nationalgrid

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July 31, 2018

VIA ELECTRONIC DELIVERY

Honorable Kathleen H. Burgess
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 – 2018 Distributed System Implementation Plan ("DSIP") Update

Dear Secretary Burgess:

Niagara Mohawk Power Corporation d/b/a National Grid ("National Grid") hereby submits its 2018 DSIP Update in accordance with the Commission's April 20, 2016 *Order Adopting Distributed System Implementation Plan Guidance* in Case 14-M-0101 which directs the Company to file an individual DSIP on a biennial basis.[1]

Please direct any questions regarding this filing to:

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Thank you for your attention to this matter.

Respectfully submitted,

/s/ Janet M. Audunson
Janet M. Audunson, P.E., Esq.
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Enc.
cc: Carlos Nouel, w/enclosure (via electronic mail)
Robert Sheridan, w/enclosure (via electronic mail)
Cathy Hughto-Delzer, w/enclosure (via electronic mail)

[1] The filing date for this DSIP Update was extended to July 31, 2018 by letter from the Secretary issued on June 5, 2018 in Cases 16-M-0411 and 14-M-0101.

2018 Distributed System Implementation Plan Update

Distributed System Implementation Plan Update

of

Niagara Mohawk Power Corporation

d/b/a National Grid

Case 16-M-0411

DSIP Proceeding

July 31, 2018

Table of Contents

Acronyms

$3V_0$:	Zero-Sequence Voltage
ABB:	ASEA Brown Boveri
ADA:	Advanced Data Analytics
ADMS:	Advanced Distribution Management System
AEO:	Annual Energy Outlook
AMF:	Advanced Metering Functionality
AMI:	Advanced Metering Infrastructure
AMR:	Automated Meter Reading
API:	Application Programming Interface
BAM:	Budget and Metrics
BCA:	Benefit Cost Analysis
BCP:	Business Continuity Plans
BNMC:	Buffalo Niagara Medical Campus
BTM:	Behind-the-Meter
C&I:	Commercial and Industrial
CAGR:	Compound Annual Growth Rate
CCA:	Community Choice Aggregation
CCVT:	Coupling Capacitor Voltage Transformer
CEAC:	Clean Energy Advisory Council
CEF:	Clean Energy Fund
CEI:	Customer Energy Integration
CEMP:	Customer Energy Management Platform
CESIR:	Coordinated Electric System Interconnection Review
CHP:	Combined Heat and Power
CIP:	Capital Improvement Plan
CISO:	Chief Information Security Officer
CNI:	Critical National infrastructure
CO2:	Carbon Dioxide
Commission:	New York State Public Service Commission
Company:	National Grid
COO:	Chief Operating Officer
COSO:	Committee of Sponsoring Organizations
CPP:	Critical Peak Pricing
CS:	Customer Solutions
CSOC:	Cyber Security Operations Center
CVR:	Conservation Voltage Reduction
DA:	Distributed Automation
DC:	Direct Current
DCFC:	Direct Current Fast Charge
DER:	Distributed Energy Resource
DERMS:	Distributed Energy Resource Management System
DG:	Distributed Generation
DLM:	Dynamic Load Management

DLRP: Distribution Load Relief Program
DMD: Download My Data
DMS: Distribution Management System
DOE: U.S. Department of Energy
DPAM: Distribution Planning and Asset Management
DPI: Deep Packet Inspection
DPS: Department of Public Service
DR: Demand Response
DRMS: Demand Response Management System
DRV: Demand Reduction Value
DSA: Data Security Agreement
D-SCADA: Distribution Supervisory Control and Data Acquisition
DSIP: Distribution System Implementation Plan
DSM: Demand Side Management
DSP: Distributed System Platform
DTT: Direct Transfer Trip
EAM: Earnings Adjustment Mechanism
EDI: Electronic Data Interchange
EE: Energy Efficiency
EIC: Engineering, Installation and Commissioning
EJP: Excelsior Jobs Program
ELR: Energy Limited Resource
EM&V: Evaluation, Measurement and Verification
EMS: Energy Management System
EPA: Environmental Protection Agency
EPRI: Electric Power Research Institute
EPS: Electric power System
ERT: Encoder Receiver Transmitters
ES: Energy Storage
ESA: Efficiency Service Agreements
ESB: Electric System Bulletin
ESCOs: Energy Service Companies
ESS: Energy Storage System
ETIP: Energy Efficiency Transition Implementation Plan
EV: Electric Vehicle
EVSE: Electric Vehicle Supply Equipment
EZR: Empire Zone Rider
FAN: Field Area Network
FERC: Federal Energy Regulatory Commission
FLISR: Fault Location, Isolation, and Service Restoration
FY: Fiscal Year
GBC: Green Button Connect
GBD: Green Button Download
GFOV: Ground Fault Overvoltage
GHG: Greenhouse Gas

GIS:	Geographic Information System
GPS:	Global Positioning System
GW:	Gigawatt
GWh:	Gigawatt hour
HAN:	Home Area Network
HC:	Hosting Capacity
HCA:	Hosting Capacity Analysis
ICAP:	Installed Capacity
ICE:	Internal Combustion Engine
IOAP:	Interconnection Online Application Portal
IoT:	Internet of Things
IPWG:	Interconnection Policy Working Group
ISO:	International Organization for Standardization
ISO-NE:	Independent System Operator – New England
ISOs	Independent System Operators
IT:	Information Technology
ITWG:	Interconnection Technical Working Group
JU:	Joint Utilities
kV:	Kilovolts
kVAR:	Kilovar
kW:	Kilowatt
kWh:	Kilowatt hour
kWh/mi:	Kilowatt hour per Mile
LBMP:	Locational-Based Marginal Prices
LED:	Light-Emitting Diode
LMI:	Low-to-Moderate Income
LMP+D+E:	Locational Marginal Pricing + Distribution Value + Environmental
LMP+D:	Locational Marginal pricing + Distribution Value
LNBA:	Locational Net Benefit Analysis
LROV:	Load Rejection Overvoltage
LSRV:	Locational System Relief Value
LTC:	Load Tap Changer
LVMs:	Line Voltage Monitors
M&C:	Monitoring and Control
M&V:	Measurements and Verification
MADC:	Marginal Avoided Distribution Costs
MCOS:	Marginal Cost of Service
MDM:	Meter and Data Management
MDMS:	Meter Data Management Services
MIWG:	Market Issues Working Group
MPG-e:	Miles Per Gallon Equivalent
MTPA:	Metrics Tracking and Performance Assessment
MW:	Megawatts
MWh:	Megawatt hours
nCAP:	New Customer Application Portal

NEM: Net Energy Metering
NERC: North American Energy Reliability Corporation
NERC-CIP: North American Energy Reliability Corporation Critical Infrastructure Protection
NESC: National Electric Safety Code
NG: National Grid
NGRID: National Grid
NIST: National Institute of Standards and Technology
NLC: Network Lighting Control
NMPC: Niagara Mohawk Power Corporation
NWA: Non-Wires Alternatives
NY: New York
NYC: New York City
NYISO: New York Independent System Operator
NYPA: New York Power Authority
NYSEG: New York State Electric & Gas Corporation
NYREV: New York Reforming the Energy Vision
NYS: New York State
NYSDEC: New York State Department of Environmental Conservation
NYSERDA: New York State Energy Research and Development Authority
NYSRC: New York State Reliability Council
OMS: Outage Management System
OT: Operational Technology
PCC: Point of Common Coupling
PHEV: Plug-in Hybrid Electric Vehicle
PLC: Power Line Carrier
PMO: Project Management Officer
POCs: Points of Control
PSRs: Platform Service Revenue
PTR: Peak Time Rewards
PV: Photovoltaic
QA/QC: Quality Assurance/Quality Control
QNA: QinetiQ North America
REV: Reforming the Energy Vision
RFI: Request for Information
RFP: Request for Proposal
RFS: Request for Solutions
RG&E: Rochester Gas and Electric Corporation
RIM: Rate Impact Measure
RTU: Remote Terminal Unit
SaaS: Software as a Service
SCADA: Supervisory Control and Data Acquisition
SCT: Societal Cost Test
SDSIP: Supplemental Distributed System Implementation Plan
SEEP: System Energy Efficiency Plan
SIR: Standardized Interconnection Requirements

SME: Subject Matter Expert
SRC: Security Resilience Committee
Staff: Department of Public Service Staff
T&D: Transmission and Distribution
TOU: Time-of-Use
TVP: Time Varying Pricing
UBP-DERS: Uniform Business Practices-Distributed Energy Resources
UC: Use Case
UER: Utility Energy Registry
UTC: Utility Cost Test
V2G: Vehicle-to-Grid
VDER: Value of Distributed Energy Resource
VT: Voltage Transformer
VTOU: Voluntary Time-of-Use
VVO: Volt/VAR Optimization
ZEV: Zero-emission Vehicle

Executive Summary

Niagara Mohawk Power Corporation d/b/a National Grid ("National Grid" or the "Company") is pleased to provide its 2018 Distributed System Implementation Plan ("DSIP") Update advancing the objectives of the New York State Public Service Commission's ("Commission") Reforming the Energy Vision ("REV") Proceeding.[1] The contents of this DSIP Update are focused on the elements of REV addressed in the Commission's REV Track One Order[2] and DSIP Guidance Order,[3] and Department of Public Service ("DPS") Staff's 2018 DSIP Guidance Update.[4] An update of the Company's Benefit Cost Analysis ("BCA") Handbook is also filed contemporaneously with this DSIP Update as directed in the Commission's BCA Order.[5] Updates to the BCA Handbook will continue to be filed contemporaneously with each subsequent DSIP Update filing, scheduled to be updated every other year.[6]

The energy landscape is changing – energy supply is becoming more diverse and less carbon intensive, and digitization and decentralization trends are accelerating. At National Grid we understand the critical role we play in enabling and supporting this clean energy transition and we are committed to providing a more efficient energy delivery system that meets the evolving needs of our customers.

> *"Our purpose, which sets out why National Grid exists, is simple – we bring energy to life."*

A key component of the clean energy transition is the evolving definition of the 'customer' - shifting beyond the typical 'consumer of electricity' – to include those who offer services, such as distributed generation ("DG") or demand response ("DR"), to the distribution system and/or directly to other customers. It is with this evolution in mind that the Company is pro-actively seeking to modernize its electricity systems and develop valuable solutions for all customers.

[1] Case 14-M-0101, *Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision* ("REV Proceeding").
[2] REV Proceeding, Order Adopting a Regulatory Policy Framework and Implementation Plan (issued February 26, 2015)("REV Track One Order").
[3] REV Proceeding, Order Adopting Distributed System Implementation Plan Guidance (issued April 20, 2016)("DSIP Guidance Order").
[4] Case 16-M-0411, *In the Matter of Distributed System Implementation Plans*, Department of Public Service Staff Whitepaper – Guidance for 2018 DSIP Updates (dated April 26, 2018)(filed May 29, 2018)("2018 DSIP Guidance Update").
[5] REV Proceeding, Order Establishing the Benefit Cost Analysis Framework (issued January 21, 2016)("BCA Order").
[6] *See* DSIP Guidance Order, pp. 63-64, at Ordering Clause No. 4, requiring the filing of "subsequent Distributed System Implementation Plans on a biennial basis beginning June 30, 2018." On June 5, 2018 the Secretary granted an extension for filing of the utilities' 2018 DSIP Updates to July 31, 2018.

National Grid believes that by ensuring the resiliency, efficiency, and openness of the electric distribution grid today and for the future, we will create a powerful platform for empowering our customers and supporting the transition to an affordable, sustainable clean energy system for New York.

National Grid will know it has succeeded when:

- All customers have knowledge, choice, and control, enabled by easy access to information, useful insights on energy options, and thriving markets for innovative new services.
- Large-scale and distributed clean energy resources are commonplace and distributed energy resources ("DER") are accessible to all, enabled by affordable DG and energy storage systems ("ESS"), effectively and efficiently integrated into a modern electric grid.
- Energy efficiency ("EE") and low-carbon fuels are the affordable, everyday choice, enabled by robust markets and third-party products.

To achieve this future, four clarifying principles underlie our implementation plans for the Distributed System Platform ("DSP"):

- **Empower all of our customers** by ensuring choice and control over their energy services.
- Cultivate an **efficient and resilient** grid that can adapt to the evolving paradigms of two-way power flows, responsive demand, and customer participation.
- Support the state of New York in achieving its **clean energy** objectives, including:
    - A 40% reduction in greenhouse gas ("GHG") emissions from 1990 levels by 2030 from the energy sector and the longer-term goal of decreasing total carbon emissions 80% by 2050;
    - Generating 50% of the state's electricity through renewable resources by 2030; and
    - Decreasing energy consumption in buildings by 23% from 2012 levels by 2030.
- **Maximize the effectiveness of performance incentives** in driving these important outcomes.

As directed in the REV Track One Order, National Grid and the other New York regulated electric utilities have taken on the role of DSP providers and in doing so have expanded their obligations so as to incorporate services that enable third-party providers of DER to deliver value to both customers and the electric system. The Company's progress and plans presented in this DSIP Update exemplify how National Grid has embraced this role. The functions and capabilities of the DSP will continue to expand over time as technologies evolve and are deployed, new market mechanisms are developed, and DER penetration increases. Through this evolution, National Grid is enhancing its capabilities through experience in a manner consistent with adaptive goals and paths.

National Grid's 2018 DSIP Update
In accordance with the 2018 DSIP Guidance Update, this DSIP Update provides detailed information about National Grid's planned DSP implementation over the coming five-year period ending July 31, 2023.

In this DSIP Update the Company will:

- Report on DSP actions and progress since the initial DSIP filing in 2016;[7]
- Describe plans for developing and implementing necessary tools, policies, processes, resources, and standards;
- 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; and
- Describe how National Grid's planning and implementation efforts are organized and managed to enable the integration of DER.

This DSIP Update has benefited from a collaborative process with the Joint Utilities of New York, DPS Staff, and other stakeholders. The Joint Utilities are working collaboratively to progress the DSPs as consistently as possible across the state while recognizing the inherent differences of each of the utility's systems. To facilitate the review of each utility's 2018 DSIP Update, the Joint Utilities are presenting their plans in alignment with a standard table of contents and leveraging common language and figures. Where appropriate the language and figures may be adapted to reflect the progress and plans of a specific utility.

The format of the DSIP Update has been structured to be responsive to the detailed guidance provided in the 2018 DSIP Guidance Update. For each of the fourteen topic areas presented in Table ES 1 below, this DSIP Update presents the context and background, progress made since the initial DSIP, and the Company's implementation plans over the coming five years. In addition, the Company responds directly to topic-specific inquiries presented in the 2018 DSIP Guidance Update.

[7] REV Proceeding, Niagara Mohawk Power Corporation d/b/a National Grid ("National Grid") Initial Distributed System Implementation Plan (filed June 30, 2016). National Grid subsequently made an errata filing to correct certain conversion formatting errors within the document and provided a revised initial DSIP in its entirety (filed July 1, 2016).

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	Energy Efficiency Integration and Innovation
	7	Distribution System Data
	8	Customer Data
	9	Cyber Security
	10	DER Interconnections
	11	Advanced Metering Infrastructure
	12	Hosting Capacity
	13	Beneficial Locations for DERs and Non-Wires Alternatives
	14	Procuring Non-Wires Alternatives

While this DSIP Update presents National Grid's current plans over the coming five years, there are multiple related proceedings and efforts underway that will influence the implementation of the plan, including:

- In the Matter of Distributed System Implementation Plans (Case 16-M-0411)
- In the Matter of the Value of Distributed Energy Resources (VDER Proceeding or VDER) (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 (Case 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 Energy Efficiency Programs (Case 15-M-0252)
- In the Matter of the Utility Energy Registry (UER Proceeding or UER) (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 New York State Standardized Interconnection Requirements (SIR) for Small Distributed Generators (Case 18-E-0018)
- Dynamic Load Management (DLM) Programs (Cases 14-E-0423 and 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)

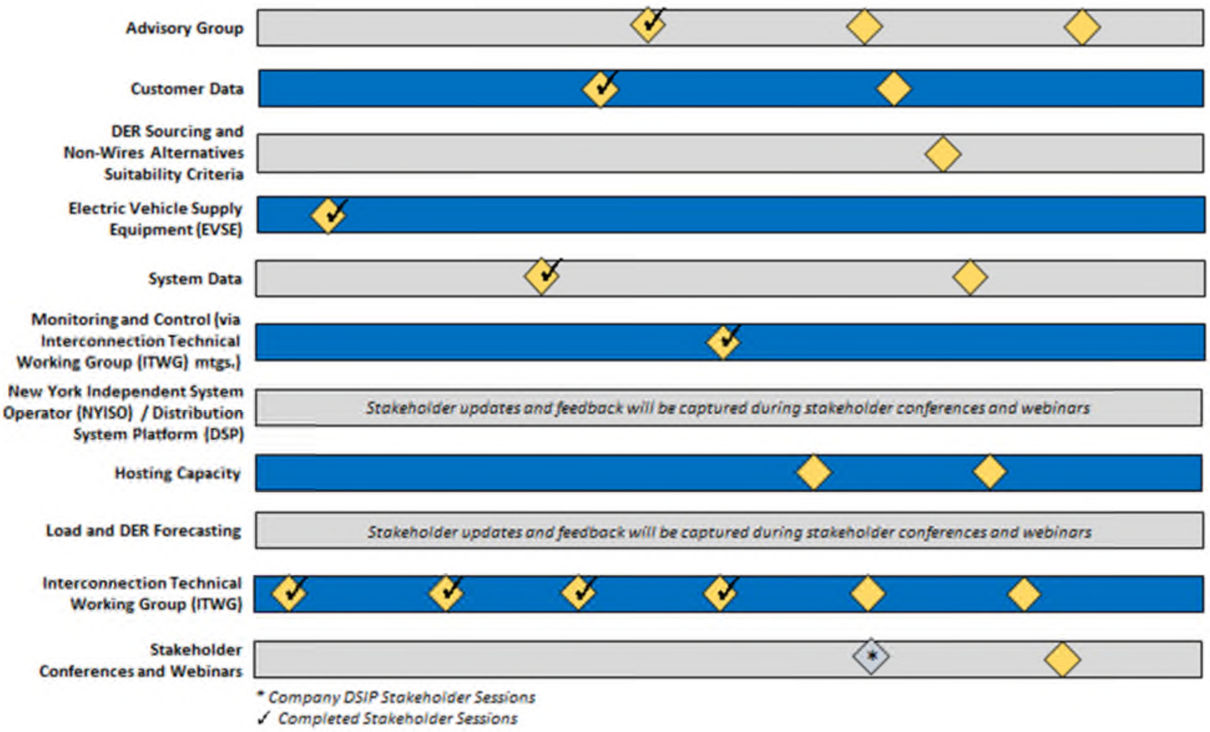
The Company will continue to engage in these proceedings and other initiatives, considering impacts and opportunities holistically across the proceedings to ensure cohesiveness, and will adapt its DSIP plans as appropriate. The next scheduled update to the Company's DSIP is expected in June 2020. In the interim, as a supplement to this DSIP Update and following further utility development efforts and DPS Staff guidance, the Joint Utilities expect to jointly prepare and file a DSP Market Design and Integration Report which identifies, describes, and explains planned market organization and functions. The estimated delivery schedule for this supplemental filing has yet to be determined.

Stakeholder Engagement

The Company in concert with the other members of the Joint Utilities will continue to engage with stakeholders in a coordinated effort to solicit input and feedback. Stakeholder engagements have ranged from holistic discussions with the Advisory Group and at stakeholder conferences, to very detailed, topic-specific workshops with subject matter experts ("SMEs"). In addition, National Grid engages with stakeholders individually on Company-specific topics such as interconnection applications and the use of new tools and processes. In the third quarter of 2018, National Grid will host a stakeholder information session to share the plans presented in this DSIP Update, answer questions from stakeholders, and demonstrate new tools and applications.

The planned topic areas and tentative schedule of engagements of the Joint Utilities with other stakeholder groups and organizations are shared in the Figure ES1.

Figure ES 1: 2018 Stakeholder Efforts



Progress and Plans

In its 2016 initial DSIP the Company identified a number of actions and investments necessary to develop in its role as the DSP. National Grid has been actively engaged with stakeholders in shaping the direction of policies and programs, has identified numerous beneficial locations and NWA opportunities for DER, has completed hosting capacity analysis on all of its radial distribution feeders, and has developed a system data portal to share important system information. The Company has also increased its EE and DR programs and streamlined its DER interconnection process and thereby reduced the cycle time for customers.

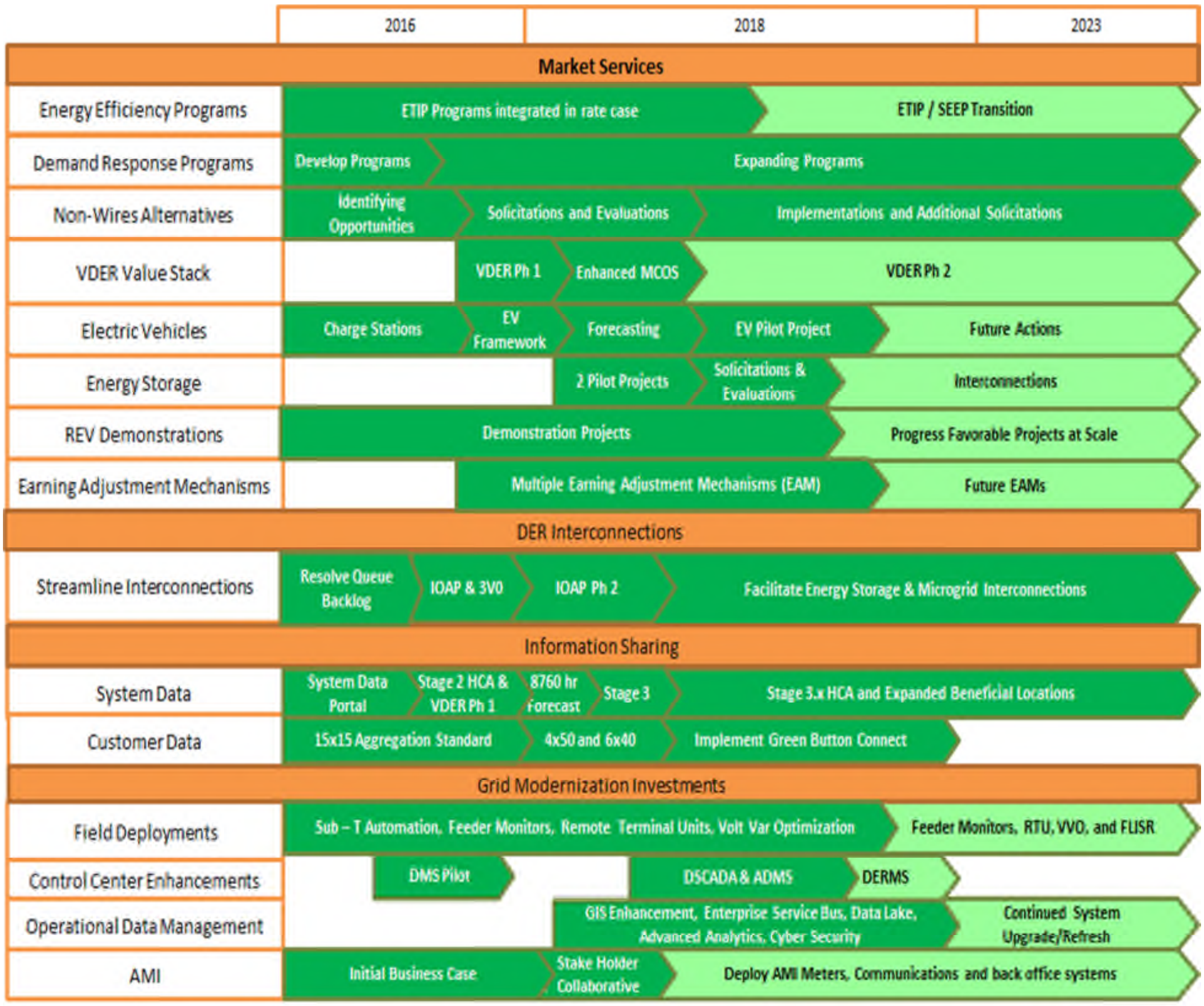
The initial DSIP plan was a key input in the development of National Grid's most recent rate case in which project scopes, estimates, and justifications for the priority elements of initiatives identified in the DSIP were presented to the Commission. Balancing the costs the Company was seeking to recover with the overall impacts to customers resulted in a three-year rate plan order issued by the Commission on March 15, 2018 ("Three-Year Rate Plan Order")[8] which adjusted

[8] Cases 17-E-0238 *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*, Order Adopting Terms of Joint Proposal and Establishing Electric and Gas Rate Plans (issued March 15, 2018)("Three-Year Rate Plan Order").

the phasing of the initial DSIP recommendations and reduced certain near-term expenditures. Within the Three-Year Rate Plan Order approximately \$236M was approved for various projects aligned with REV during the period of April 1, 2018 through March 31, 2021. Of this total amount, approximately \$149M is for initial DSIP recommendations for grid modernization, advanced metering infrastructure ("AMI"), and associated cyber security. With this funding the Company will be able to continue to make progress on foundational grid modernization projects as well as DER integration, information sharing, and market services.

Figure ES 2 below depicts some of the key progress made to date and next steps. The brighter shading within the table represents where the necessary approvals, tariffs, or funding exists; whereas the lighter shaded areas represent plans that are contingent on some future authorization.

Figure ES 2: Key Progress and Plans



Significant detail of the Company's progress and plans is provided in this DSIP Update. A synopsis of the topical sections comprising the remainder of this report is provided in this Executive Summary.

REV Demonstration Projects

National Grid has adopted a "Listen, Test and Learn" approach to guide its actions through these transformational times. The Company's REV demonstration projects illustrate its commitment to innovation in support of REV. The Company has launched six (6) REV demonstration projects since 2016 as summarized in Table ES 2 below. Through these projects the Company is testing new technologies and business models at pilot scale and will utilize lessons learned to help develop new offerings, at scale, based on the most successful demonstrations.

Table ES 2: National Grid's REV Demonstration Projects

REV Project	Targeted Sector	Selected Project Elements	Schedule
Clifton Park Demand Reduction	Electric and Gas	Bring Advanced Metering Infrastructure ("AMI") to residential customers in the Town of Clifton Park along with Volt/VAR Optimization ("VVO") equipment, inclusive of Conservation Voltage Reduction ("CVR"), and price signals comprised of Peak Time Rewards ("PTR") and a voluntary time-of-use ("VTOU") rate.	Q1 2017 to Q1 2020
Potsdam Community Resilience	Electric	Develop an engineering design and an investment grade financial model for a community resilience microgrid in the Village of Potsdam with a hybrid ownership and operation model.	Q2 2016 to Q4 2018
Distributed System Platform	Electric	Test a local, small-scale DSP that communicates with network-connected points of control on the Buffalo Niagara Medical Campus, Inc. ("BNMC") to allow these assets to provide energy and/or ancillary services to the electric distribution system.	Q2 2016 to Q3 2019
Fruit Belt Neighborhood Solar	Electric	Test utility ownership model to bring roof-top solar photovoltaic ("PV") and bill savings to underserved low-to-moderate	Q1 2016 to Q1 2019

REV Project	Targeted Sector	Selected Project Elements	Schedule
		income ("LMI") segment coupled with a partnership with the New York State Energy Research and Development Authority ("NYSERDA") to deliver energy efficiency programs to further drive energy bill savings.	
Distributed Generation Interconnection	Electric	Test alternative solutions for increasing the pace and scale of interconnecting distributed generation ("DG") systems above 50 kW through upfront investments by the Company at two of its substations, East Golah and Peterboro, coupled with a cost-allocation methodology aimed at removing barriers for DG interconnection applicants.	Q2 2017 to Q3 2018
Schenectady Smart City	Electric	Deploy and evaluate light-emitting diode ("LED") street lights equipped with smart controllers and a multipurpose communication network with the ability to remotely control LED street lights, communicate with advanced meters, and send signals to smart-energy devices in concert with developing corresponding Smart City tariffs.	Q3 2018 to Q2 2021

National Grid will continue to develop and propose new, innovative REV projects where appropriate. The Company is also working with REV Connect[9] to identify new solution offerings and business models leveraging third-party services.

Integrated Planning

The Company has enhanced its distribution system planning tools, processes, and staffing to evaluate and integrate DER in its infrastructure and operating plans for the transmission and distribution ("T&D") system. Since its initial DSIP, National Grid has re-structured its Planning and Asset Management organization to better align internal activities associated with long-term

[9] REV Connect brings electric utilities and third-party providers together to accelerate innovation, develop new business models, and provide value to New Yorkers. See https://nyrevconnect.com/

planning, DG interconnections, and non-wires alternatives ("NWA") analysis. New data management tools and software scripts have enabled the development of improved network models for all of the Company's distribution feeders and an integrated model that includes all distribution substations and sub-transmission lines. As a result, National Grid can now more efficiently evaluate the impact of DER on the distribution and sub-transmission systems.

In addition to improving its internal processes, the Company has also enhanced the transparency of T&D system needs and DER opportunities through the use of customer information portals and enhanced data sets targeted to DER developers to facilitate the increased integration of DER in a cost-effective manner. This information has been well received by stakeholders and new datasets will continue to be developed and shared as they become available.

Advanced Load and DER Forecasting

By their distributed nature, the impact of DER on the T&D system is specific in time and space, and requires the Company to develop new methods to forecast load and DER. National Grid is progressing along a multi-year plan for the development of load and DER forecasts with the level of granularity necessary to support DSP functions. Through the implementation of this plan, the Company will continue to enhance existing methodologies at the system level to incorporate new technologies and state policy goals, while concurrently developing new more granular forecasting models to assess where DER is most likely to be adopted and how the DER will impact the local load profiles. The more granular forecasts will be used by National Grid for T&D planning and they will also be shared externally with stakeholders to facilitate DER market development and decision-making. Updated load and DER forecasts are published annually to National Grid's System Data Portal, including a peak load forecast report and 8760 hour feeder loading where interval monitoring is available. As elements of the more granular forecasting models become available the Company will embed them within the annual updates. This past year, the Company created hourly (8760) forecasts by feeder and substation for use in a distribution system planning study which identified potential beneficial locations in support of proposed locational system relief value ("LSRV") in Phase Two of the VDER Value Stack Tariff.

Grid Operations

The integration of DER as an active resource makes grid operations more complex. The DSP vision demands real-time situational awareness and suggests a role for increased deployment of smart technologies which interact at multiple levels of the grid, from the customer through the bulk system, to create a system that minimizes inefficient seams or gaps.

National Grid's initial DSIP identified a number of foundational investments necessary to enable DSP functionalities, and funding for many of these investments was approved in the Three-Year Rate Plan Order. Consistent with the approved rate plan, the Company is implementing a portfolio of projects to deploy feeder monitoring sensors, VVO, and Advanced Distribution Management System ("ADMS"), as well as key back-office and control center information system enhancements to operate a more integrated and automated grid. The projects being progressed at this time represent initial foundational investments where additional funding in future rate cases will be required to continue with projects and programs that extend beyond the term of the approved rate plan as well as for any new projects that are necessary to develop additional capabilities.

In addition to these foundational investments in the grid, processes between the DSP and the New York Independent System Operator ("NYISO") must be harmonized to ensure the electric delivery system is managed in a safe, reliable and efficient fashion. Therefore, the Company and the Joint Utilities are engaging with the NYISO to define operational coordination and communications requirements necessary to preserve system safety and reliability while enabling DER wholesale market participation. The Joint Utilities will continue to coordinate with the NYISO as the NYISO develops tariff language for its DER Market Design Concept. Also, as the New York State Energy Storage Roadmap ("Energy Storage Roadmap")[10] noted, distribution and wholesale market coordination and rules and principles for dual participation of DER will be critical areas of focus during the five-year period covered by this DSIP Update.

Energy Storage Integration

The State has established an aggressive goal to integrate 1,500 MW of energy storage by 2025. The Company has been engaged in statewide policy discussions with DPS Staff, NYSERDA, and other utilities to help shape the path forward to meet this goal. Simultaneously, National Grid is implementing two ESS projects to address distribution system constraints located in the villages of Kenmore and Pulaski, and endeavors to complete these projects by December 31, 2018 in compliance with the Commission's March 9, 2017 *Order on Distributed System Implementation Plan Filings* ("DSIP Filings Order").[11]

National Grid's implementation of these two ESS projects has enabled development of standard engineering design packages for installing this technology on the Company's system. As the cost of ESS solutions continues to decline, it is expected that storage as a solution for a capacity or reliability need may become a standard tool of the DSP to address capacity, reliability and resiliency needs of the grid. The Company is in the process of developing the standard commissioning procedures, work methods, testing, and monitoring and control of these devices and expects that at some time in the future, ESS of various types will be installed on National Grid's system much in the same way as other devices, such as transformers or capacitors, are today.

The Company will actively participate in the energy storage stakeholder engagement processes associated with the Energy Storage Roadmap. The analytical work discussed in the Energy Storage Roadmap indicates that for ESS projects to be economically feasible within the National Grid service territory breakeven costs below $300/kWh[12]are necessary, and costs falling to this

[10] Case 18-E-0130, *In the Matter of Energy Storage Deployment Program* ("Energy Storage Proceeding"), New York State Energy Storage Roadmap and Department of Public Service/New York State Energy Research and Development Authority Staff Recommendations (filed June 21, 2018)("Energy Storage Roadmap").

[11] REV Proceeding *et al*., Order on Distributed System Implementation Plan Filings (issued March 9, 2017)("DSIP Filings Order"), pp. 29-31.

[12] *See* Figure 2.4.3: Energy Storage Roadmap chart on breakeven costs in the Energy Storage Integration section of this DSIP Update.

level are not envisioned until 2026,[13] beyond the time horizon covered by this DSIP Update. To further evaluate ESS opportunities within its service territory, the Company will continue to work with customers and other market participants to explore different use cases for ESS and plans to complete an internal study to identify beneficial locations at which ESS may be financially viable.

Additionally, National Grid anticipates there will be a series of updates to compensation mechanisms for ESS. In a May 29, 2018 filing of the Joint Utilities, the Company submitted for DPS Staff review two rate design proposals for a successor to net energy metering ("NEM") for mass market customers with an anticipated implementation date of January 1, 2020. Also, the Company, in a June 19, 2018 filing of the Joint Utilities, proposed a model tariff for a hybrid ESS and DG compensated under the Value Stack for the Commission's consideration.[14]

Electric Vehicle ("EV") Integration

Electrifying transportation is a crucial step in meeting the emissions goals of New York State and the entire Northeast region of the US as recognized in the New York State Energy Plan as well as in the *Northeast 80x50 Pathway*,[15] the latter which is a National Grid's affiliate's paper representing National Grid and National Grid's gas affiliates in downstate New York as well as National Grid's electric and gas affiliates in Massachusetts and Rhode Island. To facilitate the electrification of transportation in New York, the Company is progressing EV integration in a number of ways.

The Joint Utilities have developed an EV Readiness Framework to identify, prioritize, and execute actions in the near-to mid-term that will unlock the potential of transportation electrification. The framework has been posted on the Joint Utilities website.[16]

National Grid will continue to aggressively promote EV adoption to achieve the stretch carbon savings targets set in the Company's Earnings Adjustment Mechanisms ("EAMs") as approved in the Three-Year Rate Plan Order. As part of the Three-Year Rate Plan Order, the Company will commence an EV charging station development and education program that is designed to increase EV adoption while supporting New York State's zero-emission credits ("ZECs") and GHG emissions policy goals. As part of this program, the Company will make capital upgrades to enable the installation of EV charging stations at commercial customers' properties and

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[13] *Id.*, p. 48.

[14] Cases 18-E-0018 *et al.*, *In the Matter of Proposed Amendments to the New York State Standardized Interconnection Requirements (SIR) for Small Distributed Generators* ("Amended SIR Proceeding"), Joint Utilities Proposed Model Tariff for Compensation of a Hybrid Energy Storage System and Distributed Generation System (filed June 19, 2018).

[15] This paper presents an integrated blueprint for National Grid and National Grid affiliates in New York and New England to reduce GHG emissions deeply below 1990 levels while supporting economic growth and maintaining affordability and customer choice. The blueprint combines several mutually-reinforcing strategies that together provide a clear pathway to significant emissions reductions and signal a paradigm shift in the way we all relate to energy with the aim of achieving greater collaboration within the Northeast on this pressing and critical issue.

[16] *Available at*: http://jointutilitiesofny.org/wp-content/uploads/2018/03/Joint-Utilities-of-New-York-EV-Readiness-Framework-Final-Draft-March-2018.pdf

provide incentives to property owners to encourage the installation of new charging stations. The program is intended to overcome the cost and complexity barriers that prevent commercial customers, such as employers, apartment owners, retail site owners, and fleet operators, from installing charging stations for the benefit of consumers and/or their own fleets. The Company has also launched an online EV Marketplace to inform car shoppers of the benefits of EVs when making their next car purchase. The platform also provides car shoppers with information about manufacturer rebates and available tax incentives, and provides a total cost of ownership for any make or model, each tailored to the shopper's specific requirements.

To spur EV adoption within the Company, National Grid, through a shareholder-funded program, is currently offering incentives to eligible management employees for the purchase or long-term lease of a full EV or plug-in hybrid electric vehicle ("PHEV").

While the near-term grid impacts of electric vehicle supply equipment ("EVSE") are expected to be minimal and localized, the Company is proactively investigating means to appropriately manage EV charging in anticipation of higher vehicle penetration. One focus of these efforts is to link the price of EV charging to system demand levels through improved rate design, including real-time pricing signals. National Grid is evaluating modifications to its existing VTOU rate and considering alternative rate structures to further encourage beneficial charging in a manner that is aligned with cost causation. The proposal for a beneficial electrification rate, which National Grid will file with the Commission by September 14, 2018, will represent a step in this direction.

The Company is also planning to demonstrate a residential EV DR program in coordination with its residential DR platform provider. As part of National Grid's Electric Transportation Initiative project approved in the Three-Year Rate Plan, DR-capable networked chargers will be installed and participate in future DR programs offered by the Company.

Energy Efficiency Integration
National Grid and the Company's affiliates in other jurisdictions are among the leaders in delivering EE savings to its customers. As such, the Company is well-positioned to help New York significantly increase the levels of EE savings realized by electric and gas customers across the state while reducing both GHG emissions and consumer energy costs, and creating job opportunities.

The Three-Year Rate Plan Order included approval for new EE programs, increasing annual goals for the Company while moving EE expenses into base rates. National Grid is the first major electric utility in New York to fully shift Energy Efficiency Transition Implementation Plan ("ETIP") costs into base delivery rates. The savings targets approved in the Three-Year Rate Plan Order are approximately 40% above those in the Company's 2018-2020 ETIPs while increasing the budgets by more than 20% above the levels set out in the Company's December 22, 2017 filing with the Commission in Case 15-M-0252.[17]

Today, the Company's existing EE programs are focused on energy reduction and are offered uniformly across the National Grid service territory. However, moving forward, the Company will seek opportunities to target EE as well as DR programs, known as dynamic load management ("DLM") programs, to maximize distribution system value. Improved, granular forecasts and data capture are key building blocks in this effort.

Distribution System Data

The Commission, DPS Staff, and other stakeholders have placed significant emphasis on the role of system data[18] in facilitating market development, greater DER adoption, and the ability for DERs to maximize their value. Since the filing of the initial DSIP in 2016, National Grid has made significant improvements to its System Data Portal,[19] in terms of the breadth of data available, analysis of that data, and ways in which the data is presented, including:

- Reports regarding summer preparedness, peak load forecast, power quality, and T&D Capital Investment Plans
- Identification of potential NWA opportunities
- Hosting capacity maps that include feeder and substation level load data, nominal voltage, DG interconnected, DG in the Interconnection Queue, and substation transformer loading, as well as LSRV/VDER information that identifies substations and associated feeders that provide a LSRV benefit to the distribution system and the LSRV MW cap for each of those substations

The System Data Portal will continue to evolve as new market mechanisms are implemented and associated data to support them becomes available. Over the horizon of this DSIP Update, expected data enhancements include the presentation of locational data regarding beneficial locations of DER for NWA opportunities, as well as system and customer data relevant to NWA opportunities; 8760 hierarchal load and DER forecasts; updated LSRV opportunity mapping; enhanced hosting capacity maps; and potentially beneficial locations for siting ESS and EV charging stations. In addition to adding new data to the portal, the Company continues to develop more efficient processes to compile, aggregate, and publish the data.

Customer Data

Customers, and those entities providing services to customers, need accurate, secure, and timely customer data to effectively participate in DER opportunities. When sharing customer data, the

[17] Case 15-M-0252, *In the Matter of Utility Energy Efficiency Programs*, Niagara Mohawk Power Corporation d/b/a National Grid Updated 2017-2020 Electric and Gas Energy Efficiency Transition Implementation Plan ("ETIP")(filed December 22, 2017).

[18] System data is an expansive term that includes grid information such as load data, real and reactive power consumption, power quality, and reliability, as well as information on planned capital projects, beneficial locations, hosting capacity, and other system characteristics.

[19] *Available at*: https://ngrid.apps.esri.com/NGSysDataPortal/NY/index.html

Company will ensure that established protections of customer privacy are maintained. Ongoing Commission proceedings will need to continue to address conflicts that may exist between transparency, security, and confidentiality.

National Grid has collaborated in the Joint Utilities' Customer Data Working Group to advance several customer data efforts, including:

- Submitting two Joint Utilities' filings on customer privacy standards and approaches;
- Defining data sets and costs in support of Community Choice Aggregation ("CCA") efforts through development and filing of CCA tariffs;
- Evaluating potential opportunities for aggregated data automation; and
- Engaging with stakeholders to solicit feedback and inform future customer data needs and means of accessing that information.

Since the initial DSIP, the Commission has approved three new customer data privacy standards:

- The 15/15 standard[20] for aggregated energy consumption to be provided for community energy planning and CCA needs,
- The 4/50 privacy standard[21] for whole-building aggregated customer data to be provided to building owners or their authorized agents, and
- The 6/40 privacy standard[22] for small commercial and non-residential customer groupings.

National Grid plans to offer the opportunity for more granular customer data sharing through Green Button Connect My Data in concert with the Company's anticipated AMI deployment. Green Button Connect My Data will allow utility customers to automate the secure transfer of their own energy data to authorized third parties based on affirmative (*i.e.*, opt-in) customer consent and control.

Cyber Security

The DSP must maintain cyber security as a necessary component of a safe and reliable system. Cyber security protects customers and electric grid operations from a vast array of threats. As more devices, including third-party devices, are connected and integrated with utility operations, the number of potential targets increases, as does the need for a robust cyber security program.

Since 2016, in line with the generally increased awareness and understanding of cyber risks across the utility industry, the Company has made significant progress from a cybersecurity and

[20] The 15/15 privacy standard would permit an aggregated dataset to be shared only if it contains at least 15 customer accounts and no one customer represents more than 15% of the total usage for the dataset.
[21] The 4/50 privacy standard would require the building to have at least 4 accounts where no single account represents 50% or more of the annual energy use of the building. However, building owners that must comply with existing laws and ordinances, such as Local Law 84 in New York City, are exempt from the privacy standard.
[22] The 6/40 privacy standard would permit an aggregated dataset to be shared only if it contains at least 6 customer accounts and no one customer represents more than 40% of the total usage for the dataset.

digital risk & security perspective on core utility systems. National Grid's Global Information security policies have been developed, assessed, and/or established to provide objectives, scope, framework, and structured methods for implementing information security management controls to enable the Company to effectively manage the security risks to its information assets. Policies are reviewed on an annual basis and each business function is responsible to ensure that necessary arrangements are in place to monitor and report on compliance.

The Company has a set of standards in place today that protect its assets and those of its customers. As the DSP development progresses, National Grid will assess activities for cyber-security requirements, design, and implementation.

DER Interconnections

DER penetration levels are still relatively modest, but have been increasing steadily. The increased demand for interconnections in 2015 created a significant backlog in the Company's interconnection queue, which National Grid addressed by instituting a four-point plan in 2016. Implementing this plan has yielded shorter wait times and lower interconnection costs for customers. The four-point plan was comprised of:

1. Company Staffing – increased staffing of the DG team from 2016 to 2017 to respond to customer demand.
2. Single Point of Contact – established a DG Ombudsperson position to act as a single point of contact for customers and regulators to resolve interconnection issues.
3. Technical Collaboration – formed partnerships with industry organizations and key DER developers to identify solutions to major concerns. National Grid also collaborates with the Joint Utilities, the Interconnection Technical Working Group ("ITWG"), and the Interconnection Policy Working Group ("IPWG") to identify and vet changes to the SIR and develop technical guidance.
4. Education and Outreach – enhanced understanding of DG interconnection process through webinars and seminars.

During 2016, the Company successfully cleared the backlog of applications in the interconnection queue and has since maintained 100% timeline compliance for Coordinated Electric System Interconnection Reviews ("CESIRs").

In 2017, National Grid launched the first phase of an interconnections online application portal ("IOAP"). Applicants can now enter their project information online, track the status of their project throughout the interconnection process, and make electronic payments. The IOAP has been successful in helping reduce the application review stage of the process by approximately three days. The Company is now actively developing Phase 2 IOAP functions in which preliminary technical review screens will be automated.

In 2017, the Company conducted a series of stakeholder sessions and executive outreach sessions with its major DER developers/customers to understand their concerns and help improve their overall interconnection experience. National Grid continues to meet with key DER developers either weekly or bi-weekly to discuss the developer's DG project portfolio in order to increase the transparency of the Company's processes and understand/remove potential barriers in progressing projects through the interconnection process.

The Company is taking innovative steps to help DG projects connect more quickly at lower costs. First, the Company is investigating innovative means to implement necessary zero-sequence voltage ("3V0") substation protection schemes in high-potential DER areas. In 2017, National Grid placed orders for three 115 kV mobile 3V0 protection units that will allow the Company to install temporary 3V0 protection at a substation while the permanent 3V0 is being constructed. The Company expects to take delivery on these units in late 2018. This mobile technology will be used to expedite projects in which long lead times for upgrading 3V0 protection may delay the interconnection.

Second, the Company completed its construction activities for the Distributed Generation Interconnection REV Demonstration Project in December 2017 to proactively increase hosting capacity. The Company constructed common upgrades at its East Golah and Peterboro Substations sufficient to accommodate additional DG interconnections and marketed the increased capacity at those substations to DG developers. There are now sufficient pending DG applications in the Company's interconnection queue to fully subscribe the available transformer bank capacity created by the common upgrades. Based on the success and lessons learned from this demonstration project the Company is proposing to scale the concept in areas where municipal landfills and brownfield sites have high DG, or DG coupled with ESS, development potential. Such sites have drawn interest from municipal officials and the DG developer community. As part of this proposal to scale the cost-sharing concept, National Grid will test whether proactive outreach to communities and municipalities in these targeted areas can accelerate the pace of DG development by addressing local siting concerns while reducing permitting delays. To make this innovative cost-sharing solution more permanent, the Company plans to file a proposed cost-sharing tariff with the Commission to further enable the deployment of DG across the National Grid service territory.

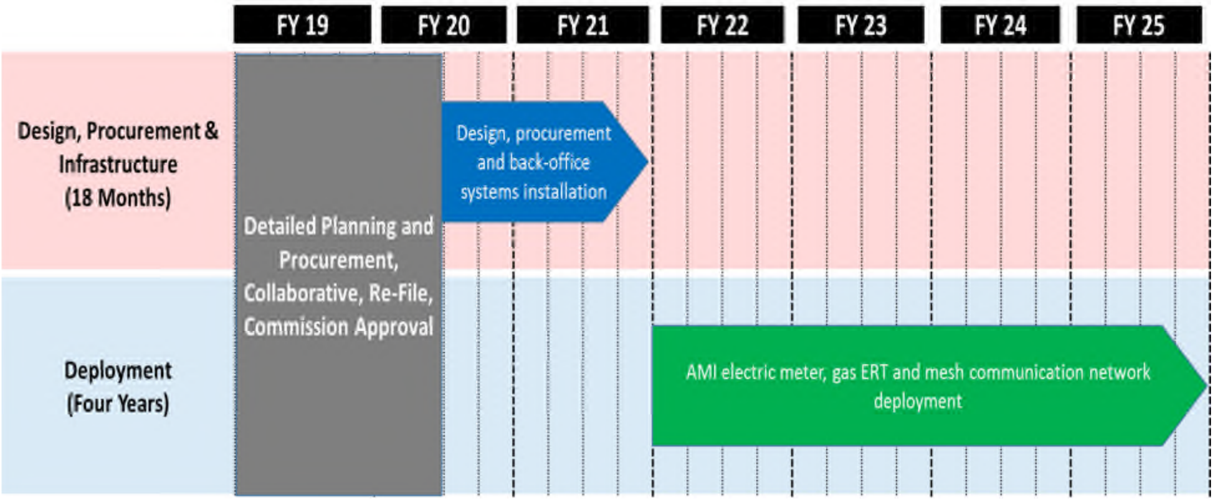
Advanced Metering Infrastructure

National Grid believes that AMI for all electric and gas customers is foundational to achieve the objectives of REV.

The Three-Year Rate Plan Order directed National Grid to convene a collaborative with DPS Staff and interested parties to further refine and update the Company's AMI system-wide business plan, a process that is underway at the time of this DSIP Update. The collaborative process includes large group meetings and smaller working group meetings to ensure a robust and well-thought-out plan is developed that reflects the priorities of a wide array of stakeholders with diverse needs. This input will be used in the development of a report and revised AMI business plan to be filed no later than October 1, 2018 for Commission review and action.

As a result of the Three-Year Rate Plan Order, the Company has adjusted the deployment schedule for AMI presented in the initial DSIP. This revised schedule is reflected in Figure ES 3 and is subject to further refinement through the stakeholder collaborative and Commission approval processes.

Figure ES 3: Timeline for Deployment of AMI



Note: the Company's fiscal year begins April 1st and ends March 31st of the year denoted. *E.g.*, FY19 begins on April 1, 2018 and concludes on March 31, 2019.

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

Hosting Capacity

Hosting capacity, defined as the quantity of DER that can be accommodated without adversely impacting the distribution system under existing control configurations and without requiring infrastructure upgrades to the primary line voltage and/or secondary network system,[23] is valuable system data for DER providers. National Grid calculates each circuit's hosting capacity by evaluating potential power system criteria violations as a result of interconnecting large solar PV systems[24] to three-phase distribution lines. This hosting capacity analysis ("HCA") allows DG developers to make more informed business decisions prior to committing resources to an interconnection application including the identification of more suitable locations.

National Grid is committed to enhancing its HCA through a series of staged releases and data refresh cycles. In October 2017, the Company replaced the Stage 1 Red Zone Maps, which provided only indicative system data, with Stage 2 interactive geographic maps that provide the

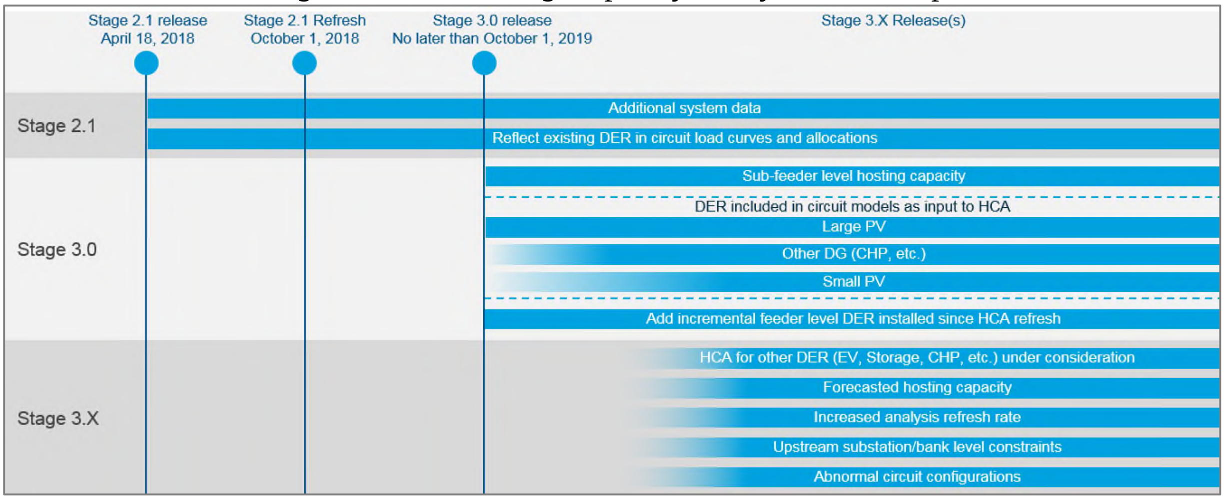
[23] Electric Power Research Institute ("EPRI"), *Defining a Roadmap for Successful Implementation of a Hosting Capacity Method for New York State*, Report Number 3002008848 ("EPRI Roadmap"), June 2016, p. 2; available at: http://www.epri.com/abstracts/Pages/ProductAbstract.aspx?ProductId=00000000 3002008848/

[24] Large solar PV is defined as those projects with an AC nameplate rating of 300 kW and above.

range of hosting capacity along a distribution feeder as well as the quantity of DG already interconnected and in the interconnection queue on that feeder. This was followed by a minor release, Stage 2.1, in April 2018 in which the Company provided additional information based on feedback from DG developers about the interconnected substations.

The Company has proactively sought opportunities to increase hosting capacity through the REV demonstration project mentioned previously but also via changes in distribution standards such as 3V0 for all new substations, two-way voltage regulation controls, switched capacitor banks, and recloser settings, as well as indirectly via more traditional system upgrades such as kV class upgrades. Going forward, other proactive measures will be considered in collaboration with the Joint Utilities and other stakeholders.

Figure ES 4: Hosting Capacity Analysis Roadmap



The Company develops its plans as represented in Figure ES4 for the HCA in collaboration with the Joint Utilities, subject to input from DPS Staff and other stakeholders. Efforts are currently underway to refresh the Stage 2 analysis by October 2018 and begin the more detailed assessments associated with Stage 3 in which the HCA will be determined and presented on a sub-feeder level. The initial Stage 3.0 release is expected to be complete by October 2019.

Potential Stage 3.X additions may expand to include additional types of DER as well as potentially forecasting hosting capacity for a period three to five years into the future. The ability to forecast hosting capacity requires further consideration among the Joint Utilities and stakeholders and is beyond the scope of Stage 3.0 and is represented as an enhancement via a future Stage 3.X release.

Beneficial Locations

From a grid operations perspective, the term 'beneficial location' refers to locations at which DER may materially benefit the electric system by increasing reliability or system efficiency, lowering operating costs, or deferring system upgrades. The Company offers multiple mechanisms to incentivize DER toward specific locations including: distribution DR programs, NWA opportunities, and LSRV zones in the VDER Value Stack tariff. In addition, National Grid's hosting capacity maps represent locations in which it may be beneficial for DER developers to locate to minimize system impacts and potential interconnection costs. As new market mechanisms are developed additional beneficial locations may be defined. The Company commits to sharing future beneficial locations as they are identified, *e.g.*, the identification of beneficial energy storage locations in support of the Energy Storage Roadmap.[25]

To provide transparency for DER developers, the Company presents beneficial location information on its System Data Portal in both tabular and interactive geographic formats. In addition to identifying the bounds of the beneficial locations, the System Data Portal also provides system information, such as primary voltage levels, historic loading, and feeder hosting capacity analysis, for DER providers to understand potential interconnection issues at that location.

Procuring Non-Wires Alternatives ("NWA")
NWA solicitations, which offer opportunities for DER developers to propose innovative solutions to meet clearly defined system needs, while providing benefits and potentially cost savings to customers, are an important mechanism for integrating DER with National Grid's electric system.

The Company's first NWA project employed DR to meet an N-1 contingency condition in the Village of Kenmore which is located in the greater Buffalo area. Since then, the Company has publically solicited proposals for seven NWA opportunities and has, or is currently evaluating those proposals for their relative benefit to cost. While the Company has not yet identified a viable NWA solution, there have been significant learnings through the NWA solicitation process and National Grid iteratively improves each solicitation by incorporating lessons learned and stakeholder feedback which has resulted in more recent DER proposals being better aligned with the distribution system needs. Going forward, the Company will continue to monitor grid needs based on annual forecasts and expects to identify new NWA opportunities by applying a Suitability Criteria Matrix.

Beginning in 2018, National Grid will file annual reports with the Commission that provide specific information about all active and completed NWA projects including: measurement and verification ("M&V") procedures, description of DER portfolios, costs, customer and community outreach plans and activities, and BCA results. The Company will also file quarterly reports containing information about project expenditures, project activities, in-service dates, and customer/operational benefits in compliance with the Three-Year Rate Plan Order.

[25] Energy Storage Proceeding, *supra* note 10.

DSIP Governance

There are numerous work processes associated with the development of the DSIP and its implementation. The processes, both internal and external, progress in parallel, often in advance of formal policies and procedures.

Externally, National Grid works closely with the 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, DSP Steering Committee, and a Regulatory Policy Committee to coordinate the numerous working teams and joint filings associated with the various REV proceedings.

Internally, National Grid maintains a DSIP Steering Committee that guides the development of the DSIP in alignment with the Company's vision and strategy, as well as providing coordination and alignment of REV issues across the organization. The DSIP Steering Committee has executive representation from across the organization including from the Customer, Regulatory Strategy, and Planning and Operations functional groups.

Future investments identified in the DSIP are integrated into the Company's rat case filings or other filings for Commission review and approval as appropriate. Several investments identified in the initial DSIP were included in National Grid's latest rate case and the Company is now advancing those projects in accordance with the Three-Year Rate Plan Order. The implementation of the DSIP projects utilizes the Company's standard governance for budgeting, project approval, and resource planning.

Among other things, National Grid is also currently in the process of re-aligning accountabilities within its organizational structure to most effectively manage its role as DSP. As part of this alignment the responsibilities for strategic decision making are being streamlined and distribution system planning and operations have been aligned under a single executive. These changes will provide efficiencies in the overall governance of DSIP implementation.

Marginal Cost of Service Study

The Company uses its existing Marginal Cost of Service ("MCOS") study to set rates for the Empire Zone Rider ("EZR") and the Excelsior Jobs Program ("EJP") and as a metric to measure the cost-effectiveness of certain DR and EE programs. While the elements included in the MCOS may be adequate for these programs, the Company determined they were not appropriate for use in developing the distribution elements (*i.e.*, DRV and LSRV) as part of the VDER Value Stack compensation components. Consequently, National Grid has completed a separate study, referred to as the Marginal Avoided Distribution Capacity ("MADC") study, to differentiate the two work efforts. The Company proposes that the MADC study results become the basis for compensating DER, including those that inject into the system, and those that respond via flexible loading, including DR. The MADC study is an important step forward in an integrated planning process.

Based on the MADC study, the Company identified 68 individual LSRV zones and 6 pricing groups, where injecting DER may offer value to the system. Concurrent with filing this DSIP Update, National Grid filed a report detailing the MADC study and its recommendations with the Commission.[26] If approved, the MADC values will support DER compensation in a fashion that better reflects their contribution to the distribution system.

Benefit Cost Analysis

Version 2.0 of the Company's BCA Handbook was filed contemporaneously with this DSIP Update filing.[27] Version 2.0 provides updated utility-specific and state-wide input assumptions and sources as well as clarifying edits to Version 1.0 methodological descriptions and the inclusion of additional example applications. As with Version 1.0, National Grid's BCA Handbook was developed in collaboration with the Joint Utilities and differs from the other utility Handbooks only where necessary to accommodate distinctions between the service territories.

Conclusion

National Grid embraces its role as a DSP provider and shares the State's goal of decreasing total carbon emissions 80% by 2050. As evidenced by the activities outlined in this DSIP Update, the Company seeks to facilitate and enable outcomes that will support this goal. The Company is making progress in the DSP provider role and looks forward to continuing on this journey and making productive steps while delivering value for customers.

Looking ahead, the Company recognizes that DSP functionalities and processes will continuously evolve and is committed to innovation and productive collaboration to further maximize the stakeholder value created by the DSP. Throughout this evolution National Grid will work with stakeholders to ensure the DSP continues to provide value to customers and is flexible enough to accommodate adaptive goals and paths forward that adjust to changing technology, policy, and consumer preferences in a cost-effective fashion.

[26] VDER Proceeding *et al*., Enhanced Marginal Cost of Service Study of Niagara Mohawk Power Corporation d/b/a National Grid to Determine Locational Value of Distributed Energy Resources (filed July 31, 2018).
[27] DSIP Proceeding *et al*., Version 2.0 of Niagara Mohawk Power Corporation d/b/a National Grid BCA Handbook (filed July 31, 2018).

1. Progressing the Distributed System Platform

Introduction

The capabilities of the DSP are expected to continuously evolve and the Company's DSIP must be flexible enough to accommodate adaptive goals and paths forward. Through this evolution, the DSP must ensure that customers receive value for what they pay for and that utility service remains affordable. Achieving these objectives will require innovation and plans that are developed collaboratively with stakeholders and new partners.

National Grid's role as the DSP has already begun and, as presented in this DSIP Update, the Company has made significant progress since filing its initial DSIP in 2016.

Long-Term Vision for the DSP

Over the next decade, New York's electricity system will become significantly cleaner, more efficient, more flexible, more reliable, and more resilient. This transformation of the state's electricity system will play a central role in the decarbonization of the state's economy.

DER which is "comprised of a wide variety of distributed energy resources, including end-use energy efficiency, demand response, distributed storage, and distributed generation"[28] are expected to be a key part of this transformation. To facilitate adoption and grid integration of these resources, National Grid and the Joint Utilities are developing DSPs that will offer DER products and services, creating new sources of value for customers and market participants.

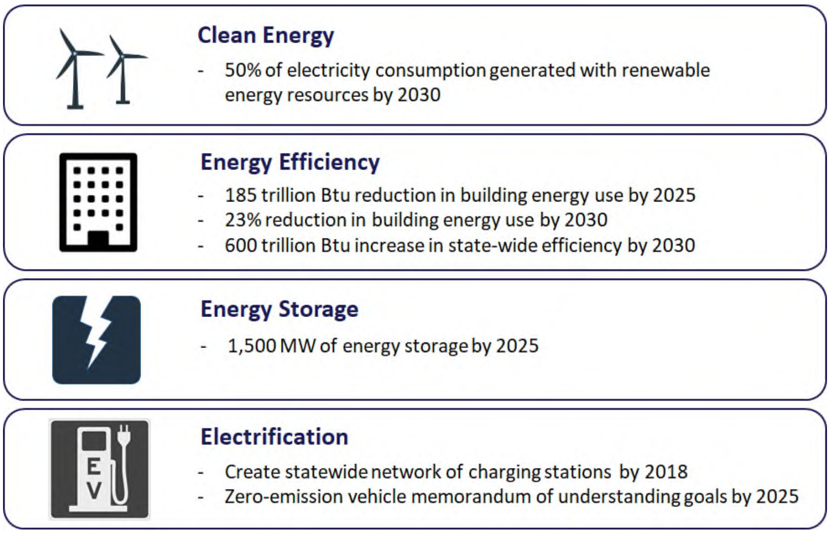
As described in this DSIP Update, National Grid has made substantial progress in laying a foundation for its DSP. Building upon this early progress requires having a vision of how DSP functions and capabilities will evolve in the foreseeable future.

The creation of DSPs is occurring within the broader context of New York's energy policy goals and its vision of a sustainable, low-carbon future. Quantitative targets for this vision were established in the State Energy Plan[29] and reinforced and supplemented by the Governor's 2018

[28] REV Proceeding, REV Track One Order, p. 3, n.3
[29] *2015 New York State Energy Plan*, https://energyplan.ny.gov/Plans/2015.aspx

State of the State address.[30] These targets include efforts to significantly expand renewable energy, energy storage, and energy efficiency (Figure 1.1). Additionally, New York, in conjunction with seven partner states, have collectively a goal to have 3.3 million ZEVs on U.S. roads by 2025[31] while the state is actively promoting EV adoption and a build-out of EV charging infrastructure.[32]

Figure 1.1: Key New York State Energy Policy Goals



These goals imply a transformation of the state's energy sector, from independent energy end-uses to an increasingly integrated energy system in which clean electricity serves a growing share of building and transportation energy demand. A flexible, smarter electric grid will be at the heart of this more integrated energy system. Modernization of the electric grid is thus a critical step toward meeting the state's energy policy goals.

The state's aggressive energy policy goals are complemented by REV objectives to: increase affordability, grow clean energy innovation, reduce greenhouse gas emissions, empower informed energy choice, improve the existing energy infrastructure, create job and business opportunities, protect natural resources, enhance energy system resiliency, promote a cleaner transportation sector, and expand energy efficiency impacts.[33] In support of these objectives, the April 2014 Staff Proposal in the REV proceeding laid out a vision for a distributed electricity

[30] *Governor Cuomo Unveils 20th Proposal of 2018 State of the State: New York's Clean Energy Jobs and Climate Agenda* (January 2, 2018), *https://www.governor.ny.gov/news/governor-cuomo-unveils-20th-proposal-2018-state-state-new-yorks-clean-energy-jobs-and-climate*
[31] *See* Multi-State ZEV Task Force, State Zero-Emission Vehicle Programs: Memorandum of Understanding (October 2013), *available at*: https://www.zevstates.us/about-us/
[32] NYSERDA Electric Vehicle Programs, https://www.nyserda.ny.gov/Researchers-and-Policymakers/Electric-Vehicles/Electric-Vehicle-Programs
[33] REV 2030 Goals, https://rev.ny.gov/

marketplace that will enable customers to participate in supplying local energy resources and manage their electricity needs.[34]

Achieving this vision will require a transformation of New York's electricity system, progressing to a system that is information-rich, facilitates customer engagement and choice, seamlessly integrates DER, and encourages clean energy resources and EE. The transition to this future electricity system is being enabled by improvements in energy infrastructure, information, communications, and grid control technologies.

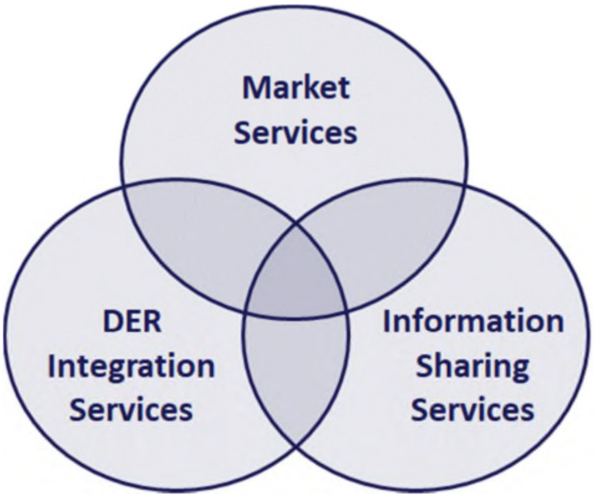
The Distributed System Platform Vision

The Commission effectively adopted the model of the DSP as defined below by the Platform Technology Working Group with the clarification that "DER providers will be viewed as customers and partners, rather than competitors, of traditional grid service":[35]

> [A]n intelligent network platform that will provide safe, reliable and efficient electric services by integrating diverse resources to meet customers' and society's evolving needs. The DSP fosters broad market activity that monetizes system and social values, by enabling active customer and third party engagement that is aligned with the wholesale market and bulk power system.[36]

Taken further, the DSP is the set of people, processes, and systems that allow utilities to provide three core, interrelated services: DER integration, information sharing, and market services (Figure 1.2).

Figure 1.2: Three Core Interrelated DSP Services

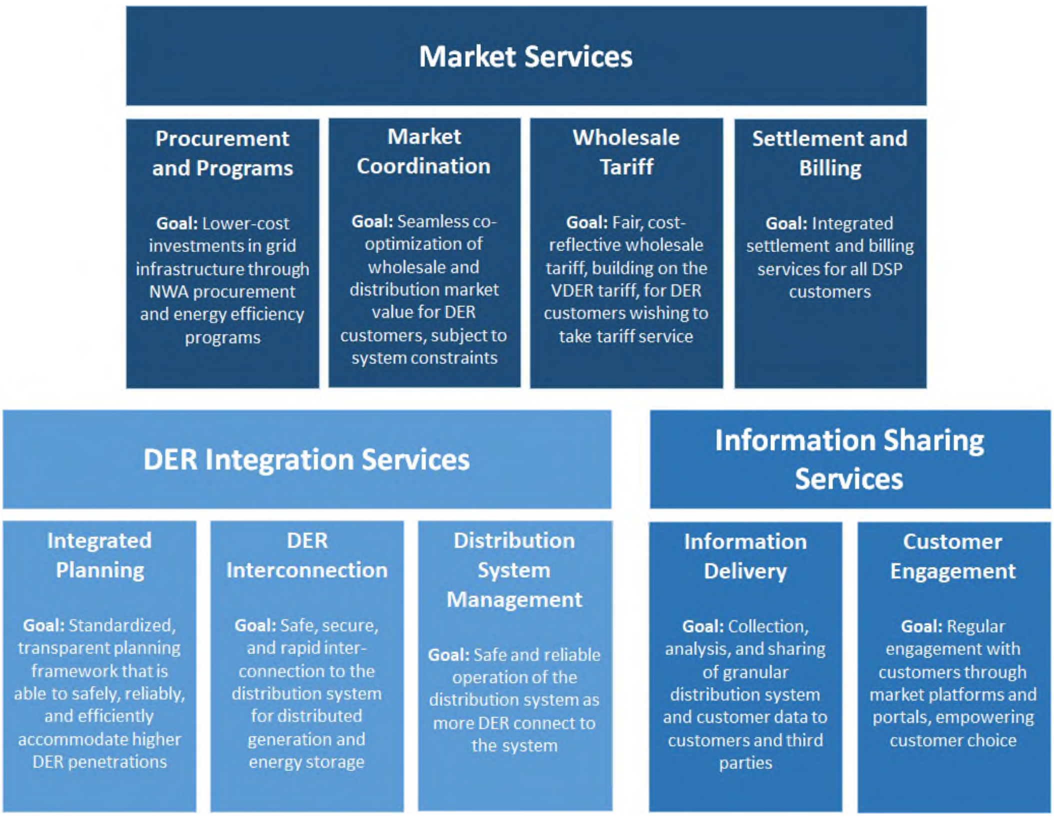


[34] REV Proceeding, REV Track One Order, pp. 10-14.
[35] *Id.*, pp. 40-41.
[36] *Id.*, p. 31.

- **DER Integration Services** refer to planning and operational enhancements that promote streamlined interconnection and efficient integration of DER, while maintaining safety and reliability.
- **Information Sharing Services** refer to information and communications systems and processes that collect, manage, and share granular customer and system data, enabling customer choice and expanding participation of third-party vendors and aggregators in markets for DER.
- **Market Services** refer to utility programs, procurement, wholesale market coordination, tariffs, and other services that create value for DER customers and providers through market mechanisms.

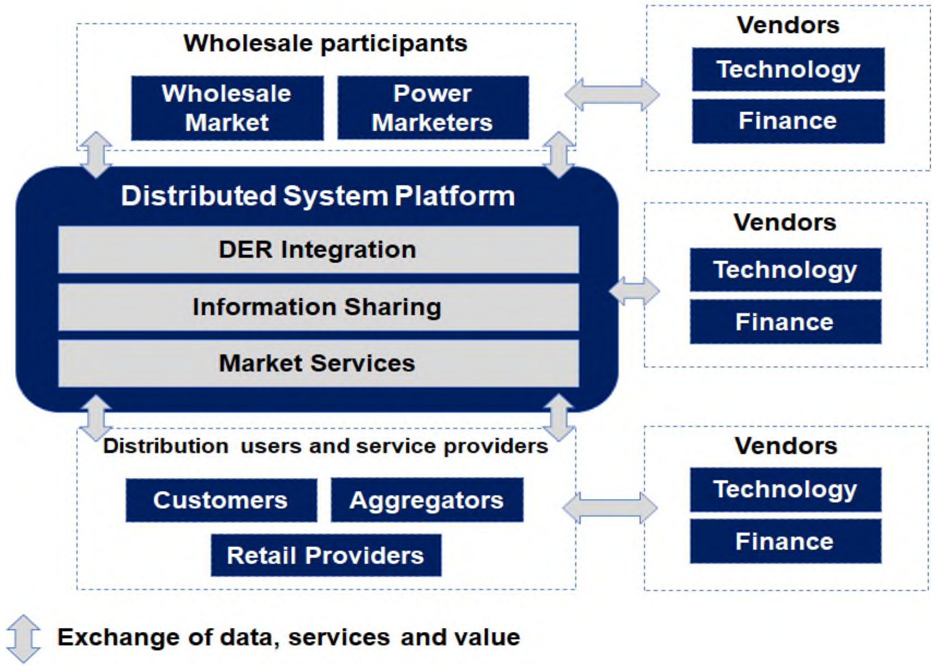
As a DSP provider, National Grid is developing the capabilities, processes, and systems that will enable key DSP functions such as: integrated planning, DER interconnection, and distribution system management (*i.e.*, DER integration services); information delivery and customer engagement (*i.e.*, information sharing services); and procurement, market coordination, wholesale tariff, and settlement and billing (*i.e.*, market services). Figure 1.3 below describes long-term goals for each DSP function. Each of these DSP services and functions support customer engagement and empowerment.

Figure 1.3 Long-Term Goals for DSP Functions within Each Core DSP Service Area



As they evolve, DSPs will increasingly bring together suppliers and buyers of electricity services, becoming more populated with information and transactions over time. DSPs will become a natural marketplace for third-party aggregators and technology vendors to gather data and offer their services. See Figure 1.4 below.

Figure 1.4 Illustration of the DSP as an Energy Marketplace



DSPs will open up new sources of value for electricity customers and market participants, by expanding customer choice, enhancing DER integration, and maximizing the distribution and wholesale value of DER. See Table 1.1 below.

Table 1.1: DSP Value to Customers and Market Participants in the Longer Term

Customers • Ability to identify products and services that lower costs, emissions, and improve reliability. • New products and services that can be tailored and bundled to meet customer preferences. • Ability to shop among different service providers. • Granular information on usage, cost, reliability, and emissions.
Market Participants • Access to streamlined interconnection, detailed information on hosting capacity, interconnection costs, and locational value. • Co-optimization of wholesale and distribution market value.

- Procurement for NWAs and other distribution services.
- Billing and settlement services for wholesale and distribution markets.
- Access to granular customer information with customer consent.

National Grid and the Joint Utilities anticipate that the DSP vision will continue to advance as key drivers and markets evolve. DSP functions and capabilities will progress through different phases, as described in the Joint Utilities Supplemental DSIP.[37] A phased approach aligns the pace of DSP investment with the speed of DER adoption. Additionally, a phased approach provides an opportunity to learn from the Company's demonstration projects, as well as the demonstration projects being undertaken by National Grid affiliates and others.

The Joint Utilities have established a framework for understanding and navigating the different phases of DSP capability, encapsulated in three DSP "models." DSP 1.0 refers to the first, and current, phase of DSP development. DSP 2.0 refers to a second phase, with enhanced integration, information, and market services. DSP 2.x refers to a longer-term phase of DSP development, characterized by the emergence of transactional distribution markets.

The current focus is on DSP 1.0 and 2.0 and the transition between them, describing three key aspects of DSP evolution: (1) function and capability; (2) customer value; and (3) enabling investments and conditions.

DSP 1.0

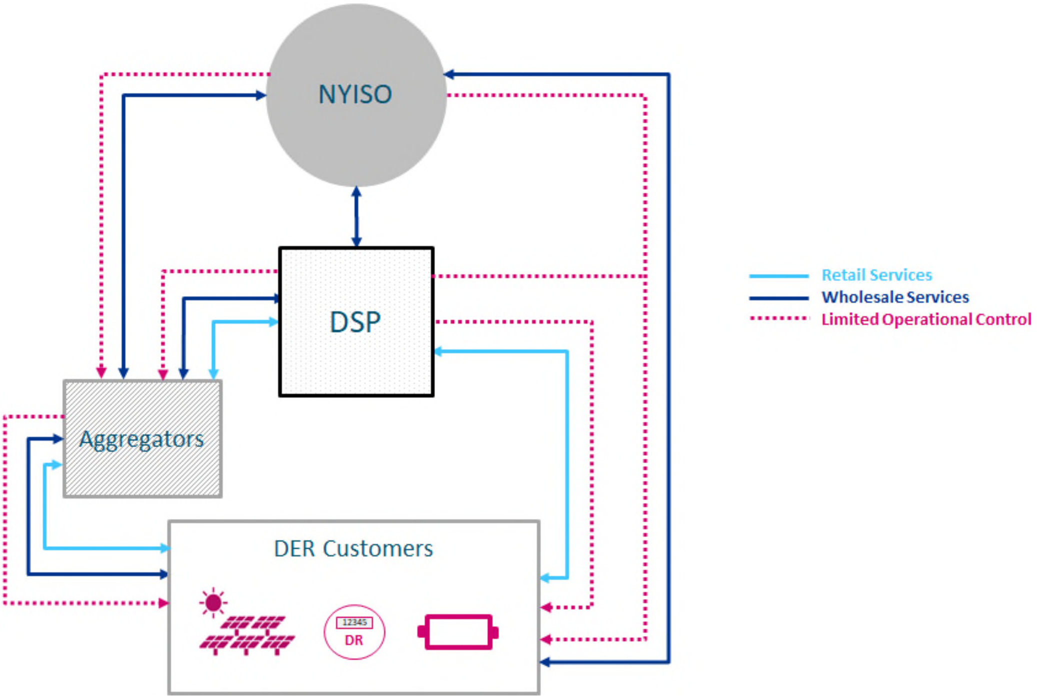
In DSP 1.0, utilities create foundations for the platform, which enables:

- More streamlined interconnection and enhanced distribution system measurement, monitoring, and control capabilities;
- Safe and reliable operation of the grid with increasingly higher levels of DERs;
- More accessible, granular information on customer use and closer engagement with customers and aggregators through information portals with appropriate data privacy considerations;
- Regular NWA procurements and incorporation of wholesale value through the VDER Value Stack tariff.

In this phase, DSPs provide retail settlement and billing services to customers based on the VDER Value Stack tariff, and wholesale settlement and billing services to aggregators for NWA procurement (Figure 1.5). DER aggregators and customers can also access wholesale settlement and billing services through the NYISO.

[37] DSIP Proceeding, Joint Utilities Supplemental Distributed System Implementation Plan ("Supplemental DSIP")(filed November 1, 2016).

Figure 1.5: DSP 1.0 Wholesale and Retail Services



DSP 1.0 promotes increased DER integration up to the limitations of today's distribution grid. Utilities have sufficient visibility and operational control over DER to maintain safe and reliable grid operations. Operational coordination with the NYISO is based on pre-determined rules for joint participation in NWA procurements and the NYISO markets.

Continued progress in DSP 1.0 will be facilitated by investments in:

- ***DER integration capabilities***: integrated planning; operational communications; measurement, monitoring, and control capabilities; distribution automation; and distribution management systems;
- ***Information sharing capabilities***: data management and analysis software; customer and aggregators interfaces;
- ***Market services capabilities***: NWA planning and procurement; NYISO coordination; and VDER tariff enhancements.

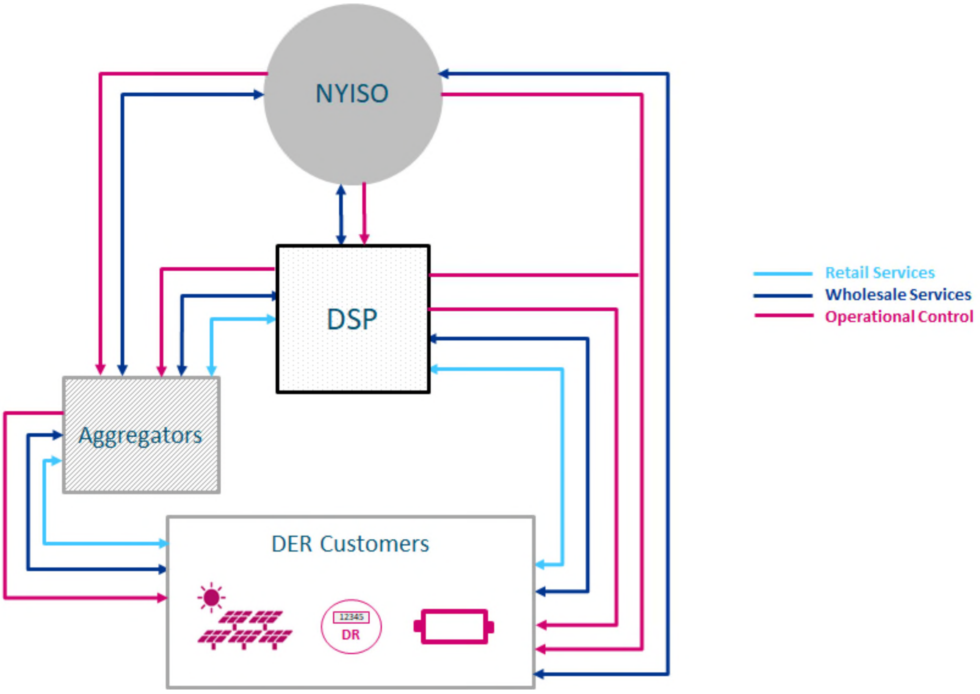
DSP 2.0

DSP 2.0 will build on the functions and capabilities of DSP 1.0, adding significantly greater visibility and operational control over DER. Greater visibility and operational control will allow for the creation of integrated markets for wholesale and distribution services.

In DSP 2.0, DSPs will offer wholesale scheduling and dispatch services, allowing customers and aggregators to maximize the value of their resources across NYISO wholesale markets and distribution markets. Aggregators and customers will still be able to access wholesale markets directly through the NYISO. See Figure 1.6 below. The DSP and NYISO will have enhanced capabilities to monitor and control DER.

Relative to DSP 1.0 (Figure 1.5), DSP 2.0 (Figure1.6) adds the provision of wholesale services from the DSP to DER customers and enhanced operational control.

Figure 1.6: DSP 2.0 Wholesale and Retail Services and Operational Control



Utilizing DSP market platforms, DSP 2.0 will provide an additional “wholesale services” route for DER customers to deliver their services to markets — illustrated by the solid blue line connecting DER customers and the DSP in Figure1.6 above. These market platforms are still being developed and will be the subject of a future DSP Market Design and Integration Report, as referenced in the DSIP Guidance Update, to be filed by the Joint Utilities with the Commission.

Several functions and capabilities in DSP 2.0 do not yet exist and require innovations in software, systems, and process. For example, DSP 2.0 is characterized by much larger volumes of information flow, which require new approaches and tools for data management and analysis. The protocols, processes, and software enabling near real-time DER control also require innovation and development.

DSP 1.0 and 2.0 are distinguished by key high-level differences in platform function and capability rather than checklists of essential features. Thus, the transition from DSP 1.0 to 2.0 will evolve and develop over multiple years, with variations among utilities. Timelines for individual utilities will depend on need, grid topology, and funding.

With further market and technology development, DSP 2.0 could eventually evolve to DSP 2.x, where DER penetration is substantially larger than it is today, loads are highly price sensitive, and decentralized transactions are feasible on a larger scale.

The remainder of this DSIP Update focuses on building the functions and capabilities necessary to continue progress in DSP 1.0 and lay the groundwork for DSP 2.0.

DSP Progress and Implementation Roadmap

Aligned with the vision above, National Grid has made significant progress in developing foundational capabilities which support the continued evolution of the DSP. On-going DSP implementation efforts are focused on grid modernization, DER integration, information sharing, and market services. Combined, these efforts benefit customers and market participants by providing information that facilitates informed market choices; stimulates DER deployment by defining a more accurate valuation of DER; and implements planning and operational methodologies that integrate DER.

DER Integration

DER integration is the foundation of many of the shared goals of the state, stakeholders, and utilities under REV. Several key DER integration initiatives have been implemented, and progress through June 2018 is represented in Table 1.2 below.

Table 1.2: Actions and Results in DER Integration through June 2018

Actions		Results
Created National Grids IOAP also referred to as New Connection Application Portal (“nCAP,”) National Grid’s IOAP.	→	Streamlined DG interconnection process.
Provided access to circuit-level hosting capacity data.	→	Developers are able to target less costly locations for DER interconnection.
Incorporating DER into forecasting used in T&D planning in a more robust and granular fashion.	→	DER forecasting is better integrated into the planning process.

Actions		Results
Established common interim monitoring and control standards for solar PV.	→	Maintains system reliability/safety under current volume of DER penetration and enables advanced market functions.
Identified potential, low-cost monitoring and control (“M&C”) solutions while implementing DG interconnection advancements.	→	Reduces barriers to entry for DER and greater cost predictability for interconnection customers.
Commenced demonstration of the following foundational investments: AMI, ADMS, Distributed Energy Management System (“DERMS”) and VVO.	→	Gained valuable lessons learned with respect to the deployment of foundational infrastructure that facilitates reliability and safety, and DER integration and market participation.
Implemented EAMs.	→	Incentivizes National Grid’s performance that is aligned with REV objectives.
Progressed REV demonstration projects.	→	Achieving greater understanding of how to deploy innovative solutions across the National Grid service territory to address system needs.
Published EV Readiness Framework.	→	Provides additional support for expansion of the EV market and EV charging infrastructure.
Implementing two ESS projects.	→	Gaining lessons learned to develop planning and engineering standards for future ESS interconnections.

Information Sharing

Sharing useful information with customers and developers is central to achieving the REV objectives and is a fundamental aspect of the DSP. Expanded information sharing, including more granular customer data and system data, will facilitate DER market development and deployment by signaling where DER can provide the greatest value to customers and the grid, aiding in the development of new DER offerings, and building business cases to support the investment decisions of third parties and customers.

An area of emphasis has been on developing business use cases for customer data and system data to identify and prioritize stakeholder data needs. The Joint Utilities, as part of the Customer Data and System Data working groups, hosted discussions about business use cases with stakeholders to clarify what data is being used, how it is being used, and what additional datasets would provide more value to third parties and customers. Objectives of the one-on-one interviews between the Joint Utilities and third-party developers included:

- Inform stakeholders from the DER development community of each of the Joint Utilities and utility data portals and identify the data available;
- Work with stakeholders to better understand how currently available utility system data is being used and what additional data or refinements to data or data access might be valuable;
- Gain a better understanding of which types of data—either currently available or additional—are most important to developers for specific projects; and
- Formulate the discussion around developer use-case examples.

As enhanced data sets become available the Company posts the information to the National Grid System Data Portal for access by stakeholders.

Through June 2018, several key information sharing initiatives have been implemented, which are summarized in Table 1.3 below.

Table 1.3: Actions and Results in Information Sharing through June 2018

Actions		Results
Developed and expanded the National Grid System Data Portal.	→	Increases access and usability of stakeholder-requested information.
Created central location on Joint Utilities website for utility links to individual NWA request for proposal ("RFP") opportunities.	→	Provides more transparency and efficiency for developers in NWA solicitations and other market opportunities.
Crafted 4/50 anonymity proposal for whole building aggregated data.	→	The Company is applying the 4/50 standard when aggregating whole building data.
Crafted 15/15 anonymity standard for customer data aggregation for community planning and CCA use.	→	The Company is applying the 15/15 privacy standard to aggregated datasets related to CCA, data posted on the system data portal, and aggregated data within RFPs for NWAs.
Crafted 6/40 anonymity proposal for customer data aggregation in regard to small commercial and non-residential customers.		The Company is applying the 6/40 privacy standard for information sharing regarding non-residential customer data in the Utility Energy Registry
Supported launch of REV Connect to communicate DER opportunities available in each of the Joint Utilities' service territories.	→	Provides greater transparency for the developer community in NWA and other REV-related opportunities.

Actions		Results
Providing various load and DER forecast data.	→	Provides greater transparency for DER developers to inform business development.
Completed stakeholder engagement sessions across nine JU DSP stakeholder engagement working groups	→	Created stakeholder opportunities to provide input on the implementation of various DSP-related efforts.

Market Services

In DSP 1.0, the goal of the market services aspect of the platform has been to enable DER greater access to market value through advances in the "3 P's" of programs, procurement, and pricing.

Table 1.4: Three-P's to Enable DER Greater Access to Market Value

Three-P's	Description
Programs	Distribution-level utility tariff-based DER programs, such as DR, EE, and NEM to increase customer adoption of DER and deliver system benefits.
Procurement	Contract-based NWAs provide compensation where, and when, system needs are identified and require a more defined operational capability and performance verification (*e.g.*, being dispatchable, non-intermittent). NWAs provide an opportunity to decrease system costs by providing close alignment of compensation to grid services provided so that DER can be compensated for delivered value through efficient pricing.
Pricing	This dynamic market mechanism encourages DER adoption by using locational value streams for DER grid services and creating price signals to drive behavior. Such price signals may be NEM successor tariffs (*i.e.*, VDER Value Stack) and TOU rates.

Progress has been made in each of these areas. Through June 2018, several key market services initiatives have been implemented, which are summarized in Table 1.5 below.

Table 1.5: Actions and Results in Market Services through June 2018

Actions		Results
Identified, developed, and implemented NWA solicitations, including common datasets and bidder pre-qualification processes.	→	Creates more opportunities and greater transparency, consistency, and efficiency for the entire NWA solicitation process.

Actions		Results
Implemented advanced utility programs: EE and DR	→	Enhances opportunities for greater DER participation.
Implemented Phase One VDER Value Stack.	→	Provides more clear market signals to developers of where applicable DER can capture enhanced locational value.
Aligned dispatch and communication protocols, and formalized roles and functions between DSP, NYISO, DER aggregators, and DER owners.	→	Allows DER to access more value through wholesale markets, while maintaining distribution and bulk power system safety and reliability.
Completed improved studies to assess distribution locational value.	→	Increases transparency to areas of the distribution system in which DER could provide the most value.
Implemented new utility business model concepts: Rate reforms, Platform Service Revenues (“PSRs”), cost recovery mechanisms, EAMs.	→	Provides further alignment of incentives and thereby driving customer engagement, DER deployment, and a more resilient electric grid to further REV objectives.

Innovation and Demonstration Projects

National Grid supports innovations through a variety of forums including engagements with colleges and universities, participation in research efforts with the Electric Power Research Institute (“EPRI”), and numerous demonstration projects.

Learning by doing is a key element of the Company’s innovation plan. The Company’s REV demonstration projects illustrate its commitment to innovation in support of REV. National Grid has launched six (6) REV demonstration projects since 2016. These projects offer an opportunity for the Company to test new technologies and innovative business models at pilot scale and utilize lessons learned to help develop new offerings, at scale, based on the most successful demonstrations.

A summary of each of the Company’s REV demonstration projects is provided below.

Clifton Park Demand Reduction (2017 – 2019)

Engage residential customers in the Town of Clifton Park with price signals and web-based tools and information, enabled by infrastructure investments in AMI and VVO, to test the use of behavioral strategies to curtail electric demand during peak times. Approximately 14,400 residential customers are part of the demonstration project. In part this project will evaluate the potential benefits of AMI and VVO in support of National Grid's business case for deployment at scale.

Key Program Delivery Milestones

- Deployment of 13,214 electric and 11,561 gas smart meters at customer sites was completed by July 2017. The customer acceptance rate was 91.3%, exceeding the 90% target.
- Based on year one data, 65 percent of customers are currently receiving pre-event notifications for PTR events. On average, 57 percent use less electricity than predicted during PTR events. PTR provide points that customers earn for curtailing demand and these points can be redeemed for gift cards from popular retailers. The Company is testing these rewards programs to motivate customers as part of behavioral strategies.
- An online portal enables customers to access hourly energy usage data and includes content for targeted outreach and education on energy reduction tips.
- Seven PTR events were called during summer 2017. Weather correlation, feeder peak conditions, and thresholds for DR events have been established and will be tested in 2018 and 2019.
- Estimated future energy savings and demand reductions of 2 to 3 percent from VVO are expected at the feeder level beginning in Q2 2019.
- Promotion of new TOU rates, smart home devices, and up to 20 PTR events are planned during 2018. The rate design tests will enable the Company to understand customer adoption and fine tune offerings that maximizes benefits to customers and grid operations using AMI.
- Detailed data analytics will be used to better understand customer behavior and enhance outreach strategy.
- Revised testing of customer participation and success for various new rate designs that focus on TOU strategy, use of smart home devices, and EV charging at off-peak hours are under development.
- Promotion of DER, strategic energy efficiency programs, and DR using advanced data analytics.

Results and Lessons Learned to Date

- Through the provision of an opt-out model Smart meters have had high customer acceptance.
- Customers are favorably responding and interested in National Grid's enhanced customer portal with interval data presentment and pages focused on energy saving tips; project offerings are trending higher after the start of the event alerts.

Potsdam Community Resilience (2016 – 2018)

The Village of Potsdam has experienced multiple severe microbursts and winter ice storms; some of them causing power outages lasting for weeks. This REV demonstration project seeks to develop an engineering design solution for a community microgrid to improve local resiliency for critical infrastructure serving local universities, a hospital, and other essential services in the Village. The project aims to develop an economic model for community microgrid projects that involves a hybrid ownership of assets between the utility and customers, accompanied by a unique tariff design that recovers the cost of the assets from the community that benefits from the microgrid.

Key Program Delivery Milestones

- Detailed engineering design has been drafted.
- Detailed business model includes a multi-stage roll out for incremental investment options and a tiered, cost-recovery model to balance costs with benefits realized based on customer types and proximity.
- Develop innovative business model that can serve as a template for microgrid development that fosters utility-private partnerships.

Results and Lessons Learned to Date

- Hybrid model for ownership of microgrid assets offers a robust model for the utility to own, maintain and safely operate the central infrastructure and third parties the opportunity to develop and monetize distributed generation assets.
- D and EE strategies can be leveraged to reduce the energy demand during emergency scenarios, reducing the size and costs of the microgrid.
- Load requirements will evolve for each facility connected to the microgrid over time which supports utility ownership of central infrastructure for efficient procurement and dispatch, and fair compensation for DER services.
- Tiered cost-recovery model provides an innovative method for financing microgrids.
- Value of Resiliency ("R") needs to be developed in a utility framework that can be used in the BCAs to value and compensate microgrids. Market economics for DERs in blue sky conditions may not be sufficient to support microgrid investments in locations that have lower energy costs.

Distributed System Platform (2016 – 2018)

This demonstration project aims to develop, deploy, and test a first of its kind distribution-level energy market. The project will test services based on a local, small-scale, but centralized DSP that will communicate with network-connected points of control ("POCs") associated with the participating customer-sited DERs. The DSP will determine and communicate the locational value of energy and provide a cloud-based platform that allows customer-owned DER to participate and provide energy to the electric distribution system initially utilizing a Locational Marginal Pricing + Distribution + Environmental ("LMP+D+E") financial model for electric services. The value of LMP+D+E will be evaluated to determine if it is a sufficient financial incentive for existing DERs to participate in the DSP market. The project will consider NYISO locational-based marginal prices ("LBMP") for day-ahead and real-time market prices and any Installed Capacity Market ("ICAP"). The distribution delivery value ("D"), is the value that DERs can provide to the electric distribution system (*e.g.*, load relief). The external or societal value ("E") provides additional compensation for (*e.g.*, low carbon, renewable, or domestic fuel sources) that may be provided by DERs. A variety of DER assets located within the BNMC in Buffalo will be used to test real-time transactions using the new DSP developed as part of this REV demonstration project.

Key Program Delivery Milestones

- Financial Model Development – Develop a method for calculating the value of D following National Grid's BCA Handbook.
- Technology Development – Design and develop a software platform that will use the financial model to calculate, communicate, and manage day-ahead and same-day events.
- Field Demonstration – Test the technical, operational, and economic effects of running a DSP marketplace in new market segments where DER development is forecasted to grow.

Fruit Belt Neighborhood Solar (2016 -2019)

The LMI residential customer segment traditionally has a very low penetration of solar PV systems due to various economic barriers. National Grid is testing a new model for "in front of the meter," utility-owned roof-top solar PV systems in the LMI residential segment and on non-profit community and faith-based buildings in Buffalo's Fruit Belt neighborhood. As part of the program the Company is partnering with NYSERDA to also deliver energy efficiency program offerings to participants for further energy cost savings.

The energy generated from these solar PV systems are directly fed into the local grid and translated to bill credits for both host homes for the life of the solar equipment and to other customer accounts within the neighborhood selected through a lottery. This demonstration project includes analysis of the effect of bill credits on reducing arrearages and evaluates the effects of concentrated solar PV generation in a residential area on the grid and strategies for optimizing it. Given the project's community engagement success coupled with meeting solar PV host goals, the Company is currently evaluating how this model may be applied on a wider scale.

Key Program Delivery Milestones

- Achieved 100% commitment for solar PV system hosting with a mix of residential and non-profit community and faith-based buildings. Expect a total of 127 account holders to benefit from the solar credits via installing 500 kW of solar PV on 75 buildings in the Fruit Belt neighborhood. Roof top PV installations are on 12.5% of homes. Prior to this project, none of the homes had solar PV.
- Grid benefits evaluation to be completed by January 2019.

Key Results and Lessons Learned to Date

- High penetration of DERs can be achieved in LMI segment with utility ownership model which in turn expands the market for third-party DER providers.
- Utility brand is trusted by customers and offers unique advantages for customer acquisition and project development Developed deep understanding of market's economic and perception barriers. Learned successful communication and customer acquisition strategies.
- This project became a catalyst for motivating owners to invest in roof replacements and other home upgrades, leading to improvement in the neighborhood housing stock.
- Project is replicable and scalable with significant cost savings from economies of scale. National Grid will develop scalable business models, investment plans, and BCAs to expand this to other LMI communities in its service territories.

Distributed Generation Interconnection (2017 - 2018)

This project tests an alternative solution for increasing hosting capacity to facilitate the pace and scale of interconnecting DG systems above 50 kW through proactive utility investments and an innovative cost-allocation methodology aimed at removing barriers for DG interconnection applicants. National Grid completed construction of common upgrades at the Peterboro and East Golah Substations in late 2017, ahead of schedule. The work included the installation of $3V_0$ protection and load tap changer ("LTC") controller upgrades on two transformers at each substation. The Company marketed the increased hosting capacity and cost-allocation mechanism to DG developers and was able to secure a sufficient level of DG interconnection applications for each substation to fully subscribe the available capacity.

Key Program Delivery Milestones

The Company's outreach and marketing efforts were a key to the project's success.

- Marketed the project in April 2017 while National Grid's substation design team completed construction drawings. The early marketing efforts included presentations to the IPWG as a means of creating awareness among the DG developer community.
- Identified interconnection locations where DG projects would have minimal impact on the Company's distribution system.
- Presented to developers as part of the NYSERDA monthly conference call with DER providers in November 2017.
- Hosted a webinar to educate potential DG interconnection applicants and answer questions about National Grid's mapping portal in December 2017, and made a presentation in February 2018 to DG developers as part of the IPWG meeting.
- Conducted planning and outreach meetings with municipalities to address permitting requirements and other concerns as DG developers proceeded with project construction.

Key Results and Lessons Learned to Date

The project showed that reducing upfront cost barriers, providing increased certainty, and shortening construction timelines can simplify the interconnection process for DG developers. As expected, these changes increased developer interest in interconnecting DG projects in the areas where the common upgrades were installed using the project's cost-allocation methodology. The Company also found that hosting webinars, developing the mapping portal, and meeting with developers through the IPWG and NYSERDA processes helped DG developers better understand the project and drove interest in submitting interconnection applications. Although successful, National Grid's experience with the initial roll out of the project, as well as developer feedback, also revealed potential opportunities for improvement; namely, the ability to target development in certain areas (*e.g.*, landfills and brownfields) and the potential benefits of proactive outreach with communities to educate and address DG siting and construction concerns.

National Grid is now considering an expansion of this cost-sharing concept to areas with municipal landfill and brownfield sites that have high DG, or DG coupled with ESS, development potential. These sites have drawn interest from municipal officials and the DG developer community.

Schenectady Smart City (2018 - 2021)

On March 26, 2018 the Company filed a proposal for the Schenectady Smart City REV Demonstration Project. The REV project will help develop best practices for smart-city infrastructure deployment, technical requirements for RFP development to support future scale up, drivers for customer success, and BCAs.

In this project, the Company will partner with the City of Schenectady to deploy and evaluate an advanced street lighting platform which supports third-party Internet of Things ("IoT") network compliant smart-city sensor nodes. National Grid intends to test three potential business models: (1) one where the Company will install and own LED luminaires and the control nodes: (2) a hybrid Company and smart-city vendor shared-infrastructure model; and (3) a municipal-owned smart-city infrastructure model.

The project will evaluate the ability of the Company to earn PSRs for allowing third-party IoT sensors on its network and provide valuable lessons learned with respect to operating and maintaining an IoT network.

Key REV Project Tests and Focus Areas for Learning

Test customer acceptance of dimmable LED street lighting systems and effectiveness of using the Company's street lighting assets to support a communications network infrastructure to enable the deployment of smart city technologies.

Street light LED Conversions with Network Lighting Control ("NLC") nodes

- Customer acceptance of advanced control options (*e.g.*, dimming) for LED street lights

- Field experience of City-wide IoT mesh network deployment
- NLC metering accuracy, asset information benefits, product / vendor comparisons

Develop Term Charge and Guidance for Rate Designs for Smart City Offerings

- Facility charge for NLC and energy incentives for savings from dimming
- Facility/data-as-a-service charge for Company-owned sensors and meters
- Network access charge for third-party sensors
- Power and attachment charge for smart-city devices mounted on lighting poles

Company-owned Smart-city Infrastructure

- Make-ready smart-city node on street light poles for city and third parties to bring their own attachments
- Create new business models and data governance

Market Animation for Third Parties as Smart-city Solution providers

- Explore platform and data as service models

Key REV Project Delivery Milestones

National Grid is developing an implementation plan and delivery milestones for a project launch in Q3 - 2018. The scope of the project includes:

- Conversion of 4,200 street light fixtures to network-controlled LEDs
- Deployment of a minimum of 100 smart-city nodes on street lights
- Provision of multipurpose network integrating different types of connected devices
- Four new rate designs with new customer offerings for smart-city infrastructure

National Grid will continue to consider new demonstration projects that align with REV objectives, enhance the Company's capabilities as the DSP, and advance state policy goals. Performance targets associated with the Company's EAMs and recently announced priorities in EE, ESS, and renewables by 2030 will serve as additional drivers in selecting REV projects. The Company is also working with the REV Connect team to identify new solution offerings and business models leveraging third-party services.

Grid Modernization and the DSP Technology Platform

National Grid envisions grid modernization as a set of collective actions and investments to make the electricity system more secure, resilient, responsive, and interactive in an environment of evolving paradigm shifts and transformations occurring across the electric industry.

National Grid's grid modernization plans encompass:

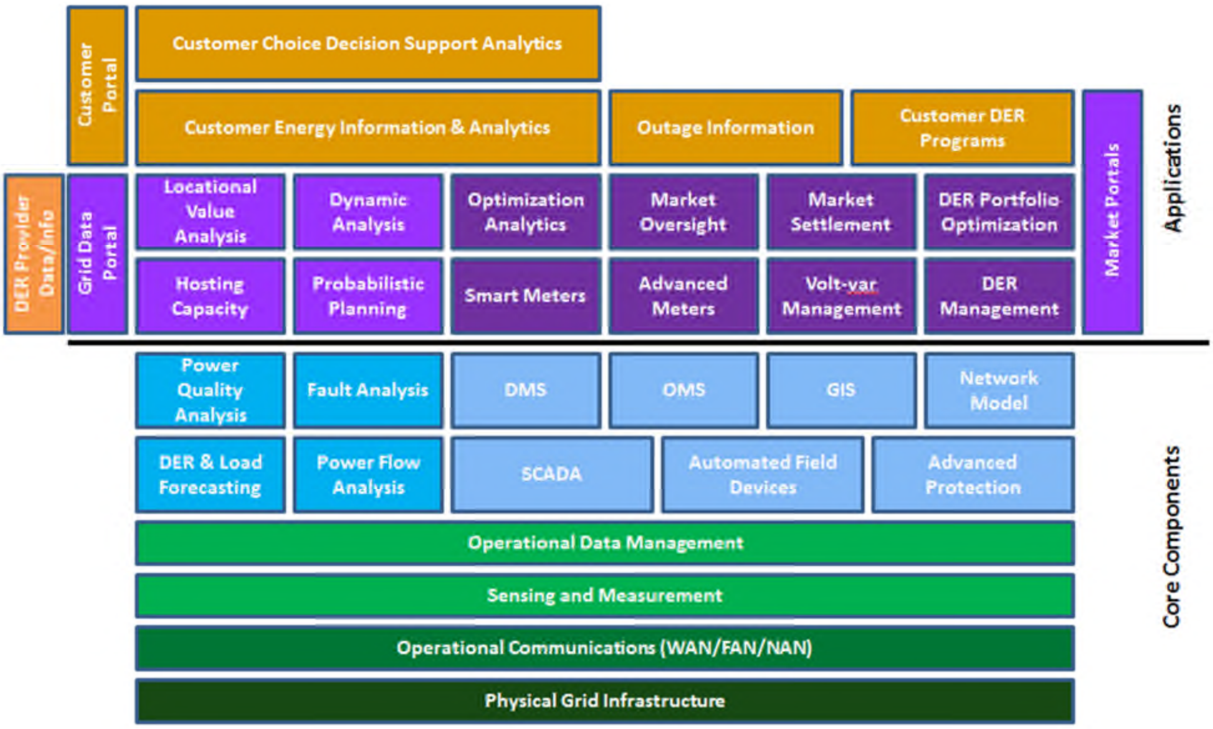
- Development of a smarter grid through advanced operational tools, grid automation, and AMI

- Applications to enhance engagement with customers and DER providers
- Effective integration of DER in grid planning and operations
- Robust information systems and cyber-security measures for operational data management and customer privacy
- Leverage utility business model, regulatory, and utility rate reforms for the benefit of customers

Many grid modernization investments have mutually reinforcing benefits, such as those that provide reliability or operational benefits while also supporting DER integration, and therefore contribute to meeting multiple objectives. Since the commencement of the REV Proceeding, all of National Grid's grid modernization investments are *aligned* with REV, however, that is not the same as saying that they are *driven* solely by REV.

The Company's grid modernization plans are generally aligned with the U.S. Department of Energy's ("DOE") *Modern Distribution Grid Report* – a three-volume set that is intended to develop a consistent understanding of requirements to help inform investments in electric distribution grid modernization.[38] Figure 1.7 below presents the core components and advanced applications of a modern distribution grid as presented in this DOE report.

Figure 1.7: Next Generation Distribution System Platform and Applications



[38] U.S. Department of Energy, Office of Electricity Delivery & Energy Reliability, *Modern Distribution Grid Report, available at* https://gridarchitecture.pnnl.gov/modern-grid-distribution-project.aspx

In the Three-Year Rate Plan Order, National Grid received approval for investments in several areas of the technology stack presented above. The Three-Year Rate Plan Order covers the period of April 1, 2018 through March 31, 2021 and includes $149M in funding to commence the grid modernization investments discussed below. Additional funding for a full scale AMI deployment as well as for projects or programs that continue beyond the term of the rate plan order will be required, and the Company will seek authorization and cost recovery in appropriate proceedings or future rate case to continue to enhance its DSP capabilities.

Advanced Metering Infrastructure: National Grid proposed a system-wide deployment of AMI in its initial DSIP and subsequent rate case filing. However, as captured in the Three-Year Rate Plan Order, the Company agreed to enhance its AMI business case through a collaborative effort and then present an updated proposal to the Commission by October 1, 2018.

Geographic Information System: Beginning in 2018 the Company has commenced an effort to enhance its Geographic Information System ("GIS") to better support integrated planning and operations. The GIS software will be enhanced and over a three-year period the GIS will be populated and new Quality Assurance/Quality Control ("QA/QC") measures implemented to ensure data quality is maintained.

Feeder Monitor Sensors: In 2017 the Company began a program to install feeder monitoring sensors at the head end of feeders that do not have interval substation monitoring integrated with supervisory control and data acquisition ("SCADA"). These clamp-on style sensors monitor load and voltage and can be integrated into SCADA via cellular communications. The granular information enhances real-time situational awareness for National Grid's Control Center operators and also provides 8760 hour historical information in support of distribution system planning.

Volt-Var Optimization: In 2019, following an initial deployment as part of the Clifton Park REV demonstration project, the Company will commence an annual program in which select feeders will be enhanced with advanced VVO controls in support of demand and energy savings associated with CVR. The program is expected to run beyond the period of this DSIP Update as long as candidate feeders can be identified which will provide a positive BCA if advanced VVO controls are implemented.

Fault Location, Isolation, and Service Restoration: The Company will continue to implement automated restoration on targeted sub-transmission circuits and plans to begin implementing similar distribution automation schemes on targeted 13.2 kV feeders beginning in 2021to improve reliability.

Distribution SCADA and Advanced Distribution Management System: Beginning in 2019 the Company plans to initiate projects to enhance operational systems in its regional distribution control centers by deploying a dedicated distribution SCADA and implementing ADMS. These projects will take approximately three years to implement and commission and will provide system operators with the ability to assess system impacts in real time and make more informed operating decisions.

Operational Communications: Implementing new capabilities such as AMI, ADMS, and distribution automation, among others, will require upgrades to the Company's telecommunications network. The telecommunication network must be enhanced to provide additional backhaul capacity and enhance bandwidth to transfer an increasing volume of data from smart devices distributed across the distribution system. There are five elements within the Company's Telecom project set that address the backhaul and bandwidth needs:

- Substation Backbone Expansion – Extend private fiber backhaul to substations to transmit substation device information to National Grid's back office for additional analysis.
- Substation Remote Terminal Unit ("RTU") Expansion – Install backhaul from the public carrier network to RTU substations to transmit substation/field information to National Grid's back office for additional analysis.
- Corporate Backbone Expansion – Increase backhaul bandwidth of the corporate data center to support data lake and analytics engine.
- Distributed Technologies Backbone Expansion – Increase the backhaul bandwidth and install a wireless gateway to transmit meter data to the National Grid data center.
- RTU upgrade for Distribution SCADA ("D-SCADA") – Reconfigure RTUs at the substations to transmit information to D-SCADA.

Operational Data Management: To enable the efficient transfer, storage, and assessment of operational data in a secure fashion, a number of information systems projects will progress including the development of an enterprise service bus, data historians and data lakes, the utilization of cloud computing, and the creation of an analytics platform. All of the new information systems must also be protected with robust cyber-security services. The portfolio of information systems projects supporting the DSP initiatives will be delivered throughout the term of this DSIP Update.

2.0 DSIP Update Topical Sections

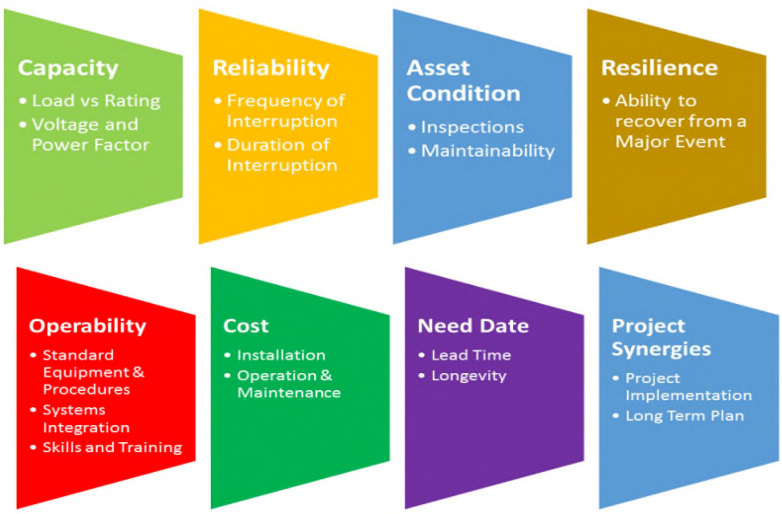
2.1 Integrated Planning

Context and Background

The electricity delivery system is getting more complex while customer's expectations for service rise. In addition to foundational grid modernization efforts by the utility, such as grid monitoring, the integration of DER into grid planning and operations is necessary to maintain safety, reliability, service quality and affordability. To leverage the capabilities of a modern grid integrated with DER, T&D System Planning needs to evolve to evaluate an increasingly complex and dynamic system environment where the combined behaviors and mutual effects of loads and supply resources can vary significantly. To best leverage DER, third-party resources must be integrated into planning and operations and not simply interconnected. This transition in approach requires greater transparency of system needs and opportunities for DER support, as well as better transparency of DER performance and availability.

Planning is a cyclical process that progresses through a series of steps: system monitoring, modeling and forecasting, risk assessment, solution development, prioritization and budgeting, and finally solution implementation. The planning process considers a wide array of variables to ensure that the system will achieve service quality standards and reliability targets in a cost-effective manner. DER impacts and opportunities must be considered in each step of this process and the expected performance of DER assessed with respect to each of the variables shown in the figure below.

Figure 2.1.1: National Grid T&D Planning Operational Variables



National Grid's planning process supports an overall financial planning process that occurs on a fiscal year that begins April 1 and ends on March 31. For example, the Company's FY19 began on April 1, 2018 and will end on March 31, 2019. To support this schedule budgeting begins in the fall of each year and the Company's capital investment plan ("CIP") is filed with the Commission by the end of January each year. In addition to its capital program the CIP includes the Company's latest assessment of potential NWA opportunities. A copy of the CIP is shared via National Grid's System Data Portal for reference by DER developers and a preliminary schedule as to when each NWA solicitation may be expected is also posted to the System Data Portal.

Current Progress

Since the initial DSIP filing in 2016, National Grid has made significant progress in the area of integrated planning. Organizationally the Company has aligned the resources performing long-term distribution planning and DG interconnections. This alignment is having positive results on the timely completion of interconnection studies as well as the integration of DER in network planning assessments. For example, the EPRI Distribution Resource Integration and Value Estimation ("DRIVE") tool has been implemented to conduct hosting capacity analysis for DER and to date has been completed on all radial 5kV and 15kV class feeders.

The Company's distribution planning group has significantly enhanced its ability to efficiently create network models by developing new tools, data sets, and processing scripts allowing the automation of tasks and improving the repeatability of analysis. For example, capturing the 8760 hour SCADA load information to populate the National Grid's System Data Portal can now be processed more efficiently and made available for routine distribution planning efforts. Load flow models have been created for all distribution feeders as has a comprehensive load flow model of all distribution substations and sub-transmission and transmission lines. These models will continue to be refined over time and will facilitate future distribution planning efforts as well as provide a foundation for future operational functionality in systems such as ADMS.

The system-wide substation load flow model was recently used to complete a ten-year network needs assessment and associated locational values in support of an enhanced Marginal Cost of Service Study ("MCOS") for DER which will be discussed later in this DSIP Update.

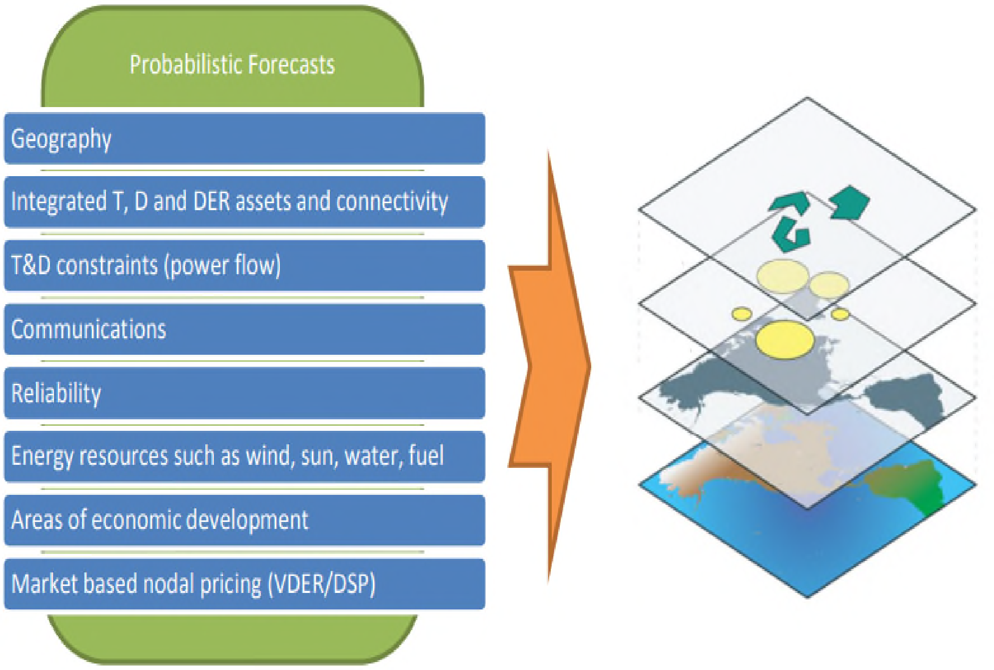
The Company continues to evaluate NWA as part of its CIP process. The new models and tools will facilitate the technical analysis and BCA is conducted in accordance with National Grid's BCA Handbook. Similarly, the BCA Handbook is being used to assess demonstration and grid efficiency projects such as VVO.

The progress described above provides the foundation for integrated planning and will enable National Grid to produce more accurate, timely, and repeatable planning results.

Future Implementation and Planning

Over the longer term the Company is driving towards a "One System – One Model" vision for planning, data integration and data management. This approach will facilitate advanced planning by integrating an increasing number of variables, complexity, and mutual effects that system planners will need to factor into plans going forward. The software models, tools, and real-time data described throughout this DSIP Update lay a solid foundation to this vision. The diagram in Figure 2.1.1 below illustrates this vision.

Figure 2.1.2: One System – One Model Vision



As described in the Advanced Forecasting Section of this DSIP Update, the Company plans to integrate forecasts with greater temporal and geospatial granularity that encompass an increasing number of variables (and their probabilities) into system planning and associated network models to more accurately reflect DER impacts.

Distribution system planning will become increasingly integrated with grid operations. In the Grid Operations Section of this DSIP Update, National Grid discusses an expanded integration of substations and distribution line sensors with its D-SCADA/ADMS system as part of the Company's approved budget in the Three-Year Rate Plan Order. The as-operated models maintained in the ADMS will enhance operations and planning. The ability to accurately capture historical loading information on an 8760 hourly basis across all feeders will help facilitate DER interconnection studies by reducing the number of engineering assumptions required in HCA. These operational models also enable enhanced distribution automation for applications such as VVO and fault location, isolation and service restoration ("FLISR"), all of which will enhance service to customers. By the end of 2023, National Grid aims to have near real-time monitoring on the all distribution stations.

To advance this one model concept, the Company will improve the availability and quality of information maintained in the GIS. Data quality and process automation are critical for the efficient evaluation of a distribution system. A three-year GIS enhancement program was approved in the Three-Year Rate Plan Order. The GIS project will consist of two phases, the first to enhance the GIS application and the second to populate the system with the desired information. Other planning tools currently linked to GIS, such as CYMDIST[39] and the EPRI DRIVE tool, will also benefit from the GIS enhancement efforts. . Efficient access to this data will benefit the development of network models for planning as well as network models envisioned for ADMS models in operations.

More distributed and granular data from customer meters would also enhance system modeling. National Grid has proposed AMI[40] and the data generated through these interval meters would be integrated into distribution system planning. AMI increases the number of monitoring parameters and the granularity of data available for planning needs. Some of the planning benefits that data from AMI could offer: interface with the CYMDIST software to better manage the connectivity model, improve load allocation across distribution feeders, determine distribution transformer loading, and provide accurate voltage and power factor information that previously had to be assumed or calculated. AMI's granular information provided at DER locations will greatly enhance the ability to consider DER impacts across the spectrum of planning variables and enhance the Company's ability to rely on a given DER as a resource (*e.g.*, DR).

The one-model approach will enhance the efficiency of HCA. In support of its HCA plans the Company is working with EPRI regarding system modeling needs required for more advanced assessments of hosting capacity.

Each of these enhancements would allow T&D system planners to evaluate the system impacts and opportunities in greater detail and with improved accuracy to help identify beneficial DER locations and improve system planning overall.

Several integrated planning studies are currently being considered for the next five years:

- Techno-economic study to identify beneficial locations of ESS
- Integration and identification of DR/EE into NWA
- Identification of new NWAs

[39] CYME provides distribution analysis software.
[40] National Grid's AMI proposal will be the subject of an updated business case to be presented by the Company to the Commission for action per the Three-Year Rate Plan Order.

Risk and Mitigation

Risks to the Company's plans for integrated planning include schedule delays of the technology projects discussed above as well as lack of experience of both the utility and DER providers with the utilization of DER as a grid resource. To mitigate these risks, the Company is creating a Grid Modernization Solutions team and a Grid Modernization Execution team to support project delivery and leverage lessons learned through REV") demonstration projects and NWA solicitations.

Stakeholder Interface

The Company's integrated planning initiatives have and will continue to be influenced significantly though interactions with stakeholders on Joint Utilities working groups such as system data, hosting capacity, NWA's, and the ITWG.

Today, DER alternatives are considered subsequent to the development of traditional utility project plans. In the future National Grid will endeavor to consider DER options in parallel with the development of traditional utility solutions.

The Company has put significant effort into developing the System Data Portal and the information that populates it. National Grid expects that the System Data Portal will continue to evolve and be capable of providing the more granular information needed by DER developers.

Additional Details

The following responds to DSP Staff's request to provide additional details to address National Grid's resources and capabilities which support integrated electric system planning.[41]

1. Means and methods used for integrated system planning

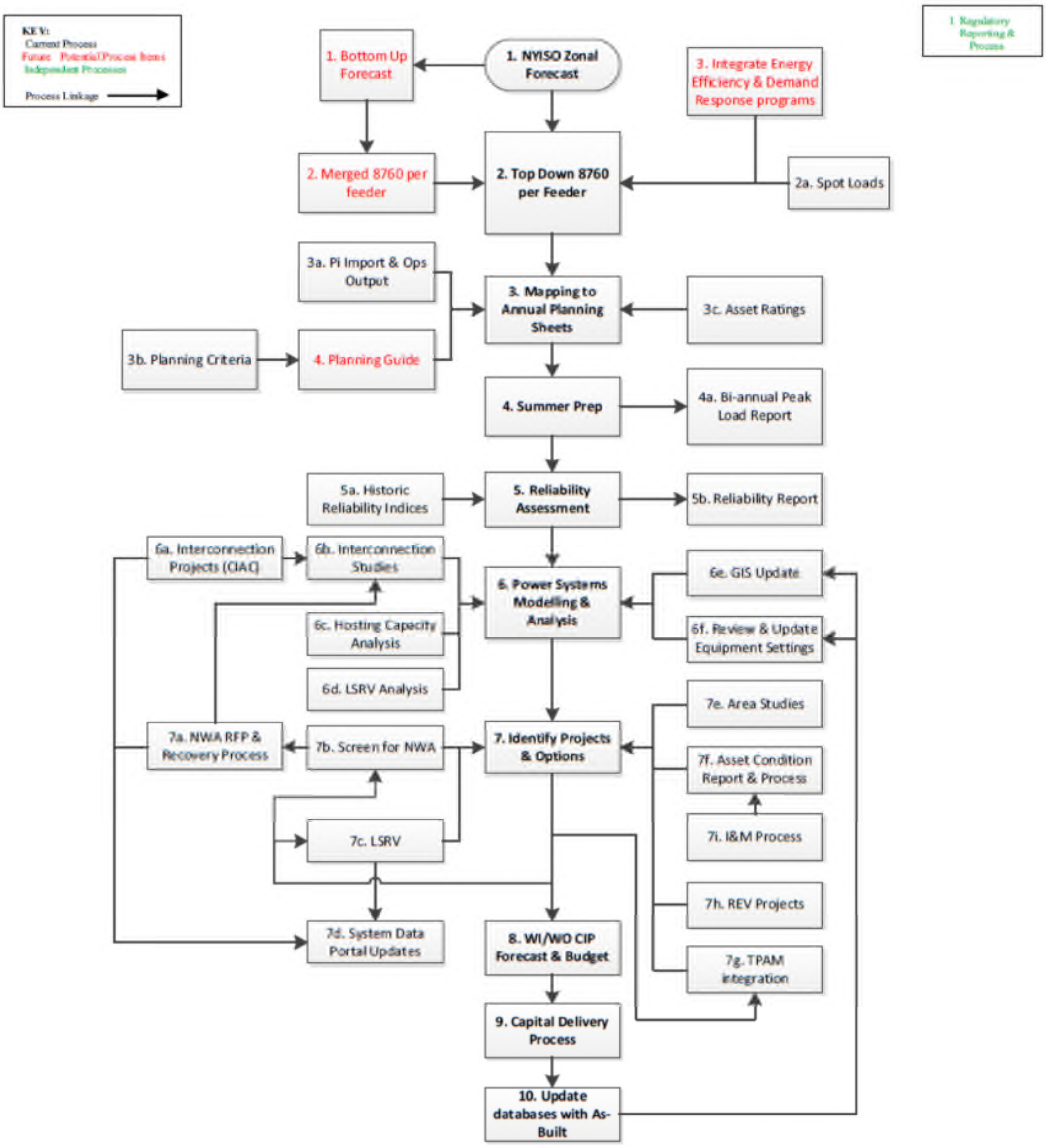
Today's integrated distribution planning process involves many different components and sub-processes, from forecast development through to project delivery.

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 later 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.

[41] DSIP Proceeding, 2018 DSIP Guidance Update, p. 8.

Figure 2.1.3: DPAM NY Integrated System Planning Process



Notes:
1. **Regulatory Reporting:** CIP, 15 Year Plan, IR, Rate Case, DSIP, Reliability Report
1. **Bottoms- Up Forecast:** High geographical and temporal granular forecast
2. **Merged 8760 per feeder:** Merged top down-bottoms up forecast
3. **Integrate EE & DR Programs:** Integrate existing and planned NGrid energy efficiency and demand response programs (may eventually be replaced by bottoms-up forecast)
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 8760 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 SS**: Map forecasts and spot loads into annual planning spreadsheets for high level assessment
3a: **PI Import & Ops Input:** Update current loading and PF 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
5a: **Historic Reliability Indices:** review of historic reliability events from IDS database
5b. **Reliability Report:** report for Staff and public
6. **Power System Modeling & Analysis:** Detailed analysis of projects triggered from high level assessment using PSSE (NYISO input), ASPEN and CYME tools
6a: **Interconnection Projects (CIAC):** System upgrades identified from interconnection studies (pass through to interconnection customer)
6b. **Interconnection Studies:** Power system studies such as power flow, fault analysis etc. used to determine interconnection upgrade projects or lack thereof

Notes:
6d: **LSRV (Location System Relief Value) Analysis:** PSSE analysis that models the T, SubT and Distribution buses used to assess opportunities for DER (DG, ESS) to resolve a system constraint
6e. **GIS Updates:** Geographical Information database that captures NGrid system assets mapped to a geographical location primarily used to update CYME models
6f: **Review & Update Equipment Settings:** protection settings, LTC settings etc. via Cascade
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's:** Review and screening of potential NWA projects
7c. **LSRV:** Determination of locations and capacities of (DG, ESS) to resolve system constraints based on the results from step 6d
7d. **System Data Portal Updates:** Periodic updates to the publically available system data portal
7e. **Area Studies:** Large scale area studies (i.e. entire town/city) triggered by schedule or multiple violations or criteria
7f. **Asset Condition Reports & Process:** review and assessment of asset condition informed by I&M
7g. **TPAM Integration**: Inform Transmission Planning of planned projects and vice versa and integrate accordingly
7h. **REV Projects:** Projects triggered via rate case 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. **WI (Walk In)/WO (Walk Out) CIP Forecast & Budget**: Budgeting, forecasting and managing of CapEx and OpEx projects

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 load and DER forecasting currently includes some probabilistic elements, most notably the impact of weather on load. Other elements are deterministic and based on such things as approved EE targets, DR subscriptions and state policy objectives. Over the next five years, the Company anticipates incorporating more probabilistic elements within its forecasts as it develops and integrates various DER adoption models.

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. Similarly GIS integrated with CYMDIST load flow tools so that the most up to date models can be created for distribution planning. Load forecasts are updated on an annual basis in time for summer preparations for system peak. The distribution planers are also organized by areas so they have awareness of other variables taking place within their area *(e.g.*, economic development, municipal planning activities, etc.). A Salesforce database tracks EE and DG in queue projects 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 Energy Management System ("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 sensitives
- 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 would timely adjust its integrated system plan if future trends differ significantly with predictions, both in the short-term and in the long-term.

National Grid refreshes its fifteen-year load and DER forecast on an annual basis and 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.

6. For the factors unrelated to DERs - such as aging infrastructure, electric vehicles, and beneficial electrification - which significantly affect the utility's integrated plan - describe how the utility's planning process addresses each of those factors.

National Grid's five-year implementation plan for load and DER forecast enhancement will include the incorporation of EVs and will monitor other beneficial electrification, such as heating conversions, in developing future forecasting models. Other factors that may influence the development of an integrated plan include asset condition issues, reliability performance, safety or operational concerns, and potential hosting capacity constraints. As described above, when developing project solutions, the planning engineers work collaboratively with other departments to understand existing issues and opportunities and then develop project plans that cost-effectively address the appropriate risks and opportunities.

7. How the means and methods for integrated electric system planning evaluate the effects of potential energy efficiency measures.

Presently, all of the Company's EE programs are offered to customers system wide. The future impacts of these programs are embedded within the load and DER forecasts used by the T&D network planners. In considering EE programs beyond those currently approved through 2020, the Company has begun to consider how certain EE programs may be targeted to specific locations and integrated with NWA and DR programs to address network needs.

8. How the utility will inform the development of its integrated planning through best practices and lessons learned from other jurisdictions.

National Grid affiliates operate electric distribution companies in Massachusetts and Rhode Island. The distribution planning functions in all three jurisdictions report to a common vice president and lessons learned are routinely shared between planning departments. The Company also participates in various forums in which planning issues are discussed including JU meetings and ad hoc meetings with utilities in other jurisdictions to compare process and progress.. 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 and distribution system automation.

2.2 Advanced Forecasting

Context and Background

Utilities, DER providers, system operators, and other stakeholders require load and supply forecasts which are timely, accurate, and sufficiently detailed to support both short-term and long-term planning. The evolving means for using DERs to address electric system needs requires utilities to undertake advanced forecasting analyses which integrate increasing numbers and types of DERs into load and supply forecasts.[43]

To date, National Grid has performed most long-term system assessments considering net peak load forecasts which incorporate projected economic and demographic impacts as well as anticipated technological advances and policy objectives. Current forecasts consider forecasted customer load growth, EE measures, solar PV generation, EVs, and DR programs in the development of annual peak load forecasts over a fifteen-year horizon. To ensure the reliability of the grid, National Grid's Distribution Planning group generally evaluates system performance considering the potential peak loading conditions under an extreme 95/5 weather scenario which corresponds to a 1-in-20 year event. This scenario is integrated with grid planning models and forms the basis by which Distribution Planning evaluates the future needs of the grid. The most recent system peak load and DER forecast for National Grid can be found on the Company's System Data Portal at: http://ngrid-ftp.s3.amazonaws.com/DSIP/Docs/National_Grid_UNY_-_Peak_Load_Forecast.pdf

The Company is an active participant in a number of NYSIO committees and working groups and components of the Company's forecasting process are inputs into the NYISO and the New York State Reliability Council's ("NYSRC") annual capability planning processes. The system-level forecast incorporates macro-economic and policy-based perspectives and is produced utilizing methodologies that have been in place for a number of years. Figures 2.2.1 and 2.2.2 show the results of the most recent (2018) system-level forecast for load and DERs.

[43] *Id.*, p. 9.

Figure 2.2.1: National Grid Summer Peaks

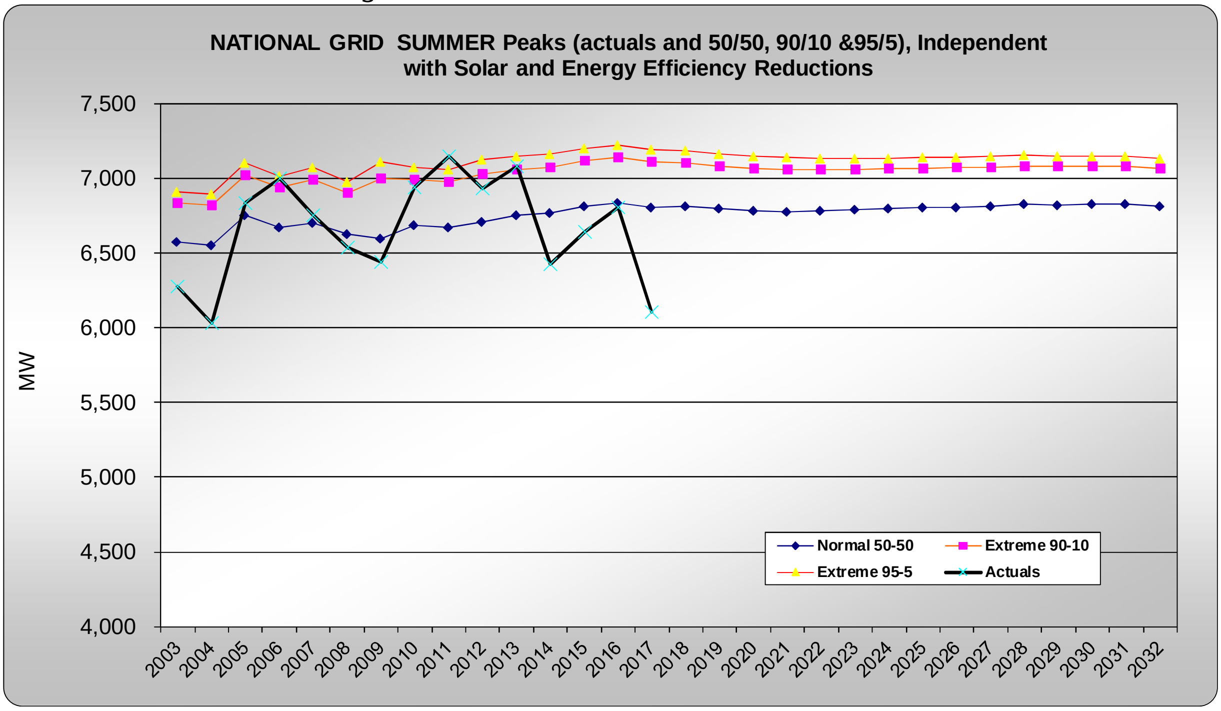
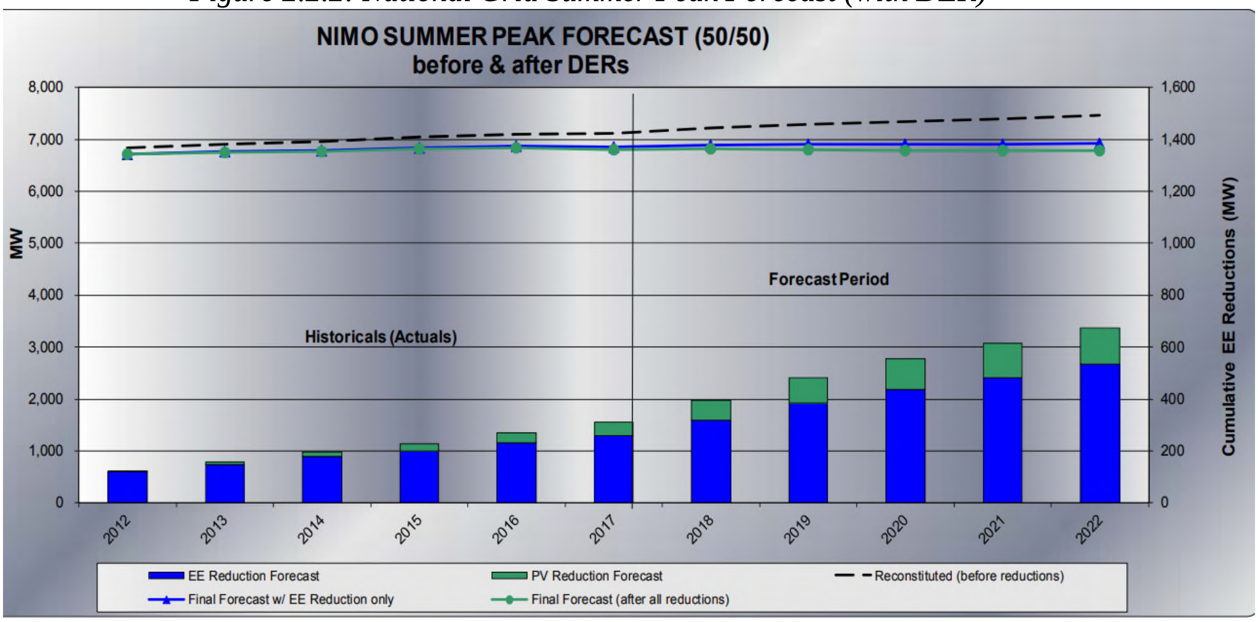


Figure 2.2.2: National Grid Summer Peak Forecast (with DER)



A number of DER components are included in the current version of the Company's Forecast Model:

- **EE Programs**

  The electric load savings forecast from EE programs considers near-term EE goals and approved budgets, usually a two-three year outlook, and for a longer term they are based on NYISO EE targets.

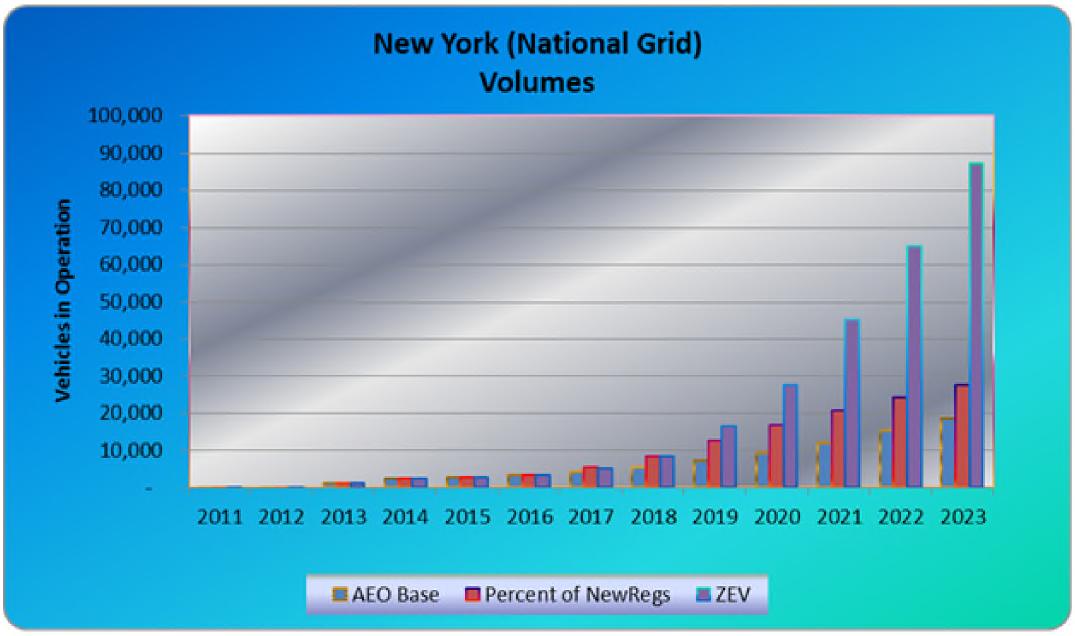
- **Solar PV**

  The solar PV load savings forecast considers near-term DG activity, usually a one- to two-year outlook on the solar PV capacity ("kW") in the interconnection queue, transitioning to NYISO solar PV targets over the longer term.

- **EVs**

  EV growth forecast considers recent increases in EV adoption for near-term targets transitioning to policy-based initiatives for the longer term. Figure 2.2.3 below represents the scenarios National Grid is considering in developing its load forecasts.

Figure 2.2.3: Company Forecast for EV



- **Direct Load Management ("DLM") Programs**

  The Company's forecast considers DLM programs that include expected peak reduction among DLM participants. Since the Company's retail DLM programs are relatively new, their impacts are still being assessed.

The impacts and opportunities for DER are location specific and in order to better address the needs of distribution system planning, National Grid is implementing new methods to forecast load and DER in a fashion that is more granular, both spatially and temporally.

Current Progress

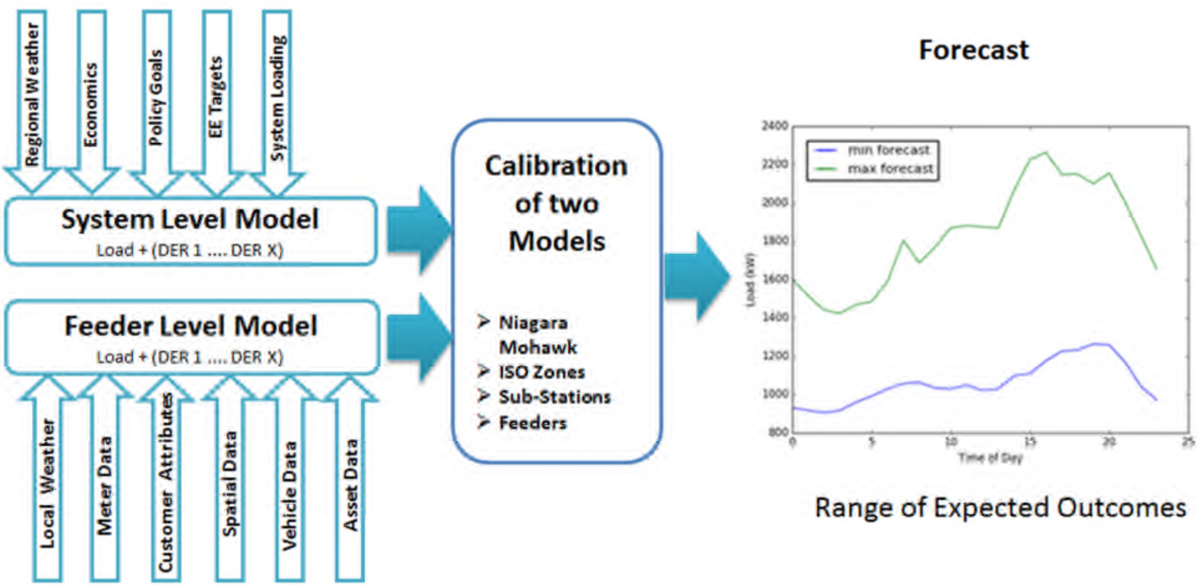
In its initial DSIP National Grid laid out a multi-year plan to enhance its load and DER forecasting to develop more granular forecasts considering inputs from a top-down perspective (*e.g.*, policy goals) and inputs from a bottom-up perspective (*e.g.*, customer demographics). The Company is progressing forecasting enhancements in alignment with that multi-year plan.

In 2017, the first 8760 hourly demand forecasts were created at the Company level and for each of the NYISO zones. Also in 2017, in support of a system-wide study to develop an enhanced MCOS study, hourly forecasts for each distribution substation and feeder were created. The feeder circuit models were created in GridLAB-D™ and customer load information was integrated within the simulation and analysis engine and calibrated with the actual peak loading of each feeder. Hourly customer load profiles were developed and used as an input to feeder models. An 8760 hourly load shape of solar PV was produced using historical weather data. Incremental solar PV was applied to each feeder by mapping this hourly load shape to the assumed penetration level and growth. The average annual impact of anticipated new solar PV was to reduce feeder peaks by 0.5% annually. Over the coming years it is expected that additional DER models will be developed and integrated into the feeder level hourly forecast.

Future Implementation and Planning

National Grid plans to continue to enhance and augment its load and DER forecasting methodologies. The vision the Company is pursuing combines the benefits of forecasts at the system level with those of forecasts at the distribution feeder level. Information from both perspectives will be calibrated so as to develop an 8760 hour forecast for all 8760 hours in the year. However, distribution planners will not likely model the distribution system for each and every hour of a multi-year planning horizon. Rather, a smaller number of scenarios can be modeled considering the range of potential outcomes over a specified planning horizon. Figure 2.2.4 below illustrates the range of outputs for a specific feeder over a six-month period for each of the 24-hour time periods of a day envisioned from this forecasting approach. This approach can be taken to produce expected ranges for various study scenarios such as summer and winter peak as well as off-peak shoulder seasons.

Figure 2.2.4: Forecasting Methodology in Development



Creating feeder level forecasts requires the development of customer load and DER growth models that can be unified in a simulation-based model for detailed analysis. Substation level forecasts will be derived from the feeder level forecasts and calibrated with the system level forecasts. To develop these forecasts, the Company is currently using a simulation-based modeling environment called GridLAB-D™ which is an open source, agent-based modeling, simulation, and analysis engine that enables detailed analyses of electric distribution systems. However, National Grid is not limited to the use of any one specific platform and in the future development of models the Company is open to using another modeling platform as appropriate.

Spatially, the Company's forecast process will result in forecasts at the Company, NYISO zones, and distribution substations and feeder levels. Temporally, the forecasts will range from hourly forecasts to multi-year annual projections. Factors influencing future growth include:

- Policy and Regulatory Drivers
- DER Market Drivers
- DER Technology Drivers
- Incentives & Financing Drivers

Over the horizon of this DSIP Update, National Grid will continually enhance both the system-level and feeder-level forecasting models. At the system level the forecast model will focus on enhancing the ability to accurately represent regulatory and policy goals by incorporating additional DERs as appropriate. At the feeder level, the more granular models will consider technical, financial and market adoption studies, as available. This approach can be leveraged across the variety of individual DER models. Each DER component will have its own projection for future growth allowing the Company to assess each DER's impact individually as well as on an integrated basis. This enables the disaggregation of net load so that the contributions of all contributing components can be understood.

Over time the Company will endeavor to develop more probabilistic forecasting techniques. Probabilistic forecasts consider multiple scenarios that can occur over time. These scenarios can be informed by utilizing historical data as well as by setting parameters around what could potentially occur. Input variables considered in these probabilistic views could include environmental, customer load, policy, regulatory, financial, and market drivers.

The goal of National Grid's Load and DER Forecasting and Analysis initiative is to enhance traditional econometric-based, statistical models with the simulation framework for forecasting load and DER with power system modeling. The Company is working with the DOE to link best-of-breed simulation tools associated with power system modelling, EVs, ESS, and solar PV.

The resources and data necessary to continue development of this initiative include:

- Remote Sensing Data
- Residential and Commercial Demographic Data
- Vehicle Registration Data
- Weather Data
- Economic Data
- Spatial Data
- Current DER Installation Data
- Customer Data
- Meter Data
- Asset Data

High-performance cloud computing, such as Amazon Web Services, will be leveraged as appropriate to improve the overall computational process.

The timetable presented below represents National Grid's plans for the continued enhancement of its load & DER forecasting models.

Table 2.2.1: Timeline of National Grid's Plans for Development of Forecasting Models

Horizon 1 (1-5 Years)					
Forecast	**Estimated to be Delivered**				
	2018	**2019**	**2020**	**2021**	**2022**
DER Forecast	More granular rooftop solar PV, EV	Introduce storage, non-rooftop solar PV	Exploring new DERs	Enhancement of prior year models	Enhancement of prior year models
Probabilistic Models and Forecast	95/5 probability based on weather	Introduce DER scenario(s)	Introduce probabilistic integration of scenarios	Enhancement of prior year models	Enhancement of prior year models
Feeder and system level load forecast	Enhance initial year feeder models	Enhance calibration of system level and feeder level forecast	Continuing improvement	Continuing improvement	Continuing improvement

Risk and Mitigation

While National Grid is fully committed to the load and DER forecasting development path described, it is not without its challenges. These include:

- Access to data and the quality, volume, and cost of acquisition
- Integrating and embedding new forecasting paradigms into existing planning processes

The Company will mitigate these challenges by:

- Hardening the Company's access to data and its quality through new data governance policies that are being developed
- Lessening the cost of data acquisition by:
  - Aggressively negotiating with vendors
  - Utilizing publicly available information wherever possible
- Continuing to engage other New York utilities through the Joint Utilities forum to share as much information as possible to ensure consistency as appropriate among the utilities.

Stakeholder Interface

National Grid engages with stakeholders and other New York utilities as part of the Joint Utilities' efforts. In addition, the Company is engaged with other leading-edge forecasting organizations through efforts with EPRI, DOE and regional Independent System Operators ("ISOs").

Additional Details

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.[44]

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 will provide access to load forecast information for DER developers and other stakeholders. Initial substation 8760 hour net load forecasts will be published to the portal by the end of 2018. Future DER forecasts will be posted to the portal as they become available over the next five years.

2. Identify and characterize each load and supply forecasting requirement identified from stakeholder inputs.

Stakeholders have requested 8760 hourly forecast information at the feeder, substation, and system level. The Company continues to work with the Joint Utilities on all forecasting topics and expects assessment of stakeholder requirements will continue going forward. As described in the Distribution System Data Section within this DSIP Update, various stakeholder needs and use cases have been presented in detail and National Grid expects this will continue to evolve over the next five years.

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 is working to develop and share the same forecasts that are used in distribution system planning in a fashion that represents the expected net load as well as the components and conditions that are represented in the forecast in accordance with adopted customer data privacy standards. The System Data Portal currently provides a detailed report of the Company's top-down peak load forecasts. The Company is currently working on the means to share the more detailed 8760 hour forecasts in a fashion that is most useful, repeatable, and efficient. Long-term forecasts are generally issued during the last quarter of each calendar year so that they are reflective of the most recent summer peak loads. National Grid will endeavor to post the 8760 load forecast curves by the end of each year to the System Data Portal. Additionally, the Company continues to assess stakeholder data needs through the Joint Utilities.

[44] *Id.*, pp. 9-10.

4. Describe the spatial and temporal granularity of the system-level and local-level load and supply forecasts produced.

Spatially, National Grid's forecast process will result in forecasts at the Company, NYISO zones, distribution substations and radial feeder levels. Temporally, the forecasts will range from hourly forecasts to multi-year annual projections.

5. Describe the forecasts provided separately for key areas including but not limited to photovoltaics, energy storage, electric vehicles, and energy efficiency.

The forecasts will be provided separately by load and DERs including but not limited to solar PVs, ESS, EVs, and EE at the system level over a fifteen-year period and at the feeder level over a five-year period. At the current time, projections for EE are expected to continue to increase from the 2017 level of -3.7% in cumulative reductions to -13% by the year 2032. Solar PVs are expected to continue to increase from the 2017 level of -0.7% to -2.3% by the year 2032. Projections for EVs are expected to be incorporated during this year's planning cycle and ESS in the 2019 vintage forecast.

6. Describe the advanced forecasting capabilities which are/will be implemented to enable effective probabilistic planning methods.

The current system level forecasts include multiple weather scenarios to develop normal 50/50, as well as extreme weather scenarios at 90/10 and 95/5, confidence levels. As National Grid progresses with the development of feeder level forecasts it will produce probability scenario(s) for the DER model elements as well

The 8760 forecasts will enable more granular planning methods when compared to yearly peak forecasts. Having probability scenarios for each DER will allow planners to consider multiple alternatives in a more probabilistic fashion. Planners will also utilize the granular forecasts to determine hourly minimums and maximums over a desired period of time. Data analyzed in this way better enables planners to perform more system analysis for different DER and load types.

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.

Each of these DER elements will be projected independently as well as through an integrated portfolio of loads and DER. This is important because the interrelated impacts of the DERs can change the timing and magnitudes of the hourly and peak loads across the system and at the feeder level.

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 forecasts prepared for National Grid's use are the same forecasts the Company will share with stakeholders. These include system level forecasts to capture macro-level economic, market, and policy initiatives and the more granular feeder level forecast for distribution planning purposes.

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

National Grid's objectives are to gather as much information as possible about the Company's individual customers, various DER markets, and the operating state of the Company's distribution system to support the granular spatial and temporal nature of the forecasts being produced. The means by which the Company acquires this data include licensing and purchasing data form external sources, as well as collecting publicly available data.

10. Describe the means and methods used to produce substation-level load and supply forecasts.

The production of substation level load and supply forecasts are derived by aggregating the connected feeder level forecasts. Feeder level forecasts are calibrated against actual feeder peak data followed by calibration with system level forecasts to ensure internal consistency of results.

11. Describe the levels of accuracy achieved in the substation-level forecasts produced to date for load and supply.

For the system peak load forecast as shown in Figure 2.2.1 above, historical peak loads are compared to the 50/50, 90/10 and 95/5 forecasts. Since National Grid just recently developed its initial 8760 hour forecasts at the substation level, the Company cannot yet assess this forecast accuracy because it does not yet have a full annual cycle of results. Once sufficient actual data exists, the Company plans to compare actual loading results to the recently developed feeder level forecasts to assess the variance of metered load to the forecasted load. Particular attention will be on the peak load periods and minimum day-time load periods.

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.

Individual 8760 forecasts have been produced by the Company for each distribution substation. This information provides increased visibility into substation loads for all hours of the year. Providing an annual load cycle will aid DER developers in evaluating impacts such a capacity constraints at peak, the potential that injections may result in reverse power flows, and the frequency for which demand response may be called for, 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.

While current forecasts consider the relative impacts of various DER, National Grid has not performed a sensitivity analysis considering multiple DER scenarios. This type of analysis will be possible after individual DER forecasts are developed with probabilistic 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.

National Grid uses an extensive amount of external data informing its DER forecasts. Information received from DER providers as part of interconnection requests and in support of EE and DR programs operated by the Company are embedded in the forecast. In addition, to the extent that market participant information is embedded in the longer-term NYSIO DER forecasts, it is similarly embedded in the Company's forecasts. However, the Company does not currently use forecasts from individual DER developers as National Grid has not been able to ascertain the value of such forecasts. The Company does, however, use external data for existing EVs from R.L. Polk & Company, a leading provider of vehicle data, for use in informing historical EV sales.

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

In keeping with National Grid's stated goal of establishing forecasts based on simulations, the Company seeks the best-of-breed, open source simulation models from the DOE and academia for modeling load and specific DER type growth. The Company has established strong relationships with the DOE national laboratories, key universities (*i.e.*, Massachusetts Institute of Technology ("MIT"), Stanford University, and University of California ("UC") Berkeley) and other utilities that are looking to approach the forecasting challenge in the same manner as National Grid. The Company is also an active member of both the NYISO and ISO New England ("ISO-NE") and brings back and utilizes best practices of those groups.

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.

Moving to a simulation mode of forecast production affords the opportunity to evolve the forecast model with additional detail and information used to improve the levels of accuracy. By using the combination of a system-level perspective (*i.e.*, the traditional area for out-of-model adjustments) and a simulation-based feeder level model where DERs are modeled directly, the potential for inaccuracies are reduced.

2.3 Grid Operations

Context and Background

National Grid serves over 1.6 million electric customers in Upstate New York. The Company's service territory covers over 25,000 square miles and includes everything from densely populated urban areas in Buffalo, Syracuse, and Albany, to remote and sparsely populated rural areas throughout Upstate New York. The Company's peak demand is relatively stable when weather normalized. The peak demand in 2017 was 6,083 MWs which was 15% below the Company's all-time high of 7,149 MWs on July 21, 2011. However, the summer of 2017 was relatively cool which resulted in lower peak loads. For comparison, an estimate of what 2017 loading would have been under the extreme weather scenario used in planning, the resulting load would have been 6,809MW a small decrease of -0.4% from the 2016 weather-normalized peak.

The electric T&D infrastructure that spans the Company's service territory and forms the "grid" has been built over decades and is comprised of many different generations of technology. Today's grid is performing well, consistently meeting reliability targets, and interconnecting DG in increasing numbers. However, the integration of DER is making grid operations much more complex. There are a number of challenges the Company faces to dynamically manage the grid and efficiently achieve the objectives of REV including:

- Less than 1% of customers have interval meters;
- About 30% of the Company's distribution substations and feeder circuits do not have interval metering available for planning and operations;
- The Company does not yet have a Distribution Management System in operation;
- More than half of the distribution line miles operate below 5 kV and have limited capacity to host significant DER; and
- There is limited two-way communication with distribution equipment located outside of the substation.

In order to maintain safe, reliable and efficient operations in a growing DER environment, the grid must be modernized and processes harmonized between the DER providers, DSP, and NYISO.

In this section of the DSIP Update, National Grid describes DSP/NYISO coordination, efforts concerning monitoring and control of DER, and the Company's grid modernization initiatives to deploy more smart technologies on the grid, enhance control center operations, and enable advanced functionalities such as VVO/CVR and FLISR.

DSP/NYISO Coordination

The individual utilities and NYISO have historically shared load forecasts, communicated DR activations, and coordinated dispatch of distribution-connected generation resources participating in NYISO's wholesale market, all with the common goal of operating and planning the electric system in accordance with good utility practices and established procedures meant to preserve safety and reliability.

Operational coordination is paramount to the efficiency of increased market participation and access to market value through contracts and tariffs that is the hallmark of the DSP vision.

National Grid, as well as the other Joint Utilities, has participated in multiple forums, including the NYISO-Joint Utilities Working Group, NYISO governance committees, and related stakeholder sessions, to help formulate market development and guide interactions, communications, and coordination between the utilities and NYISO. The Company's initial DSIP noted the limited interaction between the NYISO and utilities with regard to DER. However, over the last two years, the NYISO has developed a DER roadmap[45] that suggests a path forward in which it will make multiple options for market participation available for DER and will eventually result in changes to the wholesale tariff language and upgrades to NYISO software to enable grid and market operations.

To enable the capabilities envisioned as part of the DSP vision, each DSP will not only need to expand its historical level of coordination with the NYISO, but also build upon, and in some cases establish new forms of, coordination with DER aggregators and individual DER operators. In its DSIP Filings Order, the Commission stated that "many complex and nearly continuous interactions will need to occur among the NYISO, the DSPs, and DER operators."[46] The Joint Utilities agree, and have worked with the NYISO, DPS Staff, and stakeholders to define required information exchanges and operational coordination among the various entities.

Monitoring and Control

Increasing DER penetration introduces new complexities to grid operations including varying and multidirectional flows that impact loading and voltage control. Establishing an appropriate level of operational situational awareness, through the monitoring and control ("M&C") of grid assets and DER will enable the integration of DER in a safe and reliable fashion. Additionally, effective M&C standards will help to maintain power quality, optimization of system usage, and enhance grid reliability and resiliency. The Joint Utilities have always required M&C for grid and market operations; however the increasing grid complexity now demands greater levels of M&C. M&C supports three principal areas: operations, planning and market functions. Descriptions of these areas are summarized in Table 2.3.1 below.

[45] New York Independent System Operator, *Distributed Energy Resources Roadmap for New York's Wholesale Electricity Markets* (January 2017).
[46] REV Proceeding, DSIP Filings Order, p. 7.

Table 2.3.1 – Use Cases for Monitoring and Basic Control

Use Case	Rationale for M&C	Third-Party Benefits
Operational	Real-time situational awareness enables the safe and reliable operation of the distribution system, due to increasing complexity and interdependencies of interconnected systems (*e.g.*, D-SCADA, ADMS, and DERMS). M&C in this context is performed near real-time and provides for increased efficiency and the ability to use existing assets to full potential.	Utility management systems operating in real-time can balance safety and reliability and ultimately economic requirements with the operational characteristics of DER to enable optimal market participation. This can be at an individual DER or aggregated DER.
Planning	Provides better estimates of future operational parameters based on historical data, thereby enabling proactive development of solutions to address anticipated constraints. More granular and accurate forecasts help planners develop more targeted, cost-effective projects.	Historic load and generation data provides greater accuracy with regard to the potential impacts of a proposed interconnection which produces clearer interconnection requirements and better cost estimates for the interconnection applicant.
Market	Enables real-time monitoring and control of DER to facilitate the utilization of those resources in an efficient, safe and reliable manner	Enables increased DER interconnection and access to value streams through multiple market mechanisms (*i.e.*, wholesale, distribution, and ancillary service markets).

Through its grid modernization plans, National Grid continues to increase the level of grid monitoring on it distribution system. At this time, approximately 70% of the distribution feeders have interval load monitoring at substations that has been integrated with SCADA. For the remaining 30%, circuit loading is tracked via manual readings utilizing drag hands on analog meters. The Company is working to expand the level of circuit monitoring through the installation of substation RTUs, the deployment of line sensors at the feeder head, and capturing information from distributed intelligent devices such as reclosers, line regulators, and capacitors. Additionally, if the Company's plans for AMI are approved, the granular monitoring of the secondary system from customer meters will further enhance situational awareness and grid operations.

With respect to monitoring third-party DER, M&C is being reviewed in parallel work streams within the Joint Utilities Working Groups as well as the NYISO governance process. These include the ITWG, Market Issues Working Group ("MIWG"), and the Joint Utilities ISO-DSP Coordination Working Group.

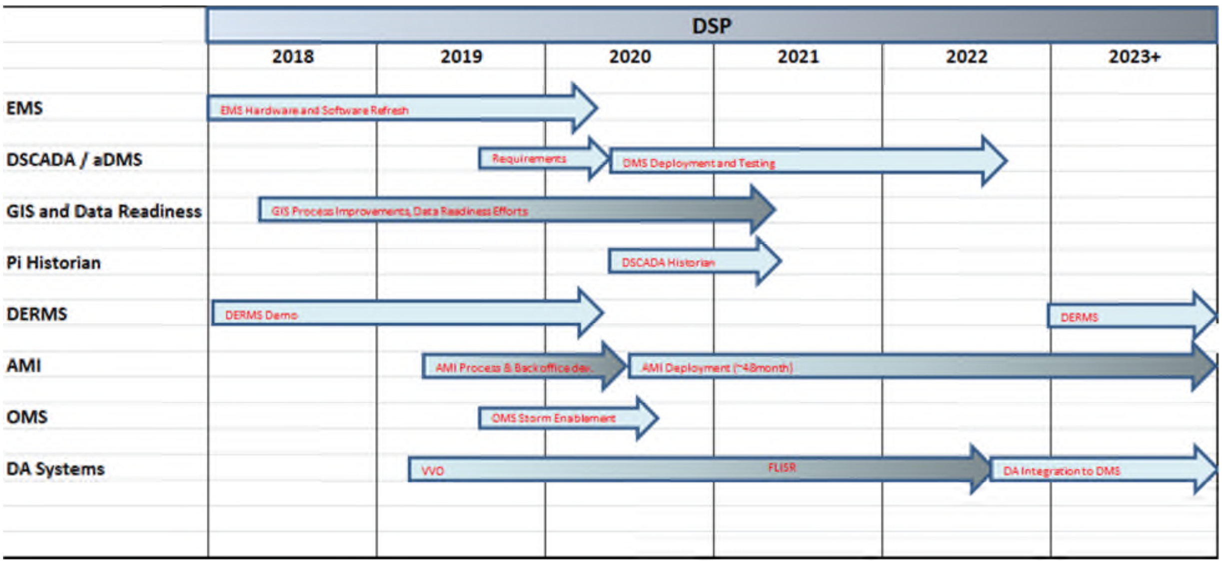
National Grid's Grid Modernization Initiatives
Advanced grid operations will require significant enhancements in technology including energy and information management systems to reliably coordinate the interactions of DER and grid-controlled devices interconnected with the electric delivery system. These grid modernization investments are foundational to enable operations of the electric grid and integration of wholesale and retail markets.

In its initial DSIP, National Grid identified a number of investments it planned to make to enhance grid operations including:

- AMI
- Distribution Automation ("DA") to include sensors, VVO, and FLISR
- Control Center Enhancements
- Telecommunications
- Operational Information Systems

National Grid maintains a Control Center Technology Roadmap to help meet operational and market expectations. The roadmap was initially developed in 2016 and has been updated to reflect the current status of implementation considering progress to date and plans aligned with the Three-Year Rate Plan Order.

Figure 2.3.1: Control Center Technology Roadmap



Each of these initiatives will help to enable DER integration with distribution system operations and developing wholesale and retail markets. They will facilitate grid and market operations through advanced M&C and automated processes and applications that optimize operational activities and thereby create value for customers and DER providers.

Current Progress

DSP/ NYISO Coordination
In the Supplemental DSIP, the Joint Utilities committed to "ongoing coordination with NYISO to identify, discuss, and resolve emerging issues" related to facilitating DER participation in wholesale markets.[47] The NYISO's DER Roadmap,[48] which outlines the progress NYISO anticipates making in the next three to five years to integrate DER (*i.e.*, controllable resources) into the wholesale energy, ancillary service, and capacity markets, was a key consideration in proactively establishing this coordination effort. As part of this DER Roadmap, the NYISO identified the types of enhancements that will be needed to effectively integrate DER, including "enhancements to wholesale market design, system planning, and grid operations to better align resource investments and performance with system needs and conditions."[49]

The Joint Utilities and NYISO formed a task force in the beginning of 2017 to define the requisite coordination protocols to promote DER integration and market services. As part of these efforts, the Joint Utilities and NYISO have coordinated on topics related to:

- Information exchanges and operational coordination between the DSP, NYISO, DER aggregators, and individual DER;
- DER aggregation registration and mapping individual DER to a transmission node;
- Pilot design coordination;
- Aligning operational coordination requirements with wholesale market rules and distribution-level service requirements;
- Short-term forecasting of load and DER for both operational and market purposes; and
- Dual participation in wholesale markets, utility NWAs, and distribution level markets.

The Joint Utilities hosted a number of stakeholder engagement sessions to communicate the progress they have made on these topics and gather input on future activities.

Operational Coordination and Communications
The NYISO has no visibility into the distribution system and therefore, while the NYISO can effectively dispatch aggregations at the transmission node level, there is no consideration for distribution system constraints at the utility level. The Joint Utilities' *Draft DSP Communications and Coordination Manual*[50] defines an initial set of coordination requirements

[47] DSIP Proceeding, Supplemental DSIP, p. 93.
[48] DER Roadmap for New York's Wholesale Electricity Market, *supra* note 45.
[49] *Id*., p. 5.
[50] Joint Utilities of New York, *Draft DSP Communications and Coordination Manual*, *available at* jointutilitiesofny.org

to facilitate DER participation in wholesale markets while maintaining the necessary situational awareness of the transmission and distribution systems. The NYISO will be responsible for the dispatch of DER aggregations for the purposes of providing energy and /or services to the bulk power system and the DSP will be responsible for ensuring that the dispatch of these DER aggregations does not compromise T&D system safety and reliability.

The Joint Utilities also developed a *Draft DSP-Aggregator Agreement for NYISO Pilot Program*[51] to close the operating and communication gap between the utility interconnection agreements and tariffs and NYISO tariffs. The document provides information to DER aggregators as to how they will need to interact with the DSP to coordinate operations while maximizing the ability of DER aggregations to deliver value across different services.

The NYISO is proposing a pilot program to test policies, common procedures, and evolving technologies. These pilots will provide valuable learnings for enhanced coordination among the parties.

Dual Participation

To further the objectives of the DSP, the Joint Utilities believe DER should be permitted to provide and be compensated for appropriate wholesale market value and/or distribution-level services as long as the service or product is separate and distinct. Developing a framework for DER to be compensated across the full set of values that they can provide to the bulk power and distribution systems aligns with overarching REV goals.

In addition to dual participation between NWAs and the NYISO wholesale market, there are also opportunities to achieve two REV goals through dual participation between the VDER Value Stack tariff and NYISO wholesale market.

National Grid currently participates and will continue to participate in both the NYISO and VDER stakeholder processes as they develop rules and frameworks for various forms of dual participation.

Short-Term Forecasting

In order to preserve system safety and reliability and to foster financially efficient and non-divergent energy markets, each DSP is actively refining its methods for building these dispersed and variable resources into its short-term forecasts, even if it lacks real-time visibility into the performance of the smaller resources.

Through the regular meetings of their task force, the Joint Utilities and NYISO worked together to more fully understand the methodologies, processes, and use cases for each party's short-term forecasting of autonomous DER behavior and load. The Joint Utilities plan on continuing this benchmarking effort with NYISO to inform possible opportunities for coordination on

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[51] Joint Utilities of New York, *Draft DSP-Aggregator Agreement for NYISO Pilot Program*, *available at*: jointutilitiesofny.org [52] DSIP Proceeding, 2018 DSIP Guidance Update, pp. 11-12.

approaches, including potential avenues for NYISO to leverage or incorporate DSP data and/or forecasts for operational and market purposes.

Monitoring and Control

In the Company's initial DSIP, National Grid included plans for foundational investments in monitoring systems, control systems, and distribution infrastructure upgrades to support DSP capabilities, including the measurement and verification of DER performance. Efforts since filing the initial DSIP have concentrated on establishing foundational M&C requirements, documented in the National Grid Electric Service Bulletin ("ESB") 756, which are essential to grid and market operations. In addition, the Joint Utilities have worked on advancing M&C capabilities to include considerations of additional technologies such as ESS. One of the primary considerations while developing these requirements is to identify lower-cost M&C solutions which are enabled through evolving technologies.

Since the initial DSIP filing the Joint Utilities have worked to understand and define the M&C requirements for evolving grid and market operations. Since January 2017, National Grid has been meeting as part of the Joint Utilities M&C Working Group to discuss implementation issues and the continued evolution of requirements, such as pursuing lower cost M&C solutions and integrating new technologies in the M&C framework. The M&C Working Group produced several technical documents for consideration by the ITWG, including proposed interim requirements for M&C based on benchmarking with other utilities and operational experience. These documents can be found at the following URL: http://jointutilitiesofny.org/resources/.

In November 2017, as a result of ITWG discussions, as recommended by DPS Staff the M&C requirements were amended as shown in Table 2.3.3 below.

Table 2.3.2 – Statewide M&C Requirements as of September *1, 2017*

Proposed Monitoring and Control Requirements by Size for Solar PV in New York State			
	< 50 kW	**Individual or Aggregated 50kW up to 500 kW**	**Individual or Aggregated 500 kW and Greater**
Monitoring	Monitoring ***may*** be required	Monitoring ***may*** be required	Monitoring ***shall*** be required
Control (PCC Recloser)			PCC Recloser ***shall*** be required
Control (RTU)		Basic Control ***may*** be required	

National Grid's Grid Modernization Initiatives

During 2017, the Company included grid modernization proposals, aligned with its initial DSIP, in a general rate case filing with the Commission. These proposals included:

- AMI
- DA (sensors, RTUs, VVO, FLISR)
- Control Center Enhancements
- Telecommunications
- Operational Information Systems (GIS, Enterprise Service Bus, Data Lake, Data Historian, Cloud Computing, and Advanced Analytics)

The Three-Year Rate Plan Order included funding to begin progress on this plan covering the period April 1, 2018 through March 31, 2020, with changes to the Company's initial proposed implementation schedule for a number of initiatives. Many of the projects identified in the initial DSIP are currently in the engineering phase or early stages of implementation.

A description of projects moving forward in support of DSP capabilities is provided below.

Distribution Management System - DSCADA and ADMS

The Three-Year Rate Plan Order approved the funding for Distribution Management System ("DMS") deployment and the Company expects to begin in 2019 and complete during 2022.

In 2017 National Grid conducted an ADMS Pilot to test software proposed for the project. The pilot tested baseline functionality on fifteen of the Company's distribution feeders modeled in a test environment for system operators. The testing and investigation of the ASEA Brown Boveri ("ABB") DMS applications covered in this pilot were acceptable and demonstrated the benefits of situational awareness (*i.e.*, optimized switching, troubleshooting, DER integration, and system configuration decisions). The pilot also proved useful in determining the ability to integrate the applications with existing hardware and software. A key learning from the pilot identified that good system data and the ability to efficiently transfer that data into the DMS network models is critical. Therefore, the Company is embarking on an associated GIS enhancement project which will facilitate the maintenance of DMS network models.

Volt-VAR Optimization / Conservation Voltage Reduction

VVO/CVR is a distribution level program where voltage control devices are intelligently controlled in a coordinated manner to optimize distribution system performance. This program is designed to flatten the voltage profile to minimize system losses, while simultaneously operating targeted distribution feeders at the lowest allowable voltage level in an effort to reduce demand and energy consumption. A comprehensive VVO/CVR program requires advanced control schemes integrated through telecommunications to respond to system dynamics in real-time. As part of the program, distribution circuits are studied by engineering for optimal placement of any additional capacitors and regulators required to achieve an optimal voltage profile.

To demonstrate the potential of enhanced volt-var control for system efficiency, the Company is currently deploying an advanced VVO/CVR system as part of its Clifton Park Demand

Reduction REV demonstration project. The system is being deployed at two substations (comprising eleven feeders) with measurement and verification expected to begin in late 2018.

DISTRIBUTED ENERGY RESOURCE MANAGEMENT SYSTEM

National Grid expects that a DERMS will be necessary to efficiently manage a grid with many DER. The DERMS will have many functions, however, the primary application will be to dispatch DER in a fashion that maintains the security of the distribution system while ensuring an economic solution.

The Company is currently in the demonstration phase of DERMS technologies as part of a REV Demonstration project at the BNMC to better understand required functionalities. The lessons learned from this project, as well as other initiatives such as the implementation of Demand Response Management System ("DRMS"), will be considered to develop the functional specifications of a full scale application. The Company anticipates that the DERMS will integrate with the ADMS currently being deployed.

Future Implementation and Planning

DSP/ NYISO Coordination

The Joint Utilities will pursue moving forward to achieve expanded opportunities for DER to be compensated across the full set of values they provide. The Joint Utilities will continue to evaluate how markets and tariffs evolve, identify lessons learned, and incorporate pertinent information into the *Draft DSP Communications and Coordination Manual.* The Joint Utilities will also expand the *Draft DSP-Aggregator Agreement for NYISO Pilot Program* into a full DSP-Aggregator agreement to transparently define the full set of roles and responsibilities of the DSP and Aggregator to facilitate grid and evolving market operations. The Joint Utilities will leverage the results of DSP pilot and demonstration projects and the NYISO pilot program to inform future refinements and develop a complete DSP-Aggregator agreement for use once NYISO establishes its DER participation model.

As part of ongoing efforts to enable the DSP and inform NYISO's DER Roadmap, the Joint Utilities will continue to coordinate with NYISO on a regular basis to address topics including, but not limited to: (1) Meter Service Provider and Meter Data Service Provider rules and requirements; (2) dual participation in wholesale markets and provision of distribution-level services; (3) short-term forecasting (for market and operational purposes) of net load and autonomous DER behavior; and (4) development of transmission pricing nodes for use in various market products. These continued coordination efforts will directly facilitate the Joint Utilities' efforts to integrate DER in a safe and reliable manner and enable a more seamless market participation framework for DER across wholesale markets and distribution-level services.

Monitoring and Control

The Joint Utilities believe that the current M&C standards are not optimal to support grid and market operations under increased DER penetration. A significant amount of DER scheduled to be installed in 2018 and is below both the 1,000 kW threshold and the new 500 kW threshold and thus will operate with no mandate for near real-time monitoring.

For National Grid, approximately 86% of the projects (*i.e.*, approximately 1,500 projects totaling approximately 39,000 kW) in the Company's interconnection queue are below 300 kW. Therefore, the DSP will not have real-time monitoring on much of the DER on the system which masks the true quantities of both generation and load.

Accurate generation and load data, enabled by increased monitoring, can enable novel mechanisms for encouraging future DER integration. For example, detailed descriptions of a circuit's temporal hosting capacity could prompt resources to enter into flexible interconnection agreements rather than pay for costly interconnection upgrades. DER could be used to alter a circuit's operating profile when that circuit approaches certain operating parameters in order to preserve system reliability and optimize system usage.

The relationship between resources, the DSP, and the NYISO place demands on M&C. The NYISO has its own requirements for resources participating in the wholesale markets and as part of its proposed DER participation model, would require six-second telemetry. The NYISO is actively working with stakeholders and the Joint Utilities to determine if there are alternative methods for calculating six-second telemetry based off of five-minute direct metering through "traditional" methods for small resources (*e.g.*, residential resources). To the extent the NYISO requirements require the collection and transmission of data beyond what is established as part of the ITWG and/or requirements of the interconnecting DSP, the DSP may request access to that data for individual DER to support operational needs.

National Grid along with the Joint Utilities will continue to research alternate M&C products and technologies to reduce the financial burden to DER owners. Where possible, standard designs and functionalities will be developed for equivalent use cases to reduce the costs of M&C.

National Grid's Grid Modernization Initiatives

The Company is creating a Grid Modernization Execution organization to deliver the projects recently approved in the Three-Year Rate Plan Order. Several of these initiatives have multi-year implementation horizons that will extend beyond the rate plan period which necessitates that investments will be requested in future rate cases to complete the projects.

Projects and initiatives that will progress during the term of this DSIP Update are as follows.

Energy Management System

The EMS platform which consists of a T&D SCADA System and the EMS applications including: state estimator, load flow, and contingency analysis. These applications are primarily focused on the transmission system model. The system is currently undergoing a routine refresh/upgrade effort which typically occurs on a six-to-seven year cadence. This upgrade will replace aging hardware and upgrade software and is scheduled to be completed at the end of 2020.

Distribution Management System (including: D-SCADA, ADMS and Outage Management System)

As described previously, and per the Three-Year Rate Plan Order, the Company will begin deployment of DMS. The DMS will allow for an integrated system that provides situational awareness and supervisory control on one platform for the Control Center Operations team. DMS will also provide a means, through an ADMS, to centralize control of distribution automation systems such as VVO and FLISR. This approach aids efficient transfer of data and helps to reduce costs and eliminate human performance issues that come with operating multiple platforms.

The D-SCADA system will allow for separation of the T&D SCADA data, providing the additional capacity needed for greater granularity in monitoring and control required by the evolution of distribution-connected resources.

The Outage Management System ("OMS") and DMS utilize a common platform for modeling the distribution system. The OMS was procured in 2009 and is to be updated when DMS is deployed.

Through future initiatives the DMS platform is envisioned to integrate with a DERMS to enable additional functionalities in support of DER integration.

Global Information System and Data Readiness

This project will deliver enhancements to National Grid's Smallworld GIS System, specifically to enable asset and data management, DSM modeling, the System Data Portal, IOAP initiative, planning load flow, HCA, and advanced analytics. The GIS data enhancement project has commenced and will be completed in 2021.

The drivers for the enhancements include:

- Distribution system and retail market operations require increased granularity and accurate and timely data to achieve the benefits associated with advanced functionalities.
- Data improvement is necessary for ADMS modeling, IOAP screens, and other corporate initiatives.
- Required closure of gaps identified through efforts like HCA, ADMS Pilot, National Grid's Massachusetts' affiliate's Worcester Smart Grid, data profiling, and day-to-day uses.
- Compliance with Asset & Data Management Business Management System ("BMS").

Operational Data Historian

The OSIsoft® PI historian is an integral part of the EMS and OMS/DMS systems. The system maintains a history of analog and status data for points monitored through SCADA and is used for operations, planning, and settlement. This system will be going through enhancements to support projects in the roadmap coincident with their deployment (*e.g.*, DMS).

Distribution Automation (VVO/CVR and FLISR)

The Company is currently deploying an advanced VVO/CVR system as part of its Clifton Park Demand Reduction REV demonstration project. The Company anticipates positive results from this demonstration project and plans to begin an annual program of additional VVO/CVR deployments beginning in 2019 and continuing beyond 2023.

The initial deployments of advanced VVO/CVR will utilize a dedicated centralized controller that evaluates real-time information from sensors on the distribution primary system. Following completion of the proposed ADMS system the Company expects to deliver future VVO/CVR from that platform.

Later, if the Company progresses with a system-wide AMI deployment, an additional 1% of CVR benefits may be achievable if secondary voltage monitoring from the AMI meters is integrated in the VVO/CVR control algorithms. As part of the Clifton Park REV demonstration project, National Grid will be conducting an analysis that examines service level voltage information, provided by the newly installed AMI meters, and utilizing that to quantify how much additional voltage headroom is available on the feeders.

The deployment of FLISR technology is planned for a relatively small number of feeders each year beginning in 2021 and will continue as a program as warranted based on annual reliability reviews. This program seeks to automate switching devices on the distribution system to improve reliability related metrics. These devices may include reclosers, breakers, and switches which can be automated or remotely controlled to locate and isolate a fault on distribution feeders resulting in faster fault isolation and restoration of impacted customers. When implemented, the system will locate and isolate a faulted section of the grid and restore as many customers as possible in advance of repairs to the damage in the isolated section. While initial autonomous operation of the FLISR system may have decentralized processing, some functions are expected to be centralized once the DMS is deployed.

DERMS

At the current time National Grid is mapping DSP functions to the requirements of a DERMS application. The vision is that the primary use of DERMS in the DSP will be to facilitate and/or manage an economic- and reliability-based dispatch with several inputs and outputs from/to existing or evolving systems with the goal being to optimize value for the customer and the DER.

Over the next five years the Company plans to conduct the following activities:

- Continue mapping DSP market and operations functionality to DERMS
- Continue DERMS demonstration projects at new locations and test new functionalities

- Continue to validate equipment and software vendors against National Grid's standards and requirements
- Develop a case for the future deployment and funding of DERMS
- Benchmark with other utilities' DERMS deployments and software vendors

Risk and Mitigation

The risks associated with grid operations are related to core DSP functions including increased automation, increasing DER interconnections, and evolving markets. Situational awareness, enabled by M&C, is a top priority in enabling both the market and operations functionality. The mitigating action for this risk is to continue to define an optimal set of requirements, balancing operational needs with developer costs, through the work of the Joint Utilities, NYISO and NYS DPS forums.

Another risk is associated with procurements related to maturing wholesale and retail market integration. The tariffs and contracts required to implement these markets must be vetted and approved before investments, like those for which DERMS would be an important enabling technology, can be made to incorporate those facets of the market into the applications. For example, DERMS and the market constructs will likely need to mature together. The mitigation for this risk is to ensure investments support strong market concepts and to continue to foster demonstration projects that provide valuable lessons for broad implementation and procurement.

Stakeholder Interface

National Grid has found the stakeholder interaction valuable in providing and soliciting feedback and guidance on processes and programs under development. The Company actively participates in a number of forums that actively seeks stakeholder interaction. These include the NYISO-Joint Utilities Working Group and the NYISO governance committees such as the MIWG, and the ITWG.

Additional Details

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.[52]

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.

National Grid will continue to ensure the safe and reliable delivery services to its customers by continuing to plan and operate the distribution system using good utility practices. Paramount to operations is the visibility of system parameters to understand loading and voltage under real-time and predicted conditions. This includes matching an understanding of system configuration

[52] DSIP Proceeding, 2018 DSIP Guidance Update, pp. 11-12.

with short-term forecasting of load and generation. The need for increased situational awareness, control, operational tools, and processes and procedures will increase in order to satisfy a secure and economic dispatch, as the number of DER increase. The need for data and tools to secure the network will increase with the development of new tariffs, markets, and participants.

The NYISO is responsible to dispatch wholesale resources in a secure and economic manner. DER and aggregations of DER interconnected to the distribution system will be allowed to sell into the wholesale market as a result of anticipated tariff changes. The NYISO does not have the ability or the responsibility to monitor or control the individual distribution-connected resources which reside with the distribution utility. Therefore, significant coordination will need to exist between the NYISO and the utilities. As a result, the Joint Utilities have developed a Draft DSP Communication and Coordination Manual as well as a Draft DSP-Aggregator Agreement to help define the necessary interactions between the NYISO, the aggregator, DER providers, and the distribution utility to facilitate the reliable and safe operation of the T&D systems. These documents will be exercised during the NYISO DER Pilot Program and any lessons learned will be incorporated as necessary.

The Joint Utilities Monitoring and Control Working Group, ITWG, NYISO-Joint Utilities Working Group, and NYISO MIWG continue to discuss the level of monitoring and control for interconnected DER to facilitate markets and operations.

2. Describe other role and responsibility models considered and explain the reasons for choosing the planned model.

The utilities are responsible for providing safe, reliable, and quality services to customers by operating the distribution system in accordance with good utility practices. The assets required to operate the distribution system (*i.e.*, systems for monitoring and controlling) are owned by the utility and borne out of utility good practices and lessons learned. As part of the REV Track One Order the utilities were assigned the role of the DSP provider within their respective service territories. The Joint Utilities undertook a process to define functions, roles, and responsibilities of a DSP and out of that extensive effort the current proposed model was developed. Alternative models were not investigated.

Additional details of the DSP and both market and grid operations will be detailed in the supplemental Market Design and Integration Report, subject to guidance from DPS Staff.

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, in conjunction with the Joint Utilities, is formulating roles and responsibilities as DSIP-related grid and market operations evolve. There are currently numerous efforts, as defined later in this section of the DSIP Update, which need to be factored into the roles and responsibilities of planning and grid operations. Several stakeholders are involved in these efforts including the NYISO, DPS Staff and DER providers.

The Joint Utilities have been coordinating with the NYISO through the NYISO-Joint Utilities Working Group and the NYISO MIWG forums. A result of this collaboration is set out in the Draft DSP Communication and Coordination Manual, as well as the Draft DSP-Aggregator Agreement, both of which will facilitate DER participation in the NYISO market.

Undoubtedly, as DER penetration increase and grid operations evolve to a more active network management mode, roles and responsibilities will have to evolve accordingly. As the various efforts outlined above progress to finalization, roles and responsibilities will be further defined.

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 for each of the following areas.

a. Organizations

The Joint Utilities undertook an effort to understand what the DSP will look like as the markets and technologies evolve. This vision includes functions that include market and grid operations as well as planning. National Grid's organizational design to implement the DSP functionality will adjust as part of the DSP evolution. Consideration is given to current and future functions and how the organization can perform the functionality in an efficient and effective manner. For information on National Grid's evolving organizational design, see Section 3.1 of this DSIP Update.

b. Operating Policies and Processes

Operating policies and processes continue to evolve as conversations continue around the NYISO Roadmap, Energy Storage Roadmap, VDER Proceeding and related matters, and market design efforts, among other initiatives. The general premise is to develop a high-level framework of processes and procedures and then create detailed (*i.e.*, lower tier) operational procedures to guide system and market operations. An example of this is the Draft DSP Communication and Coordination Manual developed by the Joint Utilities to provide guidance on the interaction among parties operating in the wholesale market.

c. Information systems for system modeling, data acquisition and management, situational awareness, resource optimization, dispatch and control, etc.

The Control Center Operations systems fall into three categories; (1) systems in operation today, (2) systems approved in the Three-Year Rate Plan Order, and (3) systems subject to funding beyond the Three-Year Rate Plan Order. The investments are described in detail in the Three-Year Rate Plan Order and are depicted above in Figure 2.3.1 - Control Center Operations Technology Roadmap.

d. Data communications infrastructure

National Grid recently completed a comprehensive review of its telecommunications systems and developed a road map identifying the people, processes, and equipment necessary to address the asset management priorities of existing infrastructure as well as shaping the forward-looking plans to address future needs.

The Company plans to deploy a multi-tiered telecommunications system to connect core grid edge components (*i.e.*, smart feeders, smart meters, and smart inverters), deploying an optimized system from the start.

e. Grid sensors and control devices

In accordance with the Three-Year Rate Plan Order, the Company is progressing with plans to install additional feeder monitoring sensors and substation RTUs to enhance situational awareness. Over the next five years National Grid expects to install RTUs at 38 distribution substations and feeder monitoring sensors at the head end of 347 feeders. This data will inform operating personnel about thermal loading and voltage issues, and other important elements necessary to cost-effectively maintain service quality. This data will also provide interval performance information which can be key to accurately identifying areas where DER may provide value.

The majority of substations with 15kV class distribution circuits were selected to have RTUs installed, while the majority of substations with 5kV class distribution circuits were selected to have distribution line sensors installed. The substations with multiple distribution circuits ranked high on the priority list, as well as those surrounded by 15kV class distribution.

f. Grid infrastructure components such as switches, power flow controllers, and solid-state transformers

As part of its VVO and FLISR programs, National Grid is installing more intelligent switching devices that can be programmed for autonomous control or operated remotely from the Company's control centers.

National Grid and its affiliates are continually evaluating alternative new technologies. For example, the Company is working with NYSERDA to assess a prototype feeder tie controller utilizing power electronics that has the capability to increase hosting capacity for DER. The Company's Massachusetts affiliate completed a pilot project that evaluated a power electronics-based secondary voltage regulator and is working with EPRI to evaluate voltage regulation utilizing smart inverters.

The Company plans to continue to review the integration of the technologies described above with DER for application in New York.

g. Cyber security measures for protecting grid operations from cybersecurity threats

Measures that need to be in place to ensure safe and reliable grid operations include capabilities that enable the prevention, detection, and response to cyber-security threats. From the perspective of the end user, enforcement of least-privilege access and monitoring of activity is a means to prevent data loss and to identify malicious activity. Access is closely monitored and analyzed to ensure that malicious user activity is detected and flagged so that necessary actions can be taken. Network traffic is monitored in real time to detect any abnormal network traffic, devices, or endpoints and to establish a baseline for traffic during grid operations so that any abnormal activity can be detected and appropriately addressed. The Cybersecurity Operational Center plays a critical role in the central monitoring of activity and brings together detection, analysis, and response in the event of a cyber-security incident.

h. Cyber recovery measures for restoring grid cyber operations following cyber disruptions

Energy and resource management systems typically have a robust architectural design. At a high level, the architecture will include equipment located at primary and backup data centers. The system will be capable of switching between the primary and backup site and operating independently in case of a site failure. Within each site, servers will be redundant with both hot and standby servers with capability to switchover.

In addition, recovery procedures will be created and maintained, including a periodic backup schedule and recovery exercise to be conducted at intervals no longer than 15 months. This architecture will enable recovery from a cyber-disruption at the individual server, site. or system level.

5. Describe the utility resources and capabilities which enable automated VVO.

a. Identify where automated VVO is currently deployed in the utility's system

The vast majority of National Grid's distribution feeders have voltage regulations schemes that are controlled in an automated fashion through autonomous controls on substation transformer load tap changers, feeder voltage regulators, and/or switch capacitor banks. In presenting the Company's grid modernization plans and more specifically when discussing VVO, National Grid is referring to advanced control schemes that coordinate the automated control of voltage regulating devices considering remote monitoring, telecommunications, and advanced control algorithms. The Company is deploying its first advanced VVO scheme as part of the Clifton Park Demand Reduction REV demonstration project. Deployment is in progress on eleven feeders and the Company expects to begin a measurement and verification process in late 2018.

b. In both technical and economic terms, provide the energy loss and demand reductions achieved with the utility's existing automated VVO capabilities

Implementation of VVO/CVR technology on select circuits is forecasted to provide a 3% reduction in energy consumed, peak demand, and associated GHG emissions. These benefits are achieved without direct customer engagement. The beneficiaries of these benefits are:

- Individual customers on managed circuits will have reduced kWh usage;
- All National Grid customers will benefit from reduced ICAP purchase requirements, to the extent that the circuits peak demand is coincident with the larger electrical system's peak demand, which will be passed on as savings to all customers; and
- Society will benefit from the reduction in GHG emissions related to energy production.
- The expected reduction in feeder peak demand may defer the need for future distribution capacity investments

The economic terms are described below in response to 5d.

c. Describe in detail the utility's approach to evaluating the business case for implementing automated VVO on a distribution circuit

There are a number of anticipated benefits of a VVO/CVR deployment which includes the following:

- The implementation of a VVO/CVR system is expected to result in improved feeder power factor, flatter voltage profiles, reduced feeder losses, reduced peak demand, and reduced energy consumption by customers. The estimated reduction in energy consumption is expected to be approximately 3% but will vary from feeder to feeder based on the individual characteristics.
- The additional operational data collected by automated capacitors and regulators, and available to control center operators, will support the improved management of the distribution system which will assist in the integration of DER. Actively maintaining proper voltage via intelligent centralized control will also improve feeder voltage performance, keeping the voltage flat and low, allowing for higher DER penetration.
- The deployment of VVO/CVR schemes will provide historical data to improved distribution system planning.
- VVO/CVR will have a direct impact on the peak load experienced by the feeders on which it is deployed. Therefore, the Company expects this technology to support the System Efficiency EAM metrics by reducing peak load.

The costs of VVO/CVR deployment can be summarized in a few categories:

- Engineering/Design Labor
- Radios and telecom equipment for distribution devices
- Upgrades to distribution devices (*i.e.*, regulators and capacitors) to accommodate remote operation
- Upgrades to substation regulation equipment (*i.e.*, regulators or load tap changers) to accommodate remote operation
- Distribution primary-based line voltage monitors ("LVMs")
- Software licensing for VVO/CVR application
- Back office support infrastructure (*i.e.*, firewalls, network connectivity support equipment)

A benefit-cost analysis utilizing the National Grid BCA Handbook was completed. The results are provided in response to question 5.d below. Within the horizon of this DSIP Update, VVO/CVR will be deployed on selected feeders via optimal feeder analysis as described previously.

d. Provide a preliminary benefit/cost analysis (using preliminary cost and benefit estimates) for adding/enhancing automated VVO capabilities throughout the utility's distribution system

A benefit-cost analysis in alignment with the BCA tool was completed on the VVO/CVR deployments envisioned in FY 2020 and 2021. Benefits considered in the analysis were reduced system losses (leading to capacity and energy reductions), avoided generation capacity cost, and avoided CO2 emissions. On these feeders, VVO is forecasted to reduce the total energy losses by about 53 GWh, while also reducing the annual peak demand by about 1 MW combined. The BCA values presented below show results of both a Societal Cost Test ("SCT",) and Utility Cost Test / Rate Impact Measure ("UCT"/"RIM").

Table 2.3.4: Benefit/Cost Analysis

$MM 20 year NPV		VVO/CVR Implementation
Benefits	SCT Benefits	$43.2
	UCT Benefits	$35.7
Costs	Capital Expenditures	$15.2
	Operating Expenditures	$7.3
	SCT Costs	$22.5
	UCT Costs	$22.5
SCT Ratio		1.92
UCT / RIM Ratio		1.59

e. Provide the utility's plan and schedule for expanding its automated VVO capabilities

Over the next five years, National Grid plans to build from lessons and successes from the VVO/CVR demonstration projects, namely the Clifton Park Demand Reduction REV demonstration project and similar projects in Rhode Island being conducted by an affiliate of National Grid.

National Grid plans to deploy VVO/CVR to approximately 111 feeders across all three regions of the state, West, Central and East. The list below describes the years and associated number of feeders the Company plans to deploy over the duration of this DSIP Update. VVO deployments in the latter years of this DSIP Update will be determined based on the needs and value, however, the current estimated number of feeders is provided as follows:

- FY19 - 11 feeders (Clifton Park Demand Reduction REV demonstration project)
- FY20 - 10 feeders across the state
- FY21 - 25 feeders across the state

- FY22 - 29 feeders across the state
- FY23 - 36 feeders across the state

The energy and demand savings will vary from feeder to feeder. The Company will monitor and verify the performance of the program as the implementation progresses and will continue to identify future feeders in which the Company anticipates a positive BCA. Feeders will be selected based on criteria including:

- Physical characteristics
- Historic and projected loading and capacity
- Inspection and maintenance information
- Historic reliability
- Load type
- Substation automation levels

During the next five years National Grid will investigate other smart grid technologies such as AMI, ADMS, standalone voltage/Power Factor control devices, and DERs' potential ability to provide VAR and voltage support to advance VVO/CVR schemes even further.

f. Describe the utility's planned approach for securely utilizing DERs for VVO functions

With changes from the revised IEEE 1547 Standard it is expected that third party- and customer-owned DG and ESS may be able to provide voltage/reactive power support, enabling greater opportunities to integrate DER assets into the grid. Utilities in Hawaii, California, and Germany now mandate the use of smart inverters.

National Grid is encouraged by the potential to integrate DER into its VVO schemes. In advance of that ambition the Company plans to:

- Continue to assess the results of an on-going effort of National Grid's affiliate in Massachusetts' affiliate that is utilizing smart inverters on its Solar Phase I-III projects
- Consider changes in the NYSIR to align with the latest IEEE 1547 Standard and smart inverter controls
- Continue discussions with the Joint Utilities, research groups, and stakeholders.

g. In both technical and economic terms, provide the predicted energy loss and demand reductions resulting from the expanded automated VVO capabilities.

See the Company's response to question 5.d above.

6. Describe the utility's approach and ability to implement advanced capabilities.

a. Identify the existing level of system monitoring and distribution automation

National Grid currently has the following levels of monitoring on the grid:

- % of feeders with EMS tied RTU = 65%
- % of feeders with distribution line sensors installed at the feeder head = 4%
- % of feeders that have reclosers with communications = 20%
- % of reclosers with communications = 71%
- % of cap banks with communications = less than 1%
- % of regulators with communications = less than 1%

The Control Center Technology Roadmap lays out the investments in Control Center Operations. National Grid is in the process of upgrading its EMS and will continue to make investments to support integration of DER which enables additional values for stakeholders.

Starting in 2007, National Grid implemented FLISR capabilities on eight sub-transmission lines that have successfully mitigated customer interruptions and the Company plans to add a further six projects in the near future. Lessons from these projects will help inform the roll out distribution automation technologies on distribution feeders. As described in the above Distribution Automation section, the deployment of automated FLISR technology will be targeted to a relatively small number of feeders each year beginning in 2021 and will continue as a program as warranted based on annual reliability reviews.

b. Identify areas to be enhanced through additional monitoring and/or distribution automation.

M&C enhances the ability to understand the performance of resources and by providing the ability to dispatch resources, results in more efficient utilization and a more economical market solution while enabling greater numbers of DER to interconnect and participate.

As described in more detail in the earlier Distribution Automation section, the deployment of automated FLISR technology system provides the ability to locate and isolate a faulted section of the grid and restore as many customers as possible in advance of repairs.

Many locations on the Company's electric system do not have load monitoring capability including many substations which do not have RTUs. Load data is essential in determining the thermal stress on equipment, a feeder's balance, load transfer capability, and DER integration. Instantaneous load readings cannot always be attained at ideal thermal peak periods. As such, the roll out of substation RTUs, deployment of line sensors at the feeder head, and capturing of data from distributed intelligent devices, will be vital to enhance grid analysis and operation.

c. Describe the means and methods used for deploying additional monitoring and/or distribution automation in the utility's system.

Prioritized investments that support DER interconnection and market operations while maintaining system reliability will be made. For example, the installation of over 100 line sensors is following a prioritization ranking approach based on the following elements:

- Stations without EMS SCADA
- VVO
- DG Interconnection
- Advanced Distribution Automation
- Ad-Hoc Monitoring (*e.g.*, trouble feeders, customer complaints, load studies, etc.)
- Step-down areas

The Company will continue to seek additional monitoring and automation technologies such as FLISR and AMI data integration.

d. Identify the benefits to be obtained from deploying additional monitoring and/or distribution automation in the utility's system.

The list below provides a sample of some of the benefits provided through additional monitoring and distribution automation:

- Increased reliability, resiliency, and system efficiencies through situational awareness
- Operational costs savings in line crew call-outs
- Improved accuracy in grid planning
- Greater visibility for grid operations
- Improved data for third parties and customers
- Improved forecasts
- Provide foundations for a more transactive grid market
- Help integrate DER assets

e. Identify the capabilities currently provided by Advanced Distribution Management Systems ("ADMS").

National Grid is in the process of deploying the DMS (D-SCADA and ADMS). The project will begin in 2019 and be deployed in 2022. The scope and timing of system applications will be reviewed and updated in the requirements phase considering the advancements in technologies. Preliminary scoping of functions include: separation of D-SCADA to allow for a larger number of analog and status points for situational awareness; load allocation; unbalanced load flow analysis applications; restoration switching analysis; and simulation analysis.

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

National Grid believes the ADMS functionalities will evolve to provide a platform for distribution automation in parallel with advancements in industry technology. The ADMS application will support operational and market facing functions of a DSP and will enable the future investment in DERMS.

Ultimately, the functions will provide the ability to use the electric system more efficiently while operating within the limits of the system which maximizes value for customers and DER providers.

g. Identify other approaches or functionalities used to better manage grid performance and describe how they are/will be integrated into daily operations.

National Grid believes that the effective dispatch of DER enables an optimized solution based on system security and economics. This functionality begins with ADMS and progresses through DERMS functionality. Both ADMS and DERMS enable markets and provide situational awareness to the grid operator.

2.4 Energy Storage Integration

Context and Background

The interest in and focus on ESS as a DER in New York has significantly increased both at the Company and among other stakeholders, including policymakers since the initial DSIP filings. In the initial DSIP, the Company expressed an interest in further considering ESS in system planning, as well as developing ESS demonstration projects either through NWA procurement or as a REV demonstration project.

In 2017, both houses of the New York Legislature passed A6571, which required the Commission to set a statewide storage target for 2030. In his State of the State speech, Governor Cuomo announced an ambitious target of 1,500 MW by 2025. In support of these efforts, on June 21, 2018, DPS Staff, in conjunction with NYSERDA, filed the Energy Storage Roadmap with recommendations for market, policy, and programmatic updates to enable New York State to meet its 2025 target and positioning the Commission for establishing the 2030 target.

Current Progress

National Grid has developed two ESS projects in accordance with the Commission's DSIP Filings Order. Those two projects were subsequently approved in the Three-Year Rate Plan Order. Since then, the Company has been steadily advancing those projects with anticipated in-service dates by the end of 2018.

Kenmore
The proposed 2 MW/3 MWH battery storage system at the Kenmore substation will test the use of energy storage to alleviate a supply constraint. The substation is supplied by three sub-transmission cables that are forecasted to surpass their normal capacity rating in the near future. The ESS project will be designed to supply energy at peak times to reduce the load carried by the sub-transmission system. This project is intended to defer the installation of additional sub-transmission capacity in the area.

At the time of this DSIP Update, National Grid has finalized contract terms with the selected vendor and has begun the permitting process.

East Pulaski
The proposed storage system at the East Pulaski Substation will test the use of a 2 MW/3 MWh battery energy storage to alleviate an "N-1" distribution constraint. N-1 constraints describe a

scenario where the network must operate with the loss of a single element of the system on which it normally relies. For example, if a failure occurs on a transformer bank at a nearby substation, the East Pulaski substation may need to supply power to a greater number of customers following load transfers than under normal conditions. This scenario has occurred, on average, approximately 2.5 times per year for several hours and increases the risk of the substation surpassing its rated capacity. This ESS project will supply energy to the distribution system to reduce the load on the transformer during these "N-1" scenarios. Additionally, based on the forecasted load growth under normal conditions, this substation transformer is projected to exceed its peak capacity in 2020. The use of this ESS will help defer the need for a transformer replacement at the East Pulaski Substation.

At the time of this DSIP Update the East Pulaski ESS project is under construction.

National Grid believes there is merit in having the two ESS demonstration projects to participate in NYISO wholesale markets. The Company will work with the NYISO to implement "dual participation" in distribution system needs and NYISO markets which will improve storage economics and return greater benefits to customers.

Finally, the Company expects that the data it collects on the performance of these ESS demonstration projects will be valuable in future planning and procurement activities.

In addition to the two demonstration projects, National Grid has been working on the following items relative to ESS:

- Assessment of ESS projects for several NWA RFPs
- Providing input with respect to modifications to the NYSIR regarding ESS interconnection requests

Future Implementation and Planning

Table 2.4.1 provides an overview of National Grid's near-term plans for ESS.

Table 2.4.1: Future Implementation and Planning

Year	Description	Implementation	Target Outcomes/Goals
2018	VDER Value Stack: ESS + Tier One Eligible Renewables	The Company is working to implement processes to comply with the Commission's April 19, 2018 Order Modifying Standardized Interconnection Requirements in Cases 18-E-0018 *et al.* that mandated the inclusion of ESS paired with clean DG.	

Year	Description	Implementation	Target Outcomes/Goals
2018/2019	VDER Value Stack: Standalone Storage	The Company will file comments, which are due August 6, 2018, on DPS Staff's proposal to include stand-alone storage under the VDER Value Stack tariff.	Timely and effective interconnection processes and fair compensation.
2018	Demonstration Projects	Complete the two, in-progress grid-scale storage batteries projects.	Technical and economical proof-of-concept; defined use cases for different ownership models.
2019-2020	ESS Beneficial Locations Study	Develop and perform an integrated techno-economic study based on the use cases provided in the answer to question 4	Determine optimal locations on National Grid's system for ESS in terms of physical and financial parameters.
2021-2023	Grid Integration of ESS	Building from the ESS Beneficial Locations Study, identify potential programs, incentives and tariff changes for ESS deployments across the T&D system and behind the meter. The Company will also investigate ownership of ESS were it is feasible and in alignment with the REV Track One order	Consider new programs, incentives and tariff changes.
2018-2023	ESS in the NWA Procurement Process	Building on the recommendations in the Energy Storage Roadmap to solicit RFPs for NWA solutions, evaluating ESS solutions based on BCA and learnings from previous ESS projects.	Attract appropriate bids for the solicitations where the technical and economic circumstances are suitable for ESS solutions.
2018-2020	Advocate for NYISO Tariff Changes	Work with the Joint Utilities and NYISO and other forums to advocate for participation models that foster economic efficiency in ESS deployment.	Full participation of ESS in NYISO markets under a fair compensation structure without double-compensation

Potential Tariff Changes

National Grid expects a series of updates to be made to the compensation mechanisms for ESS over the next five years. On May 22, 2018, the Commission, as part of the "Staff Proposal on Value Stack Eligibility Expansion," suggested that stand-alone ESS should be compensated for contributions to the power system through the Value Stack tariff. The Company filed comments on this proposal in concert with the Joint Utilities.

The Company, also in concert with the Joint Utilities, submitted proposals for DPS Staff consideration in May 2018 for the mass market Net Energy Metering ("NEM") Successor Tariff to be implemented by January 1, 2020. ESS paired with NEM will likely be eligible for the NEM Successor Tariff. In accordance with the Three-Year Rate Plan Order, National Grid agreed to propose rate designs for beneficial electrification within six months of the order. Both the NEM Successor Tariff and National Grid's forthcoming beneficial electrification rate , are likely to include time varying components, which would better align more incentives facing customers with system cost drivers, and thus produce economic rationale for behind-the-meter storage.

ESS Data Improvements

National Grid is currently making changes to ensure adequate ESS interconnection data is provided and improving the integration of this data with internal databases, GIS, and modeling software to adequately capture ESS benefits/impacts on the grid.

The Company recognizes the value of ESS and the critical role it could fulfill for the T&D system in the near future, and will continue to work with stakeholders to appropriately tailor policies, programs, and procurement of ESS.

The future grid integration of ESS will be conducted in alignment with the Energy Storage Roadmap, internal policy, state goals, and stakeholder interests.

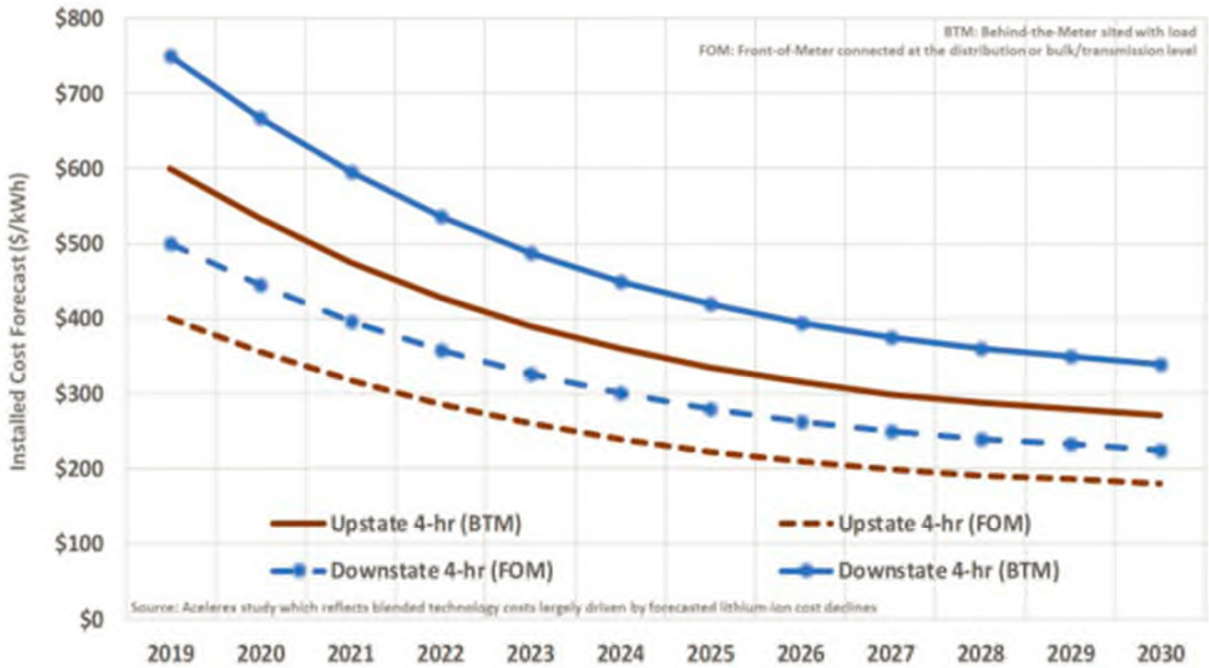
Risk and Mitigation

As described in the Energy Storage Roadmap cost justification of ESS remain one of the biggest challenges to integrating ESS on the grid in particular for the region of NY State National Grid operates in. However, if additional benefit categories can be included as part of the value proposition and the costs continue to decline, ESS could eventually become a competitive to traditional wire based projects. One of the primary objectives of the two demonstration projects in East Pulaski and Kenmore is to identify and quantify those costs and additional benefit categories.

The Energy Storage Roadmap indicates the wide discrepancy in the time at which certain use cases may be economic in the Company's service territory. Using a breakeven cost of $300/kWh from Figure 2.4.2 below and mapping those into the cost declines from Figure 2.4.1 below suggests that some front-of-the meter applications could be economic by 2021, while BTM systems might not be economic for another half decade.

Despite this, new markets are developing at the NYISO level to incorporate small-scale, aggregated, and large-scale storage into several market products. Also, in addition to the work described above regarding the beneficial locations study, the Company is also working to incorporate a number of values ESS can provide into its portfolio through efforts such as NWA and VDER.

Figure 2.4.1: Blended Energy Storage Cost Forecast for NY State by Upstate/Downstate Region[53]



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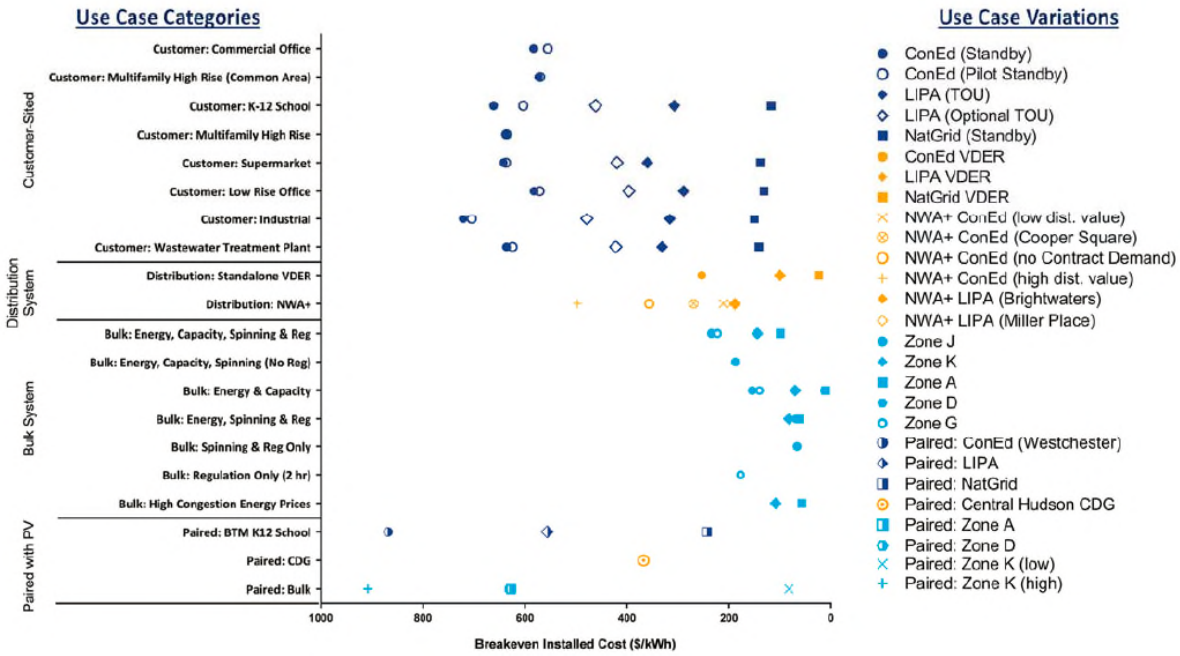
[53] Case 18-E-0130, *In the Matter of Energy Storage Deployment Program* ("Energy Storage Proceeding"), New York State Energy Storage Roadmap and Department of Public Service/New York State Energy Research and Development Authority Staff Recommendations (filed June 21, 2018)("Energy Storage Roadmap"), Figure ES3, p.10.

Figure 2.4.2: Economics of Various Storage Use Cases Comparing Revenue Streams to Total Cost over System Lifetime[54]



Stakeholder Interface

National Grid expects that interactions with stakeholders over the next five years will help define priority use cases and applications for ESS both behind- and in front of- the meter, which will inform how the Company will evaluate projects for system operation. This increased knowledge base will enhance the market by fostering opportunities for system installations, project evaluation, marketing, and customer involvement.

National Grid will participate and contribute to the various conferences and stakeholder sessions scheduled as part of the Energy Storage Roadmap process.

[54] *Id.*, Figure ES2, p. 9.

Additional Details

The following responds to DPS Staff's request to provide additional details specific to ESS resources.[55]

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.

National Grid currently has a total of 1.6 MW and 2.1 MWh of ESS currently connected to the grid. The ESS are predominantly tied with solar PV projects. The list below provides the locations of the ESS. We do not currently track the functions or operations of these third party resources at this time.

- Worcester
- Tribes Hill
- Schodack Landing
- Schenectady
- Saratoga Springs
- Red Hook
- Piseco
- Little Falls
- RT 28 Inlet
- Gloversville
- Fort Ann
- Durhamville
- Duanesburg
- Cohoes
- Clay
- Cambridge
- Brockport
- Ballston
- Averill Park
- Amsterdam
- Albany

[55] DSIP Proceeding, 2018 DSIP Guidance Update, pp. 13-15.

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.

Please refer to Table 2.4.4

Table 2.4.2: Plans to Implement and Operate Beneficial Energy Storage

Project	Kenmore
Description	Please see the "Current Progress" section of this Section for more details
Original Schedule	Anticipated in service by 12/31/18
Current Status	Signed contract with selected vendor and started permitting process
Lessons Learned to date	N/A
Adjustments & Improvement opportunities Identified to Date	N/A
Next Steps with Timelines & Deliverables	Complete permitting process.
Project	East Pulaski
Description	Please see the "Current Progress" section of this Section for more details
Original Schedule	In service by 12/31/2018
Current Status	Started construction
Lessons Learned to date	N/A

Adjustments & Improvement opportunities Identified to Date	N/A
Next Steps with Timelines & Deliverables	Complete construction.

3. Provide a five-year forecast of energy storage locations, types, capacities, configurations, and functions.

While a specific ESS forecast to the level of detail requested above does not currently exist, National Grid is performing a scoping exercise for such a study. The study will use financial and technical indicators to identify the most beneficial locations of ESS on the system, effectively acting as the forecast requested above.

The Company believes that ESS will play a critical role in supporting the most cost-effective grid possible. However, the optimal quantity, locations, and timing of deployment are still uncertain. To help answer these questions, in addition to the lessons learned from the two ESS demonstration projects described earlier in this in this section, National Grid plans to conduct a study to evaluate potential beneficial locations for ESS within the Company's service territory.

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. its location;
b. the energy storage capacity (power and energy) provided;
c. the function(s) performed[4];
d. the period(s) of time when the function(s) would be performed; and,
e. the nature and economic value of each benefit derived from the energy storage resource.

National Grid is still in the initial stages of identifying opportunities for ESS and the values associated with those opportunities. The Company anticipates it will be able to identify suitable locations, approximate capacities, and timing of deployment for prominent use cases including those below.

- **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 wholesale 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** – 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 peak load. Such an ESS would likely be operated on daily cycles which would be seasonally dependent.
- **Reduced Generation Intermittency–** Intermittent (often renewable) sources of generation can have a more limited number of use cases because they cannot be considered 'dispatchable.' By pairing ESS with these generation sources, the generation source's intermittency can be reduced, increasing the number of applicable use cases for these existing systems and therefore their value. The ESS would likely perform some daily smoothing to maximize the operator's revenue.
- **Decreased Interconnection Costs –** By using energy generated by intermittent DERs to charge at optimal times, ESS can eliminate the need for certain upgrades to the system that would otherwise be required for intermittent resources. Eliminating the need for these upgrades could significantly reduce the interconnection costs of these intermittent DERs. The timing of this performance depends on the nature of the generator and interconnection studies.
- **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, black start capability are functions that ESS could provide year round, with a specific focus on high-load periods.
- **Optimal Dispatch of Conventional Generation -** Many types of conventional generation have an optimal power output for fuel efficiency but may need to operate above or below that point at times to follow the load. Adding dynamically dispatched ESS can reduce the need for the generator to ramp up or down, allowing it to remain at optimal efficiency or even replace peaking units. The ESS could provide these functions year round.

5. Identify and describe all significant resources and functions that the utility and stakeholders5 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.

Many tools are currently and will continue to be utilized to integrate ESS into the planning and operations processes. Currently, for example, CYME's software application, CYMDIST, is being used by National Grid for continued analysis of demonstration projects, including 8760 studies utilizing the CYME ESS tool. Additional tools will be considered as the Company invests in ESS planning training through EPRI throughout 2018. To date, the EPRI Storage Value Estimation Tool (StorageVET®) training has been completed and the tool is being evaluated as a financial calculator for ESS projects. More tools will be considered by the Company for planning and operations throughout the next five years.

National Grid resources including those that are specific to studying storage, and more generic M&C resources discussed in the Grid Ops Section, support stakeholder needs in a number of areas. For example, they facilitate the interconnection process, by contributing to accurate estimates, and timely construction. Alternatively, advanced M&C can help the utility and stakeholders identify high value areas of the system, where storage can be most beneficially deployed.

6. Describe the means and methods for determining the real-time status, behavior, and effect of energy storage resources in the distribution system. Information produced by those means and methods should 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 for each charging event;
c. the time, size, duration, consumer (grid and/or local load), and purpose of each energy storage discharge;
d. the net effect (amount and duration of supply or demand) on the distribution system of each charge/discharge event (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.

National Grid does not currently have these functionalities to monitor and control ESS. However, these functionalities are expected to be developed in the future via ADMS (and potential DERMS) software that the Company envisions.

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 should 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; and,
d. the net effect on the distribution system of each charge/discharge event (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.

National Grid does not forecast the real-time behavior of individual ESS resources but through multiple efforts can collect data and information to inform many of the requests above. The first effort will be in the form of the beneficial locations study to determine specific locations on the system where ESS has value and the technical specifications of the ESS (*e.g.*, time, size, duration, consumer (grid and/or local load) and purpose of ESS discharge) associated with each location are identified. The amended NYSIR also provides the utilities with more critical technical details regarding each ESS applying to interconnect. The Company is exploring additional modelling tools and modules to perform more granular analysis of ESS units (*e.g.*, CYME ESS module with long-term dynamics analysis).

8. 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.

National Grid's System Data Portal currently provides much of the information needed to beneficially locate ESS, including hosting capacity, LSRV locations, NWA information, and system capacity data. As more data is made available to the Company (through increased system monitoring), every effort will be made to incorporate it into the portal, consistent with the Company's cyber-security and customer data protection practices.

9. By citing specific objectives, means, and methods describe in detail how the utility's accomplishments and plans are aligned with the objectives established in New York State's recently signed Energy Storage Deployment legislation and Governor Cuomo's new initiative to deploy 1,500 megawatts of energy storage in New York State by 2025.

National Grid plans on taking extensive measures to align with the 2025 initiative. The first is to perform an integrated study to jdentify specific, beneficial locations of ESS on the T&D system. The second is to develop programs, incentives and tariff changes that support ESS use cases on the bulk system, distribution system, and BTM..

10. Explain how the Joint Utilities are coordinating the individual utility energy storage projects to ensure diversity of both the energy storage applications implemented and the technologies/methods employed in those applications.

The Joint Utilities hold regular conference calls with company ESS subject matter experts to discuss lessons learned regarding the process of implementation of the ESS projects under development.

2.5 Electric Vehicle Integration

Context and Background

New York's EV policies are generally derived from the 2015 New York State Energy Plan, which committed the state to reduce GHG emissions from the energy sector 40% by 2030 and a longer-term goal of decreasing total carbon emission 80% by 2050. Transportation accounts for nearly 35% of New York's GHG emissions and the State Energy Plan specifically endorses EVs as a key element of the overarching strategy to reduce such emissions. National Grid agrees that EV adoption is critical to meeting these targets. The Company has aggressively supported transportation electrification including: installing charging stations at customer sites across its upstate NY territory; building multiple innovative EV projects as reflected in the Three-Year Rate Plan Order recent rate case including a uniquely structured EAM for EV growth tied to carbon reductions; and incenting the purchase of new EVs by National Grid eligible management employees.

A key element of the State Energy Plan is the Charge NY initiative, which was launched by the governor in 2013 to create a statewide network of up to 3,000 public and workplace charging stations and put up to 40,000 EV's on the road over five years. The initiative also developed best practices for municipal EVSE regulations, created vehicle incentives such as reduced bridge tolls, and removed regulatory obstacles for installing EVSE at public parking lots. This initiative is led by a collaboration of NYSERDA, the New York Power Authority ("NYPA"), and the New York State Department of Environmental Conservation ("NYSDEC"). These agencies are also tasked with implementing the Multi-State Zero Emission Vehicle Action Plan, of which New York is one of eight signatories. The Multi-State ZEV Action Plan established a collective goal of 3.3 million ZEVs by 2025; for New York, this is equivalent to about 800,000 to 900,000 ZEVs on the road by 2025.

In the Supplemental DSIP, the Joint Utilities described the current state of the EV market and committed to form a utility working group to develop a joint EV Readiness Framework within twelve months of completion of the comment process for the Supplemental DSIP filing (or by January 2018). The Supplemental DSIP also included a set of guiding principles co-developed with stakeholders for utility involvement in supporting the increased adoption of EVs and charging infrastructure; these helped inform the development of the Joint Utilities EV Readiness Framework. As discussed in greater detail below, the Joint Utilities completed a draft of the EV Readiness Framework in January 2018 and circulated it to interested stakeholders for feedback. In early February 2018 the Joint Utilities held a stakeholder meeting focused on aspects of the EV Readiness Framework and provided an opportunity for stakeholders to ask questions and offer additional input on the document. The final draft of the document was posted on the Joint Utilities website in March 2018 and can be found at https://jointutilitiesofny.org/resources

In support of the initiatives noted above, the Commission directed the utilities to continue preparing for higher penetrations of EVs. As noted in the DSIP Filings Order, "the Commission expects the Utilities to continue investigating EV-related infrastructure effects and modifications in anticipation of a potential future when the range of needs and demands for EVs is substantial."[56] Subsequently, the Commission initiated a proceeding in April 2018 (Case 18-E-0138) to consider the role of electric utilities in providing infrastructure and rate design to accommodate the needs and electricity demand of EVs and EVSE.

Joint Utilities EV Readiness Framework

The objectives of EV readiness planning are to identify, prioritize, and execute actions in the near-to mid-term that will unlock the potential of transportation electrification. The EV Readiness Framework, which is reflective of a significant amount of stakeholder input, is a comprehensive source of information on how the Joint Utilities intend to achieve these objectives. It also describes the difficulties in achieving widespread deployment of EV infrastructure (and vehicles, where appropriate). These include, but are not limited to, the higher price of EVs compared to conventional vehicles, the lack of public EV charging infrastructure, the lack of consumer awareness of EV benefits, and the lack of coordination among stakeholders.

Given the limited size of the current EV market, the Company, along with the Joint Utilities, believes that the EV Readiness Framework, in coordination with demonstration projects and proactive education and outreach efforts, is the most effective way for utilities to facilitate increased EVSE deployment and EV adoption. The Company has adopted this framework as part of its own EV promotion efforts.

The EV Readiness Framework identifies the following near-term priorities:

- EV charging infrastructure planning and forecasting EV growth to assess and mitigate potential system impacts;
- Streamlining charging infrastructure deployment in New York, which is characterized by reviewing service connection requirements; outlining local ordinances, building codes and design guidelines that can help reduce barriers to infrastructure installation; and highlighting the value of interoperability and standardization of charging equipment;
- Advancing rate design considerations that will improve the customer experience while minimizing impacts to utility system operation; and
- Conducting education and outreach efforts that improve customer awareness about the benefits of EVs.

The Company expects its role will vary considerably across the core elements of the EV Readiness Framework. However, the indicators for assessing market performance that the EV

[56] REV Proceeding, DSIP Filings Order, p. 9.

Readiness Framework contains will be important inputs to the Company's efforts throughout, especially as distribution system impacts of EVs may become more significant.

National Grid EV/EVSE Information

The Company estimates that 5,757 light-duty EVs are registered in the National Grid electric service territory, as of the end of Q1 2018.[57] The following table shows the growth of this statistic over recent years, including the 2013-2017 compound annual growth rate ("CAGR").

Table 2.5.1: Growth of Electric Vehicles Over Four Years

2013	2014	2015	2016	2017	CAGR
1,248	2,548	2,978	3,360	5,311	44%

The following table shows the number of EVSE charging sites and ports in the Company's electric service territory listed as listed on the DOEs Alternative Fuels Data Center website[58] as of April 4, 2018.

Table 2.5.2: Charge Points across National Grid Service Territory

	Level 2 EVSE	DC Fast Charging EVSE
Sites	266	13
Ports	519	59

Approximately 66 of the Level 2 locations, with a total of 126 ports, are operated by the Company, representing 24% of the total sites and ports in its service territory.

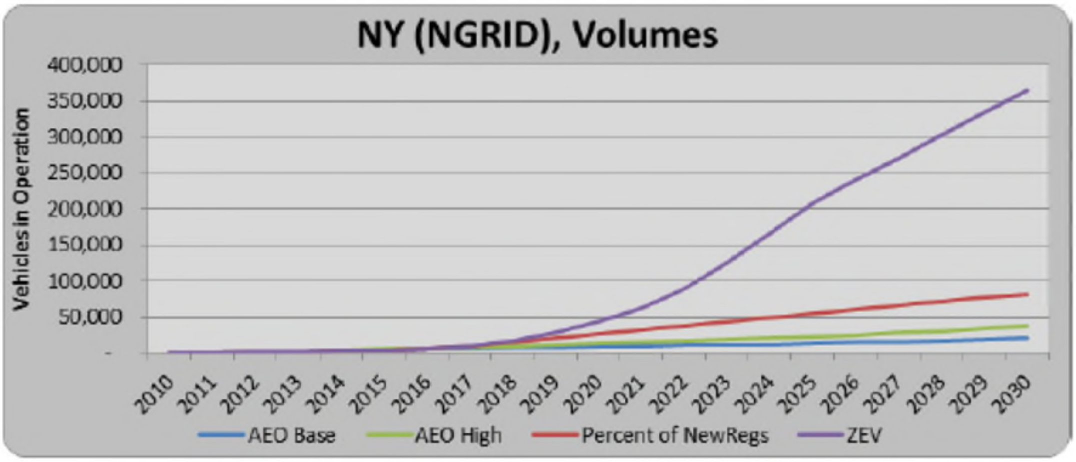
National Grid recognizes that the EV market is poised for significant growth over the next several years given the combination of supportive policies, more competitive vehicle pricing, and increased consumer offerings. To not only support this expected growth, but also act as a proactive partner in accelerating EV adoption to meet New York State's ZEV and GHG policy goals, the Company plans to effectively incorporate EV growth forecasts into system and investment planning.

The Company presently utilizes scenario-based forecasts which include projections from the DOE's Annual Energy Outlook ("AEO") projections based on past hybrid vehicle market growth and a "policy case" scenario based on the assumption that the growth necessary to reach the state's ZEV targets is achieved, all of which are shown in Figure 2.5.1.

[57] National Grid's subscription to IHS/Polk light-duty vehicle registration data, Q1 2018.

[58] Data from https://www.afdc.energy.gov/stations, accessed April 4, 2018, and filtered by National Grid electric service territory zip codes.

Figure 2.5.1: EV Penetration Scenarios in the National Grid Service Territory



All scenarios have projected modest EV adoption through 2020, with continued moderate growth through 2030 with the exception of the ZEV "policy case." As a result, current projected near-term levels of EV adoption are not expected to have a material impact on the Company's system infrastructure as noted in the EV Readiness Framework. However, incorporation of EV growth forecasts into system planning activities will be necessary to support accelerated growth in alignment with New York State's ZEV and GHG policy goals.

Current Progress

National Grid is taking progressive steps forward in the area of EV integration in alignment with each of the EV Readiness Framework categories: Charging Infrastructure Planning, Streamlining Charging Infrastructure Deployment, and Rate Design and Education and Outreach. The following paragraphs describe the Company's activities in these areas since the previous DSIP.

The Company continues to operate 66 public, Level 2 charging stations it owns in its service territory. These charging stations were installed between 2013 and 2014, leveraging NYSERDA funding. All the stations utilize a BTM configuration and are located on customer ("site hosts") premises. The electric bill is paid by the site hosts, who also establish end-user pricing. The Company pays monthly network fees and ongoing maintenance costs, including costs of replacement. To date, these stations have served 2,750 unique drivers from 1,283 postal codes. From 2016 to 2017, utilization of these stations increased by 35%. In 2017, the total energy delivered at the stations was 129,417 kWh in 20,157 charging sessions. At an average of 3.8 mi/kWh, in 2017, the total energy powered almost half a million miles.

During 2016 and 2017 National Grid installed Level 2 charging stations for employees at four of its New York facilities. This effort allows the Company to both lead by example and glean valuable data and lessons learned that can be used to inform future workplace charging initiatives at customer sites.

In 2017, the Company conducted a 2030 scenario analysis utilizing projections from the AEO customized for National Grid's service territory. This EV adoption forecast identified potential additions to the Company's capital plan through 2030. The Company's expectation is that load growth due to EVs through 2025, even in higher adoption scenarios, remains moderate and the existing system has flexibility to supply this load with relatively few modifications. The cost impact to supply this incremental load is expected to be negligible. While the scenario analysis forecasted EV adoption levels do not result in significant impacts to the Company's distribution system through 2025, by 2030 EV load growth is projected to become significant enough to drive the need for meaningful additions to the Company's capital plan. For example, in the Buffalo area, the supply and distribution system is highly utilized and has limited capacity to supply new load depending on EV penetration. Larger loads of 1 MW could be an issue with majority of the feeders in Buffalo. To supply the 2030 projected load (33 MW), the scenario analysis showed that new investments would be required potentially including two new or expanded substations. In the Syracuse area, the electric system is also highly utilized and the 2030 scenario-projected load (18 MW) predicted that an expanded substation could also potentially be required there as well. In addition, if fast charging station installations surpass the current expectations, the analysis forecasted that infrastructure enhancements of the Company's sub-transmission system along Interstate 90 would be necessary.

As previously mentioned, incorporation of EV growth forecasts into system planning activities is necessary to support accelerated growth in alignment with the state's policy goals. Detailed EV growth forecasts will also be required to identify pocketed areas of interest where EV growth is particularly concentrated, inadequate infrastructure exists, or likely a combination of both. Identification of these EV pocket areas was cited by the EV Readiness Framework as a near-term priority and will form the basis of National Grid's short-term EV planning goals. This analysis will then act as the foundation for long-term EV planning procedures. To identify locations where EV penetration may impact system infrastructure, the Company will incorporate EV growth forecasts into its planned forecast enhancements. National Grid is working to improve its EV forecasts by considering data on traffic flow, targeted utility charging development, and siting support for third-party charging developers.

Streamlining Charging Infrastructure Deployment

National Grid has initiated several efforts to streamline the process to interconnect EVs. Since the initial DSIP, the Company has supported new, dedicated EVSE service requests from public DC fast charging ("DCFC") developers including Electrify America, Tesla, and NYPA. Additionally, the Company has begun tracking new, dedicated EVSE service requests in order to monitor the growth of this segment.

The Company has conducted a RFP for EVSE to qualify for participation in its "make-ready" investment program, including Open Automated Demand Response ("OpenADR") standards. National Grid's Massachusetts affiliate is participating in a market development program for EVSE that has already been initiated which includes a set of required specifications for EVSE offerings to be qualified for inclusion in the program. These specifications include OpenADR and networking requirements among other technical requirements. The Company will leverage any lessons learned from its affiliate's program that may be appropriate for application in New York.

Rate Design and EAM

In December 2016, the Company gained approval from the Commission for its whole-house, VTOU rate. On that rate, customers who own an EV and receive supply service from National Grid have the option of receiving a one-time comparison of one-year of charges on the SC-1 VTOU versus the SC-1 standard tariff. As of mid-June 2018, there are approximately 43 customers enrolled in the rate and 34 have provided a copy of an EV registration to qualify for the bill comparison.

As part of the Three-Year Rate Plan Order, the Company received approval for a novel EAM for incremental EV adoption. This incentive rewards National Grid for increased levels of EV registrations in its service territory, relative to a peer group. The EAM is expressed in terms of lifetime carbon dioxide ("CO2") avoided from incremental EVs relative to internal combustion engines ("ICE").

Education and Outreach

As a complement to the investment demonstration to enable EV charging the Three-Year Rate Plan Order, the Company is undertaking an education and outreach effort which began with a soft launch of digital marketing in April 2018.

Also in April 2018, National Grid launched an internal program to help overcome the key barriers to EV adoption with its employees: affordability, awareness, and access. The Company is addressing the affordability barrier by offering a range of incentives, including some offered through strategic partnerships with auto manufacturers who provide exclusive discounts to eligible National Grid employees. The Company is addressing the awareness barrier by providing educational materials on EV and smart home technology basics, details on EV makes and models, information on public and workplace charging availability, and other important resources. For example, National Grid hosts "Ride and Drive" events across its service territory for its employees to test drive an EV. Finally, the Company is addressing the access barrier by aggregating all of the critical information into a "one-stop-shop" website that makes the EV purchasing process simple, enjoyable, and reliable. The Company anticipates gaining valuable lessons learned from this internal program that could be shared with its customers.

Future Implementation and Planning

Charging Infrastructure Planning

The Three-Year Rate Plan Order approved an Electric Transportation Initiative that allows the Company to invest in enabling capital infrastructure for EV charging sites. This initiative will accelerate the pace of charging station deployment by helping commercial customers, such as employers, apartment owners, retail site owners, or fleet operators, overcome cost and complexity barriers, which inhibit them from installing charging for the benefit of consumers or their own fleets. The Company will make capital upgrades to enable the installation of electric vehicle charging stations at commercial customers' properties and provide incentives to property owners to encourage the installation of these charging stations.

National Grid will make proactive investments in electrical infrastructure *both* on the utility-side of the meter *and* the customer's side of the meter (the "Site Host") to enable Site Hosts to install EV supply equipment. This is often referred to as "make-ready" infrastructure for EV charging.

Under this initiative, the Company will:

- Identify and develop prospective charging sites, working with account managers and equipment vendors to recruit large commercial and industrial customers as Site Hosts.
- Obtain a Site Host Agreement from the customer detailing the terms of participation and granting the Company an easement, or equivalent, for equipment the Company will own on the Site Host's premises, up to the base of the charging station.
- Construct and own any new distribution equipment, and hire a third party to install customer premise electrical infrastructure (*e.g.*, electrical panel, conduit, and wiring) which will be owned by the Company for each charging site.
- Offer a rebate toward the purchase cost of EVSE for selected site hosts.[59]

Participating site hosts will:

- Select desired EVSE from a qualifying equipment list developed by National Grid,
- Purchase EV Supply Equipment and apply the Company's rebate, if applicable,
- Agree to serve as customer of record for the National Grid electric service account, and to operate the EVSE for a minimum of 5 years, and
- Determine pricing, if any, charged to drivers for using charging station.

[59] National Grid has budgeted to offer a sliding-scale rebate toward a portion of the EVSE cost: up to 20% for workplaces, fleets, and other private businesses; up to 75% for multi-family dwellings or public sites, and up to 100% for low-income dwellings. The Company may not offer this rebate if a rebate is available to the customer from another source, such as NYSERDA.

The Company anticipates developing at least 30 new charging sites with approximately 300 new ports over the course of this initiative. Preference will be given to property owners who agree to promote EVs to their employees, tenants, and customers to encourage the utilization of the charging stations and advance the state's ZEV and GHG goals. Lessons learned from this initiative will enhance National Grid's ability to connect new third-party charging sites and may inform future charging program offerings by the Company.

In addition, the Company is requiring Host Sites participating in the Electric Transportation Initiative to install DR-capable networked chargers and agree to participate in future DR programs offered by National Grid.

National Grid is considering opportunities to demonstrate a residential EV-DR program beginning in 2019 in coordination with its residential DR platform provider. The next steps in such a program development would include: 1) compiling a list of customers with eligible chargers; and 2) developing the incentive for participation. Once the list is compiled, a web-based portal, which will enable further participation in such a program, will be developed and deployed. The Company intends to try to attract charger manufacturers to help with outreach to customers on charging station incentives and other information.

Rate Design

Less than 1% (43 out of 5,700) of the registered EV drivers in the Company's service territory are, at the time of this filing, enrolled in the VTOU rate, which National Grid believes is a result of limited awareness. The Company's analysis suggests that EV drivers can save an average of $150 per year by switching to the rate. Therefore, from 2018-2019, the Company will expand its initial marketing efforts for the VTOU rate to ensure broad awareness by EV drivers of their potential savings. National Grid will analyze available usage data of EV drivers on the VTOU rate (*i.e.*, peak and off-peak), and survey currently-enrolled SC1 VTOU customers with an EV to obtain information on their satisfaction with the rate, as well as their charging patterns.

In accordance with the Three-Year Rate Plan Order, National Grid will file a new "Beneficial Electrification" tariff on September 14, 2018. At the time of this DSIP Update filing, the Company is engaging with stakeholders regarding the development of this tariff. Comments from parties are due to the Company on August 10, 2018.

Beginning in 2019 the Company will assess comments upon filing the new Beneficial Electrification tariff along with the results of the expanded VTOU marketing effort to determine the most suitable EV tariff structure going forward, and plans to implement accordingly at the appropriate time.

In light of the state's policy goals for EV adoption, the Company is evaluating the impact of demand charges on DC Fast Charging station economics. According to stakeholders, DC Fast Charging is prohibitively expensive to operate during the early phase of EV market growth because of relatively low station utilization levels and demand-based delivery charges. By modifying demand rates to better align those charges with the timing of the system peak the

Company may be able to increase the number of these stations operated by third-parties in its service territory. An increase in available public charging infrastructure would address consumers' concerns about EV range, and facilitate an increase in EV adoption. However, while increased utilization of the EV charging stations may solve this short-term issue, the Company believes that to foster long term economic efficiency, rates should be based on utility cost structures rather than on specific end-use technologies.

Education and Outreach

As part of the education and outreach effort approved in the Three-Year Rate Plan Order, over the next three years the Company will demonstrate new strategies to increase customers' awareness and understanding of EVs. National Grid's campaign will endeavor to address the key concerns among residential and commercial customers about EVs, including affordability, battery range, charging availability, and charging speed. The Company's messaging will describe the performance benefits of EVs, feature technology advances, declining costs in vehicle and charging technologies, address available federal and state incentives for EVs and charging, showcase the increasing availability of charging, and promote the savings available under the Company's VTOU rate. National Grid will collaborate with a range of stakeholders and EV market participants, including NYSERDA, local auto dealers, and national automakers, to develop the campaign's materials.

The chart below summarizes the future initiatives the Company plans to undertake within the next five years to promote the integration of EVs into its service territory. Much of the proposed work is on pilot-stage projects as the Company's forecasts have yet projected EV penetration levels that warrant larger-scale projects. Much of the EV growth and focus on activities related to EV integration has significantly developed only since the initial DSIP filing. With the recently accelerated targets presented by state policy goals, National Grid is beginning to undertake additional efforts (*e.g.*, increased forecasting, more EVSE deployments, EV promotions, etc.), while continuing to investigate pilot projects which would enable the increased adoption scenarios for ZEVs.

Table 2.5.3: National Grid Plans on Electric Vehicle Integration into the Service Territory

Year	Description	Implementation	Target Outcomes/Goals
2018-2020	Charging development programs (Electric Transportation Initiative)	This is a set of broad-scale capital investments and incentives for installing EVSE, including a simplified/comprehensive EV charging Sjte Host package	Increased installation of EVSE
2018	Incorporate EV/EVSE growth forecasts into system planning	This is a set of various internal activities detailed in forecasting section below.	Inform capital plans by incorporating predicted load growth from EV/EVSE; Removing/reducing infrastructure barriers to EVSE growth

Year	Description	Implementation	Target Outcomes/Goals
2018-2019	Beneficial Electrification Tariff	Company's proposal to be filed by September 14, 2018	Increased EV adoption and customer participation in VTOU rates
2018-2019	Marketing/Education Outreach (Electric Transportation Initiative)	This is a concrete plan to develop and deploy a marketing campaign to solution providers and consumers to raise awareness	Increased awareness/adoption of EVs and EVSE

Risk and Mitigation

The EV Readiness Framework developed with the Joint Utilities is still new. Further, the Three-Year Rate Plan Order represents the first round of significant funding for EVSE and EV activities for National Grid. As a result, the next five years represent a period of relative ground-breaking effort. . As with any ground-breaking effort, there are numerous risks. This section summarizes those that could significantly impact the Company's implementation plans.

The outcome of the Commission's EVSE and Infrastructure Proceeding (Case 18-E-0138) could have significant impacts on the Company's implementation plans. National Grid continues to participate in the proceeding as appropriate to keep the consideration of its customers and stakeholders in the mind of all parties involved.

The quality and availability of data necessary to inform the Company's planned forecasting initiatives will have a significant impact on the quality of the finished product.

A certain level of customer participation is necessary in order to create a pilot that can provide statistically meaningful results for future lessons learned. Additionally, for some of the efforts to be economical, a larger area of customers will need to be targeted. The Company's EV outreach is intended to help drive participation.

As National Grid builds experience through its efforts over the next five years, it will identify risks and roadblocks to be avoided in future iterations of this work, as programs expand to scale.

Stakeholder Interface

National Grid's planned initiatives in this five year roadmap are designed to enable the market for EVSE and EVs within the Company's service territory. This in turn allows EVSE and EV developers to participate in that market and take advantage of its benefits. The Company's initiatives may also create opportunities for DR companies and other DER solution providers by creating an environment in which EVs themselves become DERs.

Through its Electric Transportation Initiative, the Company is developing a proactive process for partnering with commercial property owners and developing third-party charging sites. National Grid will be working closely with those involved in this initiative to solicit feedback to inform these new processes.

The Company's proposed pilots, such as the EV-DR program, will advance National Grid's ability to start identifying stakeholder requirements for future EV-related products and services as well as create opportunities for interactions with different stakeholders that will allow for an exchange of feedback.

In the meantime, National Grid will continue to collaborate with the Joint Utilities on common issues across utilities in New York to share information and best practices. This forum reaches a broad set of stakeholders that will likely grow as the Company and other utilities begin to implement more EV initiatives over the next five years.

Additional Details

The following responds to DSP Staff's request to provide additional details regarding EV integration.[60]

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;

60 DSIP Proceeding, 2018 DSIP Guidance Update, pp. 16-18.

k. the type and size of utility service needed to support the EV charging use case; region, area, substation, circuit, tap, and transformer

The Joint Utilities have developed the EV Readiness Framework which identifies key strategies to support EV adoption through utility action, engagement, and collaboration. The framework envisioned is an analytical precursor to investment or engagement at a scale larger than what has currently been contemplated publicly by any single utility in New York. Furthermore, based on the Joint Utilities' review of transportation electrification filings in other states, this type of jointly conceived framework regarding existing and anticipated EV charging scenarios is atypical. Investor-owned utilities that have made substantial investments in other states have targeted various aspects of the EV market—with a focus on workplace and public charging stations, and some on residential charging. Such efforts, however, have been aligned with some internally defined business and investments decisions, rather than the subject of a jointly conceived siting framework.

National Grid presently utilizes scenario-based forecasts of consumer EV growth (*i.e.* ,light-duty passenger EVs) based on projections from the DOE's AEO, which is based on past hybrid vehicle market growth, and a "policy case" based on assumed growth necessary to reach the state's ZEV targets. These scenarios have forecasted consumer vehicle growth at the service territory level and inform the Company's aggregate load forecast (*i.e.*, peak MW) and sales forecast (*i.e.*, MWh of deliveries). The current forecast's load impacts are based on residential charging needs, assuming a mix of Level 1 and Level 2 charging by National Grid's customers. The Company has not yet forecasted load impacts of public charging.

In 2018-2019, National Grid is undertaking a new forecast methodology to more accurately forecast EV growth spatially and temporally within the Company's service territory. The forecast will better inform the Company of areas likely to see infrastructure impacts associated with customer adoption of EVs and enable more accurate targeting of the Company's own investments in EVSE deployments or infrastructure upgrades to maximize benefits to customers. This new forecast methodology, currently in development, will consider as many of the characteristics described in Question 1 as is reasonably feasible.

2. Describe and explain the utility's priorities for supporting implementation of the EV charging use cases anticipated in its service territory.

Residential Charging (Single-Family/Detached Homes)

- National Grid's Beneficial Electrification tariff proposal to be filed by September 14, 2018 with increased marketing targeted to EV drivers to ensure broad awareness of potential savings.
- Analysis of usage data of EV drivers on the Company's rate offerings.
- Survey of currently-enrolled SC1 VTOU customers with an EV to obtain information on their charging patterns.
- Develop additional products and services to facilitate residential EV charging.

Residential Charging (Apartments)

- Develop ten or more large apartment charging installations through the 2019-2021 Electric Transportation Initiative (up to five ports per site) through “make-ready” investment, with charging stations to be operated by Site Host customers.
- Promote apartment charging to multi-family building owners participating in the Company’s EE programs.

Commercial Charging

- Continue to manage existing network of National Grid-owned Level 2 stations deployed with ChargePoint under the current NYSERDA grant (*i.e.*, single station installations on customer host meter), including charging station maintenance and replacement.
- Develop twenty or more large workplace charging installations through the 2019-2021 Electric Transportation Initiative (up to ten ports per site) through “make-ready” investment, with stations to be operated by Site Host customers.
- Promote workplace charging to large C&I customers participating in the Company’s EE programs.

Public DC Fast Charging

- Establish new service connections for highway corridor fast-charging stations, as requested by third-party station developers and other entities including NYPA, Electrify America, and Tesla.
- Forecast DCFC development to identify areas of prospective future distribution system upgrades.
- Develop two or more public DCFC sites through the 2019-2021 Electric Transportation Initiative (up to five ports per site) through “make-ready” investment, with stations to be operated by Site Host customers.

National Grid will also consider other alternatives to support additional charging use cases not described above.

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 system.

a. Explain how each of those resources and functions supports the utility’s needs.
The current scenario-based forecasting methodology enables National Grid to identify near-term system impacts and better inform the Company’s planning decisions. Incorporation of EV forecasting into more granular forecasts will enable the Company to better assess the system impacts associated with the growth necessary to reach the state’s ZEV target.

Additionally, the analysis will inform National Grid's direct engagement efforts with commercial customers to incentivize EV adoption through EVSE installation in high destination areas with significant vehicle dwell times. These investments will play a crucial role in achieving the Company's Carbon Reduction EAM goals by minimizing the range anxiety that exists as a barrier to widespread EV adoption through direct Company leadership in the EVSE market. These efforts will directly support National Grid's Electric Transportation Initiative by enabling strategic, data-driven EVSE site evaluation, ensuring the highest value return for customers.

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

The Company's EV forecasting strategy allows for the identification of high value areas where EVSE installation would be most beneficial and sufficient capacity exists with existing infrastructure. National Grid will investigate what opportunities exist to make this information available to third-party developers to aid in efficient siting of EVSE, consistent with limits on public disclosure considering limitations of licensed data sources and customer privacy.

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.

The New York utilities are in the early stages of planning, implementing, and managing EV charging infrastructure and services. There are a variety of customer and system data that will be necessary for planning, implementing, and managing EV charging infrastructure and services. The Joint Utilities have identified a subset of the higher priority data that will be required, as noted below.

- *Customer load profile.* The utility will need to know the customer load profile, including charging capacity pre-installation of EV charging infrastructure to help understand the impact on the customer as well as system-level impacts. AMI is necessary to develop this type of load profile.
- *Likely EV charging demand.* In workplace or other non-residential types of EV charging, the utility would need to know the anticipated charging demand (*i.e.*, how many EVs are likely to be charging) and at what level (*i.e.*, Level 2 charging vs DCFC; more likely the former). This will help characterize the charging capacity required at the facility. For a residential installation, the utility would need to know the level of charging that the customer is seeking, namely Level 1 or Level 2. Note that it is unlikely that the utility plays a substantive role in deploying Level 1 charging infrastructure.
- *Distribution asset load profile.* The utility 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 the utility to update its asset management strategy for that substation, feeder, etc.
- *Potential location of EV charging infrastructure.* To the extent that "implementation" of EV charging infrastructure is inclusive of installation, the layout of the proposed installation, namely the location of EVSE, will help determine the associated costs. More specifically, the trenching and cutting costs

associated with the installation of EVSE at existing facilities can vary significantly depending on the location of the planned installation relative to the point of connection with utility service.

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 EV adoption.

This information can be found in Table 2.5.4 below provided in response to question 6.

6. 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;
f. next steps with clear timelines and deliverables;

Table 2.5.4: National Grid's Charging Development Programs

National Grid's Charging Development Programs (Electric Transportation Initiative)	
Detailed Description of Initiative with Explanation of Alignment to National Grid's Long Range EV Integration Plan	The Company will make capital upgrades to enable the installation of EV charging stations at commercial customers' properties and provide incentives to property owners to encourage the installation of these charging stations. The initiative is intended to overcome the cost and complexity barriers that prevent commercial customers, such as employers, apartment owners, retail site owners, or fleet operators, from installing charging for the benefit of consumers or their own fleets. In this initiative, the Company will make proactive investment in electrical infrastructure, *both* on the utility-side of the meter *and* the customer's side of the meter ("Host Site"), to enable Site Hosts to install EVSE. This is often referred to as "make-ready" infrastructure for EV charging.
Original Project Schedule	Approved in the Three-Year Rate Plan Order for implementation over the rate years (FY2019-2021).
Current Project Status	Pre-launch planning.
Lessons Learned To	N/A

Date	
Project Adjustments and Improvement Opportunities Identified To Date	Lessons learned from this initiative will enhance the Company's ability to connect new third-party charging sites and may inform future charging programs from the Company.
Next Steps with Clear Timelines and Deliverables	The Company anticipates developing at least 30 new charging sites with approximately 300 new ports over the course of the initiative. Preference will be given to property owners who agree to promote EVs to their employees, tenants, and customers, in order to encourage the utilization of the charging stations and advance the state's ZEV and GHG goals.
Incorporate EV/EVSE Growth Forecasts into System Planning	
Detailed Description of Project with Explanation of Alignment to National Grid's Long Range EV Integration Plan	To accurately forecast EV growth spatially and temporally within National Grid's service territory, the Company will capture the future state of EV penetration at the most granular level in its bottom-up forecasts.
Original Project Schedule	The Company plans to accelerate incorporation of the organic growth portion of the analyses into the bottom-up forecasts this fiscal year which will enable enhanced support of the state's ZEV and GHG policy goals as well as the Company's own EV/EVSE investment and planning efforts.
Current Project Status	The Company is currently developing the organic growth portion of the EV forecast for inclusion in the bottom-up forecasts this fiscal year.
Lessons Learned To Date	N/A
Project Adjustments and Improvement Opportunities Identified To Date	The enhanced forecasting will enable the Company to precisely target EVSE infrastructure investment opportunities, inform infrastructure planning, and remove barriers to third-party EVSE deployment.
Next Steps with Clear Timelines and Deliverables	The Company will complete the organic growth portion of the EV forecast and include it in the bottom-up forecasts this fiscal year.
Marketing/Education Outreach (Electric Transportation Initiative)	
Detailed Description of Project with Explanation of Alignment to National Grid's Long Range EV Integration Plan	As part of the education and outreach effort approved in the Three-Year Rate Plan Order, over the next three years the Company will demonstrate new strategies to increase customers' awareness and understanding of EVs. The Company's campaign will endeavor to address the key concerns among residential and commercial customers about EVs vehicles, including affordability, battery range, charging availability, and charging speed. The Company's messaging will describe the performance benefits of EVs, feature technology advances and declining costs in vehicle and charging technologies, address available federal and state incentives for EVs and charging, showcase

	the increasing availability of charging, and promote the savings available under the Company's forthcoming Beneficial Electrification Rate and existing VTOU rate. The Company will collaborate with a range of stakeholders and EV market participants, including NYSERDA, local auto dealers, and national automakers, to develop the campaign's materials.
Original Project Schedule	Approved in Three-Year Rate Plan Order for implementation in rate years FY2019-21
Current Project Status	Launched April 2018
Lessons Learned To Date	N/A
Project Adjustments and Improvement Opportunities Identified To Date	N/A
Next Steps with Clear Timelines and Deliverables	With the campaign kick-off in April 2018, the following was developed as the main campaign message: "An EV is a realistic option for any car buyer." All outreach will lead with the benefits of EVs and encourage customers to visit the Company's landing page where they can find information on customer incentives and additional resources with the ultimate goal of encouraging customers to visit their local dealer. Monthly email blasts, bill inserts, and messaging through social media, including Facebook and Twitter, will be used to advertise the effort. Additionally, the Company is developing an EV display for the 2018 NY State Fair and the Company's booth usually sees over one million visitors. Lastly, the Company's EV Cars Marketplace will be promoted via paid search campaigns and digital ads.

7. Explain how the JU are coordinating the individual utility EV-related projects to ensure diversity of both the EV integration use cases implemented and the technologies/methods employed in those use cases.

The Joint Utilities recognize that practical demonstration projects will likely form the basis of planning related to transportation electrification moving forward. Further, the Joint Utilities have noted that rapid technological advances and the diversity of EVs in the market today requires utilities to begin planning for charging infrastructure today for the EV deployment of tomorrow. In order to develop a better understanding of the most effective way to engage in transportation electrification, the Company, with the Joint Utilities, continue to be involved in a wide array of demonstration and pilot projects. The diversity of those EV-related projects listed in the EV Readiness Framework reflects the diversity of approaches that utilities have developed with respect to transportation electrification.

The Electric Vehicle Working Group provides a platform for collaboration and coordination on EV-related issues for the Joint Utilities. Most recently, this working group developed the EV Readiness Framework referenced many times in this topic area, which documented a consistent approach to EV integration agreed to by the individual utilities, considering input from other key stakeholders. The framework also highlights a summary of utility EV demonstration and pilot projects. While each individual utility advances EV-related projects in their own service territory, subject to internal business decisions and resource prioritization, the Joint Utilities will continue to use the EVSE Working Group as a platform for collaboration and sharing lessons learned, thereby helping to ensure the sustained diversity of EV integration use cases and the technologies and methods employed in the use cases.

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 Department of Environmental Conservation (DEC), and DPS Staff to facilitate statewide EV market development and growth.

The Joint Utilities were proactively engaged with NYSERDA, NYPA, NYSDEC, and DPS staff through the development of the EV Readiness Framework published in March 2018. Multiple staff members from these organizations were active participants in the two stakeholder meetings, held in September 2017 and February 2018. Further, the Joint Utilities have invited staff from these organizations to present to the EVSE Working Group several times over the past twelve months—including on issues such as the costs and benefits of EV deployment in New York State and the role of demand charges in DCFC use cases.

2.6 Energy Efficiency Integration and Innovation

Context and Background

New York seeks to significantly increase the levels of EE savings realized by electric and gas customers across the state while at the same time reducing GHG emissions and consumer energy costs. National Grid and the Company's affiliates in other jurisdictions are national leaders in delivering EE programs and are expanding EE program offerings.

On December 22, 2017, National Grid updated its electric and gas 2017-2020 Energy Efficiency Transition Implementation Plan ("ETIP")[61] which 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 and overall modernization efforts. The Company will continue to strive to exceed the current energy savings goals while finding new opportunities to reduce implementation and administration costs of its EE programs. Expanded EE program offerings will take a more holistic approach to delivering customer solutions and focus on providing enhanced value to both the customer and National Grid.

The Three-Year Rate Plan Order added new EE programs, increasing annual savings goals for the Company, and moved EE expenses into base delivery rates. The Three-Year Rate Plan Order establishes National Grid as the first New York utility to shift ETIP costs fully into base delivery rates.

On March 15, 2018, the Commission approved the utilities' ETIP filings through 2020 and the transition to System Energy Efficiency Plans ("SEEP") ("ETIP/SEEP Order").[62] Per the ETIP/SEEP Order, an ETIP Budget and Metrics ("BAM") is not required for utilities that have transitioned or made a rate filing proposing the transition of EE programs into delivery rates by June 2019. The Commission further directed DPS Staff to rescind CE-01: Utility Energy Efficiency Program Cycle Guidance given these changes. In addition, DPS Staff was ordered to issue multiple guidance documents including: 1) Gross Savings Verification Guidance; 2) ETIP/SEEP Content Guidance; 3) ETIP/SEEP Reporting Guidance; 4) Appendix B Guidance; 5)

[61] Case 15-M-0252, *In the Matter of Utility Energy Efficiency Programs*, Niagara Mohawk Power Corporation d/b/a National Grid Updated 2017-2020 Electric and Gas Energy Efficiency Transition Implementation Plan ("ETIP")(filed December 22, 2017)("National Grid Updated 2017-2020 ETIP Filing").

[62] Case 15-M-0252, *In the Matter of Utility Energy Efficiency Programs*, Order Authorizing Utility-Administered Energy Efficiency Portfolio Budgets and Targets for 2019-2020 (issued March 15, 2018)("ETIP/SEEP Order").

BCA Guidance; and 6) Self-Direct Program Guidance. Due to recent proposals contained within the *New Efficiency: New York White Paper* which defines an ambitious 2025 EE target for New York State and a comprehensive EE initiative to meet that target,[63] in subsequent communication on May 9, 2018, DPS Staff delayed the utility ETIP/SEEP filings originally due June 1, 2018, until further guidance is issued.

The new 2025 EE target is set on an all-fuels basis, addressing energy savings in buildings and the industrial sector across all fuel sources. The target accounts for the energy and GHG savings that can be delivered through sustaining New York's current EE commitments while also imposing demands for new actions to increase and accelerate EE market activity. The *New Efficiency: New York White Paper* also calls out the need for more LMI customer programs, the greater leveraging of public funds, and increased market-based EE.

On May 15, 2018, the Utility-Administered Energy Efficiency BCA Filing Requirement Guidance was issued by DPS Staff.[64] This guidance document clarifies BCA filing requirements for all future utility-administered EE portfolio proposals and establishes a common template for documenting and presenting SCT analyses and requires that a common template be used by all utilities to facilitate a more efficient review of, and comparison between, the electric and gas portfolio BCA filings made by each of the utilities.

Further guidance is expected from DPS Staff regarding ETIP/SEEP filings. In accordance with that guidance, National Grid will continue to develop plans to deliver on the state's 2015 EE target.

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.[65] The Distribution Load Relief Program ("DLRP"); the Commercial System Relief Program ("CSRP"); and the Direct Load Control Program ("DLC Program"), which includes the ConnectedSolutions and coolControl Programs, were launched in 2015 by the Company. DLRP and CSRP mainly focus on C&I customers, while the DLC Program targets residential and small-commercial customers. National Grid filed its most recent DLM Annual Report on December 1, 2018 addressing the assessment of its DLM programs for the 2017 capability period and identifying changes planned for the 2018 capability period.[66]

[63] Case 18-M-0084, *In the Matter of a Comprehensive Energy Efficiency Initiative*, New Efficiency: New York White Paper (jointly prepared by DPS Staff and NYSERDA)(filed April 26, 2018).
[64] *CE-07: Utility-Administered Energy Efficiency BCA Filing Requirement Guidance*, issued by the Department of Public Service (dated May 15, 2018).
[65] 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).
[66] DLM Programs Proceeding, Niagara Mohawk Power Corporation d/b/a National Grid Dynamic Load Management Programs Annual Report for 2017 Capability Period (filed December 1, 2018). On January 25, 2018, National Grid filed a revised DLM Annual Report to respond to certain DPS Staff inquiries.

At inception, coolControl and DLRP were offered as pilot programs in the electrically-constrained Village of Kenmore, located in the Buffalo area. The Commission subsequently approved the expansion of CSRP and the DLC Programs in a May 23, 2016 order.[67] However, DLRP currently only operates in Kenmore as a contingency program that is activated for system-critical situations, which include distribution-system emergencies where stressed electrical equipment may exceed limits. DLRP includes both Reservation and Voluntary participants. There are no DLRP participants in the program. The Commission has encouraged the Company to revisit the intended use of DLRP as a local reliability program for emergency purposes and to handle loading issues rather than for peak-shaving purposes. National Grid will continue to work with the internal pricing team and with DPS Staff to determine the best use of DLRP. This investigation may even result in abandoning the DLRP if there is no clear need for such a program at this time.

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 NMPC Tariff. This program also includes Reservation and Voluntary options for participants. CSRP is a territory-wide program available to customers served from all voltages.

The DLC Program targets primary and secondary-voltage customers. The program is activated for system-critical situations or for peak shaving purposes. Through this program, National Grid has the ability to remotely adjust thermostat settings and/or cycle appliances via a smart plug load control device. The ConnectedSolutions Program connects existing Honeywell, ecobee, and Nest Wi-Fi thermostats to National Grid's DRMS. ConnectedSolutions is available to all residential and commercial customers served at primary and secondary voltage levels. For all DLC Programs, there is a one-time sign-up payment of $30 and a $20 yearly incentive that is payable the second year of participation for the reduction of load during 80% of called events and event-hours.

The coolControl Program is limited to electrically-constrained customers in the Village of Kenmore and is used to curtail electricity demand from approximately 19,000 residential and small-business customers in this constrained area. The main device offered to customers is the Emerson Sensi™ Wi-Fi thermostat. Similar to ConnectedSolutions, there is a one-time sign-up payment of $30 and a $20 yearly incentive that is payable the second year of participation for the reduction of load during 80% of events or event-hours for the coolControl Program.

Current Progress

Table 2.6.1 below shows the current implementation of National Grid's most recent ETIP in gross and net savings and future savings targets resulting from the Three-Year Rate Plan Order. Beginning April 1, 2018, as a result of the Three-Year Rate Plan Order, the Company's new rates took effect, changing the savings targets for 2018. The Company now recovers all EE

[67] DLM Programs Proceeding, Order Adopting Dynamic Load Management Program Changes with Modifications (issued May 23, 2016).

program costs through base rates, including those in its electric and gas ETIP, along with the costs of the Company's proposed LED street light EE program. The savings target approved in the Three-Year Rate Plan Order increases program savings goals above the 2018-2020 ETIP and increases the budget by more than 20% above the levels the Company had filed in 2017.

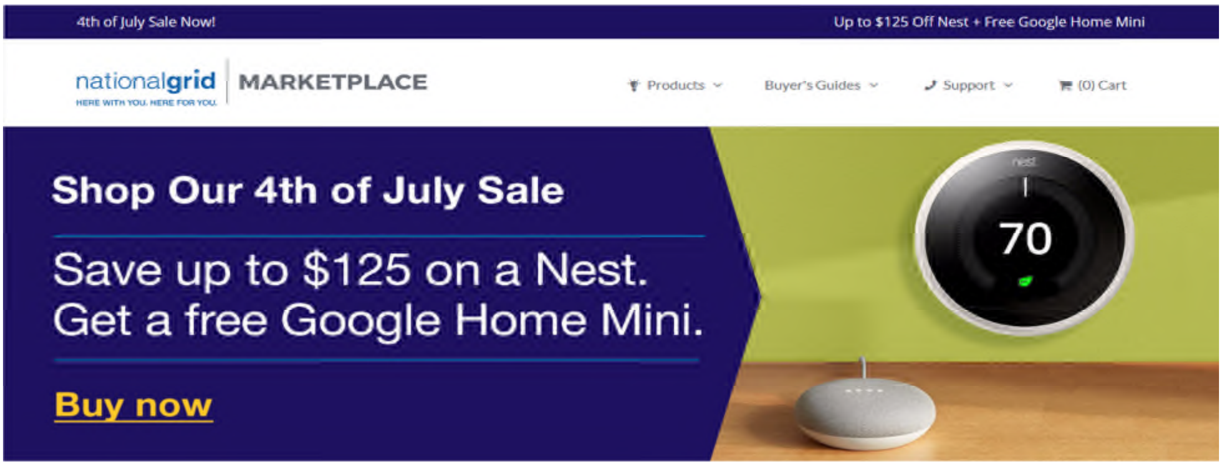
*Table 2.6.1: National Grid's Electric EE Savings Target to 2020**

	2016	2017	2018	2019	2020
Gross Savings Target (MWh)	256,339	256,496	303,622	319,383	319,383
Net Savings Target (MWh)	230,705	230,846	273,260	287,445	287,445

*2016-2017 values are from the Company's Updated 2017-2020 Electric and Gas ETIP filing in Case 15-M-0252[68] whereas the 2018-2020 values are from the Commission's March 15, 2018 Order in Case 15-M-0252.[69] 2018 targets are prorated to reflect 75% of the Company's first new rate year which commenced April 1, 2018.

The Company has launched an electronic marketplace in its Upstate New York territory[70] which will be expanded to National Grid's downstate New York affiliates later in 2018. The National Grid Marketplace is a one-stop shopping tool that sells energy-efficient and energy-saving products to help customers reduce their energy consumption.

Figure 2.6.1: National Grid Market Place Page



[68] National Grid Updated 2017-2020 ETIP Filing, *supra* note 61.
[69] ETIP/SEEP Order, *supra* note 62.
[70] *Available at*: https://marketplace.nationalgridus.com/

National Grid is piloting the use of Advanced M&V with its C&I electric customers and residential gas equipment customers. The Company is looking for opportunities to expand the use of Advanced M&V. Evaluation results for the residential program were filed with the Commission in March 2018. The C&I electric customer pilot program will be initiated later in 2018. To date, the Company has been able to verify that Advanced M&V results align reasonably well with traditional methods (*i.e.*, automated billing analysis versus traditional billing analysis).

National Grid's relatively new DLM Programs have progressed steadily and have experienced growth over the last three years. While there were no participants in DLRP during the capability period (May 1 through September 30) for 2017, the Company intends to re-evaluate the use of DLRP as an emergency program. As the only NWA project currently in operation in the Company's service territory, Kenmore has a small pool of eligible, interval-metered commercial customers capable of curtailing 50 kW or more, which is a requirement per the DLM tariff for participation in both the CSRP and DLRP. Customers have the option of installing interval meters at their cost if they are interested in participating in either the DLRP or CSRP.

The CSRP had 200 participants, totaling 188.61 MWs of curtailment, for the 2017 capability period. There were four aggregators and one direct participant in CSRP in 2017, and one CSRP test event was held on June 13, 2017. No other DR events were needed in 2017.

National Grid currently has three direct participants and five aggregators in CSRP for the 2018 capability period. There are 306 total CSRP customers with 287.5 MWs of contracted curtailment in the program. Through mid-July, the Company has called CSRP events on July 2, July 3, July 5, and July 16. With increasing temperatures, the Company anticipates the need for additional peak-shaving through CSRP DR events during the remaining 2018 capability period.

The coolControl and ConnectedSolutions Programs mainly target residential and small-commercial customers. In 2017, there were 355 Emerson Sensi™ Wi-Fi thermostats and 313 ThinkEco SmartAC kits that participated in for the coolControl Program in the Village of Kenmore. There were four events held during the 2017 capability period for the coolControl Program. There are approximately 318 Emerson Sensi thermostat devices online as a part of the coolControl Program in the Village of Kenmore for the 2018 capability period. To date, two events called this summer, those being on July 2 and July 3.

ConnectedSolutions is a system-wide program that addresses both primary and secondary voltage customers. ConnectedSolutions was launched in partnership with Whisker Labs (formerly known as WeatherBug Home ("WBH")) and in coordination with the DLM Programs of National Grid's affiliates in Massachusetts and Rhode Island. ConnectedSolutions is a Bring-your-Own-Device ("BYOD") Program that currently aggregates Honeywell, ecobee, and Nest Wi-Fi connected thermostats. At the end of the 2017 capability period, there were 1,215 Nest thermostats, 651 Honeywell thermostats, and 65 ecobee thermostats enrolled in the

ConnectedSolutions Program. In total, thermostat enrollment increased over 900% from 2016 to 2017 and this number is expected to grow in 2018. There were three (3) events called during the 2017 capability period for the ConnectedSolutions Program. In total, there were 1,931 thermostats enrolled in 2017, with a total curtailment of 1,349 kW for all three (3) thermostat device types.

As of mid-July 2018, there are a total of 2,867 Nest, Honeywell, and ecobee thermostat devices currently enrolled in the ConnectedSolutions Program. National Grid anticipates an increase in enrollment throughout the summer through its partnership with EnergyHub and an increase in marketing and engagement strategies. The Company has called ConnectedSolutions events on June 18, July 2, July 3, July 5, and July 16. Similar to CSRP, National Grid anticipates the need to call additional events during the 2018 capability period due to heat wave impacts and high temperatures.

Demand Response Management System

The Three-Year Rate Plan Order approved the funding for a commercial DRMS. DRMS capabilities include the overall management of administrative aspects of the DLM program, the dispatch of DR events, and curtailment calculations through a single, integrated system. The Company currently works with AutoGrid Systems, Inc. ("AutoGrid") to dispatch DR events and calculate curtailment for commercial customers. National Grid is currently under contract with AutoGrid for the next two years (*i.e.*, through 2019). In the 2018 capability period, AutoGrid will continue to dispatch events and calculate settlement for the events. National Grid will only calculate curtailment manually in parallel for the first DR event. Aggregators participating in the CSRP will continue to enroll participants directly into AutoGrid, as they did in 2017.

National Grid has also finalized the procurement of a residential DRMS vendor for the upcoming 2018 capability period. With the addition of a residential DRMS, the Company will be in a better position to add new residential connected devices to the **Connected**Solutions Program and to manage calling DR events for both the coolControl and **Connected**Solutions Programs. The DRMS is an integral component of National Grid's plans to significantly lower the overall costs for the **Connected**Solutions Program, as it will reduce per-device administration costs while increasing the number of connected devices that can be effectively enrolled and deployed as well as issued incentive payments. The enablement of the residential DRMS will increase participation and engagement opportunities for customers system-wide.

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. To keep pace, National Grid is exploring 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. These activities will be undertaken consistent with the principles and goals of REV and are supported by the Company's ETIP/SEEP, which seek more flexibility in program delivery and management.

Collaborating with interested stakeholders is the key to accelerating and shifting the portfolio of utility EE programs. This might be accomplished by seeking more effective measures and program structures, greater leverage of public funds, and increased market-based EE. This includes the proposed development of a shared savings approach that provides greater opportunity and reward for utilities to advance EE as a business and as a resource.

National Grid will continue to advance energy affordability by developing initiatives focused on energy solutions for LMI customers, driving deeper energy savings in building retrofits and construction, and supporting cost-effective heat pump adoption.

The Company is looking at ways to coordinate EE, DR, and NWA procurement to develop programs that lower system needs and costs. National Grid currently delivers Energy EE on a system-wide basis based on customer demand. The Company's EE Team works closely with the Load and DER Forecasting teams to coordinate the transfer of aggregated data to be given to Distribution Planning to identify areas of system improvement. A more coordinated effort will create closer collaboration among the Planning groups to communicate localized system needs to design targeted programs.

National Grid continues to work on increasing enrollment and participation in 2018 and beyond. One of the major improvements in 2018 has included the promotion of DR by the EE sales representatives to large commercial customers and national accounts. National Grid sales representatives can leverage existing industry relationships as an expanded means of program recruitment to encourage customers to sign up for DLM Programs. Furthermore, the sales representatives can target specific regions to create more opportunities and promote CSRP in areas where EE measures already have high adoption rates. Additional DLM training has been made available to the sales teams this year to further this effort.

The Company will continue to look for opportunities to bring financing options to customers. For example, Metrus Energy's Efficiency Services Agreement ("ESA")[71] is a pay-for performance, off-balance sheet financing solution that allows each C&I customer to implement EE projects with a zero upfront capital expenditure. The vendor funds 100% of the project cost while taking the title for the equipment and paying for ongoing maintenance and monitoring. The customer pays the vendor through a service charge for realized savings.

Throughout the five-year time period of this DSIP Update, each New York investor-owned utility will evolve their current ETIPs into a SEEP. The SEEP will describe the entirety of the utility's expanded reliance on and use of cost-effective EE to support their distribution system and customer needs. Within 60 days of issuance of ETIP/SEEP Reporting Guidance by DPS Staff, the utilities must develop a list of all non-ETIP EE activities underway (*e.g.*, REV demos,

[71] *See* https://www.metrusenergy.com/metrusandnationalgrid

NWAs, and other activities) and a description of the associated reporting requirements, as well as a timeline for bringing existing non-ETIP EE efforts into alignment with the common reporting guidelines. The utilities will also be expected to report anonymized project-level information to be made publicly available through the NYSERDA online dashboard.

ETIPs/SEEPs will continue to be filed separately in accordance with DPS Staff issued ETIP/SEEP Content Guidance. The current ETIP/SEEP filing, originally due June 1, 2018, was delayed by DPS Staff until further guidance is released.

The Company will focus on positioning EE as a least-cost system resource. National Grid's load forecast will continue to account for EE, where its impact can offset traditional infrastructure investments. 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 ETIPs will include not only EE, but also describe coordination with other DR programs offered by the Company, 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 ("P4P") 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.

Because of the successful delivery of EE as well as its increasing societal value in carbon mitigation, the Company expects customer savings targets to continue to increase relative to current levels. 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. One area of value to the Company and its customers will come from frameworks that support and reward deferred capital investment, especially in areas of load growth. These changes will transform the utility focus into one that is dedicated to identifying and meeting customer energy needs, while maintaining National Grid's ability to operate reliably.

The timing and sequence of work and investments are to be determined based on further ETIP/SEEP Guidance Documents to be issued by DPS Staff and are the results of collaborative efforts with interested stakeholders.

Risk and Mitigation

The forthcoming ETIP/SEEP Guidance documents must align with public policy to increase savings while minimizing financial impact to customers. To achieve triple savings targets,[72] there may be a need for increased time and funding. It may be beneficial to review the cost-effectiveness guidelines of the system-wide EE program to align the March 15, 2018 ETIP/SEEP Order and the Three-Year Rate Plan Order policies with the relevant benefit-cost test.[73]

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

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, the latter which is new for the 2018 capability period. In addition to existing thermostat manufacturers in the ConnectedSolutions Program and coolControl Program, it is anticipated that several more thermostat vendors will be added to the ConnectedSolutions Program through the use of the residential DRMS. With additional vendors, there will be an increased need for coordination and compatibility. Additionally, the success of DLM Programs is directly related to efforts of the distribution planning, NWA, and EE teams internally. As the DLM Programs expand, additional internal cooperation and coordination will be paramount.

[72] Case 18-M-0084, New Efficiency: New York White Paper, *supra* note 63.
[73] *See, e.g.*, https://nationalefficiencyscreening.org/wp-content/uploads/2017/05/NSPM_May-2017_final.pdf

Additional Details

The following responds to DSP Staff's request to provide additional details regarding EE integration and innovation.[74]

1. The resources and capabilities used for integrating energy efficiency within system and utility business planning, including among other things, infrastructure deferral opportunities as part of NWAs, peak and load reduction and/or load or energy shaping with an explanation of how integration is supported by each of those resources and capabilities, or other shared savings / benefits opportunities.

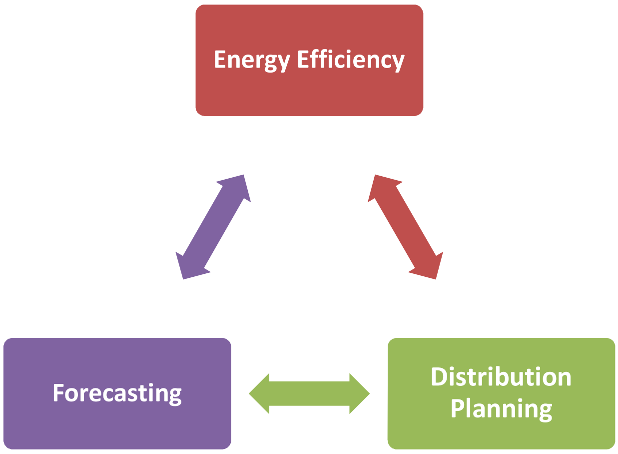
Existing DLM and EE programs can exist as first-line, cost-effective solutions for the NWA process to relieve load issues in constrained areas. DLM and EE can be effective as part of a NWA solution's DER portfolio as an early stage injection of load relief. National Grid will work to refine a process for better integrating programs such as EE and DLM into NWA assessments. The existing plan is for both DR/EE sales representatives to work with the NWA procurement team to contact customers and use enhanced incentives and/or targeted marketing strategies to reduce the initial load in identified areas. This initial contact is especially important for the expansion of the CSRP in constrained areas, where participation in DR/EE can be achieved through initial marketing that provides rebates for participants and effectively lowers costs for all customers. The CSRP is activated for peak-shaving purposes and can be used to value constrained areas in 2019 and beyond. National Grid is working internally and with DPS Staff to determine the next steps in this valuation.

The realized load reduction from DR/EE has the potential to reduce the initial NWA solution need, thereby having the potential to drive down the cost of any further associated NWA DER solution. There may be NWA areas with DR/EE potential but further analysis needs to be completed to determine DR/EE reduction goals for this initial solution. The timeframe for implementation of these solutions will range from two to the next ten years, as NWA needs are identified during the annual capital investment planning process and are scheduled over a five-year period in the Company's CIP. This effort will require additional coordination and internal efforts over the course of the next year. For additional information about the coordination between DR/EE and NWA areas, please refer to Section 2.14, Procuring Non-Wire Alternatives, of this DSIP Update.

The Company's EE team now works closely with the Forecasting and Distribution Planning teams to share data and consider opportunities to integrate EE, DR, and NWA, as shown in Figure 2.6.2 below.

[74] DSIP Proceeding, 2018 DSIP Guidance Update, pp. 18-19.

Figure 2.6.2: Integration Plan



Internally, actual savings data is shared with forecasting and subsequently utilized in T&D planning.

National Grid maintains a proprietary workflow system that stores energy and demand savings by customer location. Monthly data is currently aggregated and reported in a ETIP scorecard report on a quarterly basis under Case 15-M-0252 – In the Matter of Utlilty Energy Efficiency Programs National Grid – Quarterly ETIP Scorecard Reports.

A number of initiatives are underway in New York regarding data sharing and reporting that will shape what data is reported in the future. NYSERDA and the Clean Energy Advisory Council ("CEAC") Metrics Tracking and Performance Assessment ("MTPA") Group are developing a plan to publish energy savings data to an online data dashboard. The utilities, DPS Staff, and NYSERDA are also working to develop and file a proposal for the release of anonymized EE product data on a going-forward basis.

2. The locations and amounts of current energy and peak load reductions attributable to energy efficiency and how the utility determines these.

Currently, aggregated monthly energy savings data is shared publicly via the DPS Scorecard Reporting Process. The below Table 2.6.2 provides the energy savings achieved annually for 2016 and 2017.

Table 2.6.2: Energy Savings Achieved Annually for 2016 and 2017

Energy savings achieved annually	Actual	
	2016	2017
Energy Efficiency Gross Savings (MWh)	290,377	288,949
Energy Efficiency Net Savings (MWh)	261,339	260,054

3. How the utility develops and provides its short and long-term forecasts of the locations, times, and amounts of future energy and peak load reductions achievable through energy efficiency.

Forecasts incorporate approved EE goals for planning. The Company's Advanced Data Analytics ("ADA") team has access to and draws information from the Company's proprietary EE workflow system. This system provides project level EE measure installation data for each participant. The ADA team is currently assessing ways to utilize the data in more granular level forecasts.

From the DLM perspective, National Grid uses short-term forecasting to call DR events. As per the DLM tariff, "Planned Events may be called when the Company's day-ahead forecasted load level is at least 92 percent of the Company's forecasted summer system-wide 95/5 peak."

4. How the utility assesses energy efficiency as a potential solution for addressing needs in the electric system and reducing costs.

The Company currently delivers EE on a system-wide basis based on customer demand. National Grid is working with a vendor to identify key measures and markets with significant potential to provide cost-effective savings based on the customer base and budgets approved. NWA, procurement, and beneficial location are topics that are being addressed.

National Grid has partnered with New York State Electric & Gas Corporation and Rochester Gas and Electric Corporation ("NYSEG/RG&E") to work with a vendor to identify key Measures and Markets with significant potential to provide cost-effective savings based on existing customer bases and budgets approved across each utility's service territory. This partnership will allow both National Grid and NYSEG/RG&E to develop programs specifically targeted to our respective customer bases. Studies like this traditionally only identify end uses to target, whereas this method will facilitate the ability to target the correct end uses of customers.

5. How the utility collects, manages, and disseminates customer and system data (including energy efficiency project and load profile data) that is useful for planning, implementing, and managing energy efficiency solutions and achieving energy efficiency potential.

The Company maintains a proprietary workflow system that stores energy and peak savings by customer location. Data is aggregated and reported in a scorecard on a monthly basis to DPS Staff. As noted in the response to Question 1 above, the NYSERDA and CEAC MTPA Group are developing a plan to release data to an online data dashboard. The utilities, DPS Staff, and NYSERDA will develop and file a proposal for the release of anonymized EE product data on a going-forward basis.

Customers are able to utilize the Green Button Download My Data tool[75] for downloading energy consumption data which the customer can in turn upload if they so choose to an emerging array of online applications and benchmarking tools to make more informed energy decision which could include EE measures.

National Grid, as well as the other utilities, is working with NYSERDA to upload aggregate utility data by municipality to the UER which could be helpful for community energy planning and in support of CCA efforts which could include EE outreach.

6. 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 a new 2025 energy efficiency target called for in Governor Cuomo's 2018 State of the State Address.

National Grid will work through ongoing proceedings aimed at implementing New York State energy policies. This process is expected to include working groups that will determine guidance for implementation through a collaborative and thorough approach. The Company looks forward to creating actionable program frameworks to meet the objectives of State energy policies, both in the near term, through its evolving ETIP filings, and in the longer term as the various working groups yield deliverables. National Grid's approach to planning its EE offerings will be aligned with the principles of REV and the *New Efficiency: New York White Paper*. Taking this new target into consideration, the Company will begin to develop a plan to align with and support the new target.

The Three-Year Rate Plan Order created a set of metrics that both existing and new (with the approved additional funding) EE programs will influence. The Company is working to position its portfolio for success through innovation, partnerships, and expanded offerings. Specific examples of these initiatives are described in the Company's ETIP filing and progress will be reported through the existing reporting channels. To accelerate growth, National Grid is working to evolve its current offerings to be more responsive to the market and customer needs, while also introducing new technologies and delivery approaches that increase energy savings while

[75] *See* https://www.energy.gov/data/green-button

also reducing costs. Existing programs that do not sufficiently meet customer needs and that can be substituted with more cost-effective or more sustainable business models will be discontinued at the Company's discretion. National Grid will continually evaluate its EE portfolio to ensure it is positioned for success.

7. A description of lessons learned to date from energy efficiency components of REV Demonstration Projects with specific plans for scaled expansion of successful business model demonstrations. In addition, provide a description of each hypothesis being tested as part of energy efficiency components of ongoing Demonstration Projects and the anticipated schedule for assessment.

The Joint Utilities have pursued a variety of REV demonstration projects focused on developing a better understanding of how to effectively deploy innovative programs that include elements of EE. While the utilities are developing and implementing these REV demonstration projects independently, they have learned collectively from the different aspects of products and services that the projects have addressed, including online portals to connect customers with energy products and services, expansion of smart home rates with accompanying home energy reporting capabilities, building efficiency initiatives, and incentive programs for demand reduction. The Joint Utilities have identified two key mechanisms that can be used to boost customer participation and engagement in EE initiatives and enable new utility business models. The first is to provide customers with greater visibility into both their own energy use patterns and the wide variety of available products and services tailored to their energy needs. The utilities' smart metering, demand reduction, and home energy report demonstration projects are examples of offerings that advance engagement, motivating customers to take control of their energy use and management, and enabling utilities to successfully meet their EE commitments. The second mechanism is building specific awareness of EE opportunities through carefully crafted marketing strategies. These may include project-specific incentives for large C&I customers; distribution channel partnerships with ESCOs, retailers, and contractors; new homeowner and school-based education and awareness initiatives; and targeted marketing to customers through the online marketplace platform, based on customers' usage patterns and specific energy needs. Building on these valuable findings, several successful business models tested in the Joint Utilities' the following demonstration projects that are described in more detail in the "Progressing the Distributed System Platform" section highlight the energy efficiency components and the associated expansions.

8. Explain how the utilities are coordinating on energy efficiency to ensure diversity of both the models demonstrated and the technologies/methods employed in those applications.

The Joint Utilities have actively coordinated their EE program design and implementation since the Commission's May 2007 Order Instituting an Energy Efficiency Portfolio Standard ("EEPS Proceeding")[76] and this coordination continues today with formal and informal teams

[76] Case 07-M-0548, *Proceeding on Motion of the Commission Regarding an Energy Efficiency Portfolio Standard* ("EEPS Proceeding"), Order Instituting Proceeding (issued May 16, 2007).

addressing all aspects of the REV and Clean Energy Fund ("CEF") Proceedings. As described in the "New York Program Administrator Coordination Report" filed by the Joint Utilities and others in January 2017 as part of the CEAC process, this coordination has occurred through many different processes and groups and has had a wide range of foci and goals.[77] This coordination continues today including in the evolution of the utility energy efficiency programs from the ETIP framework to the recently instituted SEEP framework, according to which, over the next five-year DSIP planning period, each utility will integrate EE planning into their forecasted system plans and evolve their ETIP into a SEEP that describes the entirety of the utility's expanded reliance on and use of cost-effective EE to support their distribution system and customer needs.[78] As part of their continuing coordination efforts, the Joint Utilities participate in a working group in which they share information regarding development and testing of new EE programs and strategies. These coordination efforts address topics such as distribution channel marketing, home energy reporting, online energy marketplaces, and smart home rates. This coordination will inform current and future EE efforts, and help the utilities design a diverse portfolio of projects targeting a broad range of customers. These efforts include focus on the development of and outcomes from demonstration projects, to minimize duplicative efforts and ensure the sharing of lessons learned from each utility demonstration project with all of the Joint Utilities. The Joint Utilities remain committed to continuing this coordination to further support the diversity of EE programs across the state, and to achieve the new EE targets announced by Governor Cuomo on April 20, 2018.

9. Describe how the utility is coordinating and partnering with NYSERDA's related ongoing statewide efforts to facilitate energy efficiency market development and growth.

The Commission established the CEAC in its January 21, 2016 *Order Authorizing the Clean Energy Fund Framework*[79] and tasked it with several near-term deliverables. Six working groups were created along with a Steering Committee. Members include representatives from each utility and from Staff and NYSERDA. Most of the groups have completed their deliverables and have therefore been disbanded, with the exception of the MTPA Working Group. The primary purpose of the working groups was to support innovation and collaboration for an effective transition from current program offerings to post-2015 clean energy activities and on-going delivery thereafter.

National Grid was directed by the Commission in the ETIP/SEEP Order to conduct Evaluation, Measurement & Verification ("EM&V") activities that would yield timely information and to incorporate the results of those activities into the annual modifications to utility programs, resource manuals, and guidance. The utility coordinates with NYSERDA EM&V activities to avoid duplicative efforts. As part of those responsibilities, the utilities were directed to file a TRM Management Plan, which was required to include processes ensuring that each utility's and NYSERDA's input would be considered in updating the manual, to be filed annually.

[77] Matter 16-01005, *In the Matter of the CEAC's Clean Energy Implementation & Coordination Working Group*, (filed January 31, 2017), pp. 2-6.
[78] Case 15-M-0252, ETIP/SEEP Order, p. 29.
[79] Cases 14-M-0094 *et al*., *Proceeding on Motion of the Commission to Consider a Clean Energy Fund* ("CEF Proceeding"), Order Authorizing the Clean Energy Fund Framework (issued January 21, 2016).

The Company continues to collaborate and initiate projects to supplement Commission orders and to develop new or improve existing offerings. For example, National Grid is currently collaborating with NYSERDA to test user acceptance and affordability impacts of Wi-Fi thermostats and DR for low-income customers in the Village of Kenmore. This pilot will help to provide greater insight into the barriers that may prevent the adoption of Wi-Fi thermostats and the benefits and challenges that DR may present for low-income customers. This in turn will help to inform future program and policy decisions regarding offering Wi-Fi thermostats and DR options to low-income customers.

NYSERDA is currently in the process of scoping out the concept for a collaborative program with National Grid through which LMI customers will be targeted through a neighborhood approach to receive education, EE and DER offerings, and bill assistance.

NYSERDA and National Grid are also working on a Pay-for-Performance demonstration to increase EE offerings and test an Advanced M&V Platform to increase the accuracy, persistence, and reliability of EE savings.

National Grid also continues to coordinate and collaborate with NYSERDA on residential high efficiency heating equipment and multifamily offerings to drive efficiency, eliminate duplicative efforts, address market gaps, and better meet customer needs.

2.7 Distribution System Data

Context and Background

Information sharing services is a primary function of the DSP. Distribution System Data (referred to as "system data"), represents key information of the grid such as voltage levels, thermal capacity, geographical locations of assets, forecasts, etc., that is helpful to DER providers in identifying opportunities. Creating transparency for the utility's system needs and limitations, and the potential for DER opportunities is expected to foster the most efficient operation of the grid through the combined utilization of utility and third-party resources.

The initial DSIPs was largely intended to serve as a vehicle to inform stakeholders how National Grid plans to collect, analyze, and share information that facilitates retail market development, including data related to distribution system planning and grid operations.

The volume of system data is vast and relatively dynamic. In order to efficiently maintain and share various system datasets, the Company developed an on-line System Data Portal in concert with the initial DSIP. Information on the System Data Portal is refreshed on a periodic basis (monthly for some elements and annually for others) and is enhanced as new information becomes available.

This DSIP Update continues this data sharing philosophy through future plans to expand the scope and breadth of information publically available on National Grid's System Data Portal.[80]

Current Progress

Since filing of the initial DSIP, National Grid has made significant improvements to providing system data and to the portal itself, in terms of the process, automation, quality control, and analysis required to develop the data, along with increased breadth of data available and improved presentation of the data.

The following list shows the data sets currently available on the system data portal:

- Company Reports:
    - Five-Year T&D CIP
    - Fifteen-Year Electric T&D Planning Report

[80] *See* https://ngrid.apps.esri.com/NGSysDataPortal/NY/index.html

- Condition Assessment Report
- Peak Load Forecast
- Reliability Report
- Summer Preparedness
- Power Quality
- 2017 Hourly MLoad (aggregated system load for National Grid)

- Distribution Assets Overview
- Hosting Capacity
- NWA Opportunities
- LSRV/VDER

The Figures below provide a snapshot of the data sets currently available as listed above. The intent of presenting these figures in this report is to illustrate the look and feel of the data sets available and is not intended to present any detailed data.

Figure 2.7.1: Company Reports Tab

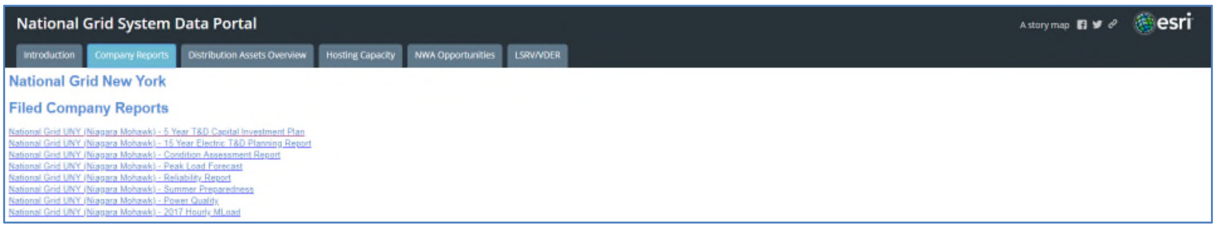


Figure 2.7.2: Distribution Assets Overview Tab

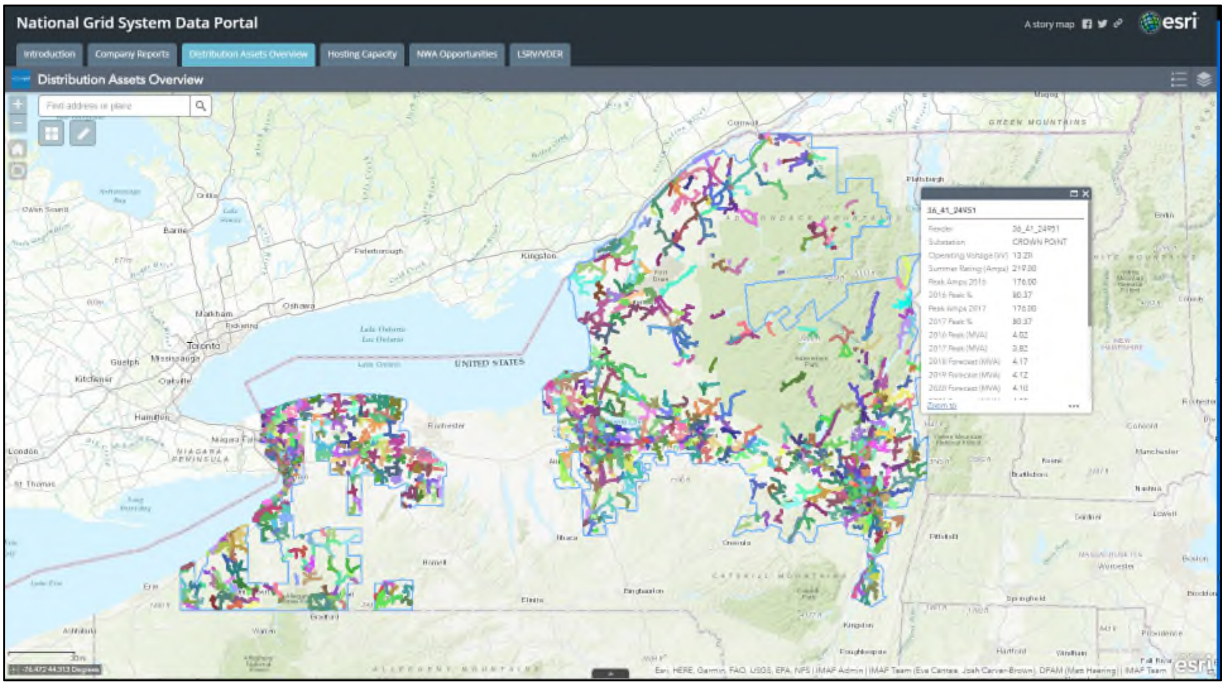


Figure 2.7.3: Hosting Capacity Tab

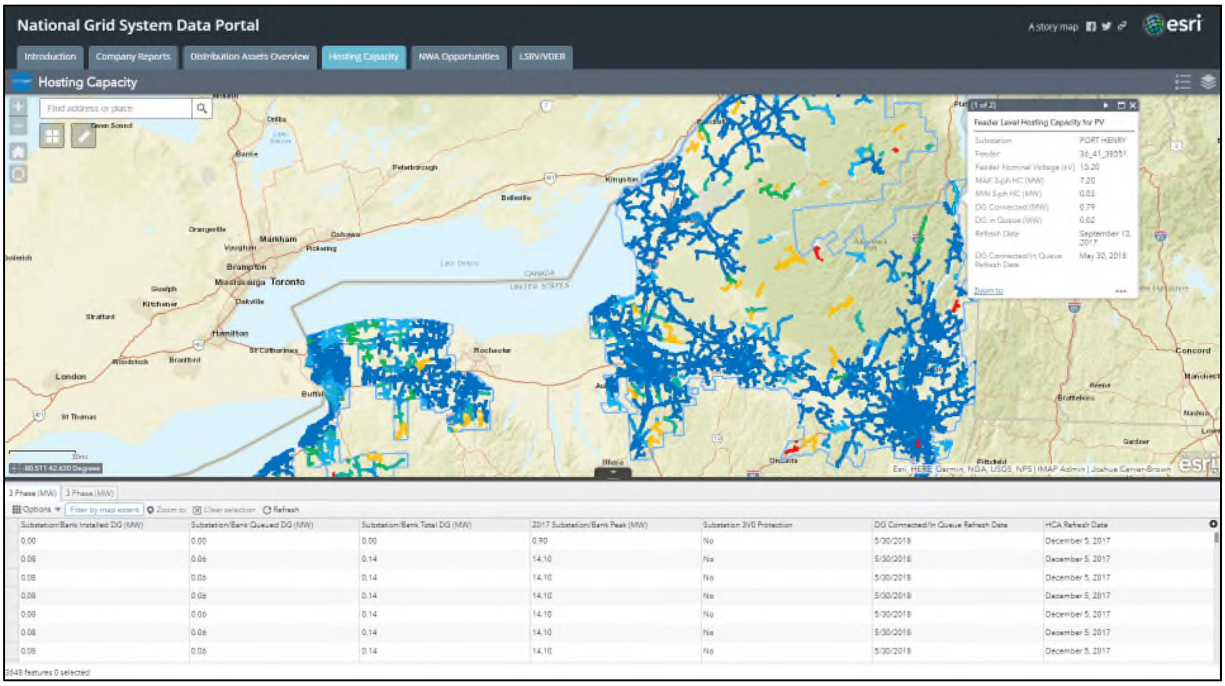


Figure 2.7.4: NWA Opportunities Tab and NWA Opportunities Document

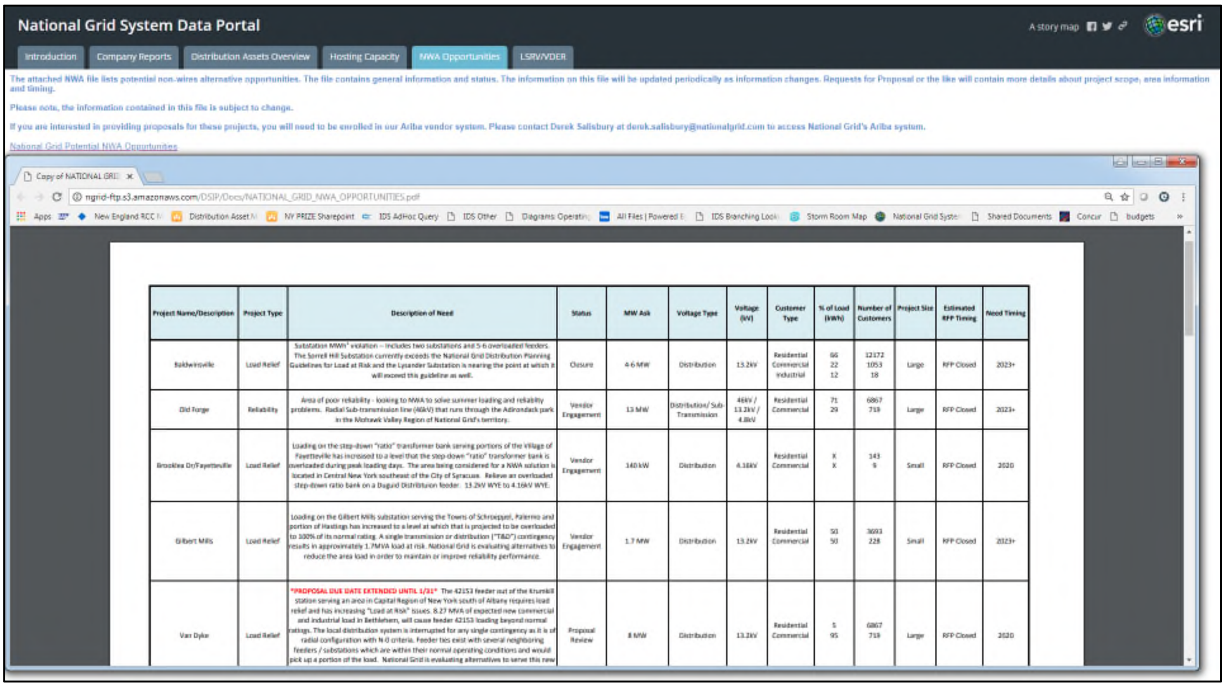
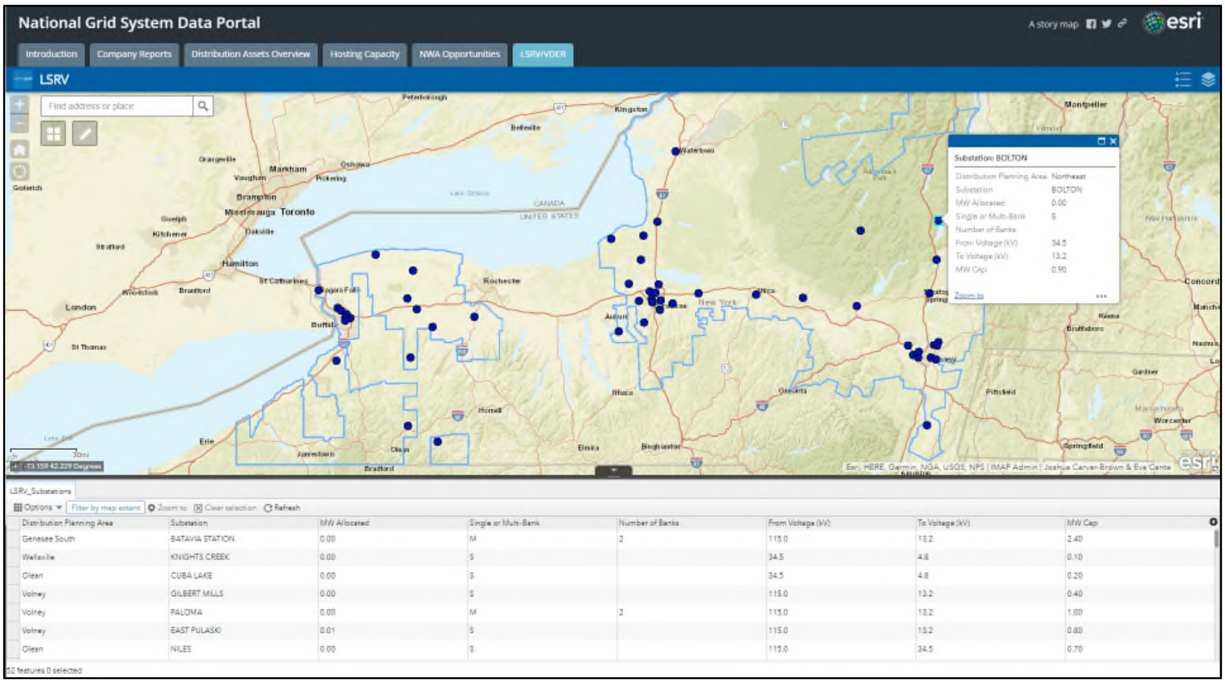


Figure 2.7.5: LSRV/VDER Tab



A description of information currently available and its intended uses by third parties is provided in Table 2.7.1 below.

Table 2.7.1: Information Available on System Data Portal

Portal Tab	Description / Data Provided	Stakeholder Utilization
Introduction	Provides link to National Grid's IOAP (referred to as "nCAP"), plus FAQs, and a link for further Help.	Assists with access to interconnection application portal and how to use the portal.
Company Reports	Provides National Grid reports including Five-Year CIP, Fifteen-Year Plan, Condition Assessment Report, Peak Load Forecast, Reliability Report, Summer Preparedness, Power Quality, and 2017 hourly load data.	Consolidated location for reports provides 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.	The data provides information that helps DER developers understand potential system constraints that may impact future interconnections.
Hosting Capacity	Provides data as to the level of DG capacity that each feeder could	Hosting Capacity gives the developer a relative indication of

Portal Tab	Description / Data Provided	Stakeholder Utilization
	accommodate without requiring infrastructure upgrades.	where interconnection costs may be higher or lower.
NWA Opportunities	Presents a NWA opportunities document which includes basic project metrics, and scope and timing of potential future NWA opportunities.	Developers are provided an advance view as to where future DER opportunities may exist in advance of formal RFP solicitations for NWAs.
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.

The Joint Utilities' stakeholder engagement sessions in 2016-2017 identified the desire for, and broad value of, information and how the utilities could work to enhance what information is provided. As such, in 2017, National Grid enhanced its data portal to improve the accessibility and usefulness of this high-value information. To better understand how data is being used and what data is necessary to meet their needs, the Joint Utilities and stakeholders co-developed multiple business use cases and identified the "need to have" and "nice to have" data that enables each use case. Table 4.7.2 below provides an example of one such use case. In addition to increasing the amount of data that is available, the Joint Utilities also worked with stakeholders to make it easier to access system data both across the utilities and within individual utility data portals. The Joint Utilities System Data Working Group continues to engage stakeholders on the business use cases for system data, identify additional datasets to share, and respond to stakeholder requests to improve ease of access to utility system data.

Table 2.7.2: Stakeholder Use Case

Stakeholder Use Case #1 (UC-1): Interconnection Cost Estimates – Pre-Coordinated Electric System Interconnection Review (CESIR)		
Description	Developers want to estimate CESIR results as a project risk analysis (interconnection costs and timeline for potential system modifications). A developer's engineer may be able to review utility-provided information to make an informed and reasonably accurate assessment of what the CESIR cost and timeline outcome might be and whether or not it would be cost-effective to go forward with the CESIR and the project.	
Information Requested	Why the Information is Requested	National Grid Implementation Plan
"Need to Have"		
Min/Max/Avg Load Data at Feeder Level	• Can provide insight into thermal limitations, voltage constraints (*i.e.*, higher loading can help mitigate high voltage problems)	• Live on Distribution Assets Overview tab for all feeders with EMS monitoring

Stakeholder Use Case #1 (UC-1): Interconnection Cost Estimates – Pre-Coordinated Electric System Interconnection Review (CESIR)		
	• Informs analysis of possible modifications due to exceeding substation backfeed thresholds • Provides generation/load ratio calculations as they relate to Sandia National Laboratories screening for DER interconnection applications	
DER Already Connected	• Related to load data above, critical component to calculating potential DER capacity on feeder/substation • Can inform of possible existence of substation level upgrades that may have already been completed at existing level of DER penetration	• Live on Hosting Capacity tab (along with DER in queue)
Pre-Application Report Information (provided with Preliminary CESIR)	• Information/feeder conditions may have changed since date of pre-application report and date of application submission • Developer may not have completed pre-application report request for reasons related to expedition of application process	• Link to nCAP portal provided on Introduction tab
SIR Inventory Information (to include application status of interconnections in the inventory)	• Validates queue information provided in other data sources • Informs timing of application submission, CESIR commencement • Informs future state of feeder/substation conditions related to potential vs. actual DER intercconnected, which in turn informs cost/impact estimation	• Link to nCAP portal provided on Introduction tab
Circuits identified by ID # on mapping tools	• Allows user to cross reference data from all different sources with mapping tools	• Live on Distribution Assets Overview tab
"Nice To have"		
Conductor Size	• Can be used to evaluate potential thermal capacity of feeder and	• Not provided at this time, however the maximum feeder ampere rating is

Stakeholder Use Case #1 (UC-1): Interconnection Cost Estimates – Pre-Coordinated Electric System Interconnection Review (CESIR)		
	estimated re-conductoring costs, if necessary	provided on Distribution Assets Overview tab
Utility Fault Current Contribution and Impedance at PCC	• Can be used to evaluate necessity of system upgrades • With some utilities requiring specific grounding transformer sizing to meet effective grounding requirements, this information is critical to performing those calculations	• Not provided at this time, as fault current is dependent on the known specific PCC location on a feeder

Following one such stakeholder session on April 20, 2017, the Joint Utilities presented an overview of publicly available system data from all NY utilities to inform stakeholders on the types, format, and granularity of information currently available and how to locate the information. In response to stakeholder feedback following this session, the Joint Utilities developed a central data portal on the Joint Utilities' website in June 2017 with links to utility-specific web portals with available system data.[81] National Grid's portal is one of the links provided on the Joint Utilities website that provides the following information:

- DSIPs
- Capital investment plans;
- Planned resiliency and reliability projects;
- Reliability statistics;
- Hosting capacity;
- Beneficial locations;
- Load forecasts;
- Historical load data;
- NWA opportunities;
- LSRV locations;
- Queued and installed DG; and
- SIR pre-application information

[81] *See* http://jointutilitiesofny.org/system-data/

Future Implementation and Planning

National Grid has plans to enhance existing data provided with the results from various studies and analysis over the next five years of this DSIP Update (*e.g.*, information sets suggested in the New York Energy Storage Roadmap). Table 2.7.3 below provides a list of the items currently under consideration.

Table 2.7.3: Planned Additions to System Data Portal

Data	When (CY)	Where
Locational data of beneficial locations for NWA Opportunities	2019	NWA Opportunities Tab
8760 load forecasts	2018	Distribution Assets Overview Tab
8760 Individual DER forecasts	2018-2023	To be determined
Updated LSRV data	2018-2019	LSRV/VDER Tab
Beneficial Locations of DER	2019-2023	Several Tabs
Hosting Capacity phases 2.1, 3.0 and 3.X	2018-2023	Hosting Capacity
Potential additional data items to support the Energy Storage Roadmap not already listed above	TBD – pending discussions with all stakeholders	TBD – pending discussions with all stakeholders

The planned revisions to the NWA Opportunities tab will aid vendors in selecting the most beneficial location and illustrate where grid limitations exist, and where the NWA solution should ideally be located to best mitigate the issue(s). The information presented will include an interactive map of the Company's service territory with the location of every NWA Opportunity marked. All the information currently presented in the NWA Opportunities document (on the System Data Portal) will be available and accessed via a pop-up box that appears when an NWA location is clicked on. Additional data may also be added as a particular NWA opportunity matures.

The System Data Portal currently displays feeder-level, yearly peak load forecasts. However, following the Joint Utilities stakeholder sessions as described previously more granular data is beneficial to developers. Therefore, planned enhancements are to add 8760 load (feeder level) and DER forecasts (feeder level). National Grid is in the process of developing forecasts for each individual type of DER as described in more detail in the Advanced Forecasting section of this DSIP Update. These granular forecasts will help developers to perform their analysis on DER opportunities. As these forecasts become available they will be shared on the System Data Portal.

More comprehensive information regarding the value of DER would be useful for developers. Currently, the Company identifies LSRV locations on an interactive map. As additional mechanisms for compensating locational value of DER may be developed, the Company will use the System Data Portal to identify for DER providers where applicable opportunities may exist on the National Grid distribution system.

As the Company identifies new beneficial locations for DER (e.g., ESS and EV), the associated data will be posted on the portal as they become available.

Hosting Capacity Analysis ("HCA") is another area in which the Company is working to enhance the information available and shared. A detailed plan for enhancing HCA is discussed in the Hosting Capacity section of this DSIP Update.

The recent New York Energy Storage Roadmap (*i.e.*, Section 4.5.4) provides guidance on the types of system data that currently exist and provides a path forward for new data items that maybe valuable for ESS project evaluation. . Along with all stakeholders, the Company will explore the potential of presenting these data sets as appropriate.

In additional to the specific items described above, the Company plans the following efforts over the next five years of this DSIP Update:

- Continue to automate the compilation, aggregation, and publication of data were possible.
- Continue to improve the usability and consistency (across utilities) of the web portal incorporating comments as they are received.
- National Grid and the Joint Utilities will continue to conduct stakeholder sessions developing use cases, and refining and expanding system data as necessary.
- The Joint Utilities will also continue engaging stakeholders on the potential for value-added information via access to more refined

Any data that is under consideration for posting to the System Data Portal must be compliant with the privacy and security rules described in the Customer Data and Cyber Security sectionss of this DSIP Update.

Risk and Mitigation

Cyber security could poses a potential threat as the portal scales up; the more data and capabilities the portal has, the more potential for exposure there is. To help mitigate these security risks, National Grid will continue to review the sensitivity of the data and determine whether or not the data can be shared. For data items that cannot be publicly provided on the Company's System Data Portal, National Grid will have to assess whether there are alternative means (e.g., by executing a Non-Disclosure Agreement with a specific DER provider). From a security perspective, vulnerability assessments and penetration testing of the portal will be undertaken by National Grid to ensure that security risks are identified and logged for remediation. Additionally, the Company's current system data platform has certain limitations for future expansion of capabilities as follows:

- There could potentially be performance degradation with an increase in the quantity of hosted data and/or a substantial increase in the number of users on the system.

- If the Company decides to provide data that is classified at higher security level, where a user login and password is required, the current platform cannot support such capability.

To mitigate these risks the Company will be investigating possible upgrades or migrating the System Data Portal to another platform.

Customer privacy rights are and will continue to be a priority for the Company and the portal must comply with all customer privacy rules.

Stakeholder Interface

As described previously the Company has conducted multiple stakeholder sessions with the Joint Utilities and incorporated feedback into the System Daata Portal as it exists today. An overview of these engagements to date and associated outcomes are as follows:

- **2017-18 Stakeholder engagement use case development sessions**: co-development five initial business use cases as described in the response to question 1 below.
- **Review of the 5 business cases:** identified the volume of requested information that is already publicly available, but previously may not have been easily accessible. As such the Joint Utilities enhanced the accessibility and similarity of the information provided
- **New Data items and classification:** provide additional information that is of greater value to developers assessed based on priorities and needs

Aligning Joint Utilities and stakeholders' expectations and understanding the purpose of each form of engagement, and what success looks like, will be important going forward.

Additional Details

The following responds to DPS Staff's request to provide additional details which are specific to distribution system data.[82]

1. Identify and characterize each system data requirement derived from stakeholder input.

As described in the Current Progress section of this section, following several Joint Utilities stakeholder sessions various use cases were developed and used to identify needs and subsequent improvements/expansion of the types of data available.

The following five use cases ("UC") listed below were evaluated:

[82] DSIP Proceeding, 2018 DSIP Guidance Update, pp. 20-21.

- UC1: Interconnection Cost Estimating – Pre (CESIR).
- UC2: Evaluate Development Risks for Potential Projects
- UC3: Microgrid Development
- UC4: Integrated Distribution Planning (LMP+D[83] & LNBA[84])
- UC5: Prospecting for Development Opportunities (Storage Focus)

2. Describe in detail the resources and methods used for sharing each type of distribution system data with DER developers/operators and other third parties.

As described throughout this section, a wealth of system data is provided via National Grid's public System Data Portal. However, not all data can be publicly shared due to legal, regulatory, system security, and/or privacy considerations, even if it may be beneficial for DER providers to have. For data not on the System Data Portal, DER developers may request information from the Company via a Request for Information ("RFI"), and the Company will evaluate and respond to the request on a case-by-case basis. RFIs should be submitted via the appropriate project manager or customer representative assigned to the project. If the project does not yet exist, inquiries should be submitted via the National Grid customer service line (1-800-642-4272), where it will be directed to the appropriate party.

3. Describe where and how DER developers and other stakeholders can readily access, navigate, view, sort, filter, and download each type of shared distribution system data.

A wide range of information is available to DER developers in a self-serve fashion from National Grid's System Data Portal. Over the next two years, further enhancements will be made such that each tab on the portal will provide the ability for the user to navigate, view, sort, filter, and download the data as a .csv.

4. Describe how and when each type of data provided to DER developers/operators and other third parties will begin, increase, and improve as work progresses.

In general, National Grid will continue to provide data on the portal as it becomes available but it is not possible to identify all new/improved data sets at this time. Please see Table 4.7.2 above for the Planned Additions to System Data Portal Table.

5. Identify and characterize the use cases which involve third party access to sensitive distribution system data and describe how the third party's needs are addressed in each case.

[83] LMP + D is Locational Marginal Price + Distribution.
[84] LNBA is Locational Net Benefits Analysis.

Sensitive data is currently distributed based on an articulated need via an RFI. The method for distribution is via an RFI response and may require the advance execution of a Non-Disclosure Agreement. Sensitive data sharing will be addressed on a case-by-case basis.

6. Identify each type of distribution system data which is/will be provided to third parties and whether the utility plans to propose a fee.

National Grid has not yet identified any fee-based data sets. However, the Company reserves the right to charge a fee for the provision of data that is outside of or above and beyond that which the Company uses for its business (*i.e.*, value-added services). The Joint Utilities are currently discussing under what scenarios advanced datasets would be provided.

7. Describe in detail the ways in which the utility's means and methods for sharing distribution system data with third parties are highly consistent with the means and methods at the other utilities.

National Grid has collaborated extensively, and continues to do so, to ensure the means and methods of sharing data are highly consistent among the utilities. The Company is an active participant in all Joint Utilities' working groups, meetings, and stakeholder sessions. Where possible National Grid attempts to provide a similar look, user experience, data, format and access capability as the other utilities do on their respective System Data Portals. For example, the hosting capacity data portals of each utility are highly consistent. Additionally, a common Joint Utilities website portal[85] has been developed.

This new Joint Utilities web portal, in addition to hosting the links to the enhanced utility-specific web portals, has increased access to and improved access to usability stakeholder-requested information. The Joint Utilities have advanced their efforts to release additional data in more accessible formats and stakeholders now have a better understanding of the data currently available through utility-specific web portals.

The Joint Utilities' use case discussions also provide a way to share with stakeholders why certain information may have a low probability for being shared. For example, a piece of information requested may be embedded in utility planning models and not readily available for public presentment, leading to further discussion around the need for the data and the potential to provide certain data as a value-add service. The Joint Utilities have not yet established fee structures for data requests but any such effort would be related to whether the data is readily available and the level of effort needed to package and deliver the data.

The Joint Utilities System Data Working Group will continue focusing on updates to and consistency of individual utility system data portals, as well as refinement and/or expansion of system data use cases to better meet stakeholder needs.

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[85] *See* https://jointutilitiesofny.org/system-data/

8. Describe in detail the ways in which the utility's means and methods for sharing distribution system data with third parties are <u>not</u> highly consistent with the means and methods at the other utilities. Explain the utility's rationale for each such case.

Wherever possible the Joint Utilities coordinate to maintain commonalities amongst the data available on each utility's System Data Portal. However, due to differences in the utility systems and data availability, total consistency is not always possible. Where there are inconsistencies, the Joint Utilities will strive to mitigate to the extent possible to do so.

2.8 Customer Data

Context and Background

Prior to the DSIP Filings Order, the state of New York did not have aggregated customer data privacy standards in place or in process and the utilities had limited understanding of which data sets might be useful to stakeholders to develop and provide customers with energy products and services. National Grid's 2016 baseline for customer data sharing included the Green Button Download My Data ("DMD") tool. With Green Button DMD, National Grid customers are able to securely download the last 13 months of their energy data in a standardized format and upload that data, if they so choose, to an emerging array of online applications and benchmarking tools to make more informed energy decisions.

Since the filing of the initial DSIP, National Grid has collaborated in the Joint Utilities' Customer Data Working Group to advance several customer data efforts, including:

- Submitting two Joint Utilities filings on customer privacy standards and approaches;
- Defining data sets and costs in support of CCA efforts through development and filing of CCA tariffs;
- Evaluating potential opportunities for aggregated data automation; and
- Engaging with stakeholders to solicit feedback and inform future customer data needs and means of accessing that information.

In terms of advancing customer data privacy standards, the DSIP Filings Order adopted a 15/15 privacy standard[86] for aggregated energy consumption datasets provided by utilities to third parties, as proposed in the Joint Utilities' Supplemental DSIP, which applies to data provided for purposes of community planning and CCA. The Commission acknowledged that the 15/15 privacy standard is conservative and further directed the Joint Utilities to track all aggregated data requests and be prepared to report on the number of requests that do not meet the 15/15 standard.[87]

The DSIP Filings Order also required the Joint Utilities to propose a building energy management and benchmarking data standard for the Commission's consideration.[88] The Joint

[86] The 15/15 privacy standard would permit an aggregated dataset to be shared only if it contains at least 15 customer accounts and no one customer represents more than 15% of the total usage for the dataset.
[87] REV Proceeding, DSIP Filings Order, pp. 26-27.
[88] *Id.*, p. 28.

Utilities performed a benchmarking study on aggregated customer data privacy standards in use or considered by other utilities across the US, and proposed to the Commission the use of a 4/50 privacy standard[89] for whole-building aggregated customer data to be provided to building owners or their authorized agent. On April 20, 2018 the Commission issued *Order Adopting Whole Building Energy Data Aggregation Standard* which was consistent with the Joint Utilities' proposal.[90] In conformance with this order, on June 19, 2018 the Joint Utilities filed proposed data access terms and conditions with the Commission.[91] Building owners that must comply with existing laws and ordinances, such as Local Law 84 in New York City, are exempt from the privacy standard.

On April 20, 2018, the Commission issued *Order Adopting Utility Energy Registry*,[92] directing full implementation of the Utility Energy Registry ("UER") by NYSERDA and the utilities and adopting a 6/40 privacy standard[93] for small commercial and other non-residential customer groupings without modifying the existing 15/15 privacy standard for residential groupings, and further directing the utilities to submit an inaugural UER dataset to NYSERDA by July 30, 2018. The Joint Utilities have engaged with NYSERDA and its consultant to understand the reporting requirements.

The Joint Utilities are actively working through numerous processes to develop and implement uniform policies and approaches in response to the Commission and stakeholder requests through conversations with DER providers. Since the filing of the initial DSIP, and in addition to the aforementioned efforts, the Joint Utilities have collaborated in the Customer Data Working Group to advance several other customer data efforts, including, providing comments in response to the Commission's notice regarding Uniform Business Practices for DER Suppliers ("UBP-DERS")

Similar to system data, access to various customer data, both individual and aggregated, is helpful for DER providers to enable customers to participate in DER opportunities to better manage their energy usage. National Grid supports the sharing of customer data within the protections of customer privacy.

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[89] The 4/50 privacy standard would require the building to have at least 4 accounts where no single account represents 50% or more of the annual energy use of the building. However, building owners that must comply with existing laws and ordinances, such as Local Law 84 in New York City, are exempt from the privacy standard.

[90] DSIP Proceeding, Order Adopting Whole Building Energy Data Aggregation Standard (issued April 20, 2018), pp. 11-12.

[91] DSIP Proceeding, Joint Utility Aggregated Whole Building Data Terms and Conditions (filed June 19, 2018).

[92] Cases 17-M-0315 *et al*., *In the Matter of Utility Energy Registry*, Order Adopting Utility Energy Registry (issued April 20, 2018).

[93] The 6/40 privacy standard would permit an aggregated dataset to be shared only if it contains at least 6 customer accounts and no one customer represents more than 40% of the total usage for the dataset.

Current Progress

National Grid filed its Aggregated Data Privacy Policy Statement on November 1, 2016 in response to the Commission's 2015 REV Track Two Order.[94] Utility filings were posted under Case 16-M-0428 with each utility filing their policy individually. National Grid and National Grid's downstate New York affiliates made one filing on behalf of all three New York companies.[95]

Each of the Joint Utilities created an internal inventory of actual aggregated customer data requests to understand the volume and types of standard aggregations requested by stakeholders and examined efforts to potentially automate the request and delivery of these aggregated data reports. From this exercise, the utilities determined that none of them had experienced substantial volumes of requests for aggregated customer data; thus, the utilities have postponed further discussion or evaluation of automating processes until there is a clearer need.

In an effort to promote energy efficiency and identify energy efficiency improvement opportunities for our customers, National Grid worked with the United States Environmental Protection Agency ("EPA") to use the EPA's ENERGY STAR Portfolio Manager® tool. Portfolio Manager® is an interactive web-based energy management tool that allows building owners or property managers to track and assess energy and water consumption across an entire portfolio of buildings. National Grid has leveraged EPA's Portfolio Manager® web services to facilitate the transfer of aggregated whole-building energy consumption data directly into customers' building records in Portfolio Manager. This new service was developed as part of National Grid's downstate gas affiliates' latest rate case that required these National Grid affiliates to upload customer usage information into the ENERGY STAR Portfolio Manager® application by January 2018. A similar implementation for the Company's upstate gas customers has been completed subject to the 4/50 whole building standard, unless a local ordinance or mandate arises that requires otherwise.

National Grid is currently applying the 15/15 privacy standard to aggregated datasets related to CCA data requests, data posted on the Company's System Data Portal and aggregated data within RFPs for NWA opportunities.

[94] REV Proceeding, Order Adopting a Ratemaking and Utility Revenue Model Policy Framework (issued May 19, 2016)("REV Track Two Order").
[95] Case 16-M-0428, *In the Matter of Utility Platform Service Revenues and Aggregated Data Access Reforms Supporting the Commission's Reforming the Energy Vision*, National Grid Aggregated Data Privacy Policy Statement (filed November 1, 2016).

The Company is also implementing the 4/50 privacy standard with regard to whole building aggregated data. Using our new portfolio manager aggregated data upload system, a 4/50 aggregated data privacy standard is applied to aggregated whole building electricity and gas datasets requested by building owners and/or their authorized agents. The only exception to this privacy standard is in regions where local ordinance requires reporting of this data.

National Grid is providing CCA providers and DER providers with as much information as possible about electricity and gas consumption and electric system needs within the confines of the privacy standards adopted by the Commission as described above.

Future Implementation and Planning

National Grid plans to implement Green Button Connect My Data capability as part of its AMI Customer Engagement plan. However, in advance of Commission approval to proceed with full AMI implementation, customer usage data can continue to be provided to end users via the Green Button DMD tool. Green Button Connect My Data will provide new capabilities which allow customers to enable and automate the secure transfer of their own energy usage data to authorized third parties, based on affirmative (opt-in) customer consent and control. Green Button Connect My Data customers will be able to authorize National Grid to enable designated third parties to securely receive data on the customer's behalf. It is envisioned as part of the Company's AMI customer engagement efforts that near real-time basic customer usage data will be provided to customers through an online energy insights portal that exists as the crux of the Company's Customer Energy Management Platform ("CEMP"), whereby customers would have both seamless and intuitive access to usage information, personalized insights, and opportunities for action (*e.g.*, DR enrollment, solar PV adoption). From the CEMP, data would be accessible for customer-authorized third parties via the Green Button Connect My Data capability.

The deployment of Green Button Connect My Data will require various software integrations and the development of 20 complex and 20 simple application programming interfaces ("APIs").

Green Button Connect My Data project development and implementation is expected during 2019-2021 with a targeted in-service date during 2021. The scope and schedule of this project maybe influenced by National Grid AMI business case that will be presented to the Commission per requirements of the Three-Year Rate Plan Order.

Providing customers access to their data through Green Button Connect My Data may increase participation in EE, DR and DG programs offered by National Grid and better enable third parties to propose customized energy solutions, which will facilitate customers' ability to better manage their energy use and bills.

Also, through collaboration with DPS Staff and other stakeholders, the Joint Utilities are finalizing development on sharing aggregated community energy consumption data through NYSERDA's UER. An inaugural UER dataset is due to NYSERDA by July 30, 2018. Thereafter monthly data is due every six months (January to June and July to December) within 30 days of the close of each semi-annual period. National Grid expects to submit the required datasets by July 30, 2018 with the exception of CCA-ineligible customer counts which will be provided by September 7, 2018 subject to approval of an extension request filed with the Secretary of the Commission.

Aggregated energy usage data for communities provided through the UER will allow communities to make informed decisions on community-based DER and energy choice aggregation programs.

Risk and Mitigation

Customer data privacy rights are a key priority and area of focus with regard to both customer-specific data and aggregated data.

National Grid continues to advocate for having third parties meet robust requirements aimed at protecting customer data. For example, the Company is requiring that Energy Service Companies ("ESCOs") and DER Providers who receive customer data through Electronic Data Interchange ("EDI") improve cyber protection (*i.e.*, secure cyber insurance) and enter into Data Security Agreements ("DSAs") with National Grid. While Green Button Download My Data only provides data to customers who access the link through their account page online, National Grid will evaluate cyber-insurance and DSA requirements regarding its implementation of Green Button Connect My Data which involves authorized third-party access to customer data.

National Grid will also ensure that any aggregated data sets being provided to third parties meet the aggregated data anonymity standard of 15/15 unless exceptions exist for specific use-cases (*e.g.*, whole building data for building owners, NYSERDA's UER). Any future exceptions to the 15/15 standard for specific use cases will be discussed first among the Joint Utilities and proposed to DPS Staff for consideration and ultimately the Commission for approval, with a goal of meeting customer and stakeholder needs and maintaining individual customer privacy.

Stakeholder Interface

Since its Initial DSIP, National Grid has collaborated with the Joint Utilities and interested stakeholders in the Customer Data Working Group. The JU shared their proposals for: 1. aggregated customer data privacy standards, 2. efforts to improve the type of data which are available, and 3. the processes for accessing customer specific data with proper customer authorization. In addition, the Customer Data Working Group hosted one-on-one conversations with DER developers to better understand their data needs, share current practices, and inform their future data sharing plans.

Additional Details

The following responds to DPS Staff's request for additional details specific to customer energy consumption and production data.[96]

1. Date Types, Description and Management Processes

a. Describe the type(s) of customer load and supply data acquired by the utility.

National Grid collects and maintains electric consumption and demand data along with gas consumption data for its customers. The type of customer load and supply data acquired by National Grid varies by customer rate class.

The list provided below defines the data types currently accessible through the Green Button Download My Data platform at National Grid. The Company has not built the detailed requirements for the future of Green Button Connect My Data, but the list of data types below would be the minimum provided and any additional data types would need to be evaluated in the design process.

- Read Date & Days
- Read Type
- Total kWh
- Delivery Charges
- Supply Charges
- Late Payment Charges
- Total Charges
- Metered Peak kW
- Metered On-Peak kW
- Billed Peak kW
- Billed On-Peak kW
- TOU On-Peak kWh (as applicable to specific rate design)
- TOU Off-Peak kWh (as applicable to specific rate design)
- RKVA
- Load Factor

Basic data for non-interval-metered customers includes cumulative kWh, net or accumulated kWh, and maximum recorded kW (if a demand meter is present). Basic data for interval-metered customers includes energy use (kWh, net or accumulated kWh, kW, kVar) at intervals specific to the customer's meter, as well as cumulative kWh, minimum/maximum kW, and kVar.

[96] DSIP Proceeding, 2018 DSIP Guidance Update, pp. 21-23.

In an effort to promote EE and identify EE improvement opportunities for customers, National Grid is working with the EPA to make it easier for our customers to use the EPA's ENERGY STAR Portfolio Manager® benchmarking tool. Portfolio Manager® is an interactive web-based energy management tool that allows building owners or property managers to track and assess energy and water consumption across an entire portfolio of buildings. National Grid affiliates have leveraged EPA's ENERGY STAR Portfolio Manager® web services to facilitate the transfer of aggregated whole-building energy consumption data directly into customers' building records in Portfolio Manager.®

National Grid has implemented the ENERGY STAR Portfolio Manager® which will support the 4/50 whole-building aggregated data privacy standard. The only exception to this 4/50 rule is in the event of a local ordinance or mandate that requires otherwise.

National Grid collects the following electric supply/generation data from revenue grade metering.

- Read Date & Days
- Read Type
- Total kWh
- Hourly Kwh values
- Delivery Charges
- Supply Charges
- Late Payment Charges
- Total Charges
- Metered Peak kW
- Metered On-Peak kW

b. Describe the accuracy, granularity, latency, content, and format for each type of data acquired.

All customers currently have access to their monthly energy usage and cost information through the National Grid Web Portal at https://www.nationalgridus.com

Additionally, Green Button Download My Data is available to all customers and provides the following monthly data dependent on customer rate class:

- Read Date & Days
- Read Type
- Total kWh
- Delivery Charges
- Supply Charges
- Late Payment Charges

- Total Charges
- Metered Peak kW
- Metered On-Peak kW
- Billed Peak kW
- Billed On-Peak kW
- TOU On-Peak kWh
- TOU Off-Peak kWh
- RKVA
- Load Factor

Green Button Download My Data can be accessed through the Track Usage link within the Your Account tab on the National Grid website. Monthly data is provided in XML format. National Grid also internally manages acquired data in its databases and provides internal reports in Excel format.

Figure 2.8.1: Usage Tracking File Download

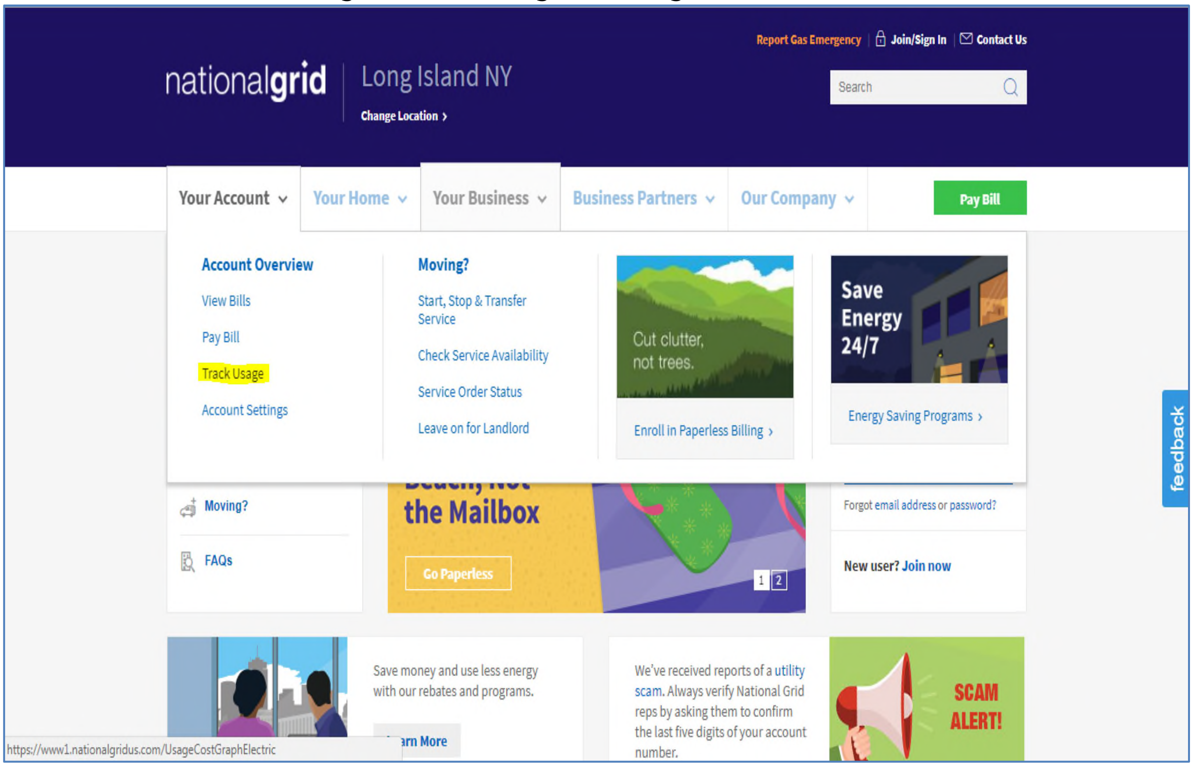


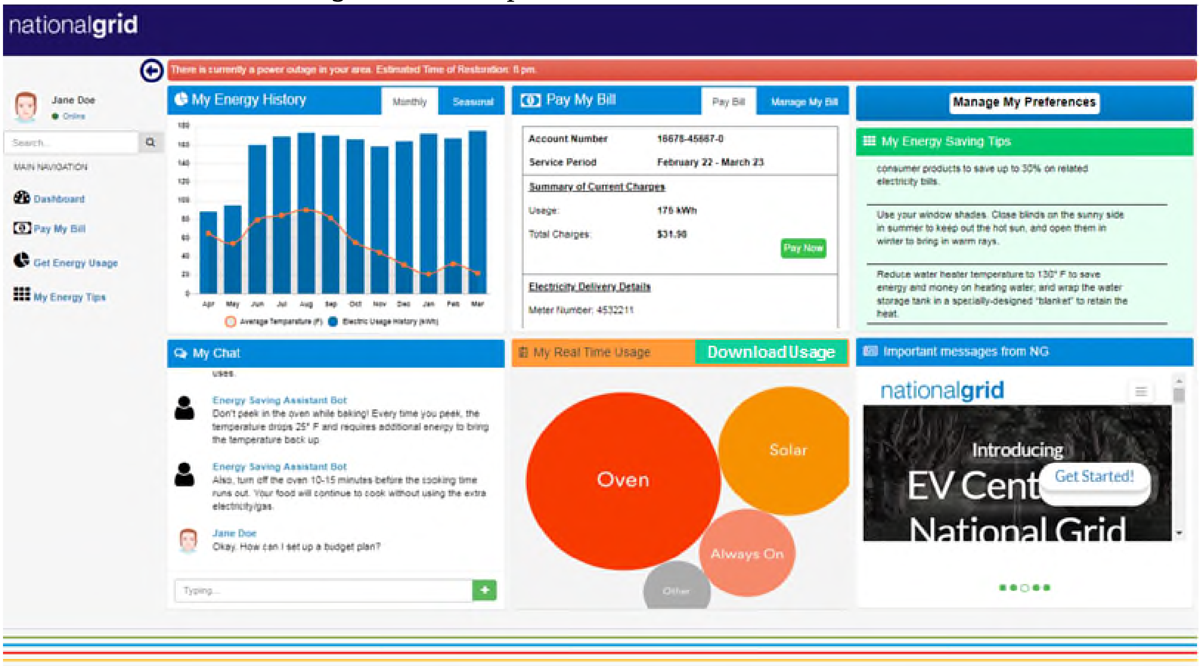
Figure 2.8.2: Green Button Download My Data

National Grid customers have the ability to download their usage information directly through Green Button Download My Data and will be able to authorize third parties to access their data through Green Button Connect My Data. The company expects to enhance the download capabilities using the Green Button Connect My Data as part of the Customer Energy Management Platform.

Within National Grid's Customer Experience Transformation portfolio of projects, an effort is underway to significantly improve the customers' digital experience. Included in this effort is the development of a customer portal in which the CEMP will be integrated. Additionally, with preference management and personalization capabilities, customers will be presented with a robust platform where they can access information about their account, manage their energy use, and view solutions that are relevant to them.

Figure 2.8.3 below is an example of what the customers may see within their portal. This is illustrative only, but shows on a general level of what customers will experience in the future, and the natural fit with CEMP and Green Button Connect My Data.

*Figure 2.8.3: Aspirational Customer Portal**



*Illustrative only and not reflective of actual customer portal

National Grid anticipates proposing the following data latency solutions as part of the Company's AMI Business Case:

- Electric
    - Fifteen-minute intervals
    - Transmitted every 4 hours (6 times a day)
- Gas
    - One- hour intervals
    - Transmitted every 8 hours (3 times a day)
- Green Button Connect / Download My Data availability:
    - Raw electric data - 4 hours
    - Raw gas data - 8 hours Bill quality data - 24 hours

Building owners have additional options to access their whole building aggregated usage data for individual properties using the EPA ENERGY STAR portfolio Manager® aggregated data upload system.

- Bill month & year
- Billing Days
- Total therms or kWh
- Total charges
- Number of bills

c. Describe in detail the utility's means and methods for creating, collecting, managing, and securing each type of data.

National Grid acquires customer load (usage) data by capturing information into its billing systems and databases that is measured and recorded by the utility's billing meter for each customer account location. These can be interval, AMI, and/or register-read meters. There are differences in the type and granularity of the customer load and supply data acquired based on customer type, meter type, and the extent to which AMI has been deployed. In some cases – generally for C&I customers – additional data such as demand (kW) and reactive power (RKVA) data will also be acquired. As National Grid implements new technologies such as AMI, more granular (interval) data will be available and evolve the data-sharing mechanisms and standards, as appropriate.

The security of customer information is increasingly critical as more granular data is collected and analyzed to make data-driven decisions. Managing customer information requires implementing, enforcing and ensuring that security policies are followed and that security controls are in place. Security policies include least privileged access rights, secure code practices, and regular security reviews to ensure information is protected. Also, security control capabilities, such as encryption, vulnerability and virus scanning, configuration of technology to minimize available services, endpoint protection, and tracking and recording of assets that process personal data, will ensure the confidentiality, availability, and integrity of information. Security controls to monitor network and user activity reduce the risk of data loss and manipulation, and can produce alerts if anomalous activity is detected.

2. Data Uses, Access and Security

a. Describe the means and methods that customers and their properly designated agents can use to acquire their load and supply data directly from their utility meters without going through the utility, should they want to.

EDI supports ESCO transactions today and National Grid is moving to use of EDI as permanent process for DER providers. The Company has included, as a requirement in RFPs for all AMI metering devices, the ability to support home area network ("HAN") integration. Vendors need to at least provide a roadmap to support HAN integration. This will allow the customer to securely obtain raw load and supply data directly from their AMI meter, through a variety of third party devices located in the home. HAN data can be managed by the customer or provided to designated third-party agents at the customer's discretion.

b. Identify and characterize the categories of legitimate users beyond customers and their properly designated agents who will be provided access to each type of data.

For customer-specific data, only customers and their properly designated agents are deemed to be legitimate users who will be provided access to each type of data.

c. For each type of data, describe how its respective users will productively apply the data and explain why the data provided will be sufficient to fully support each type of application.

The Joint Utilities have been proactively engaging with stakeholders to share their proposals for providing aggregated customer data consistent with customer privacy standards and progress in improving the type of data and the process for accessing customer-specific data with proper customer authorization. In addition, the Joint Utilities are actively conducting one-on-one conversations with DER developers to better understand their specific customer usage data needs, share current practices, and inform their future data sharing plans. Through these targeted conversations, utilities not only understand the underlying basis for the requests, but stakeholders gain better insight to the information currently available and how to access it. Regarding authorized customer-specific data, DER developers would be able to analyze the customer's load profile and energy data to suggest a customized solution which might include EE measures, DR or DG equipment.

It should be noted that the UBP-DERS addresses both the process by which DERS can acquire customer data and the use of EDI as the mechanism for sharing data.

Through collaboration with DPS Staff and other stakeholders, the Joint Utilities are finalizing development on sharing aggregated data for whole buildings with building owners and sharing aggregated community consumption data through the UER, generally at the municipal level. These new offerings will allow building owners to better manage and benchmark their building energy usage, and allow communities to make informed decisions on CDG Projects, CCA programs, and EE initiatives. The availability of aggregated community data will also better enable third-party energy choice aggregators to prospect for communities who might benefit from their services.

d. For each type of data, describe in detail the utility's policies, means, and methods for securely providing legitimate users with efficient, timely, and useful access to the data. Include information which thoroughly describes and explains the utility's approach to providing customer data to third parties who would use the data to identify and design service opportunities which benefit the utility and/or its customers.

Sharing customer data with third parties plays a key role in the success of third-party partnerships. This includes ensuring that data can be shared safely, securely, and in a timely fashion. Effective security practices and policies must be in place on both sides, at National Grid and at third parties that are leveraging customer data. To ensure this, security architects will evaluate the security controls in place as it relates to third-party systems and practices prior to sharing customer data. Third parties must ensure that customer data is only used for the purposes that are defined, that it is stored in a safe and secure manner, and is deleted upon the end of its usefulness. Controls must be in place to ensure that data is not intercepted or manipulated in transit between National Grid and third parties and that data integrity is maintained. A contractual agreement must be established between National Grid and third parties to ensure that both parties understand the nature of the data being shared and responsibilities are established, access control policies are in place, and reporting and notifications are provided in the event of a cyber breach or incident.

Additionally, National Grid has developed policies, standards and guidelines that govern data access and the protection of sensitive information which requires information to be classified appropriately and protected in accordance with the classification. National Grid's Data Privacy Policy states that personal information will not be disclosed unless:

- The disclosure is fair and lawful and consistent where appropriate, with the notified purpose(s); or
- The individual has given appropriate 'consent'; or
- The disclosure is necessary e.g. in the individuals vital interest; or
- The disclosure is covered by 'exemption' from any relevant legislation.

Transfer of any customer information to selected external third parties will only take place if (in addition to the other relevant policy / implementation framework requirements) the third party agrees as a minimum to:

- Process personal information strictly in accordance with the businesses instructions;
- Comply with relevant privacy laws and the businesses policies and procedures;
- Implement appropriate security measures to deliver the required levels of protection;
- Seek permission from the relevant National Grid business for further onward transfers (*e.g.*, to sub-processors);
- Promptly report any breaches, risk, or issues to personal information to National Grid;
- The businesses right to audit for compliance; and
- On termination of the agreement either return the personal information or dispose of it securely.

e. Describe how the utilities are jointly developing and implementing uniform policies, protocols, and resources for controlling third party access to customer data.

The Joint Utilities are actively working through numerous processes to develop and implement uniform policies and approaches in response to the Commission and stakeholder requests through the use-case conversations with DER developers. Since the filing of the initial DSIPs, the Joint Utilities have collaborated in the Customer Data Working Group to advance several customer data efforts, including:

- Submitting two joint filings on customer privacy standards and approaches;
- Defining data sets and costs in support of CCA efforts through development and filing of CCA tariffs;
- Working with DPS Staff and NYSERDA on UER and appropriate privacy standards;
- Providing comments in response to the Commission's notice regarding Uniform Business Practices for DER Suppliers (UBP-DERS);
- Evaluating potential opportunities for aggregated data automation and developing whole-building owner aggregated data access and privacy standards; and
- Engaging with stakeholders to solicit feedback and inform future customer data needs and means of accessing that information.

Currently, there are a number of channels through which customer data is shared with customers and their authorized third parties. These include utility bills, Green Button DMD, Green Button Connect My Data, EDI, UER, Secure File Transfer Protocol ("SFTP"), File Transfer Protocol with Pretty Good Privacy ("PGP") Encryption, online third-party data platforms, and the data identified in UBP for DERs.

f. Describe in detail the utility's policies, means, and methods for rigorously anticipating data risks and preventing loss, theft, or corruption of customer data.

Customer data will be shared with third-party participants to enable informed decision making, but doing so also increases the risk of data loss, theft, or corruption of the associated data. National Grid will have in place capabilities and processes that reduce this associated risk and enable the safe and reliable use of customer data for its many applications. These capabilities include advanced log management, alerting, and real-time analytic functionality that interrogate network infrastructure, detect suspicious devices and remediate at-risk endpoints. Monitoring capabilities identify endpoints and monitor network traffic and user activity to reduce the risk of malicious activity and associated potential for data loss. Standardized policies for identity and access management, enforcement of least-privilege access (ensuring that users only have access to the information and functions necessary to carry out their job function), ensuring appropriate authentication and authorization of users that can access customer data, and monitoring of privileged access place limitations to what users have access to and thereby limit the risk of insider threats. Additional controls, such as encryption of customer data at rest or transit, tracking and recording of assets that process personal data, virus and vulnerability scanning, penetration testing of assets, and staff training and awareness, will be in place to minimize the risks associated with loss, theft, and corruption of customer data.

It is critical to ensure that third parties who have access to information have adequate security policies and capabilities in place to safeguard customer data. Risk assessments are completed by security architects to provide a view of security controls that are in place and those that need to be implemented to address any residual risks. Third parties must be able to ensure that access to

National Grid's information and related customer data is restricted to those granted such access, that the data is not further shared outside of those so authorized, and that it is deleted when the data is no longer required. A contractual agreement is established between National Grid and third parties to ensure that both parties understand the nature of the data being shared, responsibilities are established, access control policies are in place, and reporting and notifications are provided in the event of a cyber breach or incident. National Grid is a strong advocate of requiring third parties such as ESCOs and DER Suppliers to have cyber insurance and DSAs in place to protect customer data.

g. Identify each type of customer data which is/will be provided to third parties at no cost to the recipient, and the extent to which the practice comports with DPS policies in place at the time, as appropriate.

Aggregated community-level energy data will be provided for NYSERDA's UER at no charge. consistent with the Commission's *Order Adopting Utility Energy Registry*.

h. Identify each type of customer data which the utility proposes to provide to third parties for a fee, and the extent to which the practice comports with DPS policies in place at the time, as appropriate. For each data type identified, describe the proposed fee structure and explain the utility's rationale for charging a fee to the recipient.

In general, National Grid proposes that any Value Added Data (including aggregated data) provided to third parties should be provided only for a fee. Value Added Data has one or more of the following characteristics:

- It is not routinely developed or shared;
- It has been transformed or analyzed in a customized way (*i.e.*, aggregated data);
- It is delivered more frequently than Basic data;
- It is requested and provided on a more ad hoc basis; and/or
- It is more granular than Basic data.

The Company has not proposed fee structures for Value Added Data except for fee structures for CCA data as required in the CCA tariffs.

Current exceptions are the provision of whole building data uploads to EPA's ENERGY STAR Portfolio Manager® for purposes of assisting building owners in complying with Local Law 84 for National Grid's downstate NY gas affiliated and community-level aggregated datasets provided by National Grid for NYSERDA's UER.

i. Describe in detail the ways in which the utility's means and methods for sharing customer data with third parties are highly consistent with the means and methods at the other utilities, and the extent to which these practices comport with DPS policies in place at the time, as appropriate.

Currently, there are a number of channels that share customer data with customers and their authorized third parties. These include utility bills, Green Button DMD, EDI, UER, SFTP, online third-party data platforms, and the data identified in UBP for DERs. The Company believes these channels are consistent with the means and methods at the other utilities. All the utilities are consistently applying aggregated data privacy standards approved by the Commission for general aggregated data, whole building aggregated data and community-level aggregated data. The Joint Utilities are also aligned on methods to share aggregated customer data to NYSERDA's UER.

j. Describe in detail the ways in which the utility's means and methods for sharing customer data with third parties are <u>not</u> highly consistent with the means and methods at the other utilities. Explain the utility's rationale for each such case.

The Joint Utilities are working together to develop a statewide standard in phases, with the understanding that utilities will have different starting points. Utilities implementing full AMI solutions plan to provide basic customer usage data to customers via online platforms and to customer-authorized third parties using the Green Button Connect My Data standard or a comparable specification. Utilities not implementing full AMI solutions expect to provide basic customer usage data to end-users via Green Button Download My Data or an alternative specification. The Joint Utilities will continue to leverage existing platforms, including EDI, SFTP, and online customer engagement platforms.

National Grid's downstate NY gas affiliates are utilizing EPA ENERGY STAR Portfolio Manager® uploads of whole building aggregated data to assist building owners in complying with Local Law 84. Utilities that do not have building owners who need to comply with a local ordinance may choose not to share whole building data using this method.

3. Green Button Connect Capabilities

a. Describe where and how DER developers, customers, and other stakeholders can readily access up-to-date information about the areas where customer consumption data provided via Green Button Connect (GBC) is available or planned.

At this juncture the Company has not developed a detailed outreach plan specific to the Green Button Connect My Data solution. National Grid is currently in the process of developing a customer engagement plan that will address all components of its AMI program, including Green Button Connect My Data functionality, in greater detail. At this time, it is envisioned that both Green Button Download My Data and Green Button Connect My Data will be accessed through a new Customer Energy Management Platform for AMI. Through this platform, customers will have the ability to download their usage information directly through Green Button Download My Data and will be able to authorize third parties to access their data through Green Button Connect My Data. National Grid will file its revised AMI Business Case and Customer Engagement Plan with the Commission in October 2018.

Subject to Commission approval, Green Button Connect My Data project development and implementation is expected during 2019-2021 with a targeted in-service date of March 2021.

b. Describe how the utility is making customers and third parties aware of its GBC resources and capabilities.

National Grid wants to play an active role in engaging customers in AMI technology and educating them about the benefits of becoming more familiar with their energy data and sharing it with third-party solutions providers. With authorized access to customers' energy data, third parties will be better able to provide a set of customized energy solutions to customers.

National Grid is currently in the process of developing a detailed AMI Customer Engagement Plan that will address all customer-related components of a future AMI deployment, including Green Button Connect My Data functionality, in greater detail. As part of the plan development process, National Grid is presenting its current thinking at AMI Collaborative sessions during the summer of 2018, while facilitating input and feedback from attending parties. These attendees include DPS Staff, DPS Office of Consumer Services, and other stakeholders.

c. Describe the utility's policies, means, and methods for measuring and evaluating customer and third-party utilization of its GBC capabilities.

National Grid currently tracks the number of customers who are utilizing the Green Button Download My Data functionality.
The number of National Grid customers that have utilized Green Button Download My Data since it was implemented in September 2014 is included in the table below.

Table 2.8.1: Number of National Grid Customers that Utilized Green Button Download My Data Since September 2014

UNY Gas and Electric	Gas			Electric			
Year	Comm	Resi	Gas Total	Comm	Resi	Electric Total	Grand Total
2014 (started in September)	7	72	**79**	75	597	**672**	**751**
2015	43	344	**387**	374	2995	**3369**	**3756**
2016	59	169	**228**	368	1349	**1717**	**1945**
2017	71	127	**198**	368	984	**1335**	**1533**
2018 (Jan - June)	22	68	**90**	177	540	**717**	**807**
Subtotal	**202**	**780**	**982**	**1345**	**6465**	**7810**	**8792**

The Company also provides and is currently testing Green Button Download My Data provided to those customers participating in the AMI demonstration project in Clifton Park. The table below provides the number of customer downloads obtained via the online AMI portal.

Table 2.8.2: Number of Customer Downloads Obtained via the Online AMI Portal

Clifton Park AMI GBD Downloads	*Number of Customer*
2017	11
2018	47
Subtotal	**58**

When Green Button Connect My Data functionality is available, National Grid also proposes to track customer utilization and third-party authorizations provided.

2.9 Cyber Security

Context and Background

As presented in the 2018 DPS Staff Guidance Update, utility cyber resources contain confidential customer and system data and perform functions which are essential to safe and reliable grid operations; consequently, the security, resilience, and recoverability of those resources is of paramount importance. Utilities must ensure that data is not lost, stolen, or corrupted and that business applications are not disabled, damaged, or destroyed by malicious acts, errors, accidents, or disasters. National Grid believes that a robust cybersecurity program is necessary to maintain a safe and reliable electric delivery system with increased DER interconnections and integration with utility operations. The importance of cybersecurity is increasing as more intelligent devices are interconnected, volumes of data increase along with an ever-growing cyber-attack surface. The need to maintain confidentiality, ensure data integrity, and improve resiliency is increasingly important as we leverage this information to drive more efficient operations and improve decision making.

The provisions built into the Cybersecurity DSIP plans will provide for:

- Availability: avoid denial of service
- Integrity: avoid unauthorized modification
- Confidentiality: avoid disclosure
- Authenticity: avoid spoofing/forgery
- Access control: avoid unauthorized usage
- Audit ability: avoid hiding
- Accountability: avoid denial of responsibility
- Third-party protection: avoid attacks on others
- Segmentation: limiting the scope of attacks on the solution
- Quality of Service: Maintaining a reasonable latency and throughput
- Privacy: Maintaining customer data in a fashion that keeps confidential customer data confidential

Current Progress

As part of the initial DSIP filing in 2016, National Grid developed a Cybersecurity & Privacy framework that established an approach to deliver cybersecurity capabilities and manage cybersecurity risks associated with grid modernization. The framework proposed a risk-based approach across people, process, and technology, establishing a risk methodology, security design principles, information security management (policies and standards), and cybersecurity capabilities and services needed to manage threats, vulnerabilities, and risks appropriately.

The framework looked to:

- Set forth a set of policies and standards to ensure National Grid is working to a common set of security objectives
- Provide architecturally-secure cybersecurity and privacy services for an efficient, easy to consume, and agile way to deliver the required capabilities to manage cybersecurity risks
- Look to build and enhance capability – reusing existing security capabilities where possible, and investing where capability is absent
- Delivering the necessary capability to protect and ensure the resiliency of National Grid systems and infrastructure; and
- Address privacy through the lifecycle for sensitive customer and system data, as well as information sharing practices.

To address cybersecurity concerns associated with this DSIP Update, the Company has developed cybersecurity services and capabilities needed to ensure the confidentiality, integrity, and availability of the systems associated with the future-state DSIP. These security services will provide the foundation for all cybersecurity or privacy related capabilities. This will include a program to provide regular privacy training and ongoing awareness communications and activities to all workers and third parties who have access to customer information within the DSP. All systems, components, and integrations related to the plans in this DSIP Update are considered in the following service domains:

- Network Security Services
- Data Security Services
- Identity & Access Management Services
- Threat and Vulnerability Management Services
- Security Operations Center Services
- Host and Endpoint Security Services
- Security Policy Management Services
- Cryptography Services
- Change & Configuration Management Services
- Security Awareness & Training Services
- Application Security Services
- Third Party Assurance Services
- Remote Access Services
- Privacy Services

In the past year, the Company has refreshed its cybersecurity strategy to account for the changing business, regulatory, and threat landscapes. National Grid has initiated the implementation of the framework and is laying the foundation to implement the cybersecurity services necessary to support the DSP and grid modernization.

National Grid has established information security policies that provide structured methods for implementing information security management controls to more effectively manage security risks to information assets. The policies outline the necessary security controls that need to be in place to assure the confidentiality, integrity, and availability of the Company's information assets. These policies are reviewed on an annual basis, accounting for regulatory mandates, industry best practices, addressing identified risks, and will be updated appropriately to ensure security is built in to all aspects of the DSP.

The Company has implemented foundational cybersecurity capabilities across the enterprise and Critical National Infrastructure ("CNI") environments by addressing key threat areas across malware/virus attack, unauthorized access, system availability, data leakage and external attacks. As part of the Company's Cybersecurity Program, the organization delivered network security improvements, CNI security enhancements, identity and access capabilities, and a Cybersecurity Operations Center to monitor networks and combat threats on 24x7 basis. The program is regularly reviewed and updated to address emerging threats and further build upon capabilities. The current program focuses on delivering threat-resistant networks, robust identity and access, improved endpoint visibility and data protections, enhancements to cybersecurity operations, and monitoring to both enable and safeguard the business. The strategy recognizes that to enable grid modernization requires cybersecurity enhancements to address the gaps between what was a relatively closed system and a modern interconnected environment that introduces a myriad of benefits to the organization and its customers, while introducing risks that need to be managed appropriately. National Grid's Cybersecurity Program seeks to improve the security posture for the Company and address the risks and threats associated with operating in an evolving utility landscape.

Combatting the threats National Grid faces today, and those that will emerge in the future, requires a holistic view of business services and dependencies, in order to acceptably manage the Company's risk profile. To address risks, the Company has established a Security and Resilience committee, made up of business unit leaders, to provide governance and oversight of the implementation of the Company's Cybersecurity Program for the enterprise, CNI, and Operational Technology estates.

The Security Resilience Committee ("SRC"), accountable to the Cybersecurity Steering Committee, has established key principles for the development of cyber strategies that are reached through collaboration and engagement with key parts of the National Grid business.

Future Implementation and Planning

The Company recognizes that DSP and grid modernization will introduce a myriad of benefits for the organization and its customers. To ensure efficient delivery of cybersecurity capabilities needed to protect, detect, prevent, and respond to risks, National Grid is evaluating how to best support the business to meet grid modernization goals and objectives. The current Cybersecurity organization provides a variety of services to ensure the protection of the Company's systems and information, including:

- Architecture & Engineering Function – responsible for assessing and developing architecture, developing patterns, assessing technology/capability health and current/future controls, establishing policy, assessing security of solutions/technology, etc.

- Cybersecurity Operations – responsible for monitoring, detection, prevention, and response to threats. Dedicated roles within this function include
    - Incident response
    - Threat and vulnerability management
    - Threat Intelligence
    - Dedicated Cybersecurity Operations Analysts

- Strategy, Innovation, & Implementation – group responsible for developing the Cybersecurity strategy, roadmap, and innovative opportunities. This group also includes a dedicated delivery function to ensure all initiatives are delivered efficiently.

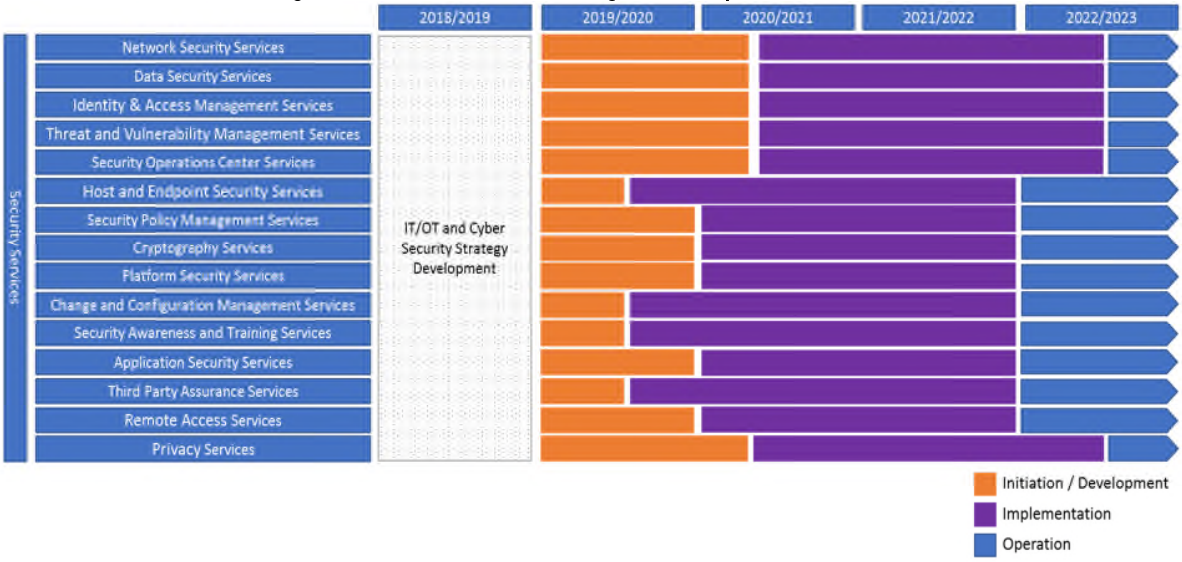
- The team additionally consists of additional functions, such as Risk, who provide additional expertise and support for identifying and managing risk.

The Company will evaluate the structure of its Cybersecurity organization, extending its current services and capabilities to safeguard DSP systems and information, appropriately identifying and mitigating threats and risks to ensure a safe and reliable grid.

The implementation plan for Cybersecurity and Privacy services will span over a five-year period, with the inclusion of a recurring review every two years to account for the evolving threat landscape and address any new potential areas of risk. This plan is in support of other grid investments, ensuring cybersecurity provisions are embedded in all investments and upgrades are made to National Grid infrastructure. The following security services are critical to the REV efforts of the Company and essential to maintaining the security posture of the organization.

The figures below depict the planned integration of security services with key information systems supporting DSP operations and their schedule for implementation.

Figure 2.9.1: Planned Integration of Secure Services



The various security lifecycle stages include four phases: initiation / development, implementation / assessment, operations / maintenance, and disposal / refresh. Each phase includes a minimum set of security tasks needed to effectively incorporate cybersecurity in the system development process. Note that phases may continue to be repeated through a system's life prior to disposal. The bi-annual review will be embedded into this process to ensure appropriate protection of National Grid's infrastructure and address any new areas of risk as a result of REV initiatives.

By integrating various existing networks, systems, and touch-points that are capable of exchanging information seamlessly, the older, proprietary and often manual methods of securing utility services will give way to more open, automated and networked solutions. The benefits of this increased connectivity depend upon robust security services and implementations that are necessary to minimize disruption of vital services and provide increased reliability, manageability and survivability of the electric grid and customer services. Recognizing the unique challenges of the Smart Grid is imperative to deploying a secure and reliable solution.

Below is a matrix developed to identify key security dependencies for each major system. These include foundational security capabilities and unique security requirements for each system.

Figure 2.9.2: Key Security Dependencies for Each Major System

	Customer							Grid Mod			Telecom		Data Analytics	
	CSS Changes	Head End / MDMS	Energy Monitoring Portal	Green Button Connect	E-Commerce Marketplace	Customer Load Management	DG IOAP	DMS/DSCADA	System Data Portal	GIS Data Enhancements	Telecoms	ESB & API Integration	Plant Information Historian	Data Lake & Adv. Analytics
Network Security Services	x	x	x	x	x	x	x	x	x	x	x	x	x	x
Identity & Access Management Services	x	x	x	x	x	x	x	x	x	x	x	x	x	x
Host and Endpoint Security Services	x	x	x	x	x	x	x	x	x	x	x	x	x	x
Security Policy Management Services	x	x	x	x	x	x	x	x	x	x	x	x	x	x
Change & Configuration Management Services	x	x	x	x	x	x	x	x	x	x	x	x	x	x
Application Security Services	x	x	x	x	x	x	x	x	x	x	x	x	x	x
Remote Access Services		x						x			x			x
Threat and Vulnerability Management Services	x	x	x	x	x	x	x	x	x	x	x	x	x	x
Security Operations Center Services	x	x	x	x	x	x	x	x	x	x	x	x	x	x
Security Awareness & Training Services	x	x	x	x	x	x	x	x						
Third Party Assurance Services		x	x	x	x						x		x	x
Data Security Services	x	x	x	x	x	x								
Cryptography Services	x	x	x	x	x	x								
Privacy Services	x	x	x	x	x	x	x							x

The key benefit in incorporating cybersecurity and privacy provisions will ensure the reliability of the power grid, with information integrity built in and the confidentiality of customer information maintained within various business processes addressing privacy concerns.

Data Privacy

Along with cybersecurity services, the Company will also extend its robust privacy program to ensure customer information is appropriately handled internally and externally with third-party vendors. National Grid is committed to respecting the privacy of others and to complying with all applicable data privacy laws. It is everyone's responsibility to 'Do the Right Thing' to ensure Personal Information is protected and processed fairly and lawfully in order to maintain the confidence and trust of our employees, customers, and vendors.

The National Grid Data Privacy Policy aims to provide a framework for appropriate and consistent safeguards for the handling of all Personal Information relating to our employees, customers, and vendors by all National Grid businesses and to ensure compliance with all applicable data privacy laws. This policy applies to all National Grid businesses, its employees, and vendors who process Personal Information on National Grid's behalf.

National Grid has adopted an integrated approach to data privacy to classify privacy and information management components into four primary categories:

- Key compliance program elements and culture;
- Key data handling and identity theft risks;
- Consumer privacy awareness and rights; and
- Security safeguards.

The supporting data privacy program utilizes a cross-functional framework that seeks to address not only legal and regulatory requirements but also the ever-changing landscape of privacy and identity theft vulnerabilities that can result in information and data compromise. The framework for compliance, privacy, security and identity theft prevention incorporates accountabilities, policies, procedures and business practices, and a fabric of technical and operational controls to manage data privacy related risks more effectively.

Risk and Mitigation

There are several potential risks that may impact cybersecurity. First, the technology landscape continues to change at an increasing pace. As technology evolves, the cybersecurity threat landscape changes along with it. Multi-year plans can be developed based on current understanding and the forecast of technological evolution but have the potential to miss the mark when it comes to emerging threats. To address this risk, cybersecurity plans are reviewed on a regular basis and are subject to change to address risks that emerge. Cybersecurity must remain agile and able to re-prioritize based on the changing threat landscape. The Cybersecurity Steering Committee will serve as the governance function to ensure that changes to the program are justified and commensurate with company's risk appetite and grid modernization objectives, while providing the ability to pivot effectively and quickly to address emerging threats.

Another potential risk is in the organization, professional staffing requirements and skills necessary to operate effectively in an evolving utility industry. The need for robust communications, sensors and controls to operate the grid at a granular level introduces risks that were not present in the past. The evolving utility landscape will require expertise within both operational technology and cybersecurity sectors, a specialty that is not widely available. The Company continuously evaluates the talent, skills, and expertise across the organization needed to meet its goals and objectives. To address this risk, National Grid will continue to build out its workforce strategy to further develop Information and Operational Technology expertise internally, as well as introduce new channels to foster this expertise across the industry through engagement with universities and industry groups.

Finally, risks can be introduced as a result of improper testing of new technologies introduced into the National Grid environment. Cyber Security is a consideration that must be on the forefront when testing new capabilities in pilots, as well as implementing technology as part of a larger roll out. This risk will be addressed by the Security Services being introduced as part of the cybersecurity framework, ensuring that cybersecurity testing and engagement is embedded within all phases of any deployment and through the entire lifecycle of any implementation.

Stakeholder Interface

DER developers and third parties seeking to leverage National Grid systems and information will engage with the Company's cybersecurity team and undergo a risk assessment. The risk assessment will result in a risk profile that will enable the Company to determine which policies, standards, and procedures are relevant for the third party to ensure they introduce minimal risk to the organization's systems and information. The prospective providers will be assessed and scored on a set of requirements to ensure sufficient controls are in place to protect any interactions with Company systems and information. By abiding by established requirements, policies, standards, and procedures, which are referenced in the following section, DER providers and third parties who seek to leverage National Grid systems will be able to operate in a manner that does not unduly increase the risk of a cybersecurity incident and in a manner that aligns with the established Cybersecurity & Privacy Framework to protect DSP-associated systems and information. As new technologies are proposed and integrated with the existing grid, the Company will identify and assess security risks as part of any project or implementation plan. Company cybersecurity policies, standards, and requirements will be made available to DER developers and third parties as appropriate, and are embedded within current vendor engagement and RFP processes.

The initial phases of DER developer and third-party engagement will include engagement with designated Cybersecurity and Digital Risk & Security team members to ensure that appropriate controls are defined and included to avoid the exposure of sensitive data, including personally identifiable information. During any RFP process or initiation of a third-party engagement event, DER developers and third parties will be assessed for the level of controls each entity has in place and a gap analysis will be completed to detail any deficiencies. Findings will be logged in a centralized location and a remediation plan will be developed based on risk and potential negative impacts. This analysis will be completed for all entities and will be re-evaluated on a basis determined by the level of risk, classification of information accessed, and other supporting factors.

The Company additionally has a Vendor Assurance program that regularly assesses vendors and third parties prioritized based on risk. This process occurs with vendors already conducting business with the Company, and utilizes a risk-based approach to ensure compliance with applicable company policies, standards and requirements.

Additional Details

The following responds to DPS Staff's request to provide additional details which are specific to cyber security concerns.[97]

[97] *Id*., pp. 23-24.

1. Describe in detail the utility policies, procedures, and assets that address the security, resilience, and recoverability of data stored and processes running in interacting systems and devices which are owned and operated by third-parties (NYISO, DER operators, customers, and neighboring utilities). Details provided should include:

a. the required third-party implementation of applicable technology standards;

b. the required third-party implementation of applicable procedural controls;

National Grid has in place Information Security Standards that provide a linkage to industry standard Regulatory, Framework and Standards References. These technology standards have been created and apply to all National Grid systems to develop an overarching Information Security Standard to be followed by all parties that impact National Grid Systems. Information Security Standards provide objectives, scope and applicability, controls, and guidelines. These Standards cover the following:

- Policy and Standards Approval Review
- Information Classification
- Password and PIN Management
- Malicious Code Prevention
- Firewall
- Security Logging and Monitoring
- User ID and Account Management
- Incident Management
- Change Control and Configuration Management
- Patch Management
- Testing
- Back-up and Recovery
- Policy Exceptions
- Technical Compliance Checking
- Disposal or Redeployment of Information Assets
- Critical National Infrastructure
- Oracle SQL and DB2 Database
- Physical Security
- Clear Desk and Clear Screen
- Cryptography
- Cloud Security
- Secure Code Development
- Information Access
- Media
- Release of Computer System Usage Information
- Emergency Revocation of User Access
- Managing Risks Related to Third Party Access

The Company has in place a vendor assurance program that evaluates vendors to ensure sufficient implementation of procedural controls in their services and product offerings. This assessment is completed in partnership with the vendors with results captured and maintained in a centralized location to risk rank vendors for prioritization of further review. This assessment review involves detailed assurance on controls based on Service Organization Controls and the National Institute of Standards and Technology ("NIST") Security and Privacy Controls to determine if a vendor is providing and/or managing data in a manner that is in the best interest of the Company and the customers that are served. This assessment underscores a vendor's position and alignment with the NIST Security control families listed below:

- Access Control
- Awareness and Training
- Audit and Accountability
- Security Assessment and Authorization
- Configuration Management
- Contingency Planning
- Identification and Authentication
- Incident Response
- Maintenance
- Media Protection
- Physical and Environmental Protection
- Planning
- Personnel Security
- Risk Assessment
- System and Services Acquisition
- System and Communications Protection
- Systems and Information Integrity
- Program Management

Vendors are also evaluated for alignment of privacy controls, listed below:

- Authority and Purpose
- Accountability, Audit and Risk Management
- Data Quality and Integrity
- Data Minimization and Retention
- Individual Participation and Redress
- Security
- Transparency
- Use Limitation

c. the means and methods for verifying, documenting, and reporting third-party compliance with utility policies and procedures;

The Company designates Security Architects on all sanctioned projects, RFP’s, and any other third-party engagements who are responsible for the evaluation of potential software products and vendors. Through this process, Security Architects ensure compliance with enterprise security requirements, controls, and policies, assessing third parties on applicable security controls to understand any potential vulnerabilities and risk introduced by a third party or new product. The process involves a detailed assessment with third-party counterparts to verify that appropriate controls and standards are in place, documented and satisfy the requirements of the National Grid. The evaluation also consists of a risk assessment and findings are documented and fed into vendor profiles that rank vendors for further evaluation based on risk. Further evaluations involve the completion of assurance reporting or certifications and in some cases, include on-site assessments of vendor facilities to evaluate security and privacy controls. As risks are identified, they are fed into the risk process for monitoring and management, with appropriate mitigation plans developed to remediate the risk as appropriate.

d. the means and methods for identifying, characterizing, monitoring, reporting, and mitigating applicable risks;

The Company has an established Risk and Asset Management policy to ensure any risk in information assets are assessed and treated in an appropriate and consistent manner. This enables the company to achieve and maintain appropriate protection of all information assets. Risk assessments are completed and measured against information assets to identify, quantify and prioritize risks against criteria for risk acceptance and objectives.

Risk mitigation prioritization depends on the information asset and the types of information contained within. National Grid has adopted four standard classifications of information base on its criticality and impact to the organization if improperly disclosed, and consist of Publicly Available, Internal Use only, Confidential, and Strictly Confidential.

These classifications drive the criticality of a risk in information assets, critical infrastructure, or information that relates to processes utilized for safe, secure and reliable transmission of electricity is treated as strictly confidential.

The results guide and determine the appropriate actions and priorities for managing information security risks and for implementing necessary controls to protect against malicious activity. Decisions to remediate risk, or to accept risk, must be documented and made by persons with appropriate authorization.

Digital Risk & Security Risk function is also responsible for performing risk assessment, remediation, and monitoring across all information services and cyber assets. The Risk function follows a 'best in breed; approach to risk management, leveraging industry frameworks such as NIST Cyber Security Framework, Committee of Sponsoring Organizations ("COSO") framework, International Organization for Standardization ("ISO") 31000, etc. to assess and identified risks in line with business context and strategic objectives. The approach considers threat, vulnerability, impact (financial and reputational), and likelihood as key inputs into risk assessments to create outputs that give the organization a view of risks it is exposed to. The risk function performs four main services, which are integrated with the overall Enterprise Risk Management program:

- Risk Identification: Notification of discovery of a potential risk event
- Risk Assessment and Response: determine inherent and residual risk along with their associated impacts and the likelihood of the risk occurring, as well as associated mitigation plans
- Risk Monitoring: Monitoring of the Risk Register to provide timely information on the actual states of risks and actions
- Risk Reporting: Applying the principles of relevancy, efficiency, timeliness and accuracy of risks and actions to ensure strategic and tactical reporting.

For assessments in advance of system deployment, the Security Services Design & Architecture team is engaged with project development to conduct various forms of security testing, such as penetration testing, application reviews, build reviews, and vulnerability assessments using pre-approved third-party vendors. Testing results feed back into the project for remediation prior to go-live.

The Company assesses and validates security of its deployed systems via automated vulnerability scanning. Automated vulnerability scanning takes place on corporate networks and network perimeters. The findings feed into the vulnerability management process and are addressed based on criticality and impact to systems and networks.

Risks identified through these processes vary in severity. If a risk is deemed severe and requires immediate action, the Company may raise an incident to review, respond, contain and mitigate the risk. The incident management policy and process is discussed in more detail in the following section. Otherwise, the risk management process above is followed, where an assessment is conducted to identify likelihood and impact, mitigations plans are developed, and the risk is monitored through its lifecycle until its mitigation.

e. the means and methods for testing, documenting, and reporting the effectiveness of implemented security measures;

Information Security Standard for Technical Compliance Checking has been created to define the standard requirements for ensuring that information security controls are being implemented properly. This standard details the baseline security requirements for all information assets, including all systems within the National Grid production, development, and test environments and includes third parties and vendors who impact National Grid systems. The Company's Vendor Assurance program also regularly evaluates existing vendors and third parties to ensure sufficient security and privacy protections are in place, in line with the Company's security requirements.

The Company completes simulated cyber security incidents and drills to test the resiliency and response in the event of a real cyber security attack. These drills are created to strengthen response, identify areas of improvement and are completed to exercise incident response plans, improve communication, and gather lessons learned.

f. the means and methods for detecting, isolating, eliminating, documenting, and reporting security incidents; and,

The Company's incident management policy ensures that a consistent and effective approach is applied to the management of information security incidents and to ensure information security events and weaknesses associated with information systems are communicated in a manner allowing timely corrective actions to be taken. The policy states:

- Information security events shall be reported through appropriate channels as quickly as possible.
- All employees, contractors, and third-party users of information systems and services shall be required to note and report any observed or suspected security weaknesses in systems or services.
- Management responsibilities and procedures shall be established to ensure a quick, effective, and orderly response to information security incidents.
- Mechanisms shall be in place to enable the types and volumes of information security incidents to be quantified and monitored.
- Where a follow-up action against a person or organization after an information security incident involves legal action (either civil or criminal), evidence shall be collected, retained, and presented in accordance with the laws of the relevant jurisdiction

The Cybersecurity Operations Center ("CSOC") provides the organization with the ability to detect suspicious activity across the organization, in real-time, through continuous monitoring of IT and CNI systems, networks, and assets on a 24x7 basis, enabling detection and targeted response to potential threats to systems and information. Additionally, the Cybersecurity Operations group works with a variety of private and public intelligence sources to continually stay abreast of emerging threats. External intelligence is coupled with internal analysis for detection of indicators of compromise across information assets which allows for further targeted detection and response to potential incidents.

The Company completes vulnerability assessments that provide an output that identify new threats, alerts, and vulnerabilities that are reported into the Cyber Health and Vulnerability Management function. Penetration testing also occurs against IT and OT infrastructure, assets, applications, and devices to assess whether they are vulnerable to attack. These processes allow for review and analysis to take place so that infrastructure can be analyzed to identify existing vulnerabilities and remediation actions to be prioritized depending on the severity of vulnerabilities.

As part of companywide cybersecurity training and awareness campaigns, employees receive annual training on how to identify and report suspicious behavior. This ensures that the Company's first line of defense has the proper awareness to potentially prevent a security incident and report them appropriately so response can be initiated to isolate and remediate the incident.

g. the means and methods for managing utility and third-party changes affecting security measures for third-party interactions.

Recognizing that some of our risk comes from external partners, National Grid has an enhanced Strategic Sourcing Process that enables us to establish strong supplier partnerships. Non-Disclosure Agreements are used to manage the risk associated with sharing data with third parties. Following a risk-based approach, the Vendor Assurance Program reviews and monitors third parties for compliance against National Grid policies and control frameworks, including cybersecurity and data privacy controls. The National Grid Cybersecurity roadmap and delivery plans includes strengthening automated enforcement of data privacy and third-party controls.

The Company has established a Change Control & Configuration Management Standard and Information Systems Acquisition, Development and Maintenance policy to address operating systems, infrastructure, business applications, off-the-shelf products, services, and applications. Controls have been established to manage the introduction of new information assets and major changes, replacement and/or removal of existing assets, and will follow formal processes of change control and configuration management. This process includes the documentation, specification, testing, quality control, and managed implementation of changes.

2. Describe in detail the security, resilience, and recoverability measures applied to each utility cyber resource which:

a. contains customer data;
b. contains utility system data; and/or,
c. performs one or more functions supporting safe and reliable grid operations.

The National Grid Cybersecurity program provides the organization with the underpinning capabilities to limit exposures to security events and establish a foundation to further develop National Grid's cybersecurity capabilities. The Cybersecurity program is prioritized based on risk and promotes a comprehensive approach to protect the organization and provide for the ability to identify, detect, prevent, respond, and recover from cyber-attacks. The overall vision is to have the necessary combination of proactive and reactive measures to provide the required situational awareness to deal with multi-pronged, targeted attacks that evolve and change over time and be prepared to respond appropriately. The program includes investments to develop further segregated networks to limit the potential impact of cybersecurity breaches and incident response capabilities to remediate breaches.

National Grid has established incident response and recovery plans, which contain playbooks for addressing various types of incidents. The plans focus on identification, containment, and remediation to ensure an incident is handled appropriately and business operations are restored as quickly and efficiently as possible. The plans and procedures are continually tested and updated based on post-incident reviews and lessons learned to ensure a constant state of readiness.

The Digital Risk & Security function additionally works with a variety of private and public intelligence sources to continually stay abreast of emerging threats and leverages defense in depth to provide multiple levels of security control and redundancy to mitigate cybersecurity threats. For all systems, including those that hold customer and utility system data and support safe reliable grid operations, secure code development and back-up and recovery services are built in to reduce the likelihood and impact a cybersecurity event.

3. For each significant utility cyber process supporting safe and reliable grid operations:

a. Provide and explain the resilience policy which establishes the utility's criteria for the extent of resource loss, damage, or destruction that can be absorbed before the process is disrupted;

The Group Resilience and Continuity Policy has been established to enable the Company to be appropriately resilient and ensure business continuity in the event of a cyberattack, disruption, technology failure, or any event that disrupts normal operations of business processes.

National Grid proactively scans the horizon to identify arising resilience threats and hazards, while improving the Company's processes to understand resilience risk exposure and risk appetite. This will allow the Company to anticipate the risk to the business, providing opportunities for early intervention and mitigation of risks. This ensures that a proper balance between risks and benefits, weighed against cost and value, is clearly understood and consistent with commercial and regulatory obligations.

In addition to the Company's ability to anticipate, National Grid can also prevent risks from materializing, both in respect of their impact and likelihood. The Company proactively builds redundancy making business processes and operations more reliable and able to withstand adverse impacts, thus reducing vulnerability.

National Grid strives to continuously improve our resilience where there are short-term gains that come into view. Over the longer term, the Company ensures that it systematically learns from previous experience and embeds this learning through an active program of training and development.

b. Provide and explain the recovery time objective which establishes the utility's criteria for the maximum acceptable amount of time needed to restore the process to its normal state;

National Grid has defined formal Service Level Agreements with third parties and vendors who provide services and depend on the operational nature and business criticality of a service or application. A contracted service level agreement is broken into five levels:

Platinum

- Defined Operational & Critical Applications that require 24x7 support and/or have >500 users

Gold

- Defined Business Core applications and others with high business impact. This is calculated by users count, incident volume, and service window required.

Silver

- Defined Business Efficiency applications with medium business impact.

Bronze

- Low business impact and normal business hour service window

Tin

- Local business hour support.

Each application and service will feature a service level agreement for incident response and timely restoration. These agreements will define service criticality leveraging business impact assessments, quantified potential for tangible loss, and a measure for intangible loss, such as reputation.

Incident severity is also a driver for response. The Company categorizes this into four levels of priority:

P1 (15 minute response target, <4 hour resolution target)
- A complete loss of an operationally critical or business critical system/service.
- A connectivity outage to a critical site or multiple sites.
- An infrastructure failure impacting multiple critical applications or services.
- Any incident escalated to this level by National Grid.

P2 (30 minute response target, <8 hour resolution target)
- A partial loss of an operationally critical or business critical system/service.
- A complete loss of a business core system/service.
- A network outage impacting a non-critical operational site/s.
- A significant loss of network connectivity (telephony or data) to a critical site.
- Any incident escalated to this level by National Grid.

P3 **(3 hour response target, <12 hour resolution target)**
- A partial loss of a business core system/service.
- A complete loss of a business efficiency system/service.
- A failure to a network segment within a Company location.
- Batch jobs for an operationally critical or business critical system which requires immediate attention to ensure the system/service is not further impacted or becomes unavailable as a result.
- Any incident escalated to this level by National Grid.

P4 **(6 hour response target, 24 hour resolution target)**
- A partial loss of a business efficiency system/service.
- A "How to" question by a client.
- A request initiated by a client.
- Minor loss of infrastructure.
- A minor loss of infrastructure impacting a single user.
- Batch job failures for Business Core or Efficiency systems which may require expedited attention to ensure the system/service is not further impacted or becomes unavailable as a result.

c. Provide and explain the plan for timely recovery of the process following a disruption; and,

Business Continuity Plans ("BCP") are developed to protect the assets of National Grid which includes People, Premise, Providers and Processes. The intent is to minimize the effects of interruptions, including cybersecurity events, by providing a framework that ensures that disrupted business processes are recovered quickly. Each BCP defines operationally critical business processes and restoration time objectives. In the case of a cyber event that impacts business processes, the Incident Response Plan will be invoked and the restoration of operationally critical business processes will take precedent.

Each BCP defines operational critical business functions, named recovery team members, recovery site locations, vital record details, upstream and downstream contacts, external contacts, vendor and service providers, application/software requirements and manual workarounds, alternate work sites, process recovery tasks, and call trees. The objective of this document is to coordinate recovery of critical business functions while resuming business processes as soon as possible and provide a minimum acceptable level of business activity until normal operations can be resumed.

d. Describe each process, resource, and standard used to develop, implement, test, document, and maintain the plan for timely process data recovery.

BCPs are maintained to ensure currency, accuracy and effectiveness and are reviewed at least on an annual basis to ensure it reflects current business processes and recovery requirements. The document details business staffing plans and requirements in the case staff absence or long-term outages.

BCPs are considered confidential and detail any vital records held by the function. These include documents, media, or reference materials that contain information critical to normal business operations. Vendors and service providers critical to business operations are detailed with key contacts and business locations. Also, applications critical to normal business operations are detailed and alternatives or manual workaround are identified.

In the event of a cybersecurity incident where data becomes unavailable, the incident response plan will be invoked to manage the event to resolution. The plan clearly defines the classification of an incident and determines the incident criticality and severity. Depending on the nature and severity of the incident, an applicable level of triage and response takes place with identified roles and responsibilities as well as notifications distributed based on established communication plans. Identified manual workaround processes may be enacted if required to carry out the minimum requirement to continue business operations.

4. Identify and characterize the types of cyber protection needed for strongly securing the utility's advanced metering resources and capabilities. Describe in detail the means and methods employed to provide the required protection.

Cybersecurity plays a critical role in protecting and securing the utility's advanced metering resources and capabilities. This includes ensuring that security services are in place to address the needs of the utility to support advanced metering resources and that any gaps are identified and remediated to ensure safe and reliable operations.

Advanced metering offers many benefits to customers, but it also increased the utility attack-surface through an increased number of endpoints and connected devices that produce data used to make informed decisions at home and on the grid. Network monitoring services will be in place to proactively scan for anomalies and abnormal behavior at the device level and at the network level. Communications will be through secure channels to reduce the risk of data being intercepted, interpreted, or manipulated during transit. User activity, from a customer and utility perspective, must be monitored to prevent data loss or manipulation to protect sensitive information, such as personally identifiable information and usage data. To do this, single sign-on, authentication, and privileged access management capabilities will enforce and monitor behavior and establish a baseline for user activity.

5. Identify and characterize the requirements for timely restoring advanced metering resources and capabilities following a cyber disruption. Describe in detail the means and methods employed to provide the required recovery capabilities.

Through the procurement process, vendors are assessed and scored based on responses to an evaluation questionnaire that requires a response to questions regarding cyber disruptions and restoration. The questions focus on confirming that capabilities are in place in the event of a cybersecurity event. The questions regarding the operational aspects of AMI capabilities seek to determine the procedures in place for incident management, defined roles and responsibilities, communication plans, points of contact, detection and alert capabilities, incident management practices, reporting, lessons learned and security policies in place.

2.10 DER Interconnections

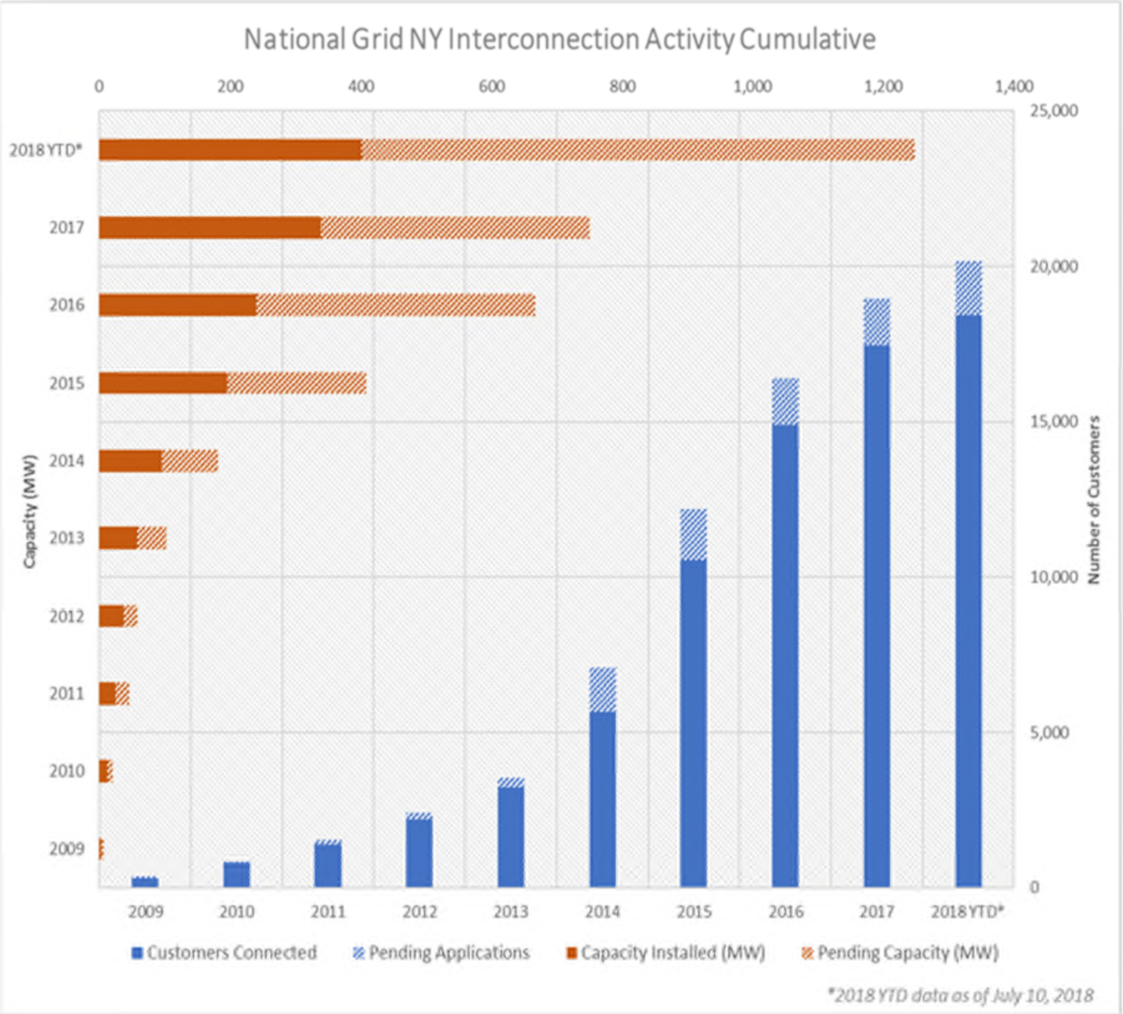
Context and Background

The REV Track One Order calls for utilities to streamline their interconnection processes for DG projects, increase the transparency of their interconnection approval processes, and adequately prepare for greater amounts of DG deployment.[98] To define the process improvements necessary to streamline the interconnection process, the Commission and NYSERDA engaged EPRI to assess state interconnection procedures in the *New York Interconnection Online Application Portal Functional Requirements* ("IOAP Report"),[99] which has served as a reference guide for increasing the automation of the online portal.

The rate of DG interconnections continues to increase as does the capacity of the DG being installed. The graphic below depicts the continuing expansion of DG interconnections within National Grid's service territory (see Figure 2.10.1).

[98] REV Proceeding, REV Track One Order, pp. 92-93.
[99] EPRI, *New York Interconnection Online Application Portal Functional Requirements*, September 2016 ("IOAP Report"), *available at*: http://www3.dps.ny.gov/W/PSCWeb.nsf/96f0fec0b45a3c6485257688006a701a/dcf68efca391ad6085257687006f396b/$FILE/EPRI%20Task%201%20Memo%20Report_Final%209-9-16.pdf.

Figure 2.10.1 DG Application-Interconnection Trends in National Grid's Service Territory



- The left vertical axis shows cumulative capacity installed and pending by year in National Grid's service territory. From 2009-2018, National Grid has installed approximately 400 MW of DG with over 800 MW pending capacity to be installed.
- The right vertical axis shows the cumulative number of applications installed by year. From 2009-2017, National Grid has more than 17,000 applications connected in its service territory and over 1,500 pending applications.
- The pending applications shown in the cross-hatched areas are those projects that are active in the queue and yet to be interconnected.

While the initial ramp up in DG applications in 2015 resulted in backlogs, National Grid initiated a four point plan to enhance its performance which eliminated the backlog in 2016 and implemented innovative plans to improve the efficiency and cost effectiveness of the interconnection processes.

In an effort to drive consistency of practice across NY, the Company participates in the ITWG and Interconnection Policy Working Group IPWG to coordinate with the Joint Utilities, DPS Staff, and stakeholders on interconnection issues. The ITWG promotes consistent standards across the utilities to address technical concerns affecting the DG community and interconnection procedures. The ITWG has focused on: anti-islanding protection; remote monitoring and control; technical screening process; and ground fault overvoltage ("GFOV") protection. The IPWG explores non-technical issues related to the processes and policies relevant to the interconnection of DG in New York. The IPWG has focused on queue management, group studies, cost sharing, alignment of construction payment timelines with local permitting processes, and development of consistent project construction schedule information for all interconnection projects.

Current Progress

Since the initial DSIP filing in 2016, National Grid made significant progress in streamlining its interconnection processes. Key initiatives and achievements are noted below.

National Grid has performed education and outreach to streamline the process for large, complex installations. Between November 2016 and January 2017, National Grid held internal and external stakeholder outreach meetings to discuss various interconnection issues.

The Company implemented a four-point plan that would soon yield shorter wait times and lower interconnection costs. The plan included:

1. **Education and outreach** - enhanced understanding of DG interconnection process through webinars and seminars.
2. **Single point of contact** - established a DG Ombudsperson role as a single point of contact for customers and regulators to resolve concerns.
3. **Staffing** - from 2016 through 2017, increased staffing to respond to customer demand and realigned engineers to enhance technical expertise to manage complex DG project volume.
4. **Technical collaboration** - formed partnerships with industry organizations and key developers to identify solutions to major concerns.

By implementing this plan the Company was able to complete 68 CESIR interconnection studies in six months. Since 2016, National Grid has maintained 100% timeline compliance in accordance with the SIR.

In 2017 National Grid launched an online application portal, National Grid Customer Application Portal (referred to as "nCAP"),[100] meeting the IOAP Phase I expectations. Customers are now able to enter information regarding their DER application online, directly track the status of their project throughout the interconnection process, and make electronic payments. By the end of 2017, National Grid had experienced a reduction of approximately three days from the application review stage of the process. Additional functionality is being developed to further compress application processing lead times.

Technical collaboration with industry groups, solar developers, and regulators has helped National Grid identify barriers for DER interconnections. Most of the capacity installed in the Company's service territory is associated with large, complex applications with 56% of installed capacity coming from just 2% of the applications. Historically, these installations required direct transfer trip ("DTT") and, in some cases, transmission GFOV protection in the upstream substation, both costly upgrades, based on utility standards for protection of risk of islanding and transmission GFOV events. Following extensive technical review the Company has revised its interconnection requirements as described below:

1. Anti-islanding Protection[101] – In most cases, installations utilizing certified inverters will not require DTT.
    - For DER projects without customer load, a utility-owned point of common coupling ("PCC") recloser replaced DTT in most cases. The elimination of DTT and the use of the PCC reclosers with reclose blocking led to other cost savings from the customer's side by reducing construction and witness testing times, reducing equipment costs, and upfront and recurring telecommunication costs.
2. Transmission GFOV Protection[102] – The substation power transformer becomes at risk for an unintentional island operation in a transmission-side ground fault event from distribution-side DER backfeeding the substation.

    - National Grid is developing an asset strategy for transmission GFOV. The Company aims to reduce the cost and timelines for installing transmission GFOV protection.
    - In general, once the aggregated capacity of the proposed DG on a substation transformer exceeds its planning criteria threshold, the next DG customer is

[100] *See* https://ngus.force.com/s/

[101] IEEE 1547 requires any DG on a distribution feeder to be detected and be tripped offline within two (2) seconds upon formation of an island from the area Electric Power System ("EPS"). An island is a condition in which a portion of an area EPS is energized solely by one or more local DGs while it is electrically separated from the rest of the area EPS.

[102] Transmission ground fault overvoltage ("GFOV") protection (or "$3V_0$") is often implemented as relaying on the delta side of a bank (confirmed as a utility best practice in PES Technical Support Task Force report on IEEE 1547-2018).

required to cover the cost of the critical substation upgrade transmission GFOV protection.

- The Company is currently piloting optical voltage transformer (“VT”) equipment replacing coupling capacitor VT (“CCVT”) equipment in a 115-13.2kV substation to save construction time on transmission GFOV protective device installations. As a trial, a substation will be chosen to have optical VT equipment installed.
- For electric transmission, National Grid in 2018 has established the requirement to install GFOV, *i.e.*, $3V_0$ on transmission-supplied power transformers in new substations and existing substations that require extensive modification or replacement of the transformer and/or its transmission supply connection within its tariff cost recovery means.

- The Company collaborated with the Joint Utilities and the ITWG in January 2018 and as of June 2018 developed ESS metering configuration requirements for revenue purposes of ESS and paired ESS plus DG facilities.

- Since then, National Grid has developed an internal guideline for the electrical interconnection of BTM, ESS use cases to operate in parallel with National Grid’s EPS. This is a living document that is amended as changes occur with regulatory and other requirements and best practices.
- National Grid is collaborating with the Joint Utilities on revenue metering requirements for a model tariff for VDER application with ESS paired with other customer-owned generation. This effort is targeted for filing with the Commission in summer 2018.

3. In mid-2017, specified in National Grid’s updated ESB 756[103] the load rejection overvoltage (“LROV”)[104] protection requirements for the DG customer’s abrupt isolation of their inverter or generator source into light load. National Grid’s ESB 756 revised in 2017 is now on an annual update review to ensure ongoing regulatory compliance and implementation of best practices; see Figure 2.10.3.

4. In mid-2018, National Grid and the Joint Utilities, in collaboration with the ITWG, provided a new CESIR template that has additional and clarified information for end users, including triggers, system impact results, and more information and scope associated with those impacts driving the associated system upgrade costs. The new CESIR format will be in universal use across the New York utilities.

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[103] Electric System Bulletin (“ESB”) 756 is available on National Grid’s website at: https://www.nationalgridus.com/ProNet/Technical-Resources/Electric-Specifications and https://www.nationalgridus.com/media/pronet/shared_constr_esb756.pdf.

[104] For more information on LROV, *see* Photovoltaic Specialist Conference (“PVSC”), 2015 IEEE 42nd Conference, June 14-19, 2015, *Experimental Evaluation of Load Rejection Over-voltage from Grid-tied Solar Inverters*, *available at* https://ieeexplore.ieee.org/xpls/icp.jsp?arnumber=7356399.

5. National Grid has also been actively supporting microgrid developments for the NY Prize competition being administered by NYSERDA through participation in regular meetings with both the developers and NYSERDA for proposed projects that would utilize multiple DER assets such as solar PV, CHP, DR, and ESS. Building from the Company's Potsdam Microgrid REV demonstration project experience, a hybrid ownership and operational model was developed and presented to the NY Prize applicants, NYSERDA, and DPS Staff. The hybrid ownership and operational model can bring together the expertise and capabilities of both the microgrid developer and the utility and result in a superior project with proper delegation of risks and responsibilities. The Company has made a dedicated effort to identify possible microgrid design alternatives for projects competing for NY Prize awards in in an attempt to advance microgrid projects that are technically and economically sound and provide benefits to the grid.

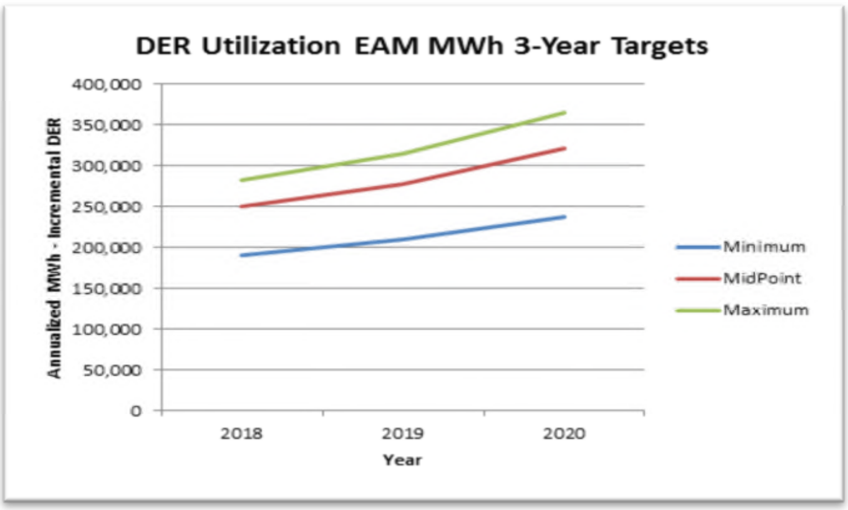
National Grid's interconnection specifications as published in ESB 756 were revised in 2017 and now are updated on an annual basis to ensure ongoing regulatory compliance and the implementation of best practices. The 2018 edition released in July 2018 incorporates IEEE 1547-2018 and UL 1741sa requirements and the April 2018 version of the amended NY SIR.

Future Implementation and Planning

National Grid shares the state's objectives to increase DER penetration for the benefit of customers. Consistent with the Three-Year Rate Plan Order, the Company developed aggressive goals for DER interconnection as illustrated by the stretch targets associated with the Company's Interconnection EAM depicted in Figure 2.10.2 below.

Figure 2.10.2 National Grid Interconnection EAM:

MWh Incremental DER Utilization Targets for 2018 - 2020



To achieve this desired level of interconnections the Company remains committed to external stakeholder engagement and collaboration with the PWG and ITWG. Within National Grid, the Company is developing a "DER Line of Sight" initiative to highlight the priority of DER projects within the overall capital delivery work plan and be more responsive to feedback from DER developer satisfaction surveys.

The Company will continue to enhance the IOAP to further automate the interconnection process.

A release of IOAP Phase II capabilities is expected to be rolled out in early 2019. The April 2018 revision of the NY SIR made changes to Technical Screens C-F, which National Grid is progressing to complete in IOAP Phase II by April 2019. The Company notes that there are discrepancies with Screen D in the new NY SIR and the JU and ITWG are working to resolve them. The preliminary technical screens requiring automation in IOAP Phase II are:

1. Screen A: Is the PCC on a Networked Secondary System?
2. Screen B: Is Certified Equipment Used?
3. Screen C: Is the EPS Rating Exceeded?
4. Screen D: Is the Line Configuration Compatible with the Interconnection Type?
5. Screen E: Simplified Penetration Test
6. Screen F: Simplified Voltage Fluctuation Test

The supplemental technical screens have been revised in the amended NY SIR; however, as issued, only Screens G and H may be facilitated by IOAP Phae II automation efforts while Screen I has elements that will require engineering review. Screens G through I are as follows:

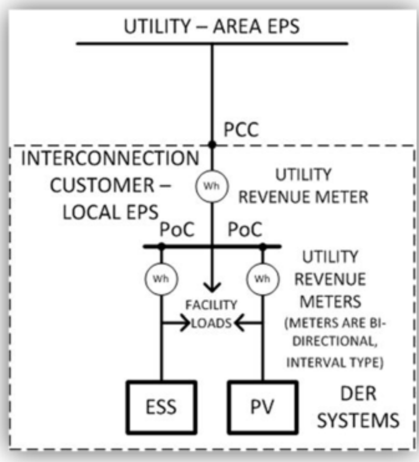
7. Screen G: Supplemental Penetration Test
8. Screen H: Voltage Flicker Test
9. Screen I: Operating Limits, Protection Adequacy and Coordination Evaluation

National Grid continues to work with DPS Staff and the ITWG to understand the hurdles to automating the supplemental screens beyond those contemplated in IOAP Phase II. The Company currently has no timeline for the delivery of IOAP Phase III and will work with DPS Staff on the need for any further development in that regard.

A major focus of future interconnection activities will focus on ESS in support of New York State's goal of interconnecting 1.5 GW of energy storage by 2025. ESS will be a major new technology that will be evaluated for best practices to integrate into the grid, allowing for higher penetration of DG into the distribution EPS, as well as providing capacity and other needed services in targeted locations on the distribution system. Paired DG and ESS are an example of technology combinations that could soon provide value to National Grid's operation of the grid. National Grid's metering configuration requirements for revenue purposes of ESS and ESS paired with DG are incorporated into the annual 2018 revision of ESB 756; see Figure 2.10.5

below. Each source and PCC points will need to be metered in compliance with the Commission's April 19, 2018 *Order Modifying Standardized Interconnecton Requirements*.[105]

Figure 2.10.3 National Grid Revenue Metering Requirement for Paired ESS+Solar PV Systems



To be more responsive to large projects that may require the installation of $3V_0$ protection schemes, the Company is procuring 115kV mobile $3V_0$ protection units. These units can be installed quickly, on a temporary basis, to mitigate the risk associated with a transmission ground fault event from DER penetration and substation backfeed. Utilizing the mobile units will allow the interconnection of DER in a timely fashion while permanent infrastructure upgrades are progressed in parallel.

In 2017 as part of a REV demonstration, National Grid proposed a cost-sharing solution for increasing the pace and scale of interconnecting DG systems through upfront investment by the Company coupled with a cost-allocation methodology aimed at removing barriers for DG interconnection applicants as part of the REV Demo project. The proposal was to install $3V_0$ at two substations, Peterboro and East Golah, to create 40 MW of DG capacity in these two areas. National Grid has completed its work at both substations. The work included the installation of $3V_0$ protection and LTC controller upgrades to two transformers at each substation. During the design and construction phases, the Company marketed the increased capacity and the Project's cost-allocation methodology to DG developers. With these efforts, the Company is now able to secure a sufficient level of DG interconnection applications for each substation to fully subscribe the available capacity.

[105] *See* Cases 18-E-0081 *et al*., *In the Matter of Proposed Amendments to the New York State Standardized Interconnection Requirements (SIR) for Small Distributed Generators, Order Modifying Standardized Interconnection Requirements* (issued April 19, 2018)("Order"), Ordering Clause No. 2, p. 27.

As a next step to build on the success of this REV demonstration $3V_0$ project, National Grid is evaluating the project outcomes and is also exploring options with DPS Staff to potentially expand this concept further.

In addition, the Company will continue to explore new technologies to make the interconnection process more efficient and reliable.

- National Grid has been conducting a pilot project with an anti-islanding protection technology that utilizes a differential, capacitive coupling power line carrier ("PLC") system using a frequency-based signal. The PLC system is different than the traditional DTT installation in that it utilizes existing distribution line facilities for transmitting the PLC frequency signal and it can be modified to include additional sites. Although the changes in risk of islanding requirements have reduced the volume of projects that require DTT, this PLC anti-islanding protection technology may be beneficial on circuits with several non-inverter based generators and in areas where land-line communications are ineffective. This pilot project began in 2016 on a 13.2kV distribution feeder for a farm waste synchronous DG and a 23kV sub-transmission circuit for a large solar PV DG in the Ogdensburg operating district. By the end of 2018, National Grid expects to prepare a final project report with lessons learned and determine the value of the PLC anti-islanding protection for future applications.
- The Company also plans to test new optical VT equipment as a substitute for more expensive CCVT equipment 115-13.2kV substations to save construction time on transmission GFOV protective device installations.
- National Grid will monitor a smart inverter project being implemented by a Company affiliate and will share results and lessons learned with the Joint Utilities and ITWG.

Once DER interconnections are made it becomes essential that facilities are maintained and meet operational requirements. Enforcement of operation and maintenance requirements and due diligence by both National Grid and DER owners through interconnection agreements, codes, and standards can support fulfillment of these goals. New York State licensing of installers, testers, and inspectors that includes continuing education requirements can help bolster the qualifications of these technical services. National Grid is supportive of the need for enforceable installation, testing, and maintenance qualifications to ensure the value of DER facilities is optimized for the benefit of owners, electric grid, and New York consumers.

National Grid also plans to continue to work collaboratively with the developers on the proposed NY Prize competition for microgrid projects and other microgrid interconnection requests in the future to advance the State's resiliency goals for communities.

Risk and Mitigation

While National Grid endeavors to automate the DER application and technical screening process to the extent possible, the results from the screening efforts may still require more detailed review for issues that require a load flow assessment. To mitigate processing lags, the Company is pursuing the integration of the CYME distribution system power flow and short circuit models with its DG application portal ("nCAP") to ensure the ability to meet the technical screen automation for the Preliminary Screening Analysis process per the amended NY SIR. To support the need when further engineering analysis is required, National Grid has commenced using the CYMDIST power system analytical software to evaluate voltage regulation in order to comply with IEEE 1453 in the Supplemental Screening Analysis and CESIR processes of the amended NY SIR.

Over the next one to two years, integrating new M&C solutions to meet NY M&C standards for DG interconnections will require commercially available communications standards and protocols that meet cyber security requirements to interface DER with the National Grid system. National Grid continues to be engaged in the development of industry standards and is working with telecommunications and internet providers as well as the DER industry to advance the development of appropriate standards.

Due to their technical complexity, an increased volume of ESS energy storage interconnection applications may stress the current means for completing interconnection studies. Of specific concern are the additional time and resources that maybe needed to adequately evaluate the protection and controls required to ensure a safe and reliable interconnection under a variety of for various operating scenarios. National Grid will be monitoring the trend in ESS interconnection applications and will apply lessons learned from solar PV interconnections to mitigate avoid back-logs.

Managing new technologies, such as smart inverter controls, can present new challenges. Meeting NYISO requirements and implementing IEEE 1547-2018 ride-through requirements will require that inverter models from manufacturers become available for National Grid's power flow and short circuit analytical software tools to properly evaluate DER impacts on the EPS.

There are challenges to automate the NY SIR supplemental screens as originally envisioned for an IOAP Phase III. It will be valuable to learn from completed research projects under NYSERDA's PON 3404.[106]

The interconnection process for community microgrids has not yet been defined and could impact the progression of NY Prize projects. National Grid remains committed to collaborate with stakeholders to continue to progress awarded projects.

Stakeholder Interface

Stakeholder outreach is performed when new DER programs are introduced. Changes within National Grid's ESB 756 Annual Revision Cycle are communicated through these outreach sessions.

[106] *See* NYSERDA PON 3404 Electric Power Transmission and Distribution Distributed Energy Resource Integration, *available at* https://www.nyserda.ny.gov/-/media/Files/FO/Closed-Opportunities/2016/3404summary.pdf

The Company conducts weekly/bi-weekly calls with some of the key DG developers with applications in the Company's interconnection queue to discuss their specific projects. National Grid uses various forums to more generally inform stakeholders such as media (*e.g.*, website, email, and newspaper), telephone and webex presentations, teleconferences, as well as face-to-face meetings.

National Grid evaluates new products through dialog with stakeholders and participation in industry conferences and meetings. New products are conceived through a collaborative practice involving all stakeholders which often requires the design, development, and implementation of new construction standards, material specifications, and procedures. National Grid is also engaged in committees of the National Electrical Code and National Electrical Safety Code to represent the utility interests and our customers' needs for electric services and supply systems to connect end-users and DER facilities.

Additional Details

The following responds to DPS Staff's request to provide additional detail specific to DER interconnections.[107]

1. A detailed description (including the Internet address) of the utility's web portal which provides efficient and timely support for DER developers' interconnection applications.

National Grid's publically available customer application portal, nCAP is an online application portal to facilitate electronic submission of applications and associated payments. The portal provides the applicant, whether pursuing a small or large DG facility, with a more streamlined experience. Customers are able to check project status, meter set dates, estimated completion date, sign documents electronically, and request changes to existing interconnection applications online. The Company is currently developing enhancements to nCAP for the automation of certain technical screens to further expedite the application preliminary screening analysis process and inform customers sooner as to next steps in the interconnection process.

2. 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:

The following will require policy development among the IPWG/ITWG to define appropriate access controls prior to sharing some of this information. What can be shared today is as noted below.

[107] DSIP Proceeding, 2018 DSIP Guidance Update, pp, 25-26.

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 provided on the DPS public website.[108] 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). Additional information on DER projects can also be obtained via the nCAP portal via a login and password that provides information for the user's projects only.

b. DER developer;

The interconnection queue publically provided on the DPS website provides the company name of each DER developer in the queue. This data is available as an Excel file.

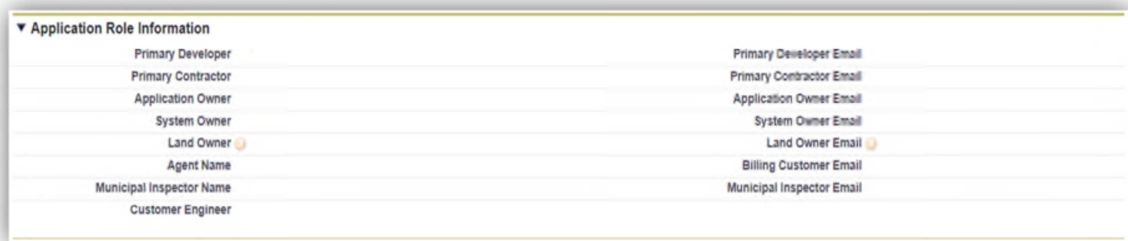
c. DER owner operator;

National Grid's customer application portal, nCAP, tracks the DER owner for operation of the connected DER facility; however, this data stored in the nCAP not publically 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, National Grid would contact the system owner and/or application owner. For large, complex DER interconnections, contact information and switching procedures are established with National Grid's control centers.

Figure 2.10.4 Customer Stakeholder Tracking in National Grid's nCAP



[108] *See* http://www3.dps.ny.gov/W/PSCWeb.nsf/All/286D2C179E9A5A8385257FBF003F1F7E?OpenDocument

e. the connected substation, circuit, phase, and tap;

National Grid's customer application portal, nCAP, tracks by circuit, substation transformer, and substation. It does track whether an application is single phase or three phase, but it does not track which phase or tap. The substation and feeder circuit are publically available on the DPS website interconnection queue. The interconnecting feeder is based on the most up to date GIS 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 related to the NYS SIR and NY ITWG criteria as may be amended periodically. Those DER facilities with M&C are integrated into National Grid's EMS at central control center locations for the specific area EPS. A DER customer provides data into the M&C and it is their responsibility to access and monitor the controls and signals transmitted or received from National Grid's EMS.

g. the DER's primary and secondary (where applicable) purpose(s); and,

National Grid's customer application portal, nCAP, does not track the applicant's intended purpose for their proposal 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 date, 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 publically available on the DPS website interconnection queue.

3. The utility's means and methods for tracking and managing its DER interconnection application process to ensure achievement of the performance timelines established in New York State's Standardized Interconnection Requirements.

National Grid provides dedicated resources to manage the DER application process. Its Customer Solutions team is the job owner for simple DER projects (less than 50kW) while the Customer Energy Integration team is the job owner for complex DER projects (greater than 50kW). These job owners utilize National Grid's customer application portal, nCAP, as a means to track and manage the DER applications throughout the interconnection process. National Grid uses a software application, Tableau, to help manage the data and provide visibility of application status via reports and key performance indicators ("KPIs") in an effort to assist job owners with workload management. KPIs are regularly monitored (*i.e.*, daily or weekly in most cases) to ensure success in meeting. The duration between application and final acceptance can be tracked publically via the DPS website interconnection queue. The figures below provide snapshots of dashboards that track interconnection progress against targets.

Figure 2.10.5: Performance Dashboard

Performance Dashboard									
		Target %				Target LT (BD)			
Level	Metric Name	US	MA	RI	NY	US	MA	RI	NY
L1	**Customer Date Attainment**	**70**	**70**	**70**	**70**				
L3	Expedited Date Attainment	70	70	70	70				
L3	Standard Date Attainment	70	70	70	70				
L2	**Application Through Study**	**100**	**100**	**100**	**100**	**90**	**90**	**90**	**90**
L3	Application Review	100	100	100	100	10	10	10	10
L3	Simple App Review	100	100	100	100				
L3	Complex App Review	100	100	100	100				
L3	Complex Screening	100	100	100	100	20	20	20	20
L3	Expedited Screening (NE Only)	100	100	100		25	25	25	
L3	Standard Screening (NE Only)	100	100	100	100	20	20	20	20
L3	Impact Study (NE)/Final CESIR (NY)	100	100	100	100		55	55	60
L3	Detailed Study (NE Only)	100	100	100		60	60	60	
L3	Validations (MA Only)	100	100			10	10		
L2	**Study Through Design**								
L3	Expedited Design								
L3	Standard Study Through Design								
L2	**Meter Set**	**95**	**95**	**95**	**95**				
L1	**First Bill Accuracy**								
L2	**First Bill Timeliness**	**70**	**70**	**70**	**70**	**60**	**60**	**60**	**60**
L3	Asset Registration (SOGs)	100	100	100	100	10	10	10	10
L2	**Reconciliation Timeliness**	**70**	**70**	**70**	**70**		**150**	**120**	**80**
L3	Final Accounting Report	70	70	70	70		120	90	60
L3	Final Bill	70	70	70	70		30	30	20

Figure 2.10.6: Regulated Timelines

NY									
Month				FYTD			FY18		
Volume	% On Time	Change	Lead Time	Volume	% On Time	Lead Time	Volume	% On Time	Lead Time
1	100%	-		2	100%		100	77%	
1	100%	-	71	4	100%	75	58	100%	60
							2,257	100%	
4	100%	-		58	100%		177	100%	
41	100%	-	9	79	100%	8	321		8
1	100%	-	53	4	100%	57	75	100%	
							0		
191	100%	-		314	100%		1,824	100%	

4. Where, how, and when the utility will provide a resource to applicants and other appropriate stakeholders for accessing up-to-date information concerning application status and process workflows.

National Grid already employs dedicated resources to assist the DER community in managing their projects throughout the interconnection process. These employees are located throughout National Grid's upstate NY divisional offices (i.e., Buffalo, Syracuse, Utica, and Albany). National Grid utilizes nCAP to provide status on an application's process workflow as amended when NYS SIR changes require, such as construction payments resulting from the April 2018 NYS SIR. Stakeholders that are properly identified in the "application roles" for an application may (depending on the complexity and scale of the project) receive email notifications at key milestones in the process. Once a stakeholder or developer submits an application, a member of National Grid's Customer Energy Integration ("CEI") team is assigned to review the application for completion, and once the application is moved through the process and a study is commenced, a job owner is assigned to manage the project through the study phase and if the project progresses to a construction phase, a CEI team member manages the project to completion.

Customers can access nCAP in a self-serve fashion to monitor the progress of their applications. To the extent Customers are in need of additional information or support, they may contact the Company through, email at Distributed.Generation-NY@nationalgrid.com. In addition, National Grid's Customer Energy Integration (CEI group) conducts weekly/bi-weekly calls with some (dependent on the complexity and scale of the project) of the major developers regarding project portfolios to facilitate manage application processing. In the construction phase, the Company tracks the progress of the utility's construction utilizing it's work management system (STORMS).

5. The utility's processes, resources, and standards for constructing approved DER interconnections.

National Grid has various external and internal processes, resources, and standards for constructing approved DER interconnections.

- National Grid's electric system bulletins (ESB) publicly available[109] and specific to DER interconnections in NY, see ESB 756 Appendix B[110].
- IEEE 1547 and UL 1741 are industry-related standards that are external provisions as referenced in National Grid's ESB 756 Appendix B
- NYS adoption of the National Electrical Code (NEC®).
- The National Electrical Safety Code (NESC®) is an external code that National Grid complies with for internal distribution and substation construction standards necessary to construct interconnections to DER facilities, as well as
- OSHA requirements and the use of various applicable IEEE and ANSI standards.

In regard to application review, National Grid utilizes screens to determine if a DG project can interconnect and if it requires a CESIR. The most recent CESIR template can be found on the ITWG website.[111] Once all application requirements are met, work orders are released to the National Grid operations organizations to progress with any make-ready work and metering requirements. Throughout the process the Company coordinates with the developer for any required site testing and commissioning. The work orders are then completed and the DER information is incorporated into the Company's GIS system.

[109] *See* https://www.nationalgridus.com/ProNet/Technical-Resources/Electric-Specifications
[110] *See* https://www.nationalgridus.com/media/pronet/shared_constr_esb756.pdf
[111] *See* http://www3.dps.ny.gov/W/PSCWeb.nsf/All/DEF2BF0A236B946F85257F71006AC98E

6. The utility's means and methods for tracking and managing construction of approved DER interconnections to ensure achievement of required performance levels.

For simple process DER projects, National Grid's STORMS work management system tracks and manages construction of approved DER interconnections and integrates progress into the customer application portal, nCAP. For complex process DER projects requiring system upgrades, National Grid's Program/Project Manager manages the engineering, procurement, and construction of the system upgrades and collaborates with the CEI team job owner(s) for routine progress meetings with DER customer(s). A Primavera P6 tool is used to track the construction schedule as well as PowerPlant for tracking and reconciling the construction costs associated with system upgrade construction of a complex process DER interconnection. National Grid and the other Joint Utilities have proposed a construction timeline template in the new NY SIR to create schedule transparency for DG projects. National Grid has an internal bi-weekly meeting set up to keep track of all the construction projects and to monitor DG project performance with engineering, customer group, and construction.

In addition, National Grid's STORMS work management system is also utilized to track and manage the line construction for the complex DER Projects. The Company classifies complex DG projects as those from 50 kW to 5 MW. As for simple projects, typically these are projects under 50 kW without any system upgrades.

7. Where, how, and when the utility will provide a resource to DER developers and other stakeholders for accessing up-to-date information concerning construction status and workflows for approved interconnections.

As previously referenced, National Grid already employs dedicated resources to assist the DER community in managing their projects throughout the interconnection process. These employees are located throughout National Grid's upstate NY divisional offices (i.e., Buffalo, Syracuse, Utica, and Albany). In addition to utilizing nCAP to manage application processing, the Customer Solutions (CS) and CEI teams also utilize National Grid's work management system (STORMS) to track and progress applications that have moved into construction status. Most applicants should be able to track the progress of their interconnection application through the nCAP portal. To the extent applicants are in need of additional information or support, they are able to contact CS and CEI team members through the help feature of nCAP and email at Distributed.Generation-NY@nationalgrid.com

2.11 Advanced Metering Infrastructure

Context and Background

AMI will provide monitoring and granular data to support customer decisions, grid operations, and control capabilities that will enable the desired functions of a modern distribution system. Granular, time-series data from smart meters and other intelligent devices at customers' premises enable advanced analyses, innovative rate designs, and customer engagement strategies which benefit both the customers and the grid. Voltage sensing and measurement functions support increased system efficiency and enable improved outage detection, and restoration processes. Capabilities supporting DER measurement, monitoring, and control are essential for DER integration. National Grid believes the granular information produced via AMI is necessary to achieve the objectives of REV. The Company's initial DSIP and subsequent rate case filings have proposed system-wide deployment of AMI.

The vast majority of the Company's 1.7 million electric and more than 640,000 gas metering points throughout the upstate New York service territory currently use Automated Meter Reading ("AMR") technology. AMR monthly reads are acquired through radio frequency collection utilizing a fleet of Company-owned service vans which drive along defined routes within communications range with each meter. In addition, a small number of larger wholesale customers and retail customers have interval meters, which currently communicate through cellular connections or through wireless internet protocols.

The AMR system, including electric meters and gas encoder receiver transmitters ("ERTs"), were originally deployed in a major program between 2002 and 2004. These meters/ERTs are anticipated to be programmatically replaced beginning in FY21. As part of the initial DSIP filed in June 2016, National Grid considered multiple options for replacing this equipment. Ultimately, the Company determined a system-wide smart meter deployment offers the best benefit-cost outcome compared to the other metering solutions evaluated and also best supports the achievement of the state's REV objectives.

Current Progress

National Grid has laid the groundwork for approval for AMI in a multi-year process. In the Supplemental DSIP, which was filed by the Joint Utilities in November 2016, a majority of the Joint Utilities, including National Grid, indicated that full AMI deployment was foundational for their roles as DSP providers. National Grid sought approval for AMI when the Company refined and re-filed its AMI business case in April 2017 as part of the National Grid Rate Case. In the Rate Case filing, the Company proposed full service territory deployment of AMI to include electric and gas smart meter technology, as well as supporting infrastructure and systems.

As a requirement of the Three-Year Rate Plan Order the Company initiated a further process, including on-going collaborative sessions, to gather and reflect stakeholder input in a revised AMI filing to be made with the by October 1, 2018. The collaborative includes DPS Staff and other interested parties and allows the Company the opportunity to refine and update its AMI business case. The collaborative includes large and smaller working group meetings. Key dates in the collaborative and filing process are summarized below.

- By April 30, 2018, the Company will hold an initial large group meeting with DPS Staff and interested parties. (***Completed April 27, 2018***) Participants also can determine whether there are sub-issues that would benefit from discussion in smaller working groups that would report their findings to all stakeholders at the subsequent large group meetings.

- Between May 15 and August 1, 2018, the Company will refine and update its AMI business plan. (***Completed***)

- On or about August 1, 2018, the Company will convene a second large group meeting with DPS Staff and interested parties. (***Scheduled for August 1 and 2, 2018***)

- By August 15, 2018, DPS Staff and interested parties may submit to the Company written comments and/or proposed modifications to the Company's refined and updated AMI business plan and BCA, responses to the parties' comments, and proposed metrics.

- By August 30, 2018, the Company will convene a third large group meeting with DPS Staff and interested parties. At this meeting, the Company will provide new information, if any, on the AMI business plan and BCA, responses to the parties' comments, and proposed metrics, and further discuss can ensue on any questions, comments, or proposed modifications from DPS Staff or interested parties.

- No later than October 1, 2018, the Company will file a report with the Secretary for the proposed implementation of AMI.

The Signatory Parties to the Settlement Agreement recognize that the Company's report will be subject to Commission action, which will afford further opportunities for comment and participation in the process.

In advance of system-wide deployment, as part of the Clifton Park Demand Reduction REV demonstration project, the Company has run an AMI demonstration for the purposes of gaining insights and experience. As part of the demonstration project, 13,213 electric AMI meters and 11,499 gas ERTs operating on a cellular network were deployed and operational by July 2017. The customer acceptance rate was 93%. Alongside the AMI deployment, the Company launched an enhanced customer portal which presents interval electric and gas usage data, and has facilitated a Peak Time Rewards ("PTR") program. The PTR program rewards customers for saving energy on specific conservation days. The Company called seven conservation days in the summer of 2017. Based on modeling results, the Company estimates 57% percent of customers used less energy during events than they otherwise may have without the pricing incentives. As a result of feedback from the AMI collaborative working groups, the Company is working to tailor the project to support the AMI Business Case. Other aspects of the Clifton Park REV demonstration include VVO, customer outreach and education, and promotion of DER opportunities such as solar PV and residential DR. The Company plans to use Clifton Park to keep learning about rate design approaches until full-scale deployment of AMI. When that occurs, the existing AMI meters in Clifton Park will then be folded into the Company's deployment schedule.

Aside from the Clifton Park demonstration project and as described by the Three-Year Rate Plan Order, the Company will be completing collaborative efforts in August 2018 and re-filing its refined and updated AMI business case by October 1, 2018. To support the filing, the Company is progressing a Request for Solution ("RFS") solicitation to evaluate the costs and capabilities of the core components of the AMI solution including the head-end collection system ("HES"), meter data management system ("MDMS"), field area network ("FAN"), and electric meter and gas ERT modules. The results of the RFS will be included in the updated business case and BCA. The RFS will include cross-jurisdictional considerations[112] and pricing with the goal of recognizing synergies that could be achieved through a larger multi-jurisdictional deployment.

The AMI collaborative provides an excellent opportunity to gather input and ensure the Company's AMI approach supports stakeholders' current and future needs. The collaborative builds from party feedback received during the Company's recent rate case. Through large group meetings and smaller working groups, the Company engaged in productive conversations with stakeholders that has helped to inform the Company's refined AMI proposal. The Company has also learned valuable lessons from the Clifton Park REV demonstration project, including:

- The initial project design included promotion of the tariffed VTOU rate. However, because the Company later recognized that most customers would not benefit from the VTOU it halted wider promotion of the rate. This decision helped the Company maintain its position as a preferred energy advisor. The Company also gained valuable insights into designing rates to reflect costs and serve wide swaths of the Company's customers equitably to ensure broad benefits.

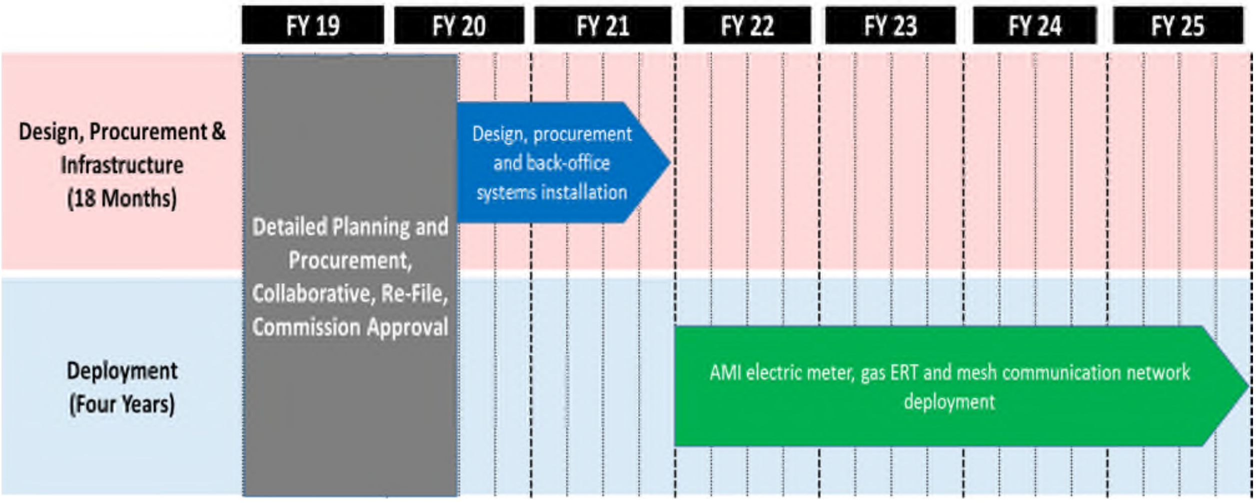
[112] Advanced Metering Functionality ("AMF")/AMI business cases have also been submitted by National Grid's affiliates in the Massachusetts and Rhode Island jurisdictions as part of their Grid Modernization and Power Sector Transformation filings, respectively.

- Contracting and business relationships can be impacted by merger and acquisition activities. A project partner was acquired by a global corporation during the demonstration project which resulted in challenges with deployment, cost estimates, and flexibility. The Company will be sensitive to these challenges during upcoming procurements and development of statements of work.

Future Implementation and Planning

The Company presented a tentative timeline for AMI deployment in the April 2017 Rate Case filing – which has since been pushed back to accommodate the collaborative process, updated procurement and re-filing schedules. The following timeline reflects this adjustment. The Company is providing this timeline for illustrative purposes only, as the actual timeline for deployment is contingent upon Commission approval.

Figure 2.11.1: Timeline for National Grid's AMI Implementation



By investing in AMI, National Grid will be taking a key step toward achieving REV objectives. AMI will support implementation of the recently released Energy Storage Roadmap, while providing a cost-effective solution for NEM successor tariffs' metering requirements. AMI will also allow the Company to assume the role of DSP provider. 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 on-site generation. These technologies will be tightly integrated into the Company's distribution infrastructure. Ultimately, enhanced M&C of these resources may support the establishment of a marketplace where services from these resources can be exchanged between ESCOs, aggregators, customers, and other interested parties.

When AMI meters have been deployed and the associated back-office infrastructure is in place, customers will have access to their 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, conservation, DR, and new pricing programs. AMI will also allow customers to monitor their energy consumption through new solutions that were proposed in the Company' Rate Case filing (*e.g.*, Green Button Connect My Data and Energy Insights Portal) that will allow customers to better manage their energy bills.

There are multiple incremental customer benefits through AMI implementation to those described above, including:

Innovative Rate Design Options - AMI lays the foundation for innovative rate design structures, such as TOU rates and critical peak pricing that can reward customers for optimizing their energy usage.

Enablement of Smart Home Devices - AMI will allow customers to manage their energy consumption through use of smart home devices such as thermostats, water heaters, and other appliances that can be integrated with AMI. Home energy management systems will be able to send and receive secure communications from the Company or third-party market entities. Based on the customer's preference, the system can automatically adjust energy consumption in response to pricing signals and calls for curtailment.

Outage Management - AMI has the ability to report a customer outage in near real-time, without the need to rely on notification from a customer or substation monitoring. The functionality also allows the Company to send a signal to AMI meters to identify areas that still require restoration and confirm when all outages have been restored. This functionality will improve situational awareness contributing to reduced restoration costs and improved outage response.

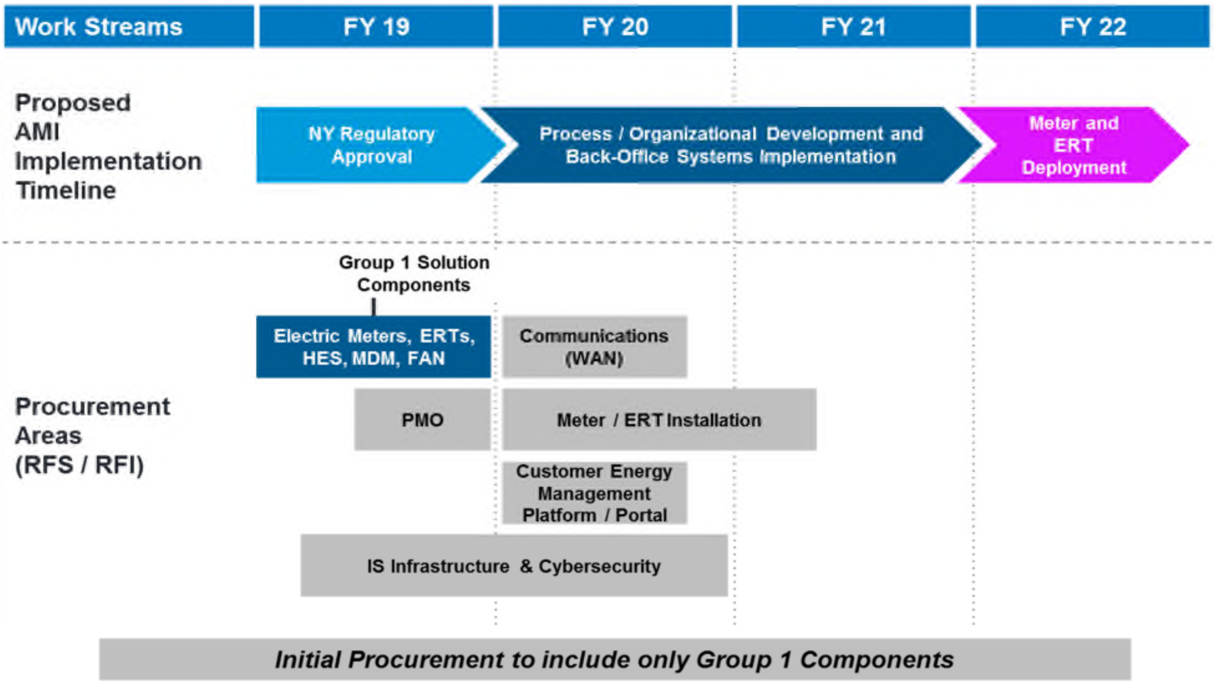
Customer Service Enhancements - AMI data can be used by call center representatives to enhance customer interactions. For example, AMI will:

- Allow call center representatives to send a signal to the meter to determine voltage levels or whether an outage is due to customer-owned equipment.
- Allow for real-time reconnects of electric meters.
- Provide historic information about prior outages and voltages.
- Provide for additional rate plans and options for customers seeking flexibility for their energy management needs.

As illustrated above, the functionalities provided by AMI support multiple use cases and it is fully expected that future use cases will continue to evolve and further benefit National Grid's customers.

In addition to the collaborative efforts and timelines described above, competitive procurement of smart meters, systems, and support services is required to address regulator and stakeholder interests in solution design details and refined project cost estimates. National Grid's current effort has leveraged the framework, documents, and experience of the 2015 Massachusetts Grid Modernization procurement review. Going forward, the scope encompasses the AMF/AMI plans of the Company for electric and gas as well as plans of National Grid's affiliates in Massachusetts and Rhode Island in order to leverage economies of scale and to reveal potential cost synergies associated with a cross-jurisdictional implementation. The procurement effort has also been designed to address a number of solution design and delivery options such as software-as-a-service ("SaaS") versus utility ownership. The procurement effort was launched in January 2018 and is designed to obtain pricing from vendors to align with the Company's collaborative schedule. Following is a depiction of the procurement approach. The initial focus in FY19 is on "Group 1" solution components and it is anticipated that additional procurements will follow to obtain bids for additional services including installation.

Figure 2.11.2: Procurement Approach



Risk and Mitigation

Procurement

Technology is changing rapidly and the Company will be faced with difficult decisions related to certain components of the end-to-end solution (*e.g.*, HES and MDMS) as well as how best to provide value for the customer while ensuring the solution is flexible and adaptable to meet existing and future needs. These concerns are being mitigated by the Company through deliberate inclusion of questions and requirements in the procurement process related to solution options and road mapping considerations.

Process Design

Process design is an extremely important component upon which program development and organizational change depends. Many utility functions will be impacted by the deployment of AMI including those performed by meter field technicians, meter shop technicians, customer service reps, control center operators, billing analysts, and others. Each role will need to be modified to support and take advantage of the incorporation of this new technology. To aid in a smooth transition for both customers and employees, the definition of how people will use the technologies is just as important as defining what the technologies are capable of doing. To mitigate these concerns, the Company is proposing a period of time (*i.e.*, currently eighteen months in its latest proposal) to not only implement and test the back office systems, but to ensure adequate process design and change management has occurred prior to meter deployment.

Customer Engagement

The level of time varying pricing ("TVP") benefits achieved will be directly related to: 1) the number of enrolled customers; and 2) the level of customer response to the new price signals and the resulting peak and energy savings. National Grid recognizes that customers will require a substantial amount of education, training, and access to tools that will enable them to become active participants in TVP programs. For example, customers will need to fully understand the cost implications of consuming electricity during hot summer days, as compared to a springtime morning, as well as how specific technology and program offerings can help them manage their energy costs. The Company will address these needs through a customer-centric approach, culminating in the development of a comprehensive Customer Engagement Plan. Customer engagement will also need to be expanded to address programs and services including EE, DR, and DER adoption. To enable this expanded access, the Company has adopted a platform approach called the Customer Energy Management Platform ("CEMP"), whereby customers would have both seamless and intuitive access to usage information, personalized insights, and opportunities for action (*e.g.*, DR enrollment, solar PV adoption).

Meter Access

Many electric meters and gas modules within National Grid's territory are located in basements, service closets, or other locations which require access via lock and key. While National Grid has considered this in its estimates, risks exist where poor accessibility could slow down deployment. In turn, the pace of benefit realization could also be impacted. Evidence of access-related deployment slowdown could be mitigated with enhanced, targeted communication to known meter locations or augmented via appointments.

Stakeholder Interface

As DER continue to grow, the Company will need greater visibility into DER performance to better utilize resources in efficient distribution grid operations. The data generated by AMI meters provide basic and foundational information for seamlessly integrating these distributed resources and modeling their behavior. AMI information will be able to support multiple DER use cases identified within this filing to include: interconnection, forecasting, ESS integration, EV integration, hosting capacity, and NWAs.

As described above, the Company has committed to an extensive collaboration process designed to obtain input from interested parties and DPS Staff prior to re-filing its AMI business case in October 2018. As part of that filing, the Company will also submit a detailed Customer Engagement Plan with sections designed to address the entire program life cycle (*i.e.*, pre-meter deployment, meter deployment, and post-meter deployment).

During the Company's initial collaborative meeting with DPS Staff and interested parties on April 27, 2018, it was noted that additional small group working sessions on customer engagement-related topics would be valuable exercises to undertake to help build out the Customer Engagement Plan. The Company held a kick-off Customer Engagement meeting on May 24, 2018 and has since hosted smaller working group sessions on the following topics.

1. Marketing, Education, and Outreach – shared current thinking, and obtained input/feedback from DPS Staff and parties, on the Company's overall approach to education and engagement of customers throughout AMI deployment period, with a focused discussion on pre-deployment.

2. Deployment – shared current thinking, and obtained input/feedback from DPS Staff and parties, on the Company's envisioned marketing materials, collateral, and customer engagement strategies during the time of AMI deployment.

3. Customer Empowerment & Enablement – shared current thinking, and obtained input/feedback from DPS Staff and parties, on the Company's envisioned post-deployment customer engagement strategies that enable customers to view, understand, and manage their energy usage. This session also covered the topics of envisioned pricing plans under AMI, as well as the topics of data access, privacy, and third-party sharing (*e.g.*, Green Button Connect).

The Company has compiled all feedback, learnings, and input from these smaller, group working sessions and will be incorporating it into the comprehensive Customer Engagement Plan that is to be filed with the Commission by October 1, 2018.

Additional Details

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.

AMI technology was deployed in the spring of 2017 to over 13,000 National Grid residential electric service customers as part of the Clifton Park Demand Reduction REV demonstration project. The technology includes AMI electric meters and gas ERTs where gas service is present. The AMI technology operates on a cellular network.

In accordance with the Three-Year Rate Plan Order and timeline described above, the Company will be completing collaborative efforts in August 2018 and re-filing an AMI report with the Commission by October 1, 2018. In addition to developing the agreed-upon components for the report, the Company will have also completed a procurement exercise (*i.e.*, RFS) to assist with cost certainty and updating the BCA.

The Company presented a tentative timeline for deployment in the April 2017 rate case filing – which has since been pushed back by a year to accommodate the procurement, collaborative, and re-filing efforts. The timeline for AMI implementation (which includes a goal of commencing meter deployment by FY22) reflects this adjustment and is presented in the prior Future Implementation and Planning section for illustrative purposes only, but it could clearly be further impacted by the approval process and/or adjustments through discussion with DPS Staff and parties.

2. Describe in detail where and how the utility's AMI provides capabilities which:

a. help the utility integrate DERs into its system and operations;

AMI increases the number of monitoring parameters and the granularity of data available to planning and operations. AMI may also afford an opportunity to increase M&C on smaller DER to foster situational awareness of the system which helps to maintain system reliability and safety. AMI also enables more detailed forecasting and distribution system planning which will lead to more efficient system utilization, while providing enhanced situational awareness for grid operators, all of which benefit customers and DER.

[113] DSIP Proceeding, 2018 DSIP Guidance Update, pp. 26-27.

b. help DER developers plan and implement DERs;

AMI provides more granular data (hourly or more frequently) to analyze the true usage of a feeder's capacity and to understand system operating profiles more readily. This, in turn, helps developers understand the DER operating profiles that most benefit the customer, the system, and the developer. An example of this may include inserting a more granular feeder loading profile into distribution planning models to more accurately ascertain the number of hours a DER may be constrained, or when to best operate a DER to offload a constrained element, thereby creating additional value to all stakeholders. As described in the Customer Data section of this DSIP Update the Company has plans to provide AMI data to customers, who may share that data with DER developers.

c. help DER operators plan and manage operation of their DERs;

The benefits of the above also apply to planning and managing operation of DER. With AMI data smaller DER owners can assess historical data as well as forecast future conditions, which helps DER developers understand how to plan their DER operations in a manner that maximizes their benefit to the customer. AMI will also help to provide additional near real-time monitoring to the Company to better understand the contributions of DER to the grid.

d. enable or enhance the utility's ability to implement and manage automated Volt-VAR Optimization (VVO);

The Company expects that the more granular data from AMI meters may enhance the effectiveness of the VVO program discussed in the Grid Operations section of this DSIP Update. In particular, a subset of AMI meters can provide granular voltage information along the distribution secondary system to centralized control systems to adjust grid operational characteristics. More granular metering information can also enhance load allocation within distribution load flow models and improve their accuracy for planning and operations. Specific to the AMI business case filed in April 2017, the Company quantified incremental VVO benefits associated with AMI in addition to those achieved by grid modernization.

e. improve the utility's ability to prevent, detect, and resolve electric service interruptions;

A benefit of smart meter technology is the ability to report an outage in near real-time. Although individual smart meters are electrically powered, they maintain sufficient battery life to transmit a message indicating loss of power. This ability has several advantages over the current process which relies on customer calls and algorithms to estimate the boundaries and customers impacted by an outage event. The meters will also transmit a return-to-service signal and can be "pinged" in an ad hoc manner to help assess the level of service restoration that has been achieved and communicate that with customers and state and municipal leaders.

The Company spends millions of dollars annually on storm restoration efforts. AMI would increase visibility during major and minor storms and this enhanced situational awareness is expected to create efficiencies for crew management and reduce response to false outages, thereby reducing costs.

f. improve the utility's ability to implement rate programs which facilitate and promote customer engagement, DER development, and EV adoption;

AMI deployment is an important enabling technology for innovative rate decisions that facilitate and promote customer engagement, DER development, and EV adoption. Without AMI, the options for customer savings and incentives are limited. With AMI and TVP for commodity and delivery, customers will have economically efficient incentives to adopt EVs, heat pumps, DR/ 'smart home' technologies, and ESS, all while getting price signals that align with the value they are delivering to the grid. Additionally, this approach may foster a technology platform on which competitive third parties can innovate to offer valuable services to customers (*e.g.*, home/building energy management, aggregated DR, smart EV charging). The increase in options for managing energy consumption and expense is at the heart of next-generation customer engagement. Under the flat volumetric pricing offered by AMR, customers have little incentive to engage with their energy use, which will change in a landscape with TVP.

Mass market AMI deployment is a crucial next step to promote economically, optimal types and levels of DER development. The VDER working group, where each of the Joint Utilities, including the Company, and other stakeholders are assisting DPS Staff with the design of mass market customer NEM successor tariffs, is operating on the premise that new DER installed by mass market customers after January 1, 2020 will be required to have interval meters, which serves to illustrate that AMI could play a crucial role in the next phase of REV. The rates that stakeholders proposed in filings on May 29, 2018 relied heavily on AMI metering for mass market DER installations to capture temporal price signals.

AMI is especially tied to EV charging, which would benefit dramatically from TVP. A recent study in Great Britain found that over one third of drivers (*i.e.*, 34%) would be more interested in buying an EV if they had a smart meter.[114]

The current rate structure, where costs are recovered volumetrically, imposes costs on EV owners above those for other members of the class, or which are tied to their actual costs on the grid. As a condition of the Three-Year Rate Plan Order, the Company is working with stakeholders to design a "beneficial electrification" rate intended to spur EV and heat pump adoption by aligning prices customers pay with costs the company incurs. While the beneficial electricification proposal is not due until September 2018, the Company anticipates that the rate will rely on AMI metering. Given the anticipated size of the opt-in program, the Company plans to leverage the infrastructure it already developed to support AMI in Clifton Park. In short, large-scale adoption of mass market EV demands better rate design that relies on AMI.

[114] *See* https://www.smartenergygb.org/en/resources/press-centre/press-releases-folder/smart-route-to-electric-vehicles

3. Describe in detail how the AMI enables secure communication with and among devices at customers' premises to support customer engagement, energy efficiency, and innovative rates.

National Grid will have experienced cybersecurity architects involved in all phases of AMI design and deployment to ensure that all communications between the meter and the home area network ("HAN") are secure, authenticated, and authorized so that customers are secure in the knowledge that their private data is protected from theft, snooping, tampering, or other threats. More detail on which specific industry standard protocols will be used for device authentication, authorization of access to meter data, and encryption of communications between the meter and HAN devices that consume meter data will be made available as the design progresses.

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.

The Company is currently working on an AMI Customer Engagement plan that will include a customer communications plan on the smart meter rollout and schedule throughout the deployment period. The Company will be proactively communicating using a variety of channels, including direct mail, email, and community meetings as well as creating a central place for information, such as schedule deployment areas and meter functionalities, to support the needs of customers and communities, stakeholders. The Company envisions that its website and direct mailing would be the primary method of updating and relaying relevant information on AMI to any interested parties.

More details on plans for AMI customer communications and stakeholder awareness will be provided in the Customer Engagement Plan filing with the Commission on October 1, 2018.

2.12 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 line and/or secondary network system.[115]

In an effort to encourage efficient DER integration, National Grid provides estimates of their system's hosting capacity for each radial distribution circuit within the Company's service territory. The results of hosting capacity analysis ("HCA") provide valuable system data that has been requested by DER providers. The hosting capacity information presented 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.

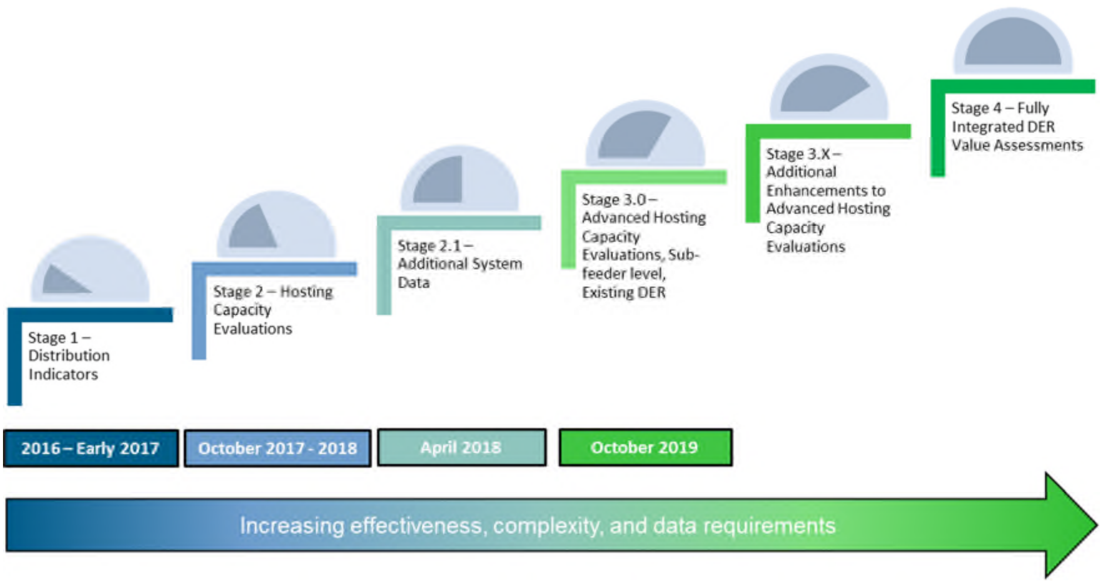
National Grid currently calculates hosting capacity on distribution feeders by evaluating potential power system criteria violations as a result of interconnecting large solar PV systems[116] to three-phase distribution lines. This streamlined approach was chosen to deliver results in a timely manner to DER developers most active in New York State.

The types of DER considered in HCA as well as the granularity in which information is assessed and presented will continue to evolve. National Grid, in coordination with the Joint Utilities, is progressing hosting capacity efforts in stages as presented in Figure 2.12.1 below.

Figure 2.12.1: Joint Utilities Roadmap for HCA Stages 2.1, 3.0, 3.X and 4

[115] 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. http://www.epri.com/abstracts/Pages/ProductAbstract.aspx?ProductId=000000003002008848.

[116] A large solar PV system is defined as a project with an AC nameplate rating starting at 300 kW.



The Company is progressing along this roadmap on schedule.

In Stage 1 several parameters such as voltage class, feeder load level, station transformer fusing, level of interconnected DG, and substation $3V_0$ were assessed and results were presented in a red zone map. Stage 2 evaluations met the Commission's targets,[117] including a system data update (stage 2.1). The Company is now working on the more detailed Stage 3 evaluations which will provide sub-feeder level hosting capacity incorporating existing installed DER into the modeling.[118] In parallel the Company will maintain the Stage 2 information and will publish an update to the feeder-level hosting capacity by October 1, 2018.

Following the publication of Stage 3 analysis results, developers will be able to identify specific sub-feeder level locations with higher levels of hosting capacity and potentially lower interconnection costs. Future Stage 3.X releases could include enhancements such as, increased analysis refresh frequency and additional information i.e. forecasted hosting capacity evaluations. The definition of Stage 4 is yet to be fully determined but will be defined incorporating stakeholder inputs and status of DER at that time.

Stakeholders can access the most up-to-date HCA through National Grid's on-line System Data Portal at https://ngrid.apps.esri.com/NGSysDataPortal/NY/index.html

[117] REV Proceeding, DSIP Filings Order, p. 14.
[118] This enhancement incorporates the interconnected DER to date into the circuit models used for the hosting capacity analysis with a priority on large PV, which remains the DER technology with the most significant impacts on hosting capacity.

Current Progress

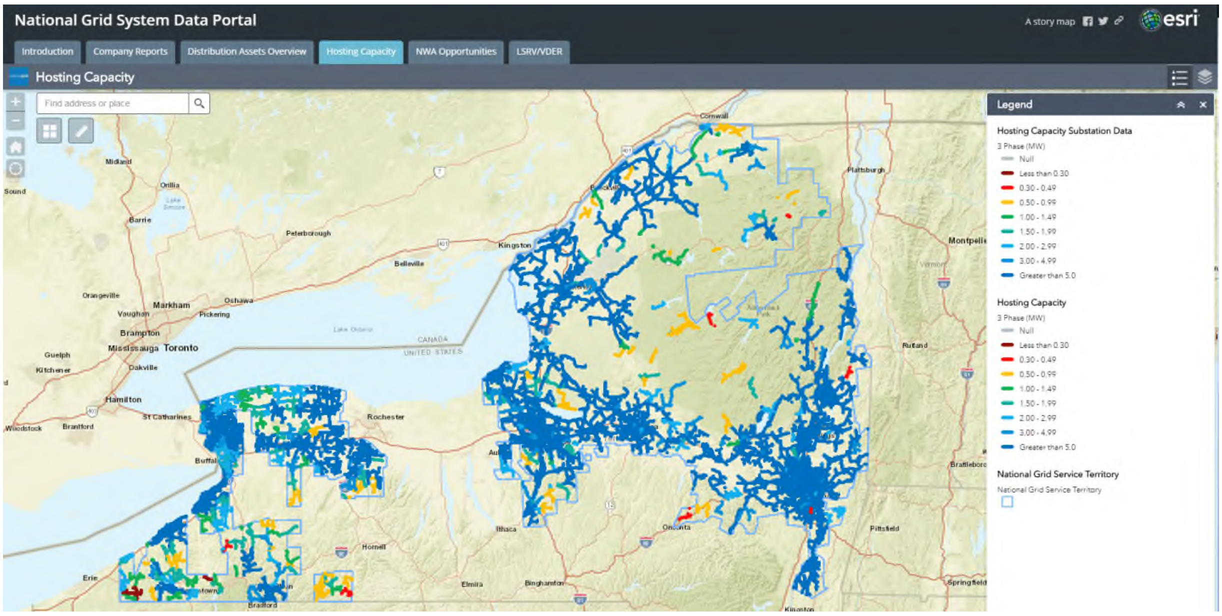
The DSIP Filings Order required Stage 2 HCA for all radial distribution circuits at and above 12 kV to be completed by October 1, 2017. The Company achieved this milestone by developing 910 15kV class feeder models in CYMDIST distribution power flow software using the DRIVE software tool developed by EPRI. The Company subsequently completed HCA on 1,009 5kV class feeders by February 1, 2018. All 1,919 radial distribution feeders were evaluated using the DRIVE tool. 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. The Joint Utilities selected the DRIVE tool and each utility is using this same tool to support further alignment and a common approach across the Joint Utilities. The DRIVE tool leverages existing circuit models in a utility's native distribution planning software to carry out an analysis of hosting capacity.

In accordance with the four-stage roadmap outlined by the Joint Utilities to facilitate the implementation of hosting capacity analyses, National Grid has completed both stages 2 and 2.1 and posted these results to the hosting capacity tab on its System Data Portal. The DRIVE tool ensures scalability moving forward as granularity and complexity increases and EPRI is constantly working to increase DRIVE's accuracy while reducing the computation time. The Joint Utilities continue to work with EPRI regarding software improvements to ensure that DRIVE can meet the ever-growing needs of the Joint Utilities moving forward.

Stage 2 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. Generally, the minimum hosting capacity value is indicative of the available hosting capacity at the most downstream node from the substation, and the maximum hosting capacity value is indicative of the available hosting capacity at a node closest to the substation. Per stakeholder input requesting hosting capacity for larger-scale solar PV systems targeting available land in rural areas, each circuit's hosting capacity was determined by evaluating the potential power system criteria violations as a result of large PV solar systems with an AC nameplate rating starting at and gradually increasing from 300 kW interconnecting to three-phase distribution lines. This method was used in place of a distributed approach which focuses on smaller rooftop solar PV units dispersed throughout a given area.

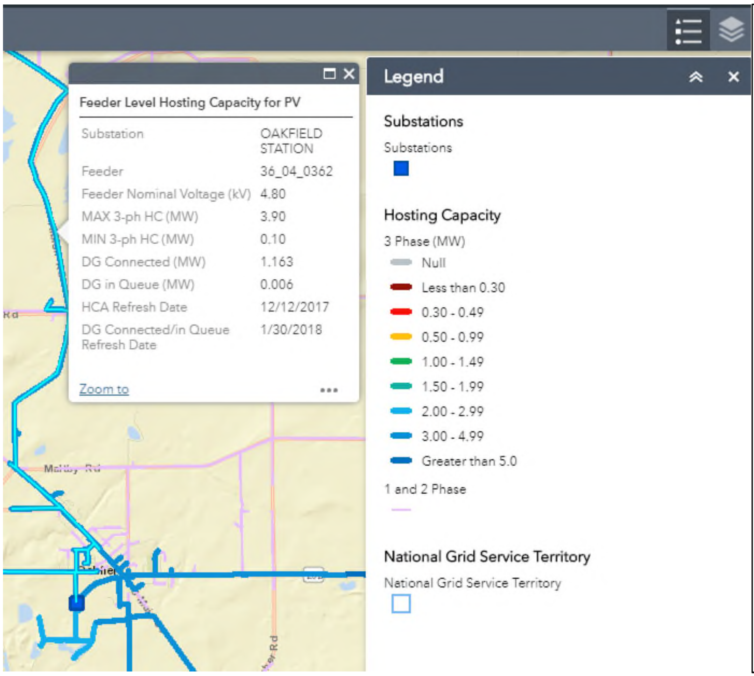
Using an ESRI-based mapping platform, National Grid currently displays the feeder objects themselves along with pertinent information for each feeder via data pop-ups on its System Data Portal. The System Data Portal is publically accessible provides users information to gain insight into the current state of National Grid's electrical system and get a better idea of locations that are most accommodating for the interconnection of distributed generation. The Hosting Capacity map displays the geographical layout of National Grid's distribution system and includes both distribution feeders at the 5kV and 15 kV voltage class as well as distribution substations.

Figure 2.12.2: Hosting Capacity Tab on System Data Portal



To guarantee a common functionality and user interface, the Joint Utilities coordinated the development of their portals so that they shared identical display and data features. When first accessing the hosting capacity maps the user is presented with a heat map of National Grid's entire distribution system that color codes the maximum hosting capacity of each distribution circuit. The user can then zoom in to an area of interest and click on an individual circuit in that area to get more detailed information. Once a user clicks on a targeted location, pop-up boxes provide system data. The Joint Utilities agreed upon a common feeder coloring scheme for Stage 2 analysis based on the maximum hosting capacity value the feeder can support. Blue-based colors signify a higher maximum hosting capacity value while red-based colors indicate lower maximums. Additionally, the breakpoints, or ranges, which define the colors were agreed upon as follows: less than 300 kW, 300-500 kW, 500-1,000 kW, 1,000-2,000 kW, 2,000-5,000 kW, and greater than 5,000 kW.

Figure 2.12.3: Feeder Level Hosting Capacity for Solar PV



Heat maps of the gross hosting capacity by feeder calculated using large centralized solar PV scenarios. Maps are colored according to the upper limit of the range of minimum gross three-phase feeder level hosting capacity.

Three-phase sections of the feeders are colored from minimum values (dark red) to maximum values (dark blue) using the following breakpoints: <300 kW, 300-499kW, 500-999 kW, 1000-1499 kW, 1500-2000 kW, 2000-2999 kW, 3000-5000 kW, and > 5000 kW.

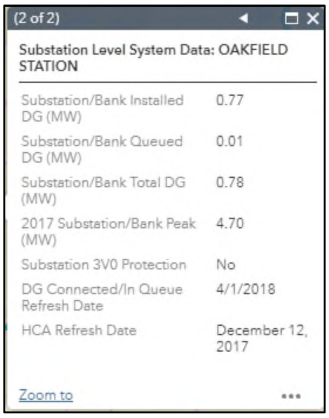
The Joint Utilities also coordinated to ensure common information was available for each feeder via data "pop-ups." For stage 2, these data pop-up boxes are used to provide valuable system data including minimum and maximum total feeder hosting capacity, voltage, and installed and queued DG values. The installed and queued DG is of particular interest as the Stage 2 analysis did not include existing DER. For this reason, the DG-connected and in-queue values are updated on a monthly basis to provide the most accurate and up to date snapshot of DG development activities on a particular feeder. The following feeder level line items are also available on the Stage 2 pop-up:

- **Substation** provides the user with the substation name the feeder of interest is connected to.
- **Feeder** is the number that National Grid uses to identify that particular circuit.
- **Feeder Nominal Voltage (kV)** is the nominal operating voltage of the feeder.
- **MAX 3-ph HC (MW)** is the maximum DER that can be accommodated at some point on the feeder (typically the feeder head).
- **MIN 3-ph HC (MW)** is the minimum DER that can be accommodated at some point on the feeder (typically the feeder tail).
- **DG Connected and DG in Queue** represent the aggregate of DG that is currently connected or in process of being connected to the feeder respectively.
- **HCA Refresh Date** shows the most recent date the last HCA was conducted.
- **DG Connected/in Queue Refresh Date** is the most recent date the DG Connected and DG in Queue values were updated.

Following the initial release of Stage 2 maps, the Joint Utilities worked collaboratively with stakeholders to identify additional data elements that could further enhance the value of the displays to developers. The Joint Utilities agreed to provide additional substation level data elements as part of a "Stage 2.1" release, which went live on April 16, 2018. The Stage 2.1 information is available in a second tab included on the data pop-up which includes information at the substation bank to which the selected feeder is tied. The Stage 2.1 substation level pop-up includes the following line items:

- **Substation/Bank – Installed and Queued DG:** These values separately represent the installed and queued DG capacity at the substation level.
- **Substation/Bank – Total DG:** This value represents total installed and queued DG capacity at the substation level.
- **Substation/Bank – Peak Load:** Substation peak load will be based on a historic year and that the year for which the data is provided will be annotated in data entry identifier for that line (*e.g.*, "2017 Substation Peak (MW)")
- **Substation – $3V_0$ Protection Status:** This value represents the status of $3V_0$ upgrades
  - **Yes -** An interconnection study and the required upgrades ($3V_0$) have been completed or station constructed such that $3V_0$ is not needed.
  - **Pending -** An interconnection study has been completed and the required upgrades are scheduled for construction
  - **No:** An interconnection study has NOT been completed; an interconnection study has been completed; $3V_0$ was required for that installation but was not implemented (developer dropped the proposal); current status unknown (*e.g.*, records incomplete, etc.)
- **DG Connected/In Queue Refresh Date:** "MM/DD/YYYY" formatted date of last DG data refresh.
- **HCA Refresh Date:** The most recent date the last HCA was conducted and results posted to the National Grid System Data Portal.

Figure 2.12.4: National Grid Substation Level System Data

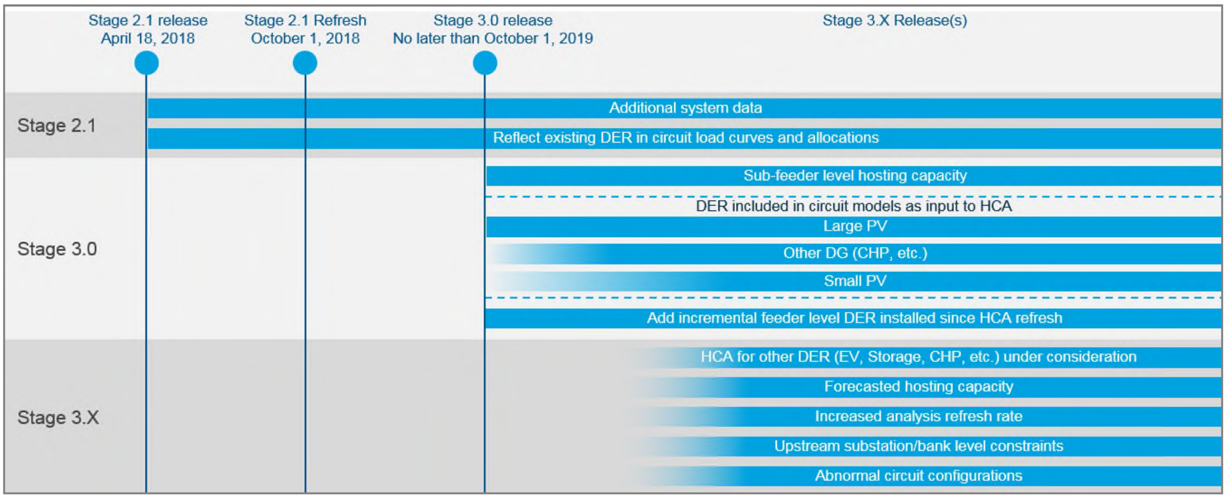


Successful completion of stages 2 and 2.1 have provided customers and project developers with a hosting capacity map which helps to identify locations for more efficient interconnection of DER, where costs are likely to be lower, with increasing granularity over time. The rollout of Stage 2.1 successfully addressed stakeholder requests to gain further insight into the data that characterizes both the feeders as well as the HCA results. The Joint Utilities continue to appreciate stakeholder feedback on how the HCA and displays can be improved moving forward into Stage 3 and beyond as they have done in Stage 2 and Stage 2.1.

Future Implementation and Planning

National Grid will continue to progress in accordance with the four-stage roadmap outlined above with each subsequent stage increasing in effectiveness, complexity, and data requirements. In the 2018 DSIP Guidance Update, DPS Staff raised the issue of forecasting hosting capacity and proactive measures to increase hosting capacity. These issues represent new use cases for HCA that require additional thought, stakeholder engagement, and potentially changes to existing tariffs. As the scope of these efforts has yet to be fleshed out, the Joint Utilities expects to consider them in a future 3.X release as represented in the Figure 2.12.5 below.

Figure 2.12.5: Joint Utilities Roadmap for HCA Stages 2.1, 3.0 and 3.X



Currently National Grid is working on a refresh of Stage 2.1 information and Stage 3.0 assessments which have scheduled delivery dates of October 1, 2018 and October 1, 2019, respectively. Consistent with the Supplemental DSIP and in alignment with stakeholder feedback, the Stage 3.0 release will include modeling of existing interconnected DER and sub-feeder level HCA. These enhancements will provide more valuable information for developers using the tool. For example, while the impact of existing DER on circuit load curves was already reflected in the Stage 2 results, the Stage 3.0 release will reflect installed DER in the circuit models directly to better reflect their impact on solar PV hosting capacity. In addition, the increased granularity of data in the Stage 3.0 release will provide more locational-specific sub-feeder level information to better inform DER developers.

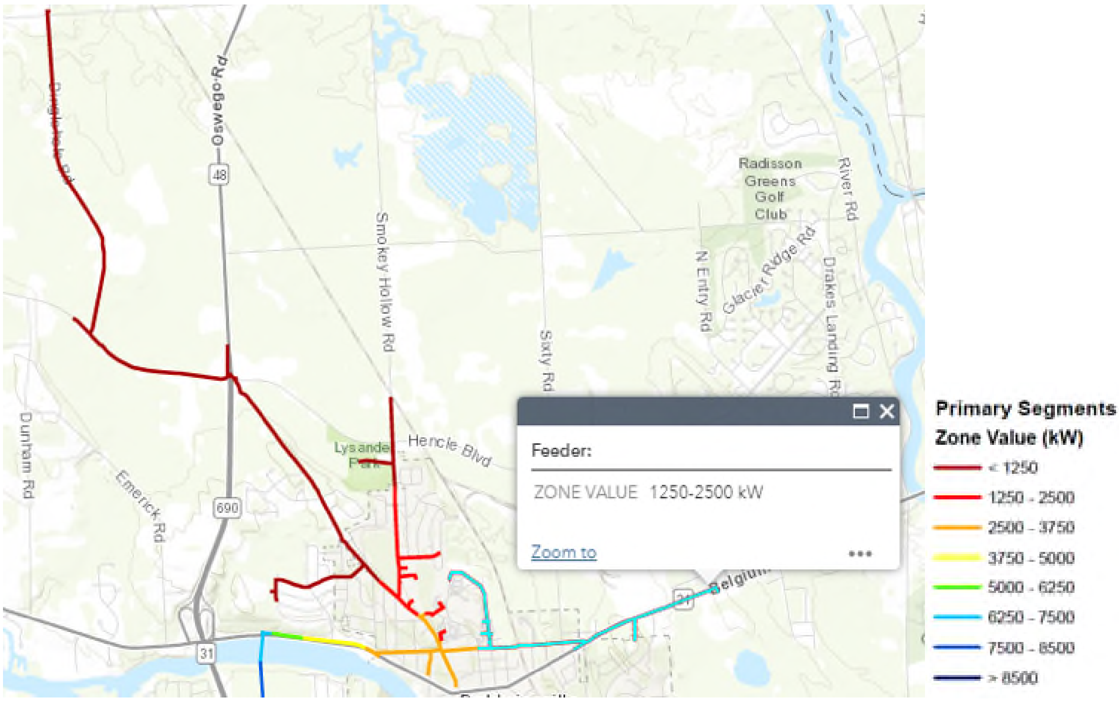
Subsequent Stage 3.X releases are expected to further enhance the information provided on the hosting capacity portal. The Joint Utilities are evaluating options to further improve the analysis and will continue to solicit the input from stakeholders on the continued development of the Joint Utilities hosting capacity roadmap. Proposed additions to potentially increase the accuracy and/or precision of HCA in Stage 3.X releases identified thus far include the following:

- Forecasted hosting capacity
- Increased analysis refresh frequency
- Hosting capacity impacts of circuit reconfiguration and operation flexibility
- Reflecting additional upstream constraints
- Incorporation of use cases for ESS

The Joint Utilities will continue to coordinate and engage stakeholders to solicit feedback on further enhancements to the hosting capacity portals. This includes options to increase the frequency with which the analysis is updated as well as new information that the portals could provide. One possible enhancement to the Stage 3 hosting capacity portals includes the addition of HCA that forecasts how these values might evolve in the future. The Joint Utilities will evaluate options for providing this information while taking into account the accuracy of such an analysis given the uncertainty in the location, timing, and configuration of prospective DER additions and projected changes to individual customer loads.

The main enhancement in Stage 3 will be presenting HCA on a sub-feeder level. The EPRI DRIVE tool will still conduct HCA on a nodal-level basis and then for reporting purposes, nodes with similar hosting capacity values based on the breakpoint ranges specified in Stage 2 will be grouped together and displayed with the appropriate color. For example, if the first several nodes outside the substation had hosting capacity values greater than 5 MW, they would be grouped together and colored dark blue; if that same feeder had several nodes towards the tail with hosting capacities between 300 and 499kW, they would be grouped together and colored light red. This more detailed HCA will enable planners to more specifically identify locations along a feeder with higher levels of hosting capacity for DER development. The below map shows an example of the sub-feeder level grouping that would be displayed for Stage 3.

Figure 2.12.6: National Grid Sub-Feeder Level Grouping



The release of EPRI DRIVE 2.0 is scheduled for Q3 2018 and this improved version will allow for the consideration of some of the proposed additions to the analysis discussed earlier, such as upstream constraints and the impact of aggregate DER across multiple feeders onto the substation level in the HCA. Existing DER will also be included in Stage 3 analysis providing further clarity into the true hosting capacity of the system. An additional benefit of DRIVE 2.0 will be with regard to operational flexibility to account for situations where a planner or operator might be limited in switching to serve a portion of one feeder from another on a temporary or permanent basis due to voltage, thermal, or protection issues arising from the changing impacts of DER to the system with changes in topology.

With respect to DRIVE, the Company prefers to perform the HCA directly within the CYME distribution analysis tool, however it realizes there will be a lag in vendor products embedding new functionality in their tool sets, so National Grid is prepared to run the enhanced DRIVE analysis process in a two-step process in which the Company's CYME models are run to produce required inputs into a stand-alone EPRI DRIVE module to support Stage 3 HCA.

Consistent with the DSIP guidance, the Joint Utilities will evaluate options for forecasting hosting capacity that take into account the accuracy of such an analysis given the uncertainty in the location, timing, and configuration of DER adoption forecasts, projected changes to individual customer loads, and any upgrades or changes to the utility system. The roadmap for forecasting hosting capacity must incorporate models of future utility system configurations, gross load forecasts, and DER forecasts. These concepts must be integrated to produce a forecast, and it must be decided what level of granularity is appropriate before the level of uncertainty rises significantly.

Forecasted hosting capacity provided to developers would help inform DER development processes and decisions. The Joint Utilities are in preliminary discussions on methods and approaches to forecast hosting capacity. The Joint Utilities have not reached a consensus on an approach and the approach could evolve from an initial high level forecasted hosting capacity to a more granular forecast as the tools evolve. The main challenge involved in forecasting DER is the DER queue is constantly changing and it is hard to tell where DER is actually going to interconnect. The forecasted hosting capacity would be a separate tab in the distribution system portal. This will allow third parties to access current and forecasted hosting capacity.

Increasing hosting capacity is another relevant topic to be evaluated over the next five years. Currently the costs to increase hosting capacity solely for the purpose of DER interconnections is borne by the interconnecting entity as part of a Contribution-in-Aid-of-Construction ("CIAC") charge in support of a specific interconnection application. These upgrades are not implemented proactively by the utility. However, increased hosting capacity is often a by-product of many traditional, utility system infrastructure upgrade projects. Examples applicable to National Grid include such things as the installation of larger transformers and wires, the conversion of distribution from 5kV to 13kV, or installation of additional voltage regulating equipment. In addition, as the level of DER has increased, the Company has revised some of its equipment and design standards for new installations to better accommodate the potential for two way power flows. Examples of these revised standards include two-way voltage regulation controls, use of switched shunt capacitors instead of fixed capacitors, and the inclusion of $3V_0$ protection schemes on all new substations.

Stakeholder engagement will be a critical input into the design of these longer-term aspects of the analysis. In the case of hosting capacity maps for ESS, input on developer use cases will help inform the analysis design criteria to deliver the most value to users. Forecasted hosting capacity will likewise benefit from stakeholder input, especially given the level of complexity of the analysis that impacts the accuracy and precision of its results. National Grid will continue to evaluate various approaches to forecasting hosting capacity with consideration to the uncertainty in the location, timing, and configuration of DER adoption forecasts and any upgrades or changes to the utility distribution system. The Joint Utilities will engage stakeholders to solicit their input on these approaches and the value proposition for developers to further inform the continued expansion of the roadmap for hosting capacity.

Risk and Mitigation

The primary use case for hosting capacity data in New York is to help guide DER investments and marketing activities to areas of the grid where the costs of interconnection are likely to be the lowest. The analyses represent the overall feeder level hosting capacity only and do not account for all factors that could impact interconnection costs (including substation constraints). Please note that issues related to circuit protection require further analysis to make a definitive determination of hosting capacity. This data is being provided for informational purposes only and is not intended to be a substitute for the established interconnection application process.

DER and system data used for HCA must be accurate and current to provide precise results. To help mitigate these issues National Grid has created automated processes and Quality Assurance/ Quality Control (QA/QC) measures. Progressing through the various stages of HCA relies on the evolution of the HCA software. The Company continues to work with EPRI on the development of its DRIVE tool and the integration with the CYMDIST distribution power flow software.

Stakeholder Interface

The Joint Utilities will continue to engage stakeholders for their input on these approaches to further inform the continued expansion of the roadmap for hosting capacity. In the case of HCA for ESS, input on developer use cases and the ESS study mentioned in the Energy Storage Integration section of this DSIP Update will help inform the appropriate work product that will be most beneficial to stakeholders. This input will be especially important given the broad range of energy storage technologies, applications, and operating characteristics that such analyses could reflect. Forecasted hosting capacity will likewise benefit from stakeholder input given the level of complexity of the analysis that impacts the accuracy and precision of its results.

Similar to the approach in 2017, the Joint Utilities plan to hold stakeholder engagement sessions corresponding with the release of each stage to provide an update to stakeholders on progress to date and solicit input on future stages. The Joint Utilities plan to continue facilitating open discussions with stakeholders via the engagement group sessions beyond the Stage 3.0 release. As described in the Supplemental DSIP, completion of Stages 3 and 4 of the hosting capacity roadmap is intended to be a long-term focus for utilities based on lessons learned from previous stages and the availability of enhanced analytical tools to conduct this degree of analysis.[119] The longer-term focus on Stages 3 and 4 complements the Joint Utilities' interest in engaging stakeholders to provide the highest value results for users.

In addition to stakeholder engagement sessions, National Grid has held webinars for developers explaining and demonstrating the hosting capacity tab 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 a useful discussion forum for fielding developers' ideas on how to improve the functionality and the information on the portal.

Additional Details

The following responds to the request of DPS Staff to provide additional details specific to hosting capacity.[120]

[119] REV Proceeding, Supplemental DSIP, p. 56.
[120] DSIP Proceeding, 2018 DSIP Guidance Update, pp. 28-29.

1. The utility's current efforts to plan, implement, and manage projects related to hosting capacity. 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 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 $3V_0$ were assessed and results were presented in a red zone maps. This was a simple approach to conducting HCA but provided solid foundations for the future Stages described below.

In Stage 2 analyses were carried out on a feeder-level only for all voltage classes, in which a maximum and a minimum hosting capacity value were provided for each feeder analyzed. Each circuit's hosting capacity was determined by evaluating the potential power system criteria violations as a result of large solar PV systems with an AC nameplate rating starting at and gradually increasing from 300 kW and interconnected to three-phase distribution lines.

Stage 2.1 provided an additional substation level data element that includes information on the substation bank which the selected feeder is tied to.

The Company is now working on the more detailed Stage 3 evaluations which will provide sub-feeder level hosting capacity (nodal analysis) incorporating existing installed DER (all technologies and sizes) into the modeling and upstream station constraints such as $3V_0$ and transformer bank loading into the analysis.

Future Stage 3.X releases could include enhancements such as increased analysis refresh frequency, forecasted hosting capacity, consideration of other DERs such as ESS and EVs, and abnormal circuit reconfigurations.

The capabilities in the Stage 4 extend beyond the formal definition of HCA and build on its foundation to perform fully integrated value assessments. The definition of Stage 4 is yet to be fully determined but it will be defined while incorporating stakeholder inputs and status of DER, at that time.

Figure 2.12.1 above shows how the stages build up from one another, improving HCA along the way, potentially leading to long-range HCA in the future.

b. the original project schedule;

The original timelines for Stage 1 and Stage 2 are the same as presented in part a. of this question, and both milestones were met on 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 to October 2019 (as discussed above). The Stage 4 timeline was not explicitly defined in the original schedule.

c. the current project status;

As described previously the Company is currently working on the more detailed Stage 3 evaluations where results from the analysis are anticipated to be available by October 1, 2019.

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 focused on data, modelling, and analysis preliminary to performing 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 already begun to investigate and 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 2 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 response in item d above.

f. next steps with clear timelines and deliverables

Looking forward, the next phases of hosting capacity will represent a more clear picture of the ability of National Grid's existing system to accommodate additional distributed generation and the information available on the System Data Portal will continue to expand helping to further guide DER developers' decisions. The subsequent phases of the hosting capacity project will require increasing complexity and data requirements to model substation level information as well as including existing distributed generation in the analysis, placing even greater importance on the quality of data moving forward.

The timeline and next steps for HCA going forward are listed below:

- The Company will publish the first Stage 2 annual update to the feeder-level hosting capacity starting October 1, 2018.
- The results of Stage 3 analysis are anticipated to be available by October 1, 2019.
- Stages 3X and 4 dates will be determined during the course of the next five years of this DSIP Update

2. Where and how DER developers/operators and other third parties can readily 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.[121]

3. 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.

All hosting capacity information that is available to third parties is available on the National Grid System Data Portal. This will be where all hosting capacity related information will be housed in the future. The timeline of future work will continue to follow the roadmap.

HCA data will be fully updated on a yearly basis with DG in queue and connected information updated on a monthly basis. Third parties can determine these dates directly in the system portal as shown in Figures 2.12.3 and 2.12.4 above.

4. The means and methods used for determining the hosting capacity currently available at each location in the distribution system.

Details of the means and methods used for determining the hosting capacity currently available are provided in the Current Progress section above.

5. The means and methods used for forecasting the future hosting capacity available at each location in the distribution system.

The Joint Utilities are in preliminary discussions on methods and approaches to forecast hosting capacity. The Joint Utilities have not reached a consensus on an approach and the approach could evolve from an initial high-level forecasted hosting capacity to a more granular forecast as the tools evolve. The main challenge involved in forecasting DER is that the DER queue is constantly changing and it is hard to tell where DER is actually going to interconnect.

[121] *See* https://ngrid.apps.esri.com/NGSysDataPortal/NY/index.html

6. 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.

The forecasted hosting capacity would be a separate tab in the System Data Portal. This will allow third parties to access current and forecasted hosting capacity. As for when this will be available, National Grid and the Joint Utilities must first determine the exact means and methods for calculating forecasted hosting capacity, then a timeline will be determined as to when in the next five years this will be available.

7. The utility's specific objectives and methods to:

a. identify and characterize the locations in the utility's service area where limited hosting capacity is a barrier to productive DER development; 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 2.12.2 (Hosting Capacity Tab on System Data Portal) provides a geographic overview of the relatives 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 recloser settings, voltage regulation capabilities, fixed shunt capacitor banks, and protection challenges

b. timely increase hosting capacity to enable productive DER development at those locations.

National Grid has considered pilots and programs to increase hosting capacity in regions with insufficient hosting capacity to support projected DG (*e.g.*, proactive $3V_0$ protection installation at Peterboro and E. Golah Substations with an associated cost sharing methodology to reduce barrier to entry for DER developers) as described in more detail in the DER Interconnections section of this DSIP Update. These types of programs need to be considered against all other spending rationale projects and will be implemented on a need basis to ensure value for our customers.

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 replace assets such as transformer banks or conductors or make voltage class upgrades, or under take other asset replacements for normal system improvement reasons, hosting capacity will likely yet indirectly be increased.

2.13 Beneficial Locations for DERs and Non-Wires Alternatives

Context and Background

The impacts of DER vary greatly depending on where they are placed on the distribution system. National Grid endeavors to identify where DERs may provide benefits to the electric delivery system and share that information on the System Data Portal. The Company strives to provide information opportunities and constraints with sufficient granularity to facilitate investment decisions by the DER providers. The objectives in defining beneficial locations are to accelerate the proliferation of DER and increase the effectiveness and efficiency of the electric delivery system.

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 efficiency. The Company considers available DER compensation mechanisms when identifying beneficial locations. To date, National Grid has identified potential beneficial locations in support of NWAs, LSRV, and hosting capacity and provided the associated grid data through the Company's System Data Portal. The beneficial locations associated with NWAs and LSRV represent areas in which appropriate DER will be compensated for the value they provide in support of the grid. Beneficial locations identified through hosting capacity analysis represent areas in which the DER developer's interconnection costs may be minimized.

While initial beneficial locations have been identified for each of these nascent programs, each is expected to continue to evolve as market mechanisms and analytic capabilities mature.

Current Progress

The Company, in collaboration with the Joint Utilities has developed and utilized consistent NWA suitability criteria to identify multiple locations where NWA opportunities are being evaluated. Similarly the Company has identified numerous locations (at the substation level) eligible for LSRV compensation as part of the VDER Value Stack. In addition the Company has completed feeder level hosting capacity analysis on all radial distribution feeders.

To date the Company is completing NWA evaluations for identified NWA opportunities, applications for 3MW of DG have been received in LSRV target areas and 1,901 feeders have hosting capacity information available via interactive maps on the National Grid System Data Portal.

In support of the VDER proceeding, the Company recently completed an integrated T&D assessment of system needs to identify and quantify the distribution locational values included in the VDER Value Stack. In this study, National Grid performed a ten-year integrated T&D assessment, at the substation level, for its entire service territory to identify future constrained locations. This information was used to estimate the Marginal Avoided Distribution Costs ("MADC") if utility projects could be deferred through the integration of eligible DER. More detail on this effort is discussed in the Enhanced MCOS Study section of this DSIP Update.

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. The intent of providing beneficial location information is to guide DER developers to locations on the grid that may offer enhanced compensation opportunities or lower interconnection costs.

Over the time horizon covered by this DSIP Update, National Grid anticipates completing additional beneficial location studies for such things as ESS and EV charging. The Company will remain engaged in the proceedings associated with technologies in developing the future beneficial location information to share with stakeholders.

Risk and Mitigation

Expanding the number of parties engaged in providing resources critical to maintaining a safe, reliable, and cost-effective grid adds significant complexities which will need to be well managed to ensure they are integrated efficiently. To mitigate this risk, the Company strives to be as transparent as possible with system data and planning processes while maintaining customer privacy and system security. National Grid's expanding tools to help mitigate these risks include: robust cyber security procedures, continued stakeholder engagement, engineering review, expansion of the System Data Portal, standards, grid operations software, expanded telecommunications, and provision of accurate grid data.

Stakeholder Interface

National Grid is engaged with DER stakeholders in multiple forums, including Joint Utilities working groups and as a party to the many REV-related proceedings. The Company continues to enhance its System Data Portal in presenting beneficial locations to provide desired information in support of DER integration.

2.13.5. Additional Details

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.[122]

1. The resources provided to developers and other stakeholders for:

a. accessing up-to-date information about beneficial locations for DERs and/or energy efficiency measures; and,

Answered in b below.

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 Hosting Capacity Analysis. 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.

In addition to the National Grid System Data Portal, information is also provided on the Joint Utilities website[123] and the REV Connect portal.[124]

2. The means and methods for identifying and evaluating locations in the distribution system where:

a. a 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,

Answered in b below.

[122] DSIP Proceeding, 2018 DSIP Guidance Update, pp. 29-30.
[123] *See* http://jointutilitiesofny.org/utility-specific-pages/nwa-opportunities/
[124] *See* https://nyrevconnect.com/non-wires-alternatives/

b. one or more DERs and/or energy efficiency measures 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-transmission and distribution systems to maintain safe and reliable service to customers. 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 candidates for NWA opportunities. Additionally, National Grid's Planning groups document the amount and location of load relief needed to mitigate system capacity or reliability needs where appropriate.

A RFP is prepared based on the needs case developed in the planning process. The RFP is filed with the Commission and posted on the public PSC website as well as in National Grid's Ariba procurement system. The Company evaluates the proposed NWA solutions presented by vendors in proposals and ranks all proposals and typically shortlists two - four proposed NWA solutions. In reaching a decision regarding the NWAs' suitability, viability, and affordability a BCA is performed using National Grid's BCA Handbook. Technical viability of a proposed NWA solution is evaluated along with the project's BCA score. NWA projects must provide a safe, reliable, and affordable solution when compared to the traditional "wires" solution. NWA projects that satisfy the technical requirements and have a positive BCA requirements will progress.

The attributes that are reviewed include:

- **Availability of Resource –** Technically feasible NWA solution(s) from a qualified supplier in time to satisfy the applicable system reliability and capacity needs
- **Intermittency –** The extent to which a resource is able to provide the required load relief, considering limitation such as seasonality, length of call windows, environmental restrictions, or other known factors that limit the performance of the resource, and ability to meet localized system needs, or statewide load peaks.
- **Dispatchability –** The ability of a dispatch-based resource to respond quickly in times of capacity or T&D needs and the extent to which the resource can be called repeatedly within a given time period.
- **Affordability –** All proposals are initially assessed for viability and affordability. Proposals describing the most affordable and viable solutions are shortlisted and vendors are further engaged to better understand costs and design. National Grid then applies the BCA to shortlisted proposals that remain viable after vendor engagement.

Criteria

The Company performs an initial screening for NWA suitability as mentioned above. That initial screening considers the criteria below. These criteria are expected to be modified as appropriate based on the lessons learned from on-going NWA efforts.

Table: 2.13.1: Criteria for Identifying and Evaluating Locations for NWA Solutions

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 (The date of system need)	Large Project	36-60 months
	Small Project	18-24 months
Cost Suitability	Large Project	Greater than or equal to $1M
	Small Project	Greater than or equal to $500K

Location of NWA Opportunities
National Grid's NWA are presented on the following publically available websites
Joint Utilities Site: http://jointutilitiesofny.org/utility-specific-pages/nwa-opportunities/
REV Connect Site: https://nyrevconnect.com/non-wires-alternatives/
National Grid System Data Portal: https://ngrid.apps.esri.com/NGSysDataPortal /NY/index.html
Pre-qualified vendors are sent NWA opportunity notifications via Ariba, National Grid's procurement system. Interested vendors may contact:

Derek Salisbury: Derek.Salisbury@nationalgrid.com -or-
Shi Hui (Irene) Liu: Shi.Hui.Liu@nationalgrid.com

Procurement
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.

3. Locations where energy exported to the system, or load reduction, would be eligible for:

a. compensation under the utility VDER Value Stack tariff;

As part of VDER Phase One Value Stack compensation mechanism, the Company identified locations for LSRV compensation and those locations and associated DER injection limits are presented on the LSRV/VDER Tab of the National Grid System Data Portal. For VDER Phase One Value Stack, LSRV opportunities exist at 52 substation locations across the Company's service territory. As part of VDER Phase 2, the LSRV locations and compensation levels may be updated.

b. utility dynamic load management programs, including the Commercial System Relief Program, Distribution Load Relief Program, and Direct Load Control Program;

National Grid currently operates DLM programs, which were created in accordance with directives provided by the Commission in Case 14-E-0423. The Distribution Load Relief Program ("DLRP"); the Commercial System Relief Program ("CSRP"); and the Direct Load Control Program ("DLC Program"), which includes the ConnectedSolutions and coolControl Programs, were launched in 2015 by the Company. DLRP and CSRP mainly focus on C&I customers, while the DLC Program targets residential and small-commercial customers

Kenmore offers two location-specific DR programs. The first, coolControl, is a Direct Load Control program offering residential and small commercial customers free direct installed smart thermostats and wi-fi enabled smart controllers that allow these customers to better manage their peak energy use, and also allow the company the option of controlling these devices under stressed system conditions. The second is the Distribution Load Relief Program. The Distribution Load Relief Program (DLRP) program incentivizes commercial customers in Kenmore, NY to commit to reducing load when the company designates an emergency event. Customers are given 2 hours notice of an event and are paid both to be on call for events, as well as for actual performance during these events. Due to the limited number of eligible commercial customers in the constrained area, the DLRP in Kenmore currently has no participants.

The Company is investigating how it may integrate DR programs into NWA portfolios. It is likely in many cases that DR may not be able to meet most system needs alone but relatively low-cost DR can be a useful component as part of a portfolio solution with other DER.

Other DR programs such as CSRP, are not locationally targeted, rather they are applied for system peak shaving.

c. and/or, increased value-based customer incentives for energy efficiency measures with load profiles that align with the system needs through utility energy efficiency programs or New York State Energy Research and Development Authority's (NYSERDA) Clean Energy Fund (CEF) programs, while ensuring utility-NYSERDA coordination.

EE programs generally provide system-wide benefits and are not usually locationally targeted. However, targeted EE initiatives are being explored in NWA locations in an effort to develop least cost NWA solutions.

2.14 Procuring Non-Wires Alternatives

Context and Background

NWA solicitations are an important mechanism for bringing DER onto National Grid's electric system. NWA solicitations offer opportunities for developers to propose innovative solutions to meet a clearly defined system need, while providing benefits and potential cost savings to customers.

At the conclusion of the Company's annual distribution planning process, as part of the development of the annual CIP, National Grid identifies opportunities with potential NWA feasibility that may go out for RFPs.

National Grid has worked diligently to improve the RFP process to ensure successful NWA proposals. For example, the Company coordinates with the Joint Utilities as part of the DER Sourcing / NWA Suitability Criteria Working Group to increase the consistency of the RFP practices across the utilities. RFPs include a detailed project overview which includes a description of the specific need and relevant high-level customer information which may include average and peak demands so that they provide the detail necessary for respondents to develop solutions and craft a proposal. RFPs also include a link to the Company's System Data Portal, which contains detailed information regarding NWA areas and other information relevant to the selection process such as the Company's BCA Handbook and an order-of-magnitude cost estimate for the 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 Company often presents an ambitious RFP response timeline but may extend due dates when possible if bidders identify and communicate a critical path need that is likely impacting multiple bidders. DPS Staff and other stakeholders are regularly apprised of the status of potential projects.

Current Progress

The Company has taken many steps to implement and refine its NWA solicitation process. These efforts include monthly phone calls to provide DER providers with project/process status updates, broader partner outreach, and consistent vendor interactions.

In 2016, the Company identified twenty-two potential areas of need on which it would perform detailed engineering analysis to determine their suitability as NWA opportunities. The first seven areas were identified using various methodologies; an additional fifteen areas were identified by applying the suitability criteria filed in the 2017 Joint Utilities Supplemental DSIP to projects in the Company's CIP. Collectively and individually, the Joint Utilities undertook significant efforts in 2017 to advance NWA processes and released several NWA solicitations to the market. To date, National Grid has publically solicited proposals for seven NWA opportunities and iteratively improves each solicitation by incorporating lessons learned and stakeholder feedback.

The following tables summarize the RFPs released by National Grid in 2017 and early 2018.

Table 2.14.1: Status of National Grid's 2017-2018 NWA Solicitations in the Procurement Process

2017-18 NWA Projects	Load Relief Needed (MW)	Need Date	Date Solicitation Issued	Proposals Due	Project Status
Baldwinsville	4-6 MW	2023	Jan 2017	2/27/17	Closed
Old Forge	13 MW	2023	April 2017	6/30/17	Evaluation
Gilbert Mills	1.7MW	2023	Aug 2017	10/6/2017	Evaluation
Fayetteville	140kW	2020	Aug 2017	10/6/2017	Closing
Van Dyke	8MW	2020	Dec 2017	1/31/18	Evaluation
Golah Avon	6 MW	2021	Dec 2017	1/31/18	Evaluation
Buffalo-53	1 MW	2020	Dec 2017	1/31/18	Closing

For the projects currently under evaluation by the Company, preliminary screenings have been completed and those projects proposals determined most viable (as determined by the screening criteria) are currently being evaluated through an in-depth engineering analysis and preparation of a Benefit-Cost Analysis, according to the procedures outlined in the Company's BCA Handbook.

A number of key lessons learned through the solicitation experience so far are being incorporated into RFPs. These include:

- Greater clarity around NYISO market participation opportunities, if any, is required in submitted proposals to help the Company understand the full potential of impacts on the grid.
- NWA providers have struggled to determine the optimal site for their DER based solely on the information in the RFP. As such the Company now includes locational

information in the solicitation and is developing an NWA opportunities map on the System Data Portal[125] as described in more detail in the Distribution System Data section.

Future Implementation and Planning

Below is a list of the Company's upcoming NWA solicitations. More information can also be found on National Grid's System Data Portal. The NWA solicitation list is updated approximately every two-three months or whenever there is a change in the status of a given solicitation. A complete list of potential future NWA opportunities for National Grid can be found on the REV Connect website.[126]

Table 2.14.2: Planned NWA Projects

2018-2023 NWA Projects	Load Relief Needed (MW)	Need Date	Estimated Solicitation Timing
Fairdale	1 MW	2020	Q3 2018
Cicero	5 MW	2021	Q4 2018
Byron	1 MW	2021	Q4 2018
North Bangor	6 MW	2023	Q4 2018
Buffalo 23kV/Huntley	3 MW	2023	Q4 2018
Mallory	3 MW	2022	Q4 2018
Watertown	10 MW	2023	Q4 2018
Forbes Ave	16 MW	2021	Q4 2018
Sonora Way	TBD	TBD	Q4 2018

125 *See* https://ngrid.apps.esri.com/NGSysDataPortal/NY /index.html
126 *See* https://nyrevconnect.com/.

In addition to pursuing solicitations for specific projects, the Company, in concert with stakeholders and the Joint Utilities, will investigate a number of challenges to further enable NWA opportunities. These efforts are summarized in the following paragraphs.

Improved RFP's

As described previously National Grid is continuing to improve the NWA RFPs and the associated information provided. For example, the needs identified in the problem statement can be better defined by using the data available from increasing levels of grid monitoring and improved forecasts such as 8760 feeder level forecasts. Also, the Company plans to provide deferred traditional solution cost figures in future RFPs with the intention of providing NWA providers a sense of viable NWA solution costs. Increased specificity in future RFPs will enable stakeholders to better understand the Company's needs and thereby provide high-quality bids and solutions that are appropriately responsive and right-sized for the Company's needs. Saving time for bidders will increase competitiveness of the bidding process, lower bid prices, and increase the cost effectiveness of this effort for National Grid's customers.

NYISO Market Development

Dubbed NWA+ in the recent New York Storage Roadmap,[127] the concept of value stacking (*i.e.*, solving a local grid need while also providing value to the NYISO wholesale market) can help maximize the value provided by NWA solutions. However, this "Dual Participation" construct presents challenges with regard to NWA control, dispatch, payments, and prioritization between the DSP and the NYISO. The Company, the Joint Utilities and the NYISO are working to address this challenge through the development of rules and procedures via a Joint Utilities-NYISO Task Force established in 2017.

EE/DR Integration

Load reduction from EE and DR programs the Company already administers may be a viable mechanism for increasing the cost-effectiveness of an NWA solution. For example, locking in EE and DR load reduction commitments by reducing the size of the need should reduce solution costs. As such, the Company's NWA procurement process will begin integrating with the Company's existing EE and DR programs as applicable for upcoming solicitations. A review of the current list of potential NWA opportunities suggests that five out of fifteen have potential for significant EE/DR integration.

Suitability Criteria

The Company's NWA suitability criteria matrix is presented in Table 2.14.3:

[127] NWA+ represents use cases with utility T&D deferral value, thereby reducing single peak system hour to provide capacity savings while providing wholesale ancillary services.

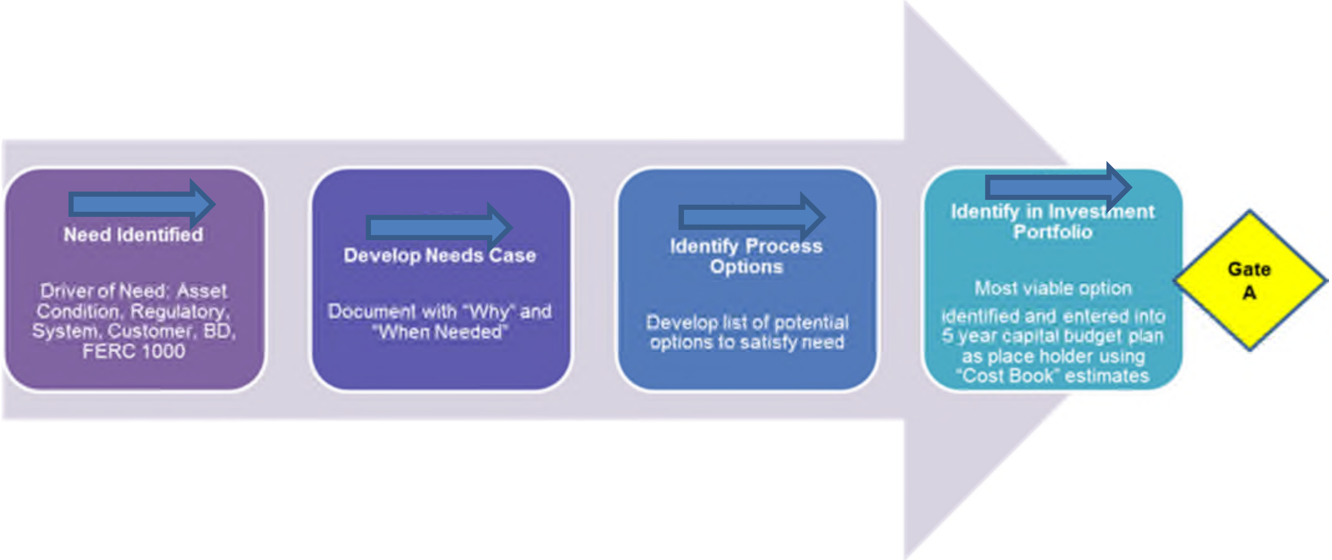
Table 2.14.3: NWA Suitability Criteria Matrix

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 (The date of system need)	Large Project	36-60 months
	Small Project	18-24 months
Cost Suitability	Large Project	Greater than or equal to $1M
	Small Project	Greater than or equal to $500K

National Grid will continue to evaluate the suitability criteria as more NWA Opportunities are solicited and, if necessary propose changes as appropriate.

In 2019, the Company will begin to apply the NWA suitability criteria earlier in the planning process. A brief description of the Company's capital planning process is illustrated in Figure 2.14.1 below. Prior to this DSIP Update, NWA was not considered until all traditional options were considered, a best option was chosen, a cost estimate was performed, and the project was submitted as part of the CIP at Gate A. The new process will consider NWA opportunities immediately after the need is identified, allowing the Company to develop the NWA solution(s) in parallel with the traditional solution, providing bidders more time to develop proposals and meet the need date.

Figure 2.14.1: RFP Development Process



Risk and Mitigation

The table below provides a list of the potential risks and associated mitigation measures the Company is considering.

Table 2.14.4: List of Potential Risks and Associated Mitigation Measures

Risk	Mitigation
NYISODual Participation / Dual Payment restrictions	Solicitation with all stakeholders to mold dual participation rules to enable NWA
Limited opportunities for low-cost, traditional job deferrals	Evaluate suitability criteria and analyze which (if any) DER technologies are best suited for smaller projects
Inherent latencies in identifying EE/DR commitments in NWA locations	Continue to work with internal EE and DR groups to speed up solicitation of EE and DR commitments
Cost of financing and contract negotiations	Proactively work internally and externally with NWA bidders to evaluate mutually beneficial flexible payment and contract structures
Addressing uncertainties in proposed solutions	Provide greater levels of accuracy and information in RFPs, work with NWA bidders to better understand the proposed technologies and their capabilities and integrate lessons learned from demonstration projects

Stakeholder Interface

The Company engages with a variety of stakeholders to align its processes and products with stakeholder needs. A summary of the major outcomes from these stakeholder sessions to date is provided below:

- Development of Joint Utilities NWA[128] and REV Connect[129] pages
- Clarification that NWA providers should include real property acquisition (or lease) as part of their solutions and the cost thereof; however the utility may provide suitable real property for a given solution on a case-by-case basis, if the Company has any surplus real property available.
- Development of a formal pricing structure is now included in the RFPs to speed up the review process and provide greater clarity to bidders.
- NWA bidders asked to net any income streams from participation in energy markets into bid the price to the Company.
- BCA structure will be incorporated into the RFP to help DER providers propose cost-effective solutions.
- Additional electrical system information now incorporated into RFPs to help NWA bidders develop more complete proposals.
- Training will be provided on how to use the Company's System Data Portal and a website link to the portal is included in each RFP.
- Creation of a standard NWA RFP template is now used to speed up creation of RFPs and provide a common format across all RPFs to aid NWA bidders.
- Development and continued improvements to the BCA tool developed by the Company to ensure all NWA benefits are appropriately considered.

Future Stakeholder Items in Progress

- Scheduling pre-RFP technical review sessions with potential bidders
- Creating a more streamlined approach to procurement via sharing best practices with regard to contract terms and conditions
- The Company plans to develop sample terms and conditions and provide a copy in future RFPs to help NWA providers secure/investigate financing options prior to proposal submittal.

Additional Details

The following responds to DPS Staff's request for additional details specific to National Grid's resources and capabilities supporting utility procurement of DERs as alternatives to traditional distribution system upgrades.[130]

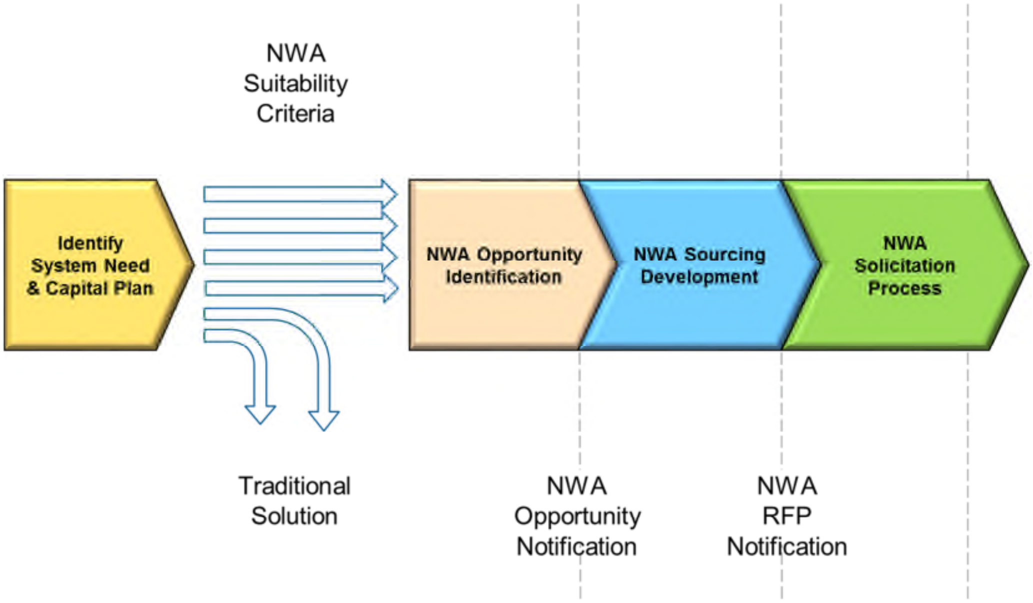
[128] *See* http://jointutilitiesofny.org/utility-specific-pages/nwa-opportunities/
[129] *See* https://nyrevconnect.com/non-wires-alternatives/
[130] DSIP Proceeding, 2018 DSIP Guidance Update, pp. 31-32.

1. 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.

The Company utilizes a multi-stage process to evaluate and deliver NWA projects. Figure 2.14.1 below provides an outline of this process. First, the Company identifies areas of need and determines, by applying the NWA suitability criteria, if an NWA project may be a feasible alternative. If the need does fit within the suitability criteria, the Company begins an engineering analysis of the need (NWA Opportunity Identification) to determine the parameters to be outlined in the NWA RFP. Next, the Company develops the RFP (NWA Sourcing Development) and releases the RFP to start the NWA Solicitation Process.

This process along with the recent change (described previously) to develop the traditional solutions in parallel with the NWA solutions, plus various stakeholder sessions (described previously) all help to ensure sufficient time for the NWA proposers to craft their responses and simultaneously enough time for the Company to meet the grid need.

Figure 2.14.1: Joint Utilities Planning Process and Sourcing Overview



2. The NWA procurement means and methods; including:

a. how the utility and DER developers time and expense associated with each procurement transaction are minimized;

The Company is currently working to develop a detailed NWA implementation process to maximize the efficiency of the procurement and implementation through operation of the NWA solution. This process will clearly define responsible, accountable, consulting, and informed parties for each step, allowing for quick turnaround and minimized costs.

National Grid has taken a number of steps to minimize DER providers' time and expenses as described in more detail in the prior Stakeholder Interface section.

b. The use of standardized contracts and procurement methods across the utilities.

The Company is working with the Joint Utilities to create a more streamlined approach to procurement with DER providers with respect to contract terms and conditions of work. At this time, the Joint Utilities agree that developing and using a standardized contract is premature as solicitation and contracting lessons are still advancing, but will continue to share best practices for issuing contracts and implementing procurement methods.

The Company also plans to develop sample terms and conditions and provide a copy in future RFPs to help NWA providers secure/investigate financing options prior to proposal submittal.

3. Where, how, and when the utility will provide a resource to DER developers and other stakeholders for accessing up-to-date information about current NWA project opportunities. For each opportunity, the resource should describe the location, type, size, and timing of the system need to be addressed by the project.

Location of NWA Opportunities
National Grid's NWA opportunities can be found at the following web addresses:
Joint Utilities Site: http://jointutilitiesofny.org/utility-specific-pages/nwa-opportunities/
REV Connect Site: https://nyrevconnect.com/non-wires-alternatives/
National Grid System Data Portal: https://ngrid.apps.esri.com/NGSysDataPortal/NY/index.html
Pre-qualified vendors are sent NWA opportunity notifications via Ariba, National Grid's procurement system. Interested vendors may contact:

Derek Salisbury: Derek.Salisbury@nationalgrid.com -or-
Shi Hui (Irene) Liu: Shi.Hui.Liu@nationalgrid.com

Other communication methods with Stakeholders are discussed in detail in the prior Stakeholder Interface section.

4. How the utility considers all aspects of operational criteria and public policy goals when selecting which DERs to procure as part of a NWA solution.

Each NWA project and its associated proposals are evaluated for technical viability and cost effectiveness. There are several stage gates for this evaluation including but not limited to: engineering analysis on the proposed NWA solution and the traditional solution, initial screening (via screening tool), electric and gas (if applicable) interconnection studies and several iterations of the BCA (that monetizes environmental benefits and other benefits that align with public policy goals). By taking both the viability and cost effectiveness into account, while also evaluating solutions submitted through a public solicitation process, the Company is considering all aspects of both operation criteria and public policy goals. The figure below provides an excerpt from the NWA screening tool used to narrow down to the best proposals:

Table 2.14.4: Excerpt from the NWA screening tool used to narrow down to the best proposals

	Control, Comms & Operations	Weight, %	Rating	Weighted Score	Comments
4	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	

5. 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. describe the location, type, size, and provider of the selected alternative solution;
c. provide the amount of traditional solution cost which was/will be avoided;
d. explain how the selected alternative solution enables the savings; and,
e. 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 System Data Portal, Joint Utilities website, REV Connect Site. Pre-qualified vendors are sent NWA opportunity notifications via Ariba, National Grid's procurement system. Interested vendors may contact:

Derek Salisbury: Derek.Salisbury@nationalgrid.com -or-
Shi Hui (Irene) Liu: Shi.Hui.Liu@nationalgrid.com

As NWA RFPs are released, closed or awarded, the Company files a publically available report with the Commission which is posted to the DPS website. In addition, as described in the Distribution System Data Chapter, the NWA tab already provides a significant amount of the information specified in this question. However improvements will be made to the NWA tab to geographically locate NWA opportunities along with a drop down list of the major RFP details that will include the deferred cost of the traditional solution.

3. Other DSIP-Related Information

3.1 DSIP Governance

DSIP Scope, Objectives and Participants

This Distributed System Implementation Plan (DSIP) Update serves as a core planning document, outlining National Grid's plans with respect to Distributed Energy Resource (DER) 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 expected to be refreshed every two years. The intended audience of this plan is DER providers, first and foremost, while others include utility, regulatory, government, and other DER stakeholders.

This DSIP Update is an informational document that provides transparency to the Company's on-going efforts and future plans in support of its role as the DSP, but, is not a document that seeks funding approval for these efforts. Commission review and funding approval of investments associated with the DSIP is the subject of rate cases or other cost recovery filings. The Company's rate case filings consider the current five-year plans within the DSIP as one element in the development of a comprehensive plan representing all aspects of the Company's business activities. In developing the plan, the Company considers many factors to prioritize future investment proposals to ensure the Transmission and Distribution (T&D) system is maintained in a safe and reliable fashion, policy objectives are progressed, and customer bills remain affordable.

The role of the DSP includes integrated planning, grid operations, information sharing services and market services. The scope of the DSIP discusses activities in all of these areas. The information contained in this DSIP Update:

- Reports on National Grid's, and the Joint Utilities, progress to date on DSP initiatives
- Describes the Company's plans for implementing DSP related policies, processes, resources, and standards
- Describes how stakeholders can access pertinent information and tools to help them understand utility system needs and potential business opportunities
- Describes National Grid's planning efforts
- Describes how the Company is organized and managed to implement the plans presented in this DSIP Update.

The plans presented in the DSIP have been influenced by significant collaboration and stakeholder engagement. National Grid works closely with the Joint Utilities in engaging DER stakeholders through its Stakeholder Advisory Group and through numerous working groups addressing the many topic areas presented in this DSIP. The Joint Utilities also meet regularly with the NYISO to discuss issues with respect to the integration of distribution and transmission markets. The distribution markets are the responsibility of the DSP, and managed by the utilities, and the transmission markets are managed by the NYISO. The implementation of the plans presented in the DSIP will require the Company to work with many of these same stakeholders, but also with vendor partners under contractual arrangements to deliver on the plans. These vendor partners can range from aggregators on a demand response program to equipment vendors supporting a technology such as VVO.

To foster the development of efficient market functions, the Joint Utilities are working collaboratively with stakeholders to design and implement new market functionalities with a high degree of consistency across the state. Implementing these DSP market functions requires integrating policies, programs, and technical capabilities in coordination with evolving wholesale markets for DER. Many of these elements are not yet fully developed. A follow-on DSP Market Design and Implementation Report will be developed jointly by the Joint Utilities and will be filed in the future as a supplement to this DSIP Update.

DSIP Work Processes

There is a number of 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 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 JU 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 DSIP Update.

Internally, National Grid develops the DSIP through the contributions of dozens of Subject Matter Experts (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 plan. The DSIP Steering Committee is made up of six vice presidents representing the Customer, Regulatory and Electric Operations organizations.

Proposed investments identified in the DSIP are integrated into the Company's general rate case filings or other filings with the Commission for regulatory review and authorization. Many of the investments identified in the initial DSIP were included as proposals in the Company's latest rate case and the Company is now advancing those projects in accordance with the Three-Year Rate Plan Order. In addition to regulatory approval, the implementation of individual projects within the DSIP must adhere to all of National Grid's standard corporate governance. These include processes for authorizing project expenditures, delegations of authority to project managers, and procurement policies, as well as resource planning and portfolio management practices. National Grid has a robust review and approval process for all capital expenditures, referred to as the sanctioning process. The approval authority/committee varies based on project's level of expenditure.

Once a project is sanctioned, an appropriate project/program manager is assigned to manage adherence to scope, cost and schedule. The progress of the project is reviewed as part of a monthly cadence. A number of tools are used including scheduling software, work management systems, as well as plant accounting and financial systems.

Efficiently engaging the appropriate human resources is critical for the success of the plan. National Grid is currently in the process of re-aligning accountabilities within its organizational structure to most effectively manage its role as DSP provider. As part of this alignment the responsibilities for strategic decision making have been streamlined; a new group dedicated to grid modernization execution is being formed to focus on key DSIP deliverables and distribution system planning and operations have been aligned under a single executive. These changes will provide efficiencies in the overall governance of DSIP implementation.

Tools and Information Resources

Throughout this DSIP Update the Company has described a number of tools that stakeholders can use to stay informed and engaged to progress their own business objectives. For example, National Grid's Interconnection Online Application Portal (IOAP) allows DER developers to apply for interconnections on-line and track the progress of their projects. Similarly the System Data Portal provides self-service access to a wide array of information to help facilitate the integration of DER in a cost-effective manner. Today customers can access their load data via the Green Button Download My Data application, and the Company plans to enhance this with the Green Button Connect My Data application as part of its proposed AMI deployment. A number of other Company information portals are also available such as the National Grid Marketplace which is a one stop shopping tool that promotes energy-efficient and energy-saving products to help customers reduce their energy consumption. The Company has made an effort to embed links to these tools throughout this DSIP Update as well as providing a complete inventory of links in the Appendix.

Joint Utilities Website

As indicated above, the Joint Utilities collectively maintain and regularly update their website (www.jointutilitiesofny.org) with valuable resources for interested parties. For example, a summary of current Joint Utilities DSP enablement activities is posted to the website homepage each month to keep third parties informed of utility efforts to advance DSP implementation. The Joint Utilities have also enhanced this website by developing central portals with utility-specific links for hosting capacity, system data, and NWA opportunities, which has helped to increase transparency, usability, and availability of information. The granularity and availability of information provided on the Joint Utilities website has been improved through targeted conversations with DER developers as part of the implementation team stakeholder efforts. The website also serves as a valuable repository for stakeholder information, providing key policy and regulatory documents, detailing past stakeholder meetings, summarizing inputs that stakeholders have previously provided and steps to address, and providing links to other resources such as REV Connect. The Joint Utilities welcome suggestions to enrich this website through their email address at info@jointutilitiesofny.org.

Managing DSIP Activities

National Grid is progressing projects and programs as presented in detail throughout the topic areas in this DSIP Update. The scope of DSP initiatives impacts almost all areas of the Company's business and as such, the organizational design of National Grid will continuously evolve to ensure resources and accountabilities align with the Company's progress as the DSP provider.

Recently a number of organizational changes have been made in an effort to streamline accountabilities. In the new operating model, the NY Jurisdictional President is accountable to our customers, communities and regulators for the overall performance of the Company. The development and delivery of the DSIP requires contributions and support from multiple business units and centralized functions. Of particular note, the Regulatory & Customer Strategy group develops strategies that position the Company for success in the changing energy landscape. The Customer Innovation & Development group develops and tests ideas for new products and services and manages large scale pilots such as REV demonstration projects. And, the Electric Distribution organization is responsible for the delivery of various projects and programs for grid modernization and the integration of DER.

The Electric Distribution organization has recently undergone a significant realignment to better deliver on the plans presented in the DSIP. Through these changes, National Grid has aligned the planning and operations functions under a single Chief Operating Officer (COO) to better manage the evolving electric delivery system and achieve REV objectives.

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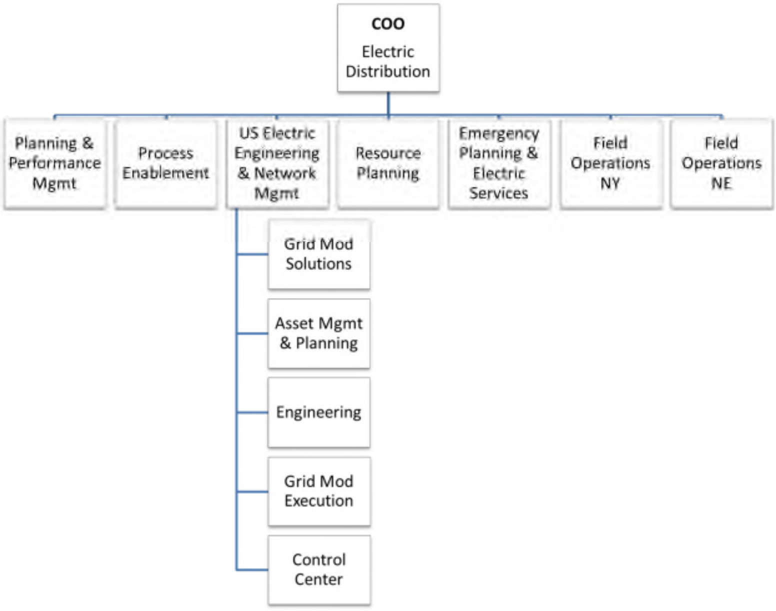
Table 3.1.3: National Grid Electric Distribution Organizational Chart



Reporting directly to the COO, the US Electric Engineering & Network Management executive will have overall accountability for:

Grid Modernization Solutions: A team that engages with stakeholders and the Joint Utilities in developing the Company's grid modernization plans and processes to progress the Company's role as the DSP. Within the Company the team coordinates with Regulatory & Customer Strategy, Customer Innovations & Development and numerous functional organizations in the development and maintenance of the DSIP.

Asset Management and Planning: This team integrates the DSIP recommendations into the Company's five year capital investment plans. The team assesses the needs of the electric distribution system and develops infrastructure plans and DER interconnection studies to ensure the electric system is designed to operate in a safe and reliable fashion in a high-DER environment. This team includes resources to evaluate NWA opportunities as part of the development of T&D system plans, and manages the system data that is shared with DER developers.

Engineering: This team focuses on integrating new technologies on the distribution system including metering, telecommunications, and advanced control systems such as VVO and Fault Location, Isolation and Service Restoration (FLISR).

Grid Modernization Execution: This is a newly formed team charged with managing the implementation of infrastructure projects and programs identified in this DSIP Update.

Control Center Operations: The regional Control Centers monitor and manage the electric T&D systems in real time. As discussed in the Grid Operations section of this DSIP Update, a number of new power management systems will be deployed during the term of this DSIP to further enable DSP capabilities.

Stakeholder Engagement

Building on the structure established in 2016 the Joint Utilities have continued to collaborate effectively with stakeholders to enhance communication channels and develop this 2018 DSIP Update.

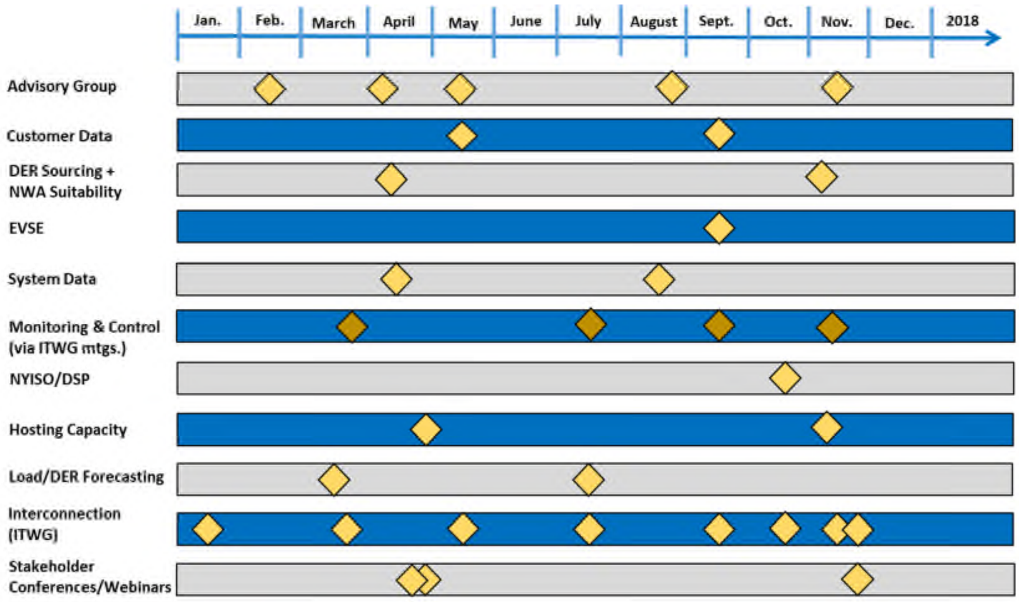
To support consistency across the companies, the Joint Utilities aligned around a common definition of the platform, which includes the three core DSP services of DER integration, information sharing, and market services. Information and updates organized around these three aspects of the platform were presented in a conference with stakeholders on November 30, 2017. The Joint Utilities then developed a common outline for the 2018 DSIP Update filings in order to align with the requests for information provided in the 2018 DSIP Guidance Update to make it easier for stakeholders to access the same information across company filings. The utilities also shared timelines and key milestones for filing development in order to support continued comparison and consistency.

In 2017 and during the first six months of 2018, the Joint Utilities focused on implementation efforts based on commitments made in the Supplemental DSIP and individual initial DSIP filings. The Joint Utilities maintained ten implementation working groups. These groups allowed the companies to share information, jointly develop consistent methodologies and Joint Utilities filings, and work with stakeholders to solicit feedback on those methodologies and filings. As a result, the approaches described in the 2018 DSIP Update filings have greater uniformity and stakeholders will experience DSPs and market functions that are more consistent across the companies. For example, hosting capacity displays will include the same information and visual elements across companies. To support these collaborative processes across the six companies, the Joint Utilities retained the services of ICF to provide project management office functions and technical expertise, as well as coordination of the implementation working groups and related stakeholder engagement efforts.

The Joint Utilities also continued to collaborate on stakeholder engagement, both through the stakeholder Advisory Group as well as through meetings organized around specific topics across ten working groups.[131] The 2017 implementation teams and stakeholder engagement meeting schedule are summarized below.

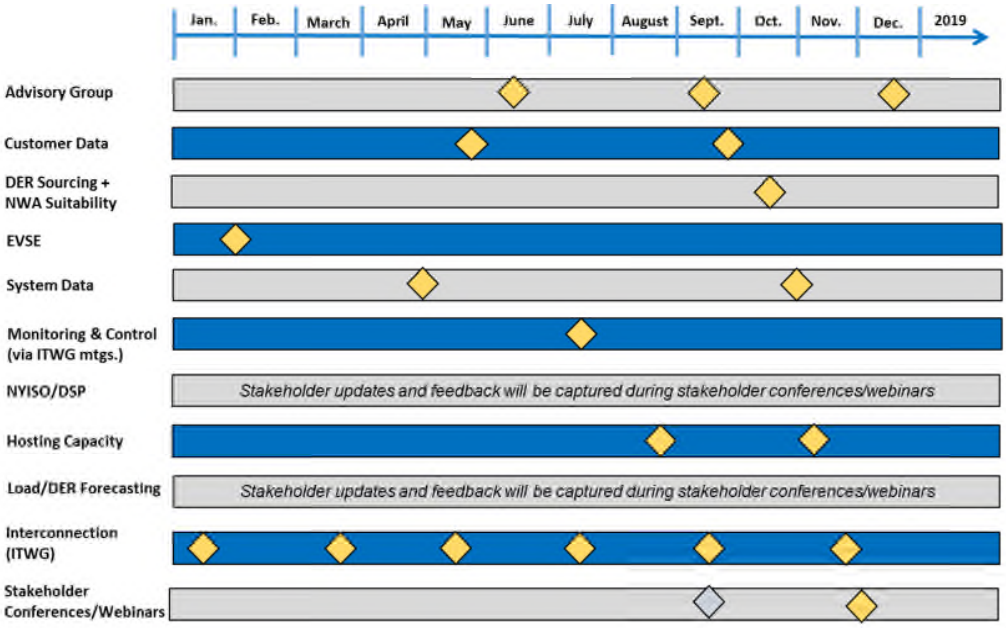
[131] The Advisory Group, made up of approximately fifteen (15) representative companies, is an open forum for stakeholders who are actively engaged in the REV process and the DSIP filings to advise the Joint Utilities in a productive and collaborative stakeholder engagement process.

Figure 3.1.2: 2017 Stakeholder Engagement Efforts



As the companies advanced development of their DSIP Updates into 2018, the Joint Utilities continued to engage stakeholders, as needed, in parallel with the working group efforts. Each company will host a utility-specific meeting with stakeholders in the third quarter of 2018 and the Joint Utilities anticipate holding a larger stakeholder conference in the fourth quarter of 2018 to discuss implementation efforts and plans for 2019. The schedule of stakeholder engagement efforts for 2018 are summarized below.

Figure 3.1.7: 2018 Stakeholder Engagements Efforts



Dependencies

As presented throughout this DSIP Update, there are numerous activities and actions that are planned to occur during the five-year horizon of this DSIP Update. There are a number of key dependencies that will influence the progression of the plans in this DSIP Update including.

- The direction and outcomes of numerous on-going proceedings for such things as VDER, EE, EV, and ESS may impact the scope and timing of implementation plans.
- The Company's AMI plans may be adjusted in accordance with the on-going stakeholder collaborative and updated business plan to be submitted for Commission consideration by October 1, 2018.
- The term of the Company's Three-Year rate plan is through March 31, 2021. Funding DSIP elements beyond this period will be the subject of a future rate case.
- The Company's plans may be dependent on the advancement of tools and technologies. For example, the Company is actively engaged with EPRI in supporting the development on new analytical models to enhance hosting capacity. The schedule of software releases for the EPRI DRIVE tool and the incorporation of new functionalities in other load flow tools could impact deployment schedules for providing additional system data to DER developers.

- The evolution of the DSP will be dependent on the penetration of DER and the participation of customers and third parties in the various programs and services available. Cost impacts on DER manufacturing and integration, either positive or negative, will significantly impact their rate of DER deployment.
- New or shifting state policy goals may impact the relative priority of elements within this DSIP Update plan.
- Continuously evolving cybersecurity threats could impact the scope of various elements within this DSIP Update.
- Lessons learned from REV demonstration projects will continue to shape the DSIP and may highlight new opportunities at scale.

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 every other year.

3.2 Marginal Cost of Service Study

Traditional Marginal Cost of Service

National Grid's Marginal Cost of Service ("MCOS") Study is addressed in the April 28, 2017 testimony of the Company's Electric Rate Design Panel in Cases 17-E-0238 *et al.*[253] On July 10, 2017 the Company filed corresponding Corrections and Updates Testimony.[254] The Company uses the MCOS Study to set rates for the Empire Zone Rider ("EZR") and the Excelsior Jobs Program ("EJP") and as a metric to measure the cost effectiveness of certain DR and EE programs.

Locational Marginal Cost of Service

Concurrent with the filing of this DSIP Update, the Company has released a new enhanced Marginal Cost of Service ("MCOS") study for the express purpose of creating compensation mechanisms for DER. To avoid confusion with National Grid's traditional MCOS study, which will continue to be used for certain ratemaking purposes, the Company will henceforth refer to this enhanced MCOS study as the Marginal Avoided Distribution Capacity ("MADC") study. The MADC study determines locational marginal costs through a forward-looking, system-wide analysis to determine: (1) where DER may be able to provide locational support to the electric distribution system through targeted relief in areas where load growth has the potential to create electrical stress on the system; and (2) assigns a value to that relief by comparing it to the traditional investment needed to alleviate such forecasted stress. The Company's enhanced MCOS study is being filed with the Commission contemporaneously with this DSIP Update in the VDER Proceeding as well as the DSIP Proceeding.[255]

As of the 2016 DSIP filing, National Grid did not have a methodology for estimating locational value system wide on the distribution grid. As of its March 9, 2017 *Order on Net Metering Transition, Phase One of Value of Distributed Energy Resources, and Related Matters,*[256] the Commission found that in regard to developing locational price signals, "National Grid and New

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[253] *See* http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7BD9BAEE18-5700-4E40-91AE-EC55FC480722%7D.

[254] *See* http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7BF4D0C103-B818-474F-BBA8-2A59B973E339%7D.

[255] VDER Proceeding *et al.*, Enhanced Marginal Cost of Service Study of Niagara Mohawk Power Corporation d/b/a National Grid to Determine Locational Value of Distributed Energy Resources (filed July 31, 2018).

[256] VDER Proceeding, Order on Net Energy Metering Transition, Phase One of Value of Distributed Energy Resources, and Related Matters (issued March 9, 2017)("VDER Phase One Order").

York State Electric and Gas/Rochester Gas and Electric (NYSEG/RG&E) are considerably behind."[257]

As required by Ordering Clause No. 13 in the VDER Phase One Order, on April 24, 2017, National Grid filed a Work Plan and Timeline to Determine Locational Value of Distributed Energy Resources "2017 Work Plan") which lays out a methodology for the enhanced MCOS study. The Company renamed the work to determine the value of specific locations on the distribution system the MADC study to differentiate the two work efforts. The Company has proposed that the MADC study results become the basis for compensating DER, including those that inject into the system, and those that respond via flexible loading, including DR.

Marginal Avoided Distribution Capacity

The MADC follows four basic steps:

1. Development of system-wide load flow model
2. Development of load and DER forecasts at the substation level
3. Identification of potential DER opportunities to address system needs
4. Evaluation of locational values

In accordance with the 2017 Work Plan, National Grid developed multiple sets of load and DER forecasts for each distribution substation. The MADC study evaluates two sets of forward-looking ten-year forecasts: (1) a top-down forecast based on data available from the NYISO zonal level load data and growth trends; and (2) a bottom-up Company forecast utilizing customer-level information to develop feeder-specific 8760 hour load profiles over the study horizon. The top-down zonal forecasts are disaggregated down to individual substations and the bottom-up feeder-level forecasts are aggregated or "rolled up" to create similar substation views. The bottom-up forecasts include load from existing customers and scaling factors to account for projected loads from new customers.

Multiple load flow cases were analyzed to assess the system performance during coincident peak loading as well as during more localized non-coincident peak loading to capture the strain on local infrastructure. System needs considered thermal constraints, voltage excursions, and contingency at-risk load. For the duration of the ten-year study horizon, the model identified the specific constrained assets, the timing at which the planning criteria violations are forecasted to materialize, and the magnitude of relief (kW) required to address the violation.

National Grid's engineering teams then developed traditional utility solutions for each of the violations identified from the load flow analyses. The cost estimates for each of the traditional solutions were based on recent projects and cost projections approved in the Three-Year Rate Plan Order.

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[257] *Id.*, p. 115.

The Company evaluated results from the load flow analyses against planning criteria to identify potential projects where the addition of DER could provide alternatives to traditional investment. Generally, if a need could be addressed by the capacity of DER, it was identified for further consideration with two exceptions. Projects were removed from the MADC study if an asset was already scheduled to be replaced due to age or state of repair (*i.e.*, asset condition) and only if the updated infrastructure solved the constraint identified by the load flow model. Similarly, an existing project was removed from the MADC study if it appeared in National Grid's CIP with an in-service date of 2020 or earlier. These imminent-need projects were excluded as the Company is obligated to replace such assets to meet planning standards for safe and reliable service regardless of the quantity of DER on the system.

For each defined violation, the Company created a list of locations where DER performance, aligned with system need, would be beneficial. In most cases, the locations include a list of feeders. In select cases, they also include higher voltage lines.

In cases where the locations for DER had the possibility to solve more than one model violation, and obviate the need for multiple potential projects, the Company adjusted the projected value of those locations appropriately given the type of project and size of the need.

As in the traditional MCOS study, the crux of the MADC study is representing utility spending in a $/kW fashion. The Company used the study results – the size of the need, the timing, and the cost of the traditional solution – to generate a schedule of revenue requirements that could be deferred by DER. This is conceptually similar to the procedure the Company used in assessing the Village of Kenmore NWA project and plans to continue to use going forward to evaluate other NWA opportunities.

The MADC study results are unique estimates of the value of a marginal increment of load relief on a $/kW basis based on the potential to defer the proposed traditional investment over the ten-year study horizon for each location. This $/kW estimate can become the basis for locational compensation in expanded DR programs or the LSRV in the VDER Value Stack tariff as it exists today.

The current implementation will allow the Company to expand its DR programs and offer locational elements of the Value Stack tariff with increased precision versus the Phase One Value Stack. All customers will benefit from such improved valuation, which could allow the Company to offer new products which create value for the customer through bill savings and value for the system through reduced costs.

National Grid has found the process of running the MADC study useful for internal planning purposes, in addition to producing estimates of value directed by the Commission. Continued repetitions will create iterative improvements.

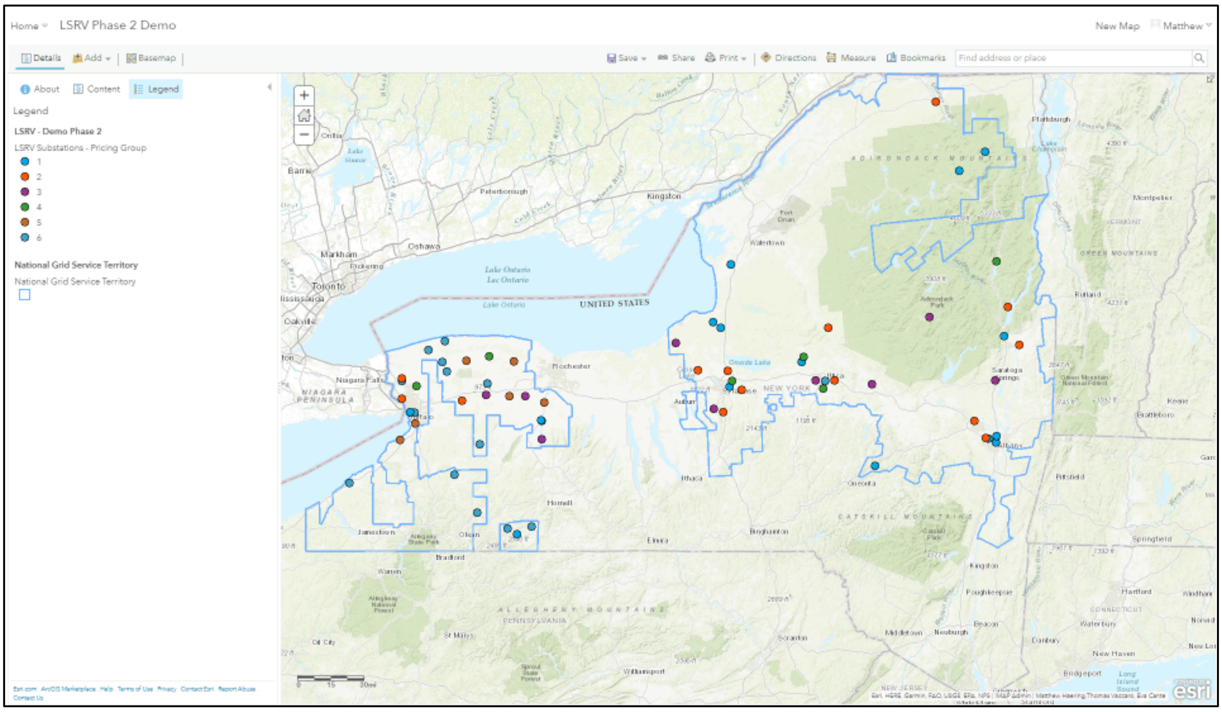
The Company has already identified areas in the MADC study which can be improved for future iterations, notably:

1. Improving the link between CYME network analysis software and PSS®E planning software;
2. Utilizing more complex forecasts; and
3. Producing a feeder level analysis.

The areas that have been identified in the MADC study as being suitable for compensating DER, based on the opportunity to contribute to local infrastructure deferral, are presented in Figure 3.2.1 below.

National Grid looks forward to continuing collaboration with the DPS Staff and stakeholders regarding the best practices of MCOC study estimates as the basis for DER compensation.

Figure 3.2.1: Map of Proposed LSRV Zones based on MADC Study Filed with the Commission on July 31, 2018



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 DSIP Plan. As stated in the BCA Order:

> *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.*[258]

The BCA Framework Order required each utility to file its proposed BCA Handbook with its initial DSIP on June 30, 2016.[259] As required by the BCA Order,[260] 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 Order. The utilities' BCA Handbooks deviate from each other only where necessary to accommodate distinctions among the various service territories.

Version 2.0 of the Company's BCA Handbook, being filed contemporaneously with this DSIP Update in the REV Proceeding and DSIP Proceeding, provides 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 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.

Pursuant to the BCA Order, the Company has made the calculation methodologies and universal input parameters used for its benefit-cost analyses transparent and publicly available in its 2018 Version 2.0 BCA Handbook.

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[258] REV Proceeding, BCA Order, p. 29.
[259] *Id.*, p. 31.
[260] *Id.*

The Version 2.0 of the Company's BCA Handbook will be available on the National Grid System Data Portal at https://ngrid.apps.esri.com/NGSysDataPortal/NY/index.html

Table 3.3.1. New York Assumptions for Version 2.0 of BCA Handbook

New York Assumptions	Source
Energy and Demand Forecast	NYISO Load & Capacity Data Report ("Gold Book")[261]
Avoided Generation Capacity Cost ("AGCC")	DPS Staff ICAP Spreadsheet Model[262]
Locational Based Marginal Prices ("LBMP")	NYISO Congestion Assessment and Resource Integration Study Phase 2 (CARIS Phase 2)[263]
Historical Ancillary Service Costs	NYISO Markets & Operations Reports[264]
Wholesale Energy Market Price Impacts	DPS Staff: To be provided[265]
Allowance Prices (SO_2 and NO_X)	NYISO: CARIS Phase 2[266]
Renewable Energy Certificate ("REC") Contract Price	Most recent NYSERDA solicitation results[267]

261 The NYISO 2018 Load & Capacity Data Report ("Gold Book") is available in the Planning Data and Reference Docs folder at: http://www.nyiso.com/public/markets_operations/services/planning/documents/index.jsp.

262 The ICAP Spreadsheet Model is found under Case 14-M-0101 at the Commission's website: http://www.dps.ny.gov. The filename is BCA Att A Jan 2018.xlsm.Updates will be filed in the same location.

263 The finalized annual and hourly zonal LBMPs from 2018 CARIS Phase 2 are expected to be available by December 2018 on the NYISO website in the CARIS Study Outputs folder within the Economic Planning Studies folder at: http://www.nyiso.com/public/markets_operations/services/planning/planning_studies/index.jsp.
Until such time that the finalized 2018 CARIS 2 data is published, the utilities will employ the 2016 CARIS Phase 2 results.

264 Historical ancillary service costs are available on the NYISO website at: http://www.nyiso.com/public/markets_operations/market_data/pricing_data/index.jsp.

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

266 The allowance price assumptions for the 2018 CARIS Phase 2 study will be available on the NYISO website in the CARIS Input Assumptions folder within Economic Planning Studies at: http://www.nyiso.com/public/markets_operations/services/planning/planning_studies/index.jsp. Until such time that the finalized 2018 CARIS 2 data is published, the utilities will employ the 2016 CARIS Phase 2 results

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

Appendix: 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 Interconnection Online Application Portal (IOAP) (new Customer Application Portal (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;
  - Hosting Capacity Analysis;
  - Non-Wires Alternative opportunities;
  - Locational System Relief Value (LSRV) areas, and
  - Reports tab (Note: The BCA handbook will be added following its filing on 7/31.)
- 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
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- National Grid Electric System Bulletin Number 756:
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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 Department of Public Service (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
- Distribution System Implementation Plan (DSIP) Proceeding Case 16-M-0411:
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- DPS: Interconnection Technical working Group:
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- 2015 New York State Energy Plan:
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- New York Independent System Operator (NYISO) Homepage: http://www.nyiso.com/public/index.jsp
- New York State Energy Research and Development Authority (NYSERDA) Homepage: https://www.nyserda.ny.gov/
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- Electric Power Research Institute (EPRI): Impact Factors, Methods, and Considerations for Calculating and applying Hosting Capacity: https://www.epri.com/#/pages/product/000000003002011009/?lang=en
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- DOE: Alternative Fuels Data Center: https://www.afdc.energy.gov/stations
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- Energy.Gov: Green Button Open Energy Data: https://www.energy.gov/data/green-button
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- National Standard Practice Manual: https://nationalefficiencyscreening.org/wp-content/uploads/2017/05/NSPM_May-2017_final.pdf