hours to help shave the peak. It is assumed to charge throughout the daytime when the solar PV is generating. The estimated impact at the time of peak load is presented in Appendix A of the Niagara Mohawk Power Corporation Electric Peak (MW) Report.

¹⁰² DSIP Proceeding, *supra*, note 28, pp. 28-31.

¹⁰³ *Supra*, note 21.

Short-Term Forecast

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 that facilitates DER participations in the NYISO wholesale market under FERC 2222. The short-term forecasting can also help support activation of targeted load relief and NWAs. The ability to incorporate more complex short-term forecasting features such as forecasting the operation of ESS in general into a load forecast 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 ESS for both NEM and Value Stack compensation is already automated and integrated into the Company's billing system depending on customer type and project configuration. This function is supported by the Company's customer energy integration consultants and billing specialists utilizing National Grid's Customer Service System and Salesforce system. For NWAs, the Company has the ability to use the NWA recovery mechanism, detailed in the rate, to recover funds related to NWA solutions which may include ESS compensation (for NWA solutions that include ESS). The NWA recovery mechanism allows the ability to collect certain NWA charges through a surcharge, when needed and approved.

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, customer and system data that would be necessary for planning, implementation, and management of ESS includes hourly load and generation demand of affected system assets in order to determine the required amount of ESS capacity. This data is developed into a needs statement to determine the amount of energy capacity, power capacity, and duration that ESS is required to meet the system load relief, reliability, and/or resiliency need. A needs statement would then be used to provide the proper technical parameters for a developer within a request for proposal to meet the utility system need.

Energy developers and other stakeholders can also access the Company's ESS hosting capacity maps within National Grid's system data portal in order to have an interactive resource that gives access to data sets that National Grid uses to assess ESS opportunities. . More information relating to Hosting Capacity can be referenced within Section 2.9, Hosting Capacity, and Section 2.8, Data Sharing, respectively.

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 ESS can be interconnected and integrated into the T&D system to advance the objectives established in CLCPA. The suite of initiatives accomplished and planned around improving the interconnection process for ESS, publishing and

evolving the Company's ES hosting capacity maps, and innovating on alternative ways to interconnect ESS more cost effectively and quickly while maintaining safety and reliability of the system, summarize how the Company envisions interconnection of ESS in support of the clean energy goals within CLCPA. The Company has and continues to investigate ways to beneficially incorporate ESS as a non-wires solution. The planned ES projects mentioned in this section will provide valuable experience on how ESS can address T&D reliability needs to provide benefits to all customers and advance National Grid's capability to plan, engineer, construct, operate, and maintain ESS 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 ESS can unlock within New York, specifically on deliverability of renewable energy.

5.5 Electric Vehicle Integration

The following responds to DSP Staff's request to provide additional details regarding EV integration.¹⁰⁴

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 laws, policies and programs. For LDVs, the forecast aligns with the Advanced Clean Car II rules, and the MHDV forecast aligns with the recently adopted Advanced Clean Truck (ACT) rule. The Company also creates a high and low scenario that allow 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 Level 2 ("L2") and DC Fast Charging ("DCFC") infrastructure for National Grid residential and commercial customers. These EV charging loads are aggregated into the Company's load forecast.

As discussed in the sections above, National Grid introduces probabilities to each of these scenarios, 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,

¹⁰⁴ DSIP Proceeding, *supra*, note 9, pp. 16-18.

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 territory, in order to provide a comprehensive suite of charging solutions for all customers. As outlined in the EV Integration section above, customers require many flexible options 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 addresses customer needs in these areas:

- EV Make-Ready Infrastructure Program
- Residential Managed Charging Program
- EV Rate Design Programs
- Medium- and Heavy-Duty EV Order

National Grid 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.

In the course of 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 help the state to achieve the ZEV goals. These efforts are described in further detail in the National Grid and Joint Utility filings in Case 23-E-0070 – addressing barriers to medium- and heavy-duty EV charging infrastructure.

b. Explain how each of those resources and functions supports the stakeholders’ needs.

As outlined in the EV integration section, 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, includes them in marketing and recruiting activities, and collaborates with them to build a combined experience in deploying EV charging infrastructure. The Company plans to continue to support these engagements with stakeholders with additional capacity forecasting details, to provide the lowest-cost EV charging infrastructure for all customers in the Company's service territory, including both LDV and MHDV charging needs.

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, and the Company filings can be found in the Commission proceeding Case 18-E-0138 - addressing the light-duty EV make-ready programs, residential managed charging programs, and establishing 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 the charging loads, charging behaviors, and number of drivers by segment. The Company also uses this information to determine the level of charging at each 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: As highlighted in question three, 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 the 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 transmission and distribution systems. These efforts are described in further detail in the National Grid and Joint Utility filings in Commission proceeding Case 23-E-0070 – addressing barriers to medium- and heavy-duty EV charging infrastructure.

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 the 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 information can be found in Table 5.5.1 below provided in response to Question Seven.

- 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: National Grid’s Charging Development Programs

National Grid’s Phase 1 EVCS Program	
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. This program enables proactive investment in electrical infrastructure on both the utility and the customer side of the meter. This program helps meet the state’s ZEV goals and helps to reduce GHG emissions throughout the

National Grid's Phase 1 EVCS Program	
	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 detailed status of this program is included in various Company filings in the EVSE and Infrastructure Proceeding –which address the light-duty EV MRP, residential managed charging programs, and establishing the DCFC PPI program.
Original Project Schedule	As discussed above, the EV Make-Ready Infrastructure Program is approved through 2025, the Residential Managed Charging Program is approved through 2025, and the demand management technologies program funding will be deployed through February 28, 2026. The EV Rate Design Programs and Medium- and Heavy-Duty EV programs are still awaiting a Commission order as to schedule details.
Current Project Status	<p>National Grid files annual reports in in the EVSE and Infrastructure Proceeding and has made substantial progress in supporting the goals of the EV Make-Ready Order as follows:</p> <ul style="list-style-type: none"> • LDV Make-Ready: National Grid make-ready funding has supported 2,150 EVSE ports (1,979 Level 2 (“L2”) ports and 171 DCFC ports). This is in addition to the 1,403 EVSE ports in the Company's Phase 1 program, bringing the total support to 3,553 EV ports in the Company's service territory. • MHDV Make-Ready Pilot Program: The Company has supported MHDV customers through the fleet assessment services program, as well as one project enrolled in the program, and one project pending approval. • Fleet Assessment Services: The Company has completed 74 assessments for fleet customers across its service territory, assessing more than 4,000 vehicles. • Transit Authority Make-Ready Program: The Company has supported the two transit authorities in its service territory (Niagara Frontier Transportation Authority and Capital District Transportation Authority) in reaching their state goals of 25% electrification by 2025. <p>The EV Make-Ready Infrastructure Program currently has a robust waiting list and continues to receive ongoing feedback from the vendor community indicating strong interest in continuing to grow this program through 2025.</p>
Lessons Learned to Date	<p>EV Make-Ready Infrastructure Program participants (both site hosts and trade allies) have been consistently satisfied with the process in the EV charging programs.</p> <p>Program incentives provided by National Grid are driving EV adoption and customer participation, and have been important for customers to make the commitment to installing EVSE. Third-party trade allies have been crucial in engaging with customers and site hosts; their training, marketing, and experience have helped accelerate EVSE deployment.</p>

National Grid's Phase 1 EVCS Program	
	<p>Continued education on EVs and charging station equipment is crucial to continue to encourage future EV adoption. National Grid continues to invest in the customer experience for site hosts and trade allies, through both enhancements to the application portal as well as the interconnection process. The National Grid fleet programs are also promoting wide adoption of EVs, though there are still opportunities for process improvement.</p> <p>Flexibility is important in order to react to technology changes, local policy changes, or permitting challenges. The Company has helped stakeholders navigate this process and will continue to do so to provide a seamless transition to electric transportation.</p>
Project Adjustments and Improvement Opportunities Identified to Date	The Company routinely assesses the success of the EV Charging Programs, and incorporates many lessons learned to accelerate future deployment of EV charging solutions. The customer onboarding process, trade ally engagement process, and site selection are example areas where the Company is seeking to streamline its efforts to provide a faster and easily navigated for both program participants and trade allies.
Next Steps with Clear Timelines and Deliverables	The Company will continue to manage the program to its completion according to the timelines above, in order to deploy as many EV charging ports and EV driver support solutions as possible throughout the territory. The more than 3,500 EV charging ports already installed have helped the state meet its ZEV goals, as well as have a significant impact on its GHG reduction goals, and the Company's existing and new programs will continue to accelerate that progress through 2026 and beyond.

8. Describe how the utility is coordinating with the efforts of the New York State Energy Research and Development Authority ("NYSERDA"), the New York Power Authority ("NYPA"), New York State Department of Environmental Conservation ("NYSDEC"), and DPS Staff to facilitate statewide EV market development and growth.

The Company has been engaged with NYSERDA, NYPA, NYSDEC, and DPS Staff through the implementation of all of the EV Charging Programs and will continue to do so throughout the rest of the program. National Grid has worked closely with those agencies as customers go through the process of installing EVSE on their premises, and the Company has kept the process as streamlined as possible through each phase of the program.

The Joint Utilities Electric Vehicle Working Group has also collaborated closely with these organizations throughout the years of the program, including many stakeholder sessions, technical working group discussions, industry webinars, and other customer or stakeholder events.

5.6 Clean Heat Integration

The following responds to DSP Staff's request to provide additional details regarding clean heat integration.¹⁰⁵

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.).**

National Grid's 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;**

Table 5.6.1: Scenario Distribution of Existing Instances

Premise Type	Count
Multi Family Home	483
Single Family Home	6,586
Small Business	230
Totals	7,299

- c. **the forecast number and spatial distribution of anticipated instances of the scenario over the next five years;**

Table 5.6.2: Scenario Distribution of Forecasted Instances

2024	
Description	Applications Needed
Partial Load ASHP	350
Full Heating ASHP	800
HP + Integrated controls	200
HP + Decommissioning	800
GSHP	300
Custom	30
Custom Space & Envelope	30
HPWH	1,010
Custom HPWH	10
Desuperheater	50

¹⁰⁵ DSIP Proceeding, *supra*, note 9, pp. 18-20.

2024	
Description	Applications Needed
Dedicated DHW WWHP	5
Combo Bonus	0
Totals	3,585

2025	
Description	Apps Needed
Partial Load ASHP	350
Full Heating ASHP	900
HP + Integrated controls	200
HP + Decommissioning	800
GSHP	300
Custom	35
Custom Space & Envelope	35
HPWH	1,100
Custom HPWH	20
Desuperheater	50
Dedicated DHW WWHP	5
Combo Bonus	0
Totals	3,795

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 and several variables impact this. 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, 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 (“JMC”) which meets regularly to discuss planning and progress, quality assurance and quality control, technical considerations, and marketing of the program. The Company also works with a number of vendors that help support the Clean Heat program by ensuring the Company has a network of qualified contractors to install heat pumps and that they are installed to National Grid’s 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.

b. Explain how each of those resources and functions supports the stakeholders’ needs.

- JMC Planning Working Group: This is a platform to discuss potential program changes using the new product tracker and any statewide program issues.
- Joint Utilities QA/QC Cal I: The group reviews contractor evaluations to update statuses, any QA checklist for revisions/updates, Clean Heat Connect updates, and policies and procedures documents.
- Joint Utilities Marketing Meeting: National Grid coordinates with the 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 webinars and DPS Staff requests. Additionally, this meeting serves as a forum to through comments and edits to Clean Heat 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. The community also evaluates new technology for inclusion in the Clean Heat program.

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 they are used to optimize targeting efforts and spending by engaging those with a higher propensity to participate in the Clean Heat program. Many attributes go into determining the customer’s segment, some include usage, income, behaviors, education, and age.

Once a customer has participated in the Clean Heat program, data is maintained to track National Grid’s performance. Some of the customer data maintained is name, address, and bill account number. Data maintained on program information is 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 in support of National Grid's and the state's carbon reduction goals. The Company is expanding its contractor network so as to have more qualified workers that can speak directly to customers, address their questions and concerns, and successfully encourage customers 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 customers. Every contractor is required to submit a manual J, or approved equivalent, 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 in a single day. Ground Source Heat Pump projects generally take a few days but can take up to two weeks depending on the size and type of loops. Incentive applications are submitted after installation.

Custom commercial and large multifamily project schedules 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;

During the 2022 program year, National Grid did not fully spend its allocated 2022 budget, nor reach its goal. However, the Company made great strides over prior years' performance, with a 115% increase in MMBtu savings from 2021 and achieving 79% of the 2022 MMBtu savings goal.

d. lessons learned to-date;

It is important to establish on-going contractor training to support the Company's contractor network with added cold climate sizing and design training requirement for ASHP participating contractors.

e. project adjustments and improvement opportunities identified to-date; and

A midstream avenue for Heat Pump Water Heaters was added in 2022 with additional incentive dollars to customers installing integrated controls or decommissioning, as well as. providing a

kicker to gas customers in identified zip codes with additional dollars to convert to energy efficient electric heat pumps.

f. next steps with clear timelines and deliverables.

The Company will analyze new technology for eligibility within the Clean Heat program and establish incentive rates as appropriate.

7. Describe how the utility is coordinating with the efforts of the New York State Energy Research and Development Authority (“NYSERDA”), the New York Power Authority (“NYPA”), New York State Department of Environmental Conservation (“NYSDEC”), DPS Staff, or other governmental entities to facilitate statewide clean heat market development and growth.

National Grid meets biweekly with NYSERDA to discuss and promote joint marketing efforts statewide. DPS Staff joins 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.¹⁰⁶

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 has the opportunity to play a role within the system planning and NWA process. Over the next three to five 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 documentation in the EE section of the document. This was answered above.

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 EE and building electrification programs help customers save energy, increase the comfort of their homes and businesses, and reduce their carbon footprint. EE and building electrification are the foundation necessary to meet CLCPA goals. The Company monitors developments – in technology, finance and understanding of consumer behavior – in order to adjust program offerings as needed. In addition, the Company is committed to the CLCPA's goals of increased investment in disadvantaged communities. The Company is working with DPS Staff, NYSEERDA, and other utilities to create a tracking and reporting mechanism in support of the State's compliance efforts to ensure at least 35% of clean energy investments accrue to disadvantaged communities. In furtherance of this effort, consideration of how to reach disadvantaged communities is being integrated into the Company's program design and delivery.

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.

¹⁰⁶ DSIP Proceeding, *supra*, note 9, pp. 20-22.

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 transitioning NYSERDA market development and pilot activities to the utility portfolios (e.g., Real Time Energy Management Sub-initiative, weatherization), coordinating delivery of workforce development, refinements to the NY Technical Resource Manual, and joint EM&V for statewide initiatives.

In conjunction with the other Joint Utilities, National Grid implements the Affordable Multifamily Energy Efficiency Program, providing EE to affordable housing through comprehensive and non-comprehensive projects.

National Grid collaborates with NYSERDA within the LMI Portfolio by providing funding to the EmPower program for one-to-four family homes and by connecting the Affordable Multifamily Energy Efficiency Program with NYSERDA's FlexTech program to provide technical assistance to affordable housing. National Grid also provides funding to NYSERDA to support the Energy Advisor site to direct customers to relevant EE and bill assistance programs and is looking to collaborate with the recently launch regional Clean Energy Hubs.

5.8 Data Sharing

The following responds to DPS Staff’s request to provide additional details which are specific to data sharing.¹⁰⁷

1. Provide a functional overview of the planned IEDR.

The IEDR plan currently contains two phases; Phase 1 will enable the development of at least five priority data use cases over twenty-four to thirty-six months (Q4 2023 completion), while Phase 2 will enable over forty additional data use cases over thirty to thirty-six months (2026 completion). NYSERDA serves as the Program Sponsor for this effort and forms the Steering Committee with DPS Staff. The IEDR Order approved a Phase 1 budget of \$67.5 million for the utilities and NYSERDA¹⁰⁸ 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 New York State 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.

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, selected the following use cases for the IEDR IPV to be released by Q1 2023.

Table 5.8.1: Initial Public Version (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.

¹⁰⁷ DSIP Proceeding, *supra*, note 9, pp. 22-23.

¹⁰⁸ IEDR Proceeding, *supra*, note 13, pp. 19-21.

Use Case	Description
Large Installed DERs	This use case supports Energy Service Entities 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 Energy Service Entities 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 selected the following use cases for the IEDR MVP to be released by Q4 2023.

Table 5.8.2: Minimum Viable Product (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.
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

Use Case	Description
	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	<p>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.</p> <ol style="list-style-type: none"> 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.

In Q3 2022, NYSERDA announced the selection of E Source to lead the IEDR Development Team. The Development Team will also include UtilityAPI, Flux Tailor, TRC Companies, and HumanLogic. Together, the team will be responsible for designing, building, and operating the IEDR platform to accomplish the policy goals and program outcomes as described in the Commission’s IEDR Order Link in a cost efficient and expeditious manner. The Development Team will leverage E Source’s OneInform and UtilityAPI’s Green Button Connect 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.

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.

Initially each utility worked internally to fill the IEDR Data Survey and submitted results at the end of October 2021. To facilitate ongoing coordination, the Joint Utilities collaborate with NYSERDA and DPS Staff by attending the Utility Coordination Group (“UCG”) monthly meetings and additional workshops. 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
- Data availability of a small subset of requested data elements
- Consistency of data element nomenclature across all utilities

- Sensitivity of certain requested data elements

On February 28, 2022, each utility submitted responses to the IEDR Phase 1 Notice of Utility Data Requirements filed by NYSERDA with the Commission on February 8, 2022 in the IEDR Proceeding seeking input on an approach to deliver preliminary data elements to the IEDR by May 2022. While the Joint Utilities are fully supportive of sharing useful information to achieve New York's clean energy goals, customer privacy and cybersecurity must also be given careful consideration. As such, the Joint Utilities coordinated additional discussions with DPS Staff and NYSERDA regarding the need to put in place the necessary mechanisms consistent with New York privacy laws and regulations.

The Joint Utilities developed internal processes to collect and process the data and ultimately transfer it to a secure, central location in accordance with appropriate legal and privacy considerations. The Joint Utilities continue to coordinate discussions with DPS Staff and NYSERDA to protect customer privacy and mitigate cybersecurity concerns. On December 1, 2022, the Joint Utilities filed a petition for clarification seeking Commission direction regarding the direct sharing of protected customer data with the IEDR Development Team. The Joint Utilities have also been focusing on preparing the necessary agreements to work with the IEDR Program Team, and its vendors, including the new developer that will build and operate the IEDR.

The Joint Utilities submitted their first round of test data on June 17, 2022 in support of the IEDR Development Team's task to build out the platform. The Joint Utilities sent a second round of IPV test data for Hosting Capacity maps and DER use cases in November/December 2022. This will assist the IEDR Development Team in understanding the structure and format of utility data, which will aid in implementation of the IPV use cases and overall development of the IEDR platform.

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 will be providing electric network and gas network 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

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 gdb format to the IEDR platform via 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

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 1 and 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.

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 April 19, 2023, thirty-four 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.aspx>.

5.9 Hosting Capacity

The following responds to DPS Staff's request to provide additional details which are specific to hosting capacity.¹⁰⁹

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. s yet to be fully determined but it will be defined while incorporating stakeholder inputs and the status of DER at that time. Figure 2.9.1 in Section 2.9, Hosting Capacity, shows how the stages build up from one another, improving HCA along the way, potentially leading to long-range HCA in the future.

¹⁰⁹ DSIP Proceeding, *supra*, note 9, 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.

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. The Company will also be performing its yearly update to the base 4.1 HCA data on October 1, 2023.

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 of Section 2.9, Hosting Capacity.

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 2023 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 is planned for October 1, 2023.

- 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 section of Section 2.9, Hosting Capacity.

- 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 2023.

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 2.9.2 (PV Hosting Capacity Tab on System Data Portal) in Section 2.9, Hosting Capacity, 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% 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

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 chapter of this 2023 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.¹¹⁰

- 1. Describe the various DER-related billing and compensation programs 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, remote net metering, 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 was to automate the VDER Value Stack billing and crediting as described above. Below is a detailed table discussing the various workstreams of the VDER Value Stack automation project.

Table 5.10.1: DER-related Billing and Compensation Program Changes

Workstream Nos.	Programming Changes	Deployment
1	Satellite Relationships: Add, update, and remove relationship through batch process; programming of load zone exemption; and automatic removal of satellite when removed from host relationship	August 2020 (completed)
2	Billing of Value Stack Stand Alone (onsite) – Phase 1 and Phase 2; and Crediting of Value Stack Remote Crediting Host – Phase 1 and Phase 2;	March 2021 (completed)
3	Billing of Value Stack CDG Phase 1 and Phase 2 projects with satellite transfers; Billing of Value Stack Net Crediting Phase 1 and Phase 2 projects with satellite transfers; and Value Stack Remote Crediting satellite transfers	August 2022 (completed January 2023)
4	Value Stack CDG host bank distributions; Value Stack CDG host bill cancel / rebill; Value Stack CDG reporting (<i>i.e.</i> , future transfers, prior month transfers, and return to host bank transfers); and Value Stack CDG annual allocations	July 2023 (in progress)

- 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**

¹¹⁰ DSIP Proceeding, *supra*, note 9, pp. 25-27.

support those needs. For planned components, provide the sequence and timing of key investments and activities required for component implementation.

As described in the response to Question One above, the VDER Value Stack automation project has been ongoing since 2017 with the anticipated completion in July 2023.

Details on the Wholesale Value Stack/Aggregation are described in Question Three.

The Company has added full-time employees and established a new renewable energy billing department in April 2023. A newly hired renewable energy billing manager will oversee all the back-office billing transactions that support accurate and timely DG billing. Structures and processes are established to handle customer inquiries and CDG allocation changes where the intake portal is integrated with the DG interconnection portal. This allows for tracking of inquiries as well as assuring they get into the correct workstreams.

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 required for component implementation.

FERC 2222 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
- 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.**

Phase 4 of the VDER automation is on schedule to be completed and is anticipated to minimize billing and crediting problems. See response provided above to Question One.

- 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.

CDG Billing

Value Stack and CDG net crediting bill calculations will be fully automated in July 2023. The net crediting application process as well as allocation management will still rely on a manual process.

Expanded Solar for All

For the Expanded Solar for All program, 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.

- 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.**

Table 5.10.2: 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. In the case of the VDER CDG automation roll out, both production and manual bills were generated for each CDG host to ensure that the billing system was correctly

calculating host bills and satellite credits. If these two bills matched, the CDG project was pulled into automation.

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 Company is launching a new Solar Hub section on its website which is anticipated to go live in the fall of 2023. 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 is also conducting targeted onboarding for CDG hosts onto the MyBusiness Account portal from May through July 2023. In addition, the Company is offering small group web training sessions on understanding the new CDG host reports that will launch in July 2023. A presentation was made on these reports at the May 1, 2023 CDG Billing & Crediting Working Group meeting.

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 detail specific to DER interconnections.¹¹¹

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 recommends 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:**

¹¹¹ DSIP Proceeding, *supra*, note 9, 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.¹¹² 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.

¹¹²Available 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

The following responds to DPS Staff's request to provide additional details specific to AMI.¹¹³

- 1. Provide a summary of the most up-to-date AMI implementation plans, including where AMI has been deployed to date.**

See the Implementation Plan, Schedule, and Investments section of Section 2.12, Advanced Metering Infrastructure.

- 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 the Customer Benefits and Stakeholder Needs section of Section 2.12, Advanced Metering Infrastructure.

- 3. Describe the AMI-acquired data and information that is planned to be available through the IEDR.**

Similar to Green Button Connect My Data, the Company plans to provide customer billing data, with customer consent, to the IEDR platform. With the transition to AMI smart meters, the Company is assessing the frequency in which the data can be shared in near-real time now that 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: Billing Data Information collected by AMI

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.**

¹¹³ DSIP Proceeding, *supra*, note 9, pp. 28-29.

As smart meter deployment begins in 2023, 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. Please also see Figure 2.12.2: Meter Deployment Timeline above for the latest timeline.

5. Provide a summary of plans and timelines for future expansion and/or enhancement of AMI functions.

National Grid is planning to have new AMI data presentment functionality available for customers via an enhanced website, referred to as the CEMP. To date the Company has made the integration of AMI data available for the MVP Alpha customers in Central New York. Additional web functionalities will come online as more meters are deployed over the next four years. Possible features include:

- Proactive Energy Billing Alerts
- Data Browser Widget for Energy Cost and Bill View Data
- Data Browser Widget for Energy Cost Bill view (day-to-day)
- Data Browser Widget for Detailed Daily use with Weather and Timing
- Home Energy Analysis with Appliance-Level Load Disaggregation (High-level Data)
- Sense web application with Appliance-Level Load Disaggregation (Granular-level Data)
- Bill Guide and Bill Comparison
- Green Button Download and Green Button Connect My Data (for sharing data with qualified third-party energy service companies with customer consent) now with AMI data.

Other key functionality expansions include:

- Storm Outage Management System: Outage management benefits are planned to start in late 2023 upon successful integration of OMS and AMI back-end systems. Benefits will continue and mature through full meter rollout. Some outage management-related benefits are realized early on, such as the single power off notification from a meter to OMS. Other outage management related benefits such as mass pinging and nested outage benefits are not realized until a critical mass of meters available later in the meter rollout period. Accordingly, the full benefits of automated customer communication will not be realized until the end of the deployment period.
- Volt-VAR Optimization: As AMI meters can read and report usage data multiple times a day, they can act as end-of-line sensors to centralized VVO/CVR control systems via integration with ADMS and MDMS. The VVO/CVR control systems can then make voltage and reactive power adjustments to optimize the distribution systems voltage and power flows to reduce power consumption on the grid and for customers and over time energy. Through the integration of AMI voltage data with the VVO/CVR solution, additional voltage optimization can be achieved, resulting in additional efficiency and savings. The Company plans to enable AMI links in its existing VVO/CVR schemes once the AMI data is available on the feeders where VVO/CVR are deployed and the ADMS application is fully developed and tested.

- LTC-AMI: National Grid has been updating LTC Controllers at 13.2 kV substations in anticipation of linking ADMS applications with AMI data to actively control the front-end voltage loop of various feeders. To date, the Company has upgraded twenty-four substations specifically for this purpose. Other programs and initiatives have also been upgrading substation LTC controllers to the type required to enable LTC-AMI functionality. This feature is expected to be available after 2026.

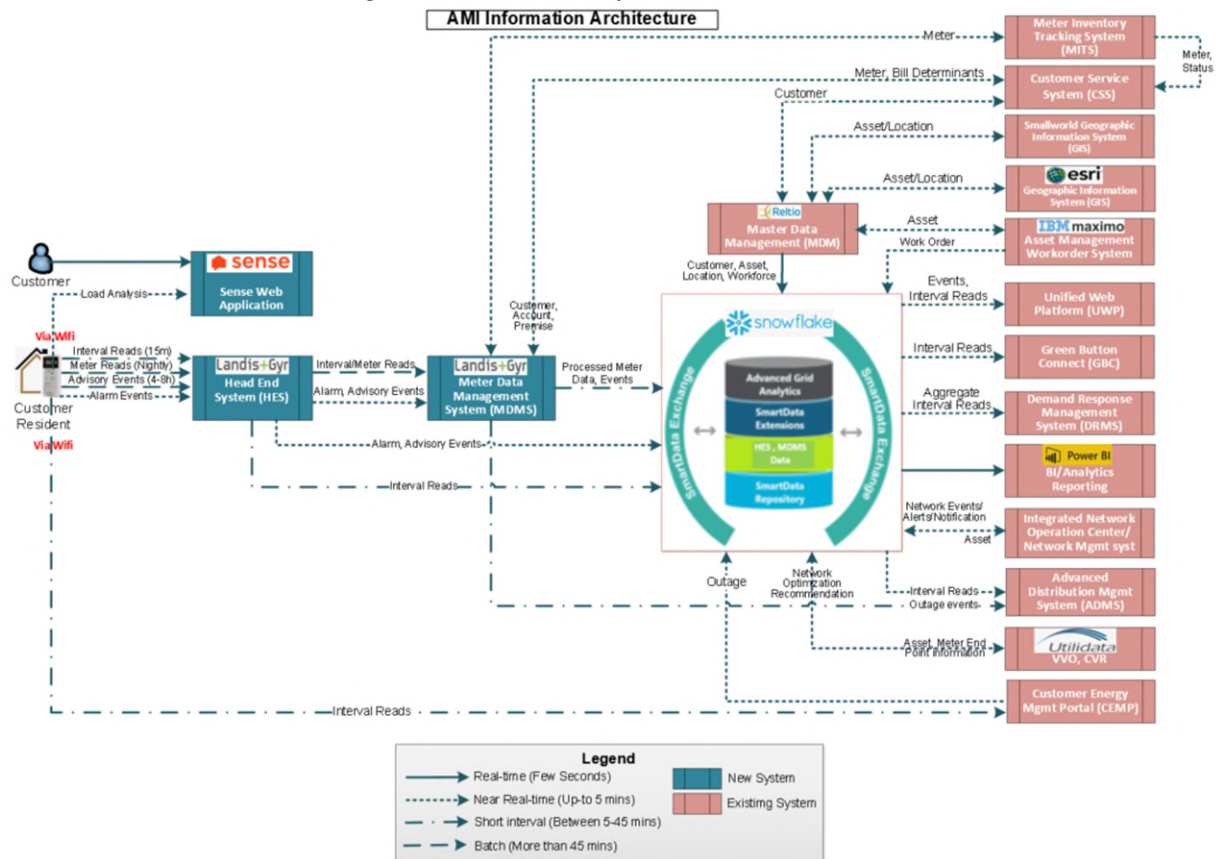
Additional AMI-enable future functionalities are summarized in the AMI Benefits Implementation Plan and included in the table below.

Figure 5.12.1: AMI-Enabled Future Functionalities

Functionality	Description	Technology Dependencies	Timetable
Grid Mapping/Locational Awareness	Algorithms allow meters to define their location at a transformer and feeder level to better collate GIS data while providing enhanced insights to load forecasting, voltage and outage management systems.	Grid-edge computing application, integration with Grid Modernization functionalities	5-10 years
Enhanced Load Disaggregation	Provide customers with real-time energy monitor and real-time device-level breakdown with access to real-time alerts	Grid-edge computing application with HAN integration	5-10 years
Bypass Theft Detection	Theft detection uses real-time, high resolution analysis of data from power flows rather than anecdotal alarms and alerts to detect customer energy theft through meter tamper/bypass as well as direct connection of loads to the low-voltage wiring.	Grid-edge computing application	5-10 years
Intelligent Voltage Monitoring	Intelligent Voltage Monitoring enables voltages on the distribution network to be analyzed at the meter level, to optimize the asset life of transformers while ensuring power delivery at acceptable voltage ranges and power quality standards. Exceptions are reported.	Grid-edge computing application	5-10 years
Distributed Outage Detection	Analytics are performed at the meter to identify power on/power off signals along with voltage data to quantify power outages for segments of the distribution system, which are then integrated into an OMS to support service restoration.	Grid-edge computing application, OMS integration	5-10 years
Temperature monitoring	Detecting a rise in temperature in a meter socket can alert utilities prior to a potential fire or possible overheating concern.	Grid-edge computing application	>10 years
Arc sensing	Electrical arc sensing on both the customer- and grid-facing components supports safety and reliability benefits by proactively identifying anomalies and unsafe conditions.	Grid-edge computing application	>10 years
High-Impedance Detection	Identification of high-impedance points in the distribution network, including at the meter, which can result in voltage complaints, connection failures, and even fire in some cases.	Grid-edge computing application	>10 years
Broken Neutral Detection	Detects broken neutral and poor ground conditions as they are developing on the customer side of the transformer so that potential safety problems can be identified and corrected as quickly as possible.	Grid-edge computing application	>10 years
Active Demand Response	Autonomous demand management locally and intelligently by integrating with customer HAN devices to support demand reduction in accordance with utility demand events. Integration with EV charging stations can provide additional demand benefits while facilitating electrification.	Grid-edge computing application with HAN integration	>10 years

- 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 5.12.2: 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.¹¹⁴

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 website *available at* <https://www.nationalgridus.com/Business-Partners/Non-Wires-Alternatives/>
- Joint Utilities website *available at* <http://jointutilitiesofny.org/utility-specific-pages/nwa-opportunities>
- REV Connect website *available at* <https://nyrevconnect.com/non-wires-alternatives/>
- Piclo Flex website *available at* <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 and replace the use of Ariba for the pilot duration. In the future, National Grid may utilize a different market platform to procure services from DERs, Aggregators, and EE.

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, and/or operations; and/or**

¹¹⁴ DSIP Proceeding, *supra*, note 9, pp. 29-31.

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.

The Company will determine future constraints and needs of the transmission, Sub-T, 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 kicker offering for additional opportunities.

The Company is also considering how DERs 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 Current Progress and Risks and Mitigations sections of Section 2.13, Beneficial Locations for DERs and Non-Wires Alternatives.

Emerging system needs are identified as early as possible. This allows for comprehensive consideration of the NWA 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 National Grid's 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.picoflex.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 NWA 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 solutions as well as to minimize contract negotiations.
- Solution Delivery: Evaluation of submitted proposals are completed and if the proposal successfully passes technical viability and the BCA, an award is made to the successful bidder. Projects that do not pass technical viability and the BCA continue with the traditional solution.

National Grid 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. The Company plans to continue developing a standardized contract and will continue to share best practices with the other Joint Utilities regarding 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.

See response to Question One above.

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.

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:

Table 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. Beginning in 2023, as part of a Pilot with Piclo Flex, NWA opportunities are visible to any interested parties on usa.picloflex.com. 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, National Grid 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. National Grid will file the first NWA BCA in 2023.