Advanced Metering Infrastructure (AMI)
Benefits Implementation Plan
Niagara Mohawk Power Corporation
d/b/a National Grid

January 19, 2021

Contents

1. Introduction

Niagara Mohawk Power Corporation d/b/a National Grid ("National Grid" or the "Company") submits the following Advanced Metering Infrastructure (AMI) Benefits Implementation Plan (this "Plan") in accordance with the New York Public Service Commission's (Commission) Order Authorizing Implementation of Advanced Metering Infrastructure with Modifications ("AMI Order").[1]

With the AMI Order, the Commission authorized a transformational investment in smart meters that can enable benefits for customers and address operational needs while providing meaningful contributions toward the clean energy goals set forth in the Climate Leadership and Community Protection Act (CLCPA). Learning from a wide variety of stakeholders including customers and vendors, as well as from past AMI pilots, peer utilities, and industry best practices, the Company has developed this Plan to maximize the value of the AMI investment across the following benefit categories:

Avoided O&M Costs
AMR Meter Reading
Meter Investigation
Remote Connect and Disconnect
Reduction in Damage Claims
Storm Outage Management System
Field Collection System (FCS) Meter Reading
Interval Meter Reading
Customer Benefits
Volt-VAR Optimization
Energy Insights/High Usage Alerts
Time-Varying Pricing (TVP)
Electric Vehicle (EV) Pricing
Avoided Program Costs
Capital
Operations & Maintenance (O&M)
Value of Distributed Energy Resources (VDER) Metering
Distributed System Platform (DSP)

Table 1-1: Quantified AMI Benefits in the AMI Business Case and BCA

Section 2 below provides additional background on the development of the Company's AMI proposal. Section 3 details the threshold steps to benefit realization. Section 4 provides a detailed overview of the quantified benefits from the Company's AMI Business Case, as

[1] Cases 17-E-0238 and 17-G-0239, Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Niagara Mohawk Power Corporation d/b/a National Grid for Electric and Gas Service ("2017 Rate Case"), *Order Authorizing Implementation of Advanced Metering Infrastructure with Modifications* (November 20, 2020) ("AMI Order"), Ordering Clause 5.

identified in Table 1-1, above. Section 5 describes additional unquantified benefits that AMI can enable in the future.

2. Background

In July 2016, the Company filed a Distributed System Implementation Plan (DSIP), which set forth a plan for investments needed to modernize its system and enhance its DSP capabilities.[2] In the DSIP, the Company identified AMI as a foundational component of its grid modernization effort. The Company included an AMI business case that described and compared alternative AMI deployment options and, based on the results of a benefit-cost analysis (BCA), proposed territory-wide implementation as the cost-effective fit-for-purpose solution.

In April 2017, the Company filed a more detailed and updated AMI business case supporting full-scale AMI deployment as part of its general rate case.[3] The Company initiated an AMI collaborative process in April 2018 in accordance with the Joint Proposal approved by order of the Commission in the rate case. The collaborative process culminated in the November 15, 2018 filing of the Report on the Proposed Implementation of Advanced Metering Infrastructure (the "AMI Report"). After filing the AMI Report, the Company supplemented its AMI proposal with additional benefit opportunities identified in peer utility filings, as well as reduced costs, which enhanced the case for AMI in New York. The enhancements were outlined in five supplemental filings.[4]

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

- **Customer Benefits:** "[T]he deployment and use of AMI can be harnessed to transform the relationship between National Grid and its electric and gas customers. With AMI, National Grid can improve its response to power outages, as the Company will have more accurate and granular information regarding the voltage and current status of customers' services. AMI can empower customers by providing them with information about their energy usage and allowing them to take action to manage their electric and gas costs."[5]

---

[2] Case 14-M-0101, Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision.

[3] *See* 2017 Rate Case, *Direct Testimony of the AMI Panel* (April 28, 2017).

[4] *See* 2017 Rate Case Company filings dated February 22, 2019; September 4, 2019; January 22, 2020; September 18, 2020; and October 28, 2020; *see also* Cases 20-E-0380 and 20-G-0381, Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Niagara Mohawk Power Corporation d/b/a National Grid for Electric and Gas Service ("2020 Rate Case"), *Direct Testimony of the AMI Panel* (July 31, 2020).

[5] AMI Order at pages 26-27.

- **Operational/System:** "National Grid will likely need to invest funds in its metering infrastructure in the near future, whether to replace AMR [Automated Meter Reading] meters and gas modules in kind, or to upgrade to AMI. This presents an opportune time to upgrade to AMI while avoiding the costs of replacing the existing AMR meters in kind."[6]

- **Clean Energy:** "AMI is an important and valuable contribution to enabling the Company to assume the role of the [Distributed System Platform (DSP) provider], to increasing use of [Distributed Energy Resources (DERs)] to support system operation, to increasing the use of measures such as VVO to reduce energy use and emissions, and to facilitating customer access to products and services provided by third-parties."[7]

In approving the AMI proposal, the Commission evaluated the accompanying BCA models and assumptions that were included in the AMI business case.[8] The Commission based its decision on the information from the Company's opt-in TVP scenario with three modifications. First, the Commission approved approximately $9.07 million in incremental costs to reduce data latency from 15-minute intervals available to customers every four hours, to 15-minute intervals available every 30-45 minutes.[9] Second, the Commission adjusted the rate at which customers were assumed to participate in an opt-in TVP rate from 20 percent to 15 percent.[10] Third, the Commission incorporated an energy usage reduction of 1.5 percent from customer behavior.[11] With these adjustments, the Commission approved the Company's AMI proposal, finding that using the more conservative assumptions "suggests that the benefit-cost ratio [of 1.10] is durably above one."[12]

The Commission also directed the Company to develop this Plan. In doing so, it explained that the purpose is to assist with understanding the benefits identified in the BCA, track the attainment of the benefits, and learn from AMI implementation.[13]

3. Threshold Steps to Benefit Realization

The following section describes threshold steps that must be completed to deliver AMI and the accompanying benefits.

3.1. Program Management and Change Management

National Grid's vision is to be at the heart of a clean, fair, and affordable energy future. Delivering that vision requires a commitment to enabling a fair and affordable transition to a clean energy economy by maintaining a customer-centric approach to managing and delivering change. This commitment is demonstrated in a variety of ways, including the robust set of

[6] *Id.* at page 36.
[7] AMI Order at page 27.
[8] *See id.* at page 35 (Noting that the Commission compared the Company's BCA assumptions, costs, and benefits with those used by other utilities, and found the model to be reasonable).
[9] *Id.* at page 31.
[10] *Id.* at pages 35-36.
[11] *Id.* at page 36.
[12] *Id*.
[13] AMI Order at page 48.

standards developed as part of its Business Management System (BMS), which AMI will leverage. As set forth in Figure 3-1, there are ten core principles of the program and change management standards that the AMI project will adhere to for promoting common practices and successful outcomes. Each principle has been well defined and includes a related set of performance requirements. Furthermore, the BMS standards are accompanied by a comprehensive Company portal that includes training, tools, and templates. An illustration of the core principles for program and change management appears below.

A number of Company business functions support the AMI project team, in areas such as program management, change management, business architecture, and process mapping. Additionally, the functions will provide for an independent assessment of the AMI project through their program assurance and project controls teams. As an example, the Program Assurance group will conduct independent assessments for compliance with the above BMS standards and share the results with leadership. Likewise, the project controls team will conduct recurring evaluations of the effectiveness of controls being leveraged to mitigate project risks.

While the proposed AMI deployment timeline includes two years for back-office systems implementation and detailed design, the Company recognizes the importance of proactive planning to ensure internal resources are appropriated and organized to successfully deliver the AMI project. The Company is also taking steps to prepare Requests for Proposals (RFPs) for external support in the areas of project management, business integration, and system integration (discussed further below). Such "implementation readiness" activities also include assembling project plans and schedules, organizational resourcing, establishing business unit collaboration and communication processes, and preparing for internal sanctioning.

Figure 3-1: Core principles of program and change management standards

3.2. Project Sanctioning

The Company's investment planning protocols require the project to undergo an internal sanctioning process. Based on the size of the AMI capital investment, the sanctioning process includes six review committees representing increasing levels of delegation of authority. Five of the committees will review and provide feedback on the documentation, clarifying the proposal (a process referred to as "noting") before the project is officially "approved." The approval will then enable the formal initiation of the project, including execution of the project contracts. The AMI team is currently completing the internal sanctioning documentation and will manage the project through this process toward approval, which is anticipated in March 2021.

As part of the sanctioning process, the team is required to prepare a sanction paper for each of the project's major components: gas, electric, and information technology (IT). The papers outline the project's background, drivers, timeline, complexity, risks and projected expenditures for the duration of the project, as well as a specific funding request for sanctioning approval. The papers will be presented together at the review committee meetings along with a presentation covering the entire project.

The initial sanctioning request includes two components: approval for funds to conduct the first year of the project plan and a shift in the delegation of authority. Given the size of the project, the AMI team anticipates repeating the internal sanctioning process each year to secure annual approval of the project budget. Shifting the delegation of authority for this approval will help the AMI project team shorten the sanctioning process for future approvals related to the project.

3.3. Establishing the Project Governance & Workstreams

3.3.1. Project Governance & Resourcing

The Company intends to establish an AMI program governance structure, which will include representation from senior leadership and subject matter experts from across the Company. The Company is in the process of refining this workstream-based approach by incorporating lessons learned from discussions with other large internal programs, meetings with consultants in the implementation space, and meeting with peer utilities who have implemented AMI. Figure 3-2 illustrates an example of the program governance structure the Company plans to employ.

Figure 3-2: Example program governance structure

The Company expects to use a mix of new and existing employees to manage AMI program implementation. In some cases, as AMI changes the way the Company operates, existing staff will be repurposed. Additional staff is expected to support areas such as project management, implementation, change management, and business integration.

The Company will provide AMI information and training to all employees with an emphasis on enabling customer service representatives to assist customers. Such information and training will be provided through a variety of channels and materials to ensure that information is delivered and accessible to all employees. The channels and materials will include:

- Company Town Halls;
- Employee Communications;
- Emails;
- In-person Training Sessions;
- Frequently Asked Questions (FAQ) Resources;
- User Manuals; and
- Instructional Videos.

The Company will provide additional details on employee training, as part of the revised Customer Engagement Plan (CEP), which the Company is required to file within six months of the issuance of the AMI Order. Likewise, the Company will develop a phased training program for employees who will be installing and testing the communications network, electric AMI meters, and gas modules. The Company expects such employee training to occur for a subset of employees during the two-years of back-office system installation, and for the training to continue, as needed, through the deployment phase.

As AMI implementation progresses, the Company also intends to use existing employee capabilities to analyze and leverage AMI data to maximize energy saving benefits and assess the overall impact of AMI implementation. For example, teams within the Company, such as Advanced Analytics and Energy Forecasting, have skills in both electric domain knowledge and quantitative analysis to ensure the Company is capturing and delivering benefits.

3.3.2. Customer Integration

As part of its AMI proposal, the Company worked collaboratively with stakeholders to develop and refine a robust CEP. With the CEP as a roadmap, the Company will increase awareness of AMI, guide customers through the meter deployment process, and empower customers to use the new technology. Implementing the CEP is a key component of the Company's effort to inform and educate customers about the benefits of smart meters. The outreach efforts are aimed at increasing participation and acceptance of AMI, as well as the eventual adoption of new insights and services. This effort will include a collaboration among internal teams focused on customer engagement, such as Customer Insights, Marketing, Customer Energy Management, and Customer Experience Products. Working together, this internal coordination will ensure the materials, processes, and outreach efforts defined in the CEP are successfully executed. As customer needs evolve, the team will develop the means through which insights or benefits continue to be delivered to customers. Additional details regarding customer integration, including a general timeline, will be provided as part of the revised CEP.[14]

3.3.3. Business Integration

Business integration is an important step toward ensuring AMI implementation is successful and efficient. It strengthens the Company's AMI-related communication and collaboration processes across business units by aligning project resources. Likewise, by proactively managing change, business integration provides for a smooth transition into the ongoing management of the AMI resources and associated programs once initial project deployment is complete.

Many Company employees will be impacted by the transition to AMI, including meter field technicians, meter shop technicians, customer service representatives, control center operators and billing analysts. Each role will be transformed by the incorporation of this new technology. To aid in a smooth transition, the Company will use a business integrator to promote internal communication, engagement, and adoption of the AMI technology and functionality. This will include alignment with programs such as the deployment of a Customer Information System (CIS), Advanced Distribution Management System (ADMS), other grid modernization investments, and other IT business objectives.

The business integrator will also be supported by industry-leading consultants and will establish robust partnerships with other teams across the Company. The objective of establishing these partnerships is to raise awareness of the AMI efforts, coordinate tasks to ensure efficient implementation, and build change management processes to enable the transition to new ways of working once AMI program implementation is complete.

[14] AMI Order Ordering Clause 8.

3.3.4. System and Grid Integration

Systems and grid integration activities are also key to harnessing the full capability of smart meter benefits across the Company's infrastructure, software, and systems. By successfully deploying physical equipment and enabling data exchanges between the meters, modules, and collectors to back-office systems, the Company can maximize the effectiveness of the overall AMI platform. The Company's approach to systems and grid integration includes:

- Capability analysis and end-to-end definition of functionality at each step;
- Systems architecture to define data interfaces between systems and components;
- Defining detailed requirements for all systems and interfaces;
- Custom configuration and development of system application programming interfaces (APIs);
- A well-coordinated deployment strategy that minimizes the impact to communities and customers;
- Detailed test case planning and definition; and
- Careful test execution and defect documentation.

In general, AMI platforms have highly complex data exchanges. To address these complexities and facilitate the exchange of standardized data elements among all affected systems, the industry has turned to systems integration solutions supported by an enabling middleware technology, such as an enterprise service bus (ESB). The Company plans to follow this same industry-accepted approach. In addition to a functional platform, other benefits of strong systems integration include:

- Improved system response time and performance;
- Lower labor costs and increased operational efficiency; and
- Compatibility across system devices and software.

The Company's systems- and grid-integration teams will manage these activities in coordination with a dedicated IT project management office (PMO) team and qualified vendor partners, who will be chosen through the vendor selection and management process.

Below is a high-level overview of the key AMI systems that will be installed, upgraded and integrated and the approximate timeline associated with the implementation of those systems.

Phase 1 (~12 - 18 months after project kickoff):

- Upgrade/integrate with Customer Service Systems (CSS – customer account management) & Billing systems;
- Install/integrate Meter Data Management Systems (MDMS – meter data collection, processing and management);
- Install/Upgrade and integrate with Work Order Management Systems (WOMS – mgmt. of installation of meters);
- Install/integration Field Area Network (FAN) system software (software related to the network devices required to establish the AMI communication network.

Phase 2 (~15-21 months after project kickoff):

- Install/integration with Cloud infrastructure (cloud storage and services for AMI data);
- Install/integration with Customer Energy Management Platform (CEMP) – platform for visual display of AMI usage data;
- Upgrade/integration with Asset Management Systems – for tracking inventory and lifecycle of AMI assets.

Phase 3 (~21-27 months after project kickoff):
- Initial Outage Management Systems (OMS) integration;[15]
- Upgrade/integrate with Geographic Information Systems (GIS) – geospatial information related to meters and other utility endpoints.

All Phases:
- Install and upgrade Cybersecurity tools – end-to-end security tools for endpoints, network equipment software, infrastructure, etc. (discussed further in Section 3.3.5 below);
- Upgrade/integration with middleware and ESB – platforms and systems used for data exchanges.

The Company has also been evaluating future-state customer system technology to eventually replace existing legacy systems used for billing across its jurisdictions with a single, more flexible and adaptive platform. The Company's experience with the Clifton Park Reforming the Energy Vision (REV) Demand Reduction Demonstration Project (Clifton Park Demonstration), which incorporated the deployment of AMI to approximately 13,000 customers, shows that the legacy CIS system used now will initially be suitable for integration of the MDMS employed by the AMI program. Going forward, a newer CIS will become increasingly important when AMI-enabled capabilities, such as advanced time-varying and peak period rates, dynamic energy management, and remote meter interaction, become prevalent. The approval and deployment of a new CIS system is currently being considered as part of the Company's pending rate case.

3.3.5. Cyber Security Integration

Cyber security provides protection of cyber assets (*e.g.*, computer hardware and software, information) from theft, damage, disruption or misdirection of the services they provide. The importance of cyber security is increasing as more intelligent devices are interconnected and 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 the Company leverages this information to drive more efficient operations and improve decision making. Incorporating cyber security and privacy provisions into all AMI investments and activities supports the reliability of the electric grid and ensures that information integrity and the confidentiality of customer information can be maintained. The cyber security provisions planned for AMI will provide:

- Availability: avoid denial of service;
- Integrity: avoid unauthorized modification;
- Confidentiality: avoid disclosure;

[15] Please note that the benefits from full OMS integration are not expected to occur until meter deployment is complete in 2027.

- Authenticity: avoid spoofing/forgery;
- Access control: avoid unauthorized usage;
- Auditability: avoid hiding;
- Accountability: avoid denial of responsibility;
- Third-party protection: avoid attacks on others;
- Segmentation: limit the scope of attacks on the solution;
- Quality of service: maintain reasonable latency and throughput; and
- Privacy: maintain customer data in a fashion that keeps confidential customer data confidential.

All systems, components, and integrations are considered in the following service domains: Network; Data Protection; Identity and Access Management; Vulnerability; Security Orchestration, Automation and Response (SOAR); Platform, Third Party Risk, and Training; and Awareness. These service domains feature foundational capabilities in place to support the current state of National Grid's operations and are improved on an on-going basis, further enhancement is required to ensure that the risk associated with AMI is mitigated through the deployment of security controls to address cyber security risk associated with the future state of grid operations. Cyber security integration will be incorporated as appropriate, as part of the System and Grid Integration timeline discussed in Section 3.3.4 above and the Communication, Meter, and Module Deployment timeline discussed in Section 3.5 below.

3.4. Electric Meter and Gas Module Approval

In collaboration with the AMI vendor, the Company will petition for approval for use of the proposed electric AMI meters and gas modules consistent with the Commission's requirements. To further this effort, the Company has conducted internal workshops with subject matter experts to prepare and organize the materials required to petition for meter and module approval. The Company is currently projecting to file a petition for approval of residential gas modules (*i.e.*, accounting for ~97% of gas customers) as early as May 2021, with anticipated approval by May 2022.[16] Similarly, the Company is projecting to submit a completed application with the vendor (as further described below) for approval of single-phase electric meters (*i.e.*, accounting for ~91% of electric customers) as early as January 2022, with anticipated approval by June 2022. The Company and AMI vendor expect applications to address the remainder of the customer base to be filed in close proximity and with similar projections for review and approval.

The electric meter approval process is governed by New York Codes, Rules and Regulations (NYCRR) 16 Part 93. As required therein, the Company will provide an "intention to use upon approval" letter to the Commission certifying that it intends to use the meter types identified in the petition. The meter types will conform with the requirements specified in the latest version of American National Standards Institute (ANSI) C12 standards and will be commercially available. The Company will sponsor the meters and the vendor will submit a completed application including demonstration of test results from a Commission-approved independent

[16] The Company is optimistic that this represents a conservative estimate for the timeframe required to obtain NYS approval. The potential also exists for a subsequent similar approval to incorporate the latest Wi-SUN communication protocol.

laboratory. The AMI vendor will be required to provide all supporting meter testing documentation to the Commission and the Company. Witness testing of the meter types will be performed at the Company's meter lab with the manufacturer and Department of Public Service Staff ("Staff") present. The Company anticipates meter approval would follow.

Regarding gas modules, the Company, in accordance with 16 NYCRR Part 227, will ensure the AMI gas modules will meet or exceed the requirements specified in the appropriate ANSI standards. The Company will make available one or more units of equipment covered by the application for testing and/or retention for such purposes by the Commission as set forth in NYCRR. Regarding the formal petitioning process, the Company will sponsor the AMI gas module and submit a complete application, in accordance with 16 NYCRR Part 227. After submission of the application to the Commission, the Company will coordinate with Staff and the manufacturer for appropriate witness testing, as requested by the Commission. As with the electric meters, the Company anticipates gas module approval would follow witness testing.

In addition, the Company is developing a meter testing plan, as required by the AMI Order. The meter testing plan will outline testing to be performed once meter shipments are received for installation, as well as the Company's plans for ongoing meter testing to be performed after the meters have been installed. The Company will file the meter testing plan within 120 days after issuance of the AMI Order.

3.5. Communication Network, Electric Meter and Gas Module Deployment

The Company will follow a six-year AMI deployment program as shown in Figure 3-3 below. The initial project ramp-up phase will include project sanctioning, onboarding resources, and contract execution. The two-year period following project kickoff will address detailed design, additional procurement activities, and the installation of the back-office systems. This period will also include key activities for further refinement of deployment planning.

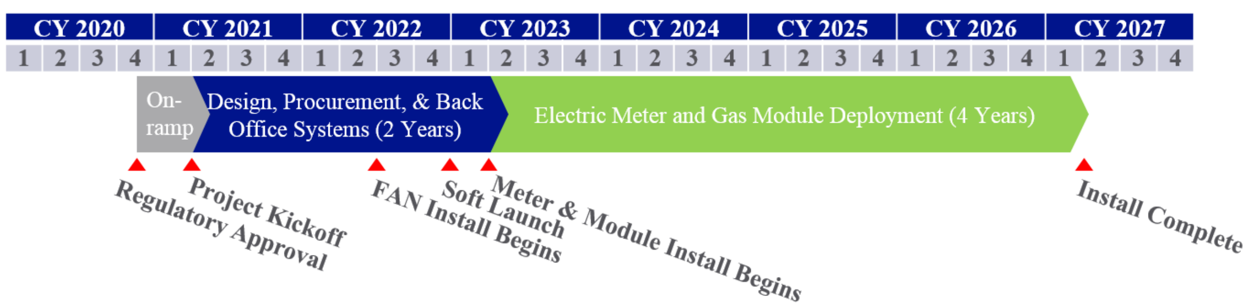


Figure 3-3: National Grid AMI Program Implementation Schedule

The Company proposes to install approximately 1.7 million electric AMI meters and 640,000 gas modules across its service territory. Under the Company's proposal, 20 percent of the electric meters and gas modules will be installed in the first year of deployment, followed by 35 percent in both years two and three, and 10 percent in year four of the deployment period. As depicted in Figure 3-3, the Company plans a soft launch three months in advance of the mass deployment. The soft launch will be used to test and refine the Company's process. A detailed integrated meter and FAN deployment strategy is under development and assumes regulatory approval of the associated meters and modules as outlined in Section 3.4, above. The Company plans to share an initial draft of the deployment strategy with Staff in March 2021, and expects to iterate and refine this strategy both leading up to the soft launch and throughout the deployment period. The Company is considering multiple factors in developing its deployment strategy, with one of the key priorities being dual-fuel areas with a larger saturation of AMR modules reaching the end of their useful life. The Company also plans to begin FAN deployment approximately nine months in advance of the electric AMI meters and gas modules, to provide greater flexibility during the four-year deployment.

For areas with sufficient population density, the Company will utilize a radio frequency mesh network to facilitate meter communication with the backhaul system. However, in some areas approximately five percent of devices will not be amenable to deploying a mesh network, requiring the Company to use cellular radio communications instead. The FAN will leverage devices to enable the transmission of data from the mesh-network linked AMI meters to the back-office systems (*i.e.,* collectors and relay routers). Collectors are larger bandwidth devices that manage mass data collection, while relay routers extend the range of meter communications. When possible, the electric meter will also serve as the communications platform for the gas module. This capability reduces the volume of FAN devices required while passing the necessary electric and gas data to back-office systems. The Company will refine its detailed topographical analysis and network design leading up to the installation of FAN devices in order to optimize the location of network equipment. Through the AMI solution, the Company anticipates a monthly and three-day read rate of 99.5% for all meters available over the communication network.

In conjunction with the above described deployment strategy, the AMI team will be closely coordinating with the Customer Meter Services (CMS) and Resource Planning groups (*e.g.*, for distribution line resources) to ensure adequate resources have been designated for project activities in advance of the FAN deployment, soft launch, and mass deployment of meters and gas modules, respectively. The Company will develop and deliver training materials prior to the installation timelines depicted in Figure 3-3.

4. Quantified Benefits

The following section describes benefits quantified as part of the AMI BCA. Each subsection includes: a description of the benefit, key steps to benefit realization beyond the threshold steps discussed in Section 3, followed by an overview of the benefit calculation from the BCA, and a general benefit prioritization. The Societal Cost Test (SCT), Utility Cost Test (UCT), Rate Impact Measure (RIM), and nominal figures show the 20-year values included in the BCA.

The benefit prioritization follows a *High, Medium, Low* classification that reflects the magnitude and timing of the benefits. *High* indicates benefits critical to program success (significant magnitude realized earlier in the program), *Moderate* indicates benefits with meaningful, though more moderate, magnitudes and/or more future-facing benefits, and *Low* indicates benefits that do not have a significant impact on the overall BCA.

In addition, the Company identifies the first benefit year, which indicates the calendar year when a given benefit is expected to begin, as well as the steady-state benefit year, which indicates the calendar year in which the Company anticipates the benefit will reach its recurring annual value for the remainder of the 20-year BCA.

4.1. Avoided Operation and Maintenance (O&M) Costs and Related Emission Reductions

As shown in Table 4-1, the total avoided O&M cost benefit and related emission reductions is estimated at $188.83 million (20-year NPV) and comprised of seven elements: 1) AMR meter reading; 2) meter investigations; 3) remote connect and disconnect capabilities; 4) reduction in damage claims; 5) storm OMS; 6) FCS meter reading; and 7) interval meter reading.

Component	20-Year NPV (FY20$M)
AMR Meter Reading	$36.87
Meter Investigations	$11.06
Remote Connect and Disconnect Capabilities	$85.90
Reduction in Damage Claims	$9.73
Storm OMS	$43.38
FCS Meter Reading	$0.85
Interval Meter Reading	$1.04
Total	$188.83

Table 4-1: Avoided O&M Costs and Associated Emission Reductions ($M)

4.1.1. AMR Meter Reading

National Grid's electric and gas territories currently use AMR meters, requiring monthly reads via radio frequency technology. To obtain the meter readings, a fleet of radio equipped service vans drive along specific routes to collect the information. By phasing out AMR meters with AMI-enabled technology beginning in project year 3, the Company will reduce the costs and emissions associated with AMR meter reading vehicles, personnel, annual software costs and annual maintenance costs for the replaced AMR meters.

Benefit Components

The AMR meter reading benefit is comprised of three elements: 1) total benefit from reduced AMR meter reader full-time equivalent (FTE) positions; 2) total benefit from eliminated AMR meter reader vehicle costs; and 3) the associated emission reductions.

(1) Total benefit from reducing AMR meter reader positions

As the Company deploys AMI meters, the reduction in AMR meters will reduce the need for AMR meter reading FTE positions. This benefit calculation takes the annual cost per AMR meter reader and multiplies it by the number of AMR meter reader positions that will be reduced. The calculation also includes reductions in the associated annual AMR maintenance requirements.

(2) Total benefit from eliminated AMR meter reader vehicle costs.

In addition to avoiding the need for the meter reader positions as a result of the new technology, National Grid will also be able to reduce the number of Company vehicles required to read the AMR meters. This benefit calculation multiplies the number of meter reading FTE reductions by the meter reading vehicle cost per FTE.

(3) Total benefit from eliminated AMR meter reader vehicle emissions.

AMI will reduce the number of truck rolls and miles driven to read meters and complete certain types of work orders that can be carried out from the office with AMI functionality. The reduction in Company vehicles miles in turn reduces diesel fuel consumption, which reduces CO_2 emissions.

Steps to Benefit Realization

Realizing the AMR meter reading benefit, will require the following key actions:

- Confirming expense reductions associated with AMR-related meter reader FTEs and meter reading vehicles on a one-year delay after deployment begins in each region (Q2 2024 to Q2 2027).

Based on the proposed deployment schedule, which assumes the Company deploys approximately 20 percent of the meters and modules in year 3, 35 percent in years 4 and 5, and 10 percent in year 6, the Company anticipates reaching a steady state for realizing the AMR meter reading benefit in project year 7.

SCT	UCT	RIM	Nominal	Priority	First Benefit Year	Steady State Year	Annual Steady State Benefit
$36.87M	$30.97M	$30.97M	$80.13M	Medium	2024	2027	$4.55M

4.1.2. Meter Investigations

With smart meters providing automatic and on-demand meter reads and diagnostic checks to alert and inform the Company about anomalous situations, there will be fewer visits for manual meter investigations, thus reducing labor and vehicle costs. This benefit only applies to electric meters as the Company will investigate gas meters for safety reasons. However, the Company can avoid in full, or in part, the following types of manual meter investigations:

- Check electric meter multiplier investigations;
- Irregular electric meter investigations;
- Electric meter number verification investigations;
- Use on inactive electric meter investigations;
- Electric meter and gas module reads; and
- Electric meter and gas module high-bill meter reads.

Benefit Components

The meter investigations benefit is composed of three elements: 1) reduction of labor required to perform meter investigations; 2) reduction of vehicle costs associated with performing the investigations; and 3) the related emission reductions.

Steps to Benefit Realization

Realizing the meter investigations benefit, will require the following core actions:

- Building relevant back-office processes to complete the meter investigations using the AMI network, as part of the Business Integration work during the two-year back office system phase (Q2 2023);
- Training back-office employees by region as appropriate (consistent with revised CEP), in coordination with deployment schedule, to use the AMI network to complete remote meter investigations (Q2 2023 to Q2 2027);
- Transitioning meter investigation processes for manual meter investigations categories from field personnel to back-office employees (Q2 2023 to Q2 2027);
- Confirming meter investigation FTE and vehicle reductions on a one-year delay after deployment begins in each region (Q2 2024 to Q2 2027).

Based on the proposed deployment schedule, which assumes the Company deploys approximately 20 percent of the meters and modules in year 3, 35 percent in years 4 and 5, and 10 percent in year 6, the Company anticipates reaching a steady state for realizing the meter investigation benefit in project year 7.

SCT	UCT	RIM	Nominal	Priority	First Benefit Year	Steady State Year	Annual Steady State Benefit
$11.06M	$9.25M	$9.25M	$24.03M	Medium	2024	2027	$1.37M

4.1.3. Remote Connect and Disconnect

AMI provides the ability to connect and disconnect electric service remotely and in near real-time, resulting in reduced labor and vehicle costs for avoided meter visits. This capability avoids initial and, in some cases, repeat visits to the meter for manual meter connects and non-collections related disconnects, providing the customer with quicker service. The estimated savings assumes the Company would need to continue manual field connects and disconnects for dual-fuel and gas-only customers since the gas modules would not have the remote connect functionality upon meter deployment. For potential future functionality enabled by “smart” gas meters, including remote disconnect, please see Section 5.1.3. With respect to collections-related disconnects, the Company will comply with all Home Energy Fair Practices Act (HEFPA) requirements, including but not limited to compliant termination notices, seasonal regulations, and required visits to customer premises. Additional HEFPA-related details will be included as part of the Company's revised CEP.

Benefit Components

This benefit calculation is comprised of three elements: 1) reduction of vehicle costs associated with certain meter disconnects and reconnects; 2) reduction of labor costs associated with certain meter disconnects and reconnects; and 3) the associated emission reductions. The cost reduction components are aggregated, and the Company applies a labor repurpose rate to account for labor which will be re-allocated to perform other functions.

Steps to Benefit Realization

Realizing the remote connect/disconnect benefit, will require the following key actions:

- Confirm remote connect/disconnect capabilities as part of meter deployment testing (Q1 2023);
- Build processes for remote connects/disconnects, including continued HEFPA compliance (Q2 2023);
- Train employees on processes to remotely connect/disconnect meters, including HEFPA-compliance procedures(Q2 2023 to Q2 2027);
- Transition portion of connect/disconnect process to back-office employees using the AMI network (Q2 2023 to Q2 2027);
- Confirm number of repurposed field service representatives and vehicles on one-year delay after deployment in each region (Q2 2024 to Q2 2028).

The Company anticipates the Remote Connect/Disconnect benefit will be realized on a graduated delay consistent with the proposed deployment schedule, which assumes the Company deploys approximately 20 percent of the meters and modules in year 3, 35 percent in years 4 and 5, and 10 percent in year 6. Based on the foregoing, the Company expects to reach a steady state for realizing the Remote Connect/Disconnect benefit in 2027.

SCT	UCT	RIM	Nominal	Priority	First Benefit Year	Steady State Year	Annual Steady State Benefit
$85.90M	$72.22M	$72.22M	$186.61M	High	2024	2027	$10.61M

4.1.4. Reduction in Damage Claims

The reduction of service visits lessens the potential for accidents or damage to third-party property to occur on the way to or at the service site, thus decreasing the number of damage claims. Despite mindfulness and a commitment to safety, accidents while driving to and from service orders, routine meter reading routes, or other day-to-day activities can occur. The remote interaction capability of AMI technologies limits the number of metering service representatives on the road and, therefore, reduces the risk for accidents and damage at customer premises.

Benefit Components

This benefit calculation identifies the average number of damage claims per meter, determines the monetary value of these claims, and allocates a percentage reduction (2 percent) as a result of AMI meter functionality.

Steps to Benefit Realization

Realizing the Reduced Damage Claims benefit, will require three core actions:

- Tracking reductions in damage claims after full meter deployment (Q2 2027).

During deployment, the Company will still rely on AMR meter readers and manual meter investigations. Likewise, during deployment crews will be working in the field installing meters and modules, including a team dedicated to addressing meter/gas module installations that incur problems. As such, the Company assumes the Reduction in Damage Claims benefit will not be realized until after meters are fully deployed in 2027, at which point 100 percent of the benefit will be realized each year thereafter.

SCT	UCT	RIM	Nominal	Priority	First Benefit Year	Steady State Year	Annual Steady State Benefit
$9.73M	$8.10M	$8.10M	$22.38M	Medium	2027	2027	$1.39M

4.1.5. Storm Outage Management System (OMS)

The Company spends millions of dollars annually on storm restoration efforts. AMI would increase visibility during major and minor storms due to the ability to contact meters remotely and determine outage status. This enhanced situational awareness creates efficiencies with crew management and deployment as well as the avoidance of false outages, thereby reducing costs. Additionally, AMI will provide the same benefits for non-storm days.

Benefits Components

This benefit was determined by reviewing key outage information over 2.5 years to identify outages where a truck roll could likely be avoided with AMI. Specific comments attributed to each outage were analyzed to determine avoidable outage truck rolls. Costs were then assigned to the identified outages by extracting the outage duration and multiplying by personnel and fleet costs based on the crew type and truck type rolled out, respectively. Total benefits were then annualized. Roughly half of the benefit was determined to be attributable to major storm events by aligning outages to dates of major storms.

Steps to Benefit Realization

With the exception of limited functionality, such as individual meter pinging, realizing the OMS benefit is dependent on the ADMS project (OMS refresh) as well as underlying IT infrastructure and interface build out.

Outage management benefits are planned to start in late 2023 upon successful integration of OMS and AMI back-end systems. Benefits will continue and mature through full meter rollout. Some outage management related benefits are realized early on, such as the single power off notification from a meter to OMS. Other outage management related benefits such as mass pinging and nested outage benefits are not realized until a critical mass of meters are available later in the meter rollout period. Accordingly, the full benefits of automated customer communication will not be realized until the end of the deployment period.

The Company will be reviewing and building out end-to-end processes to ensure all roles and responsibilities are clearly understood in order to realize the benefits AMI will provide from an outage management perspective.

Care must be taken to ensure the system integration, business processes, and customer communications is clear to avoid confusion and false communications.

- Building full end-to-end processes and making necessary roles and responsibilities changes in the Company for incorporation of AMI as it relates to outage management (Q2 2021 to Q2 2023);
- Initial integration of AMI back-end systems with OMS, which requires intelligent processing and OMS integration of power off/on messages to ensure accurate outage notifications are reported (Q3/Q4 2023);
- Initial training and refresher training for employees on processes to remotely monitor system during outages (Q3 2023 to Q2 2026);
- Tracking use of OMS to identify nested outages as well as performing mass meter pings will require wide area meter rollout leading up to Q2 2027.

The Company assumes this benefit will not reach a steady state until after meters are fully deployed in 2027, at which point 100 percent of the benefit will be realized each year thereafter.

SCT	UCT	RIM	Nominal	Priority	First Benefit Year	Steady State Year	Annual Steady State Benefit
$43.38M	$0.00	$0.00	$99.71M	High	2023	2027	$6.24M

4.1.6. Field Collection System (FCS) Meter Reading

Benefits Components

The Company currently uses the FCS to perform manual and AMR meter reading for both residential and commercial customers. With the implementation of AMI meters, the FCS back-office costs will be phased out as the AMI system utilizes different back-office systems to manage data collection and processing.

Steps to Benefit Realization

Realizing the FCS Meter Reading benefit, will require the following key actions:

- Track reductions in FCS back-office system costs on a one-year delay of the meter deployment schedule (Q2 2023 to Q2 2027).

The Company anticipates the FCS Meter Reading benefit will be realized on a graduated delay consistent with the proposed deployment schedule, which assumes the Company deploys approximately 20 percent of the meters and modules in year 3, 35 percent in years 4 and 5, and 10 percent in year 6. Based on the foregoing, the Company expects to reach a steady state for realizing the FCS Meter Reading benefit in 2027

SCT	UCT	RIM	Nominal	Priority	First Benefit Year	Steady State Year	Annual Steady State Benefit
$0.85M	$0.72M	$0.72M	$1.89M	Low	2024	2027	$0.10M

4.1.7. Interval Meter Reading

Benefits Components

The AMI system will replace the current MV90 system. The MV90 system supports electric interval metering reading. This benefit is for the costs that will be avoided, including MV90 licensing and IT support, and avoided field visit costs due to AMI deployment.

Steps to Benefit Realization

Realizing the Interval Meter Reading benefit, will require the following key actions:

- Confirm reductions in interval meter reading costs following the start of AMI meter deployment (Q2 2024).

The Company assumes this benefit will be realized when meter deployment begins in 2023, at which point 100 percent of the benefit will be realized each year thereafter.

SCT	UCT	RIM	Nominal	Priority	First Benefit Year	Steady State Year	Annual Steady State Benefit
$1.04M	$0.90M	$0.90M	$2.10M	Low	2023	2023	$0.10M

4.2. Customer Benefits and Related Emission Reductions

Customer benefits include: 1) Volt-VAR Optimization (VVO); 2) Energy Insights / High Usage Alerts; 3) Time-Varying Pricing (TVP); and (4) Electric Vehicle (EV) Pricing. Table 4-2 provides a summary of the 20-year NPV of these benefits.

Table 4-2: Customer Benefits and Associated Emission Reductions ($M)

Component	20-Year NPV (FY20$M)
Energy Insights/High Usage Alerts	$90.55
Volt-VAR Optimization	$17.84
Time-Varying Pricing	$46.38
Electric Vehicle Pricing	$4.41
Total	$159.18

4.2.1. Energy Insights/High-Usage Alerts

Through the deployment of AMI smart meters and associated back-office infrastructure, customers and the Company will have enhanced access to customer usage data, with granularity at sub-hour reading intervals. National Grid will build a Customer Energy Management Platform ("Platform") that will act as a hub for residential, commercial and industrial customers to view their energy usage, including the smart meter interval data. The Platform will allow customers to view raw 15-minute data illustrating their consumption within 30 to 45 minutes for electric and eight hours for gas (billing quality data will be available within 24 hours). With this data, customers can compare their usage and costs against certain variables such as weather, historic consumption and neighbors' usage to understand factors that may be driving their energy use.

Furthermore, the Company anticipates the ability to offer customers the choice to disaggregate high-resolution meter data, providing appliance-level energy usage and detailed information that can enable greater insight for customers to understand how their appliances, business buildings, and homes use electricity. This detailed data is expected to further enhance energy efficiency and demand response programs with actionable insights and information.

Benefit Components

For this benefit, the Company assumed electric consumption forecasts and Platform participation to be at 50 percent. Energy reduction due to enhanced energy data access is projected at 1.5 percent consistent with the AMI Order.

Total commodity savings

This benefit is calculated for both electric and gas. The calculation is comprised of two parts: 1) the reduction of GWh/Therms consumed; and 2) the dollar per unit value of avoided GWh/Therms.

To calculate the electric savings, the Company first established the aggregate electric demand of both residential and commercial customers after EE programs. Then, this aggregate demand was multiplied by the cumulative AMI deployment, the percentage of Platform participation, and by the reduction due to real-time data visualization to find the reduction of GWh consumed, which can be used to derive electric commodity savings.

Likewise, to find the gas commodity savings, the Company first established the gas residential aggregate demand in Therms. The total gas residential demand was then multiplied by the cumulative AMI deployment by the percentage of Platform participation and then by the reduction due to real-time data visualization to get the gas consumption reduced in Therms. This reduction in gas consumption is then multiplied by the service classification (SC)-1 Average Price ($/Therm) to determine the total commodity savings.

Steps to Benefit Realization

Realizing the Energy Insights/High-Usage Alert benefit, will require the following key actions:

- Develop CEMP deployment strategy and requirements based on proposed features and industry best practices (Q3 2021 to Q2 2022);
- Procure CEMP vendor(s) through RFP process (Q2 2022 to Q4 2022);
- Develop CEMP web & mobile digital tools with vendor(s) and internal teams, coordinating with existing/planned Customer Experience Product portfolio and associated IT architecture. Initial release to be fully tested and implemented by the time the first meter is installed (Q4 2022 to Q2 2024);
- Continue efforts to enroll customers to receive authorized communications over email and text message via customer-selected account communication preferences (continuous);
- Utilize agile development practices to provide iterative improvements incorporating customer feedback and new AMI-related features, such as future TVP features, in future releases (continuous post-deployment);
- Develop and complete employee trainings consistent with employee training plan to be filed as part of revised Customer Engagement Plan (Q2 2023 to Q2 2024);
- Develop and implement three-phase Customer Engagement Plan per deployment schedule by region (throughout deployment period):
    - Develop and file the revised CEP (Q4 2020 to Q2 2021);
    - Customer Marketing, Education, and Outreach to build AMI awareness and trust (Q4 2021 to Q4 2026);
    - Customer Experience through Deployment (90-60-30 Day Plan) to inform customers of installation and available choices (Q1 2022 to Q2 2027);
    - Customer Empowerment and Enablement to educate customers on new information and tools (Q2 2022 to continuous post-deployment);
- Track customer adoption against metrics.

Based on the proposed deployment schedule, which assumes the Company deploys approximately 20 percent of the meters and modules in year 3, 35 percent in years 4 and 5, and 10 percent in year 6, the Company anticipates reaching a steady state for realizing the Energy Insights/High-Usage Alerts benefit in project year 6.

SCT	UCT	RIM	Nominal	Priority	First Benefit Year	Steady State Year	Annual Steady State

							Benefit
$90.55M	$51.38M	$51.38M	$193.29M	High	2023	2026	$9.55M

4.2.2. Volt-VAR Optimization (VVO)

As AMI meters can read and report usage data multiple times a day, they can act as end-of-line sensors to centralized VVO / conservation voltage reduction (CVR) control systems via integration with ADMS and MDMS. The VVO/CVR control systems can then make voltage and reactive power adjustments to optimize the distribution systems voltage and power flows to reduce power consumption on the grid and for customers and over time energy. Through the integration of AMI voltage data with the VVO/CVR solution, additional voltage optimization can be achieved, resulting in additional efficiency and savings. Without this AMI integration the VVO/CVR must maintain a safety margin based on its very limited voltage reading feedback from the distribution system to ensure customer voltages are maintained with the ANSI C84.1 range. Having the AMI voltage readings at every customer premise located on the VVO/CVR scheme reduces the need for this safety margin.

Benefit Components

For the purposes of the AMI business case, VVO/CVR-AMI benefits will be incremental to those achieved by the VVO/CVR scheme without the AMI integration. To determine this incremental benefit the Company reviewed results and reports from other utilities who have implanted the same VVO/CVR-AMI system. In particular, a report from Utilidata and AEP revealed an incremental 1% savings in energy consumption was obtained. As such, National Grid took a conservative approach and applied 0.5% reduction in its calculation of these benefits.

Steps to Benefit Realization

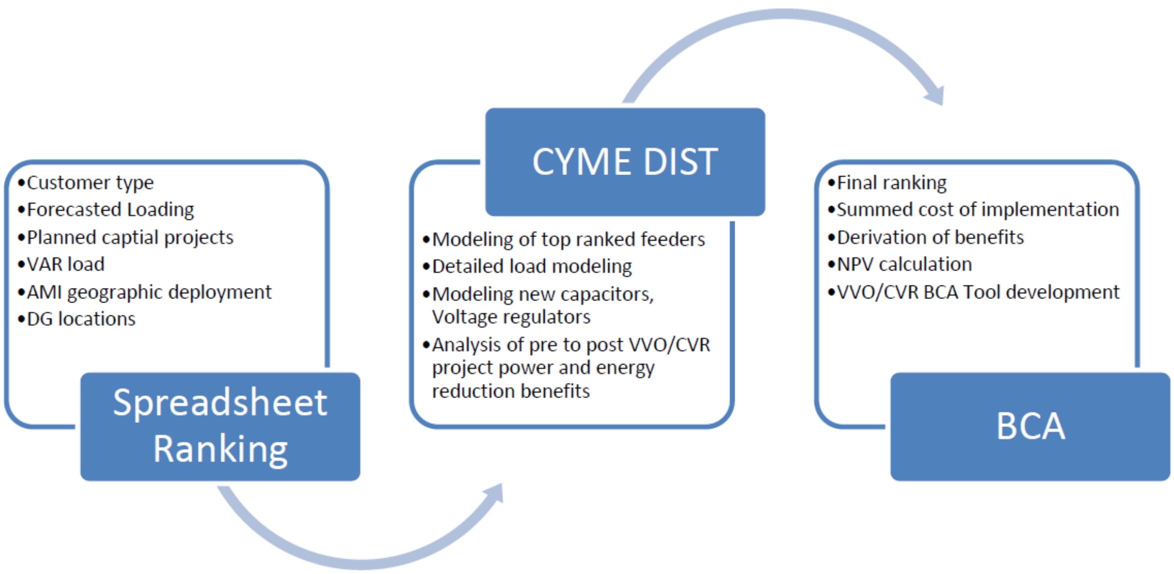
Realizing the VVO/CVR-AMI benefit, will require the following key actions:

- Planning and selection of optimal VVO/CVR locations – completed for planned projects through FY25:
    - Planning steps include identification of new equipment such as capacitor banks and voltage regulators, plus load transfers to improve load balancing and help flatten the phase voltage profile across the feeder.
- Engineering design of VVO/CVR systems for each location (*see* “Where will VVO/CVR be deployed?” section for current status);
- Completion of current VVO/CVR schemes currently under construction and implementation of future VVO/CVR locations;
- Installation of AMI smart meters at the VVO/CVR locations (VVO/CVR locations are being factored into the AMI deployment plans);
- Incorporating data into VVO/CVR program via integration between MDMS and ADMS;
- Enhancing the ADMS VVO/CVR app to capture the smart meter data;
- Operating VVO/CVR-AMI; and
- Conducting measurement and verification.

SCT	UCT	RIM	Nominal	Priority	First Benefit Year	Steady State Year	Annual Steady State Benefit
$17.84M	$9.00M	$9.00M	$44.39M	Medium	2027	2027	$1.18M

***How Were VVO/CVR Feeders and Stations Identified?*[17]**

Starting in early 2019 the Company undertook an integrated study that considered several variables such as forecasts, customer types, planned capital projects, AMI deployment plans, and distributed generation (DG) locations to conduct a BCA and prioritize locations based on value, for VVO/CVR to maintain voltage compliance across the distribution system and help adopt high levels of DER penetration via improved voltage control.



Where will VVO/CVR be deployed?

The Clifton Park VVO/CVR demonstration project that is currently undergoing extended measurement and verification (M&V) testing was the Company's first VVO/CVR deployment in New York. Following the Clifton Park project and though application of the planning study process described above, the Company initiated a statewide rollout in fiscal year (FY) 2020, deploying VVO/CVR schemes on thereof its highest value substations and 12 feeders that will undergo M&V during summer 2021. A further four substations and 26 feeders are undergoing construction through FY 2021. As an extension of the program, an additional 94 distribution circuits from 21 substations across the three upstate New York divisions (West, Central, and

[17] Additional detail regarding the Company's VVO/CVR plans and implementation can be found in the Company's 2020 Distributed System Implementation Plan (DSIP).

East) are targeted for deployment between FY 2022 and FY 2025. The Company plans to continue in FY 2026 and beyond, so long as remaining locations provide incremental benefits that exceed the costs and additional locations are supported by the Commission. Please see the list below of planned VVO/CVR installations. Note that the timing and locations of projects listed for FY22 and beyond are subject to change.

Start Construction (FY)	Sub-Station Name
FY18	Grooms Road
FY18	Elnora
FY20	Lockport Rd (Sta 216),
FY20	Peat St
FY20	Patroon
FY21	Maple Rd (Sta 140)
FY21	Belmont
FY21	Butternut
FY21	Queensbury
Projects and timing below are subject to change pending resolution of the Company's pending 2020 Rate Case	
FY22	Lakeview - Sta. 182
FY22	Berry Rd - Sta. 153
FY22	Fly Rd
FY22	Rosa Rd
FY23	Pebble Hill
FY23	Everett Rd
FY23	Renaissance Rd - Sta. 229
FY24	Malta
FY24	Curry Rd
FY24	Ayer Rd - Sta. 211
FY24	West Olean
FY24	Wetzel Rd
FY24	Chadwicks
FY25	Sand Creek
FY25	Hudson
FY25	Batavia
FY25	Sweet Home Rd - Sta. 224
FY25	Tully Center
FY25	Thousand Islands

4.2.3. Time-Varying Pricing (TVP)

AMI deployment enables National Grid to provide time-varying price signals to customers. The modeled benefits in the AMI business case come from savings derived from avoided supply costs. These savings may result from reduced energy consumption, or more likely, shifting usage from higher priced periods to lower-priced periods. In particular, much of the benefit accrues to customers through avoided capacity costs. TVP is a critical component of meeting the goals and objectives of the CLCPA in a cost-effective fashion.

In the AMI business case, the Company designed an illustrative TVP package for supply rates. The TVP used simple time-of-use (TOU) pricing to capture the variation in energy prices and critical peak pricing (CPP) to transmit some of the variability of capacity costs. The Company envisioned that TOU periods would be pre-defined and relatively static. On the other hand, the CPP periods would cover the 70 hours in the year likeliest to capture that year's New York Control Area peak, which sets the capacity obligation and costs for customers. CPP events would be called on a day-ahead basis. Customers may save money and create benefits under the TOU or CPP pricing by shifting their usage away from the peak period, or lowering their usage overall.

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

Benefit Components

The modeled benefit is calculated using: 1) the total benefit from avoided costs due to CPP peak shaving; and 2) the total benefit from avoided costs of energy due to a TOU program.

(1) Total Benefit from Critical Peak Pricing (CPP) peak shaving

A CPP mechanism provides a strong price signal to customers to help them save on capacity costs. Capacity costs are allocated in New York by the New York Independent System Operator (NYISO) based on customers' usage in the peak hour (*i.e.*, the hour with the highest overall load) in the calendar year. The quantity of energy customers consume in that hour is known as their capacity tag. Combining the capacity tags for all customers who take supply from the Company, yields the Company's capacity obligation. The peak hour of the year has fallen in the summer every year of the NYISO's existence; however, the exact hour of peak demand is known only after the summer concludes. With CPP, the hours most likely to contain the peak are projected for the year and a higher price is created based on capacity costs in those hours. CPP therefore provides predictability for customers and distributes capacity costs that are set by a single hour's worth of usage in the summer over 70 hours. In the BCA scenarios, CPP events are limited to a specific number of hours during the year and called on a day-ahead basis to strike a reasonable balance between likelihood of capturing the peak hour and predictability for customers.

The modeled benefit from CPP is the reduction in capacity cost to the Company's customers. To calculate the benefit associated with CPP, the Company multiplied the forecasted annual peak load multiplied by an achievable load reduction percentage (based on AMI deployment and CPP adoption) multiplied by an anticipated CPP Capacity Payment $/MW avoided. CPP may have a secondary benefit of reducing usage during high-priced energy hours, and in-turn reduce costs associated with consumption in those hours, but this was not quantified separately.

(2) Total Benefit from Avoided Energy due to Time-of-Use (TOU) Program

In the BCA scenarios, supply charges will vary by specific times of day, every month, with peak (higher price) and off-peak (lower price) periods defined. In response to TOU rates, customers save by reducing consumption during higher cost peak periods and/or shifting use from peak to off-peak periods.

This modeled benefit calculation is generally comprised of a multiplication of forecasted load during peak hours multiplied by achievable load reduction percentage (based on AMI deployment and TOU adoption) multiplied by avoided average fuel costs per MWh of generation.

Steps to Benefit Realization

Realizing the TVP customer benefit will require the adoption of a territory-wide TVP rate structure on an opt-in or opt-out basis.

After the Company has completed the back-office systems work and associated training, it plans to propose an opt-in supply rate, or suite of TVP rates, that will produce benefits that equal or exceed those modeled in the opt-in TVP case. Such a suite of rates *may* include a supply pricing structure of hourly pricing for energy with a capacity tag for capacity as one option. Staff proposed, and the Commission approved, such an option for supply as part of a package with opt-in standby rates for mass market customers. A second option may include more conservative TOU periods that vary on a seasonal basis.

National Grid commits to collaborate with the New York State Electric and Gas Corporation (NYSEG) and Rochester Gas and Electric Corporation (RG&E) to develop similarly structured time-varying rates. The Companies will regularly inform Staff of their progress.

In addition to the opt-in rates, the Company believes that the benefits of AMI will increase with default (*i.e.*, opt-out) TVP for both supply and delivery. The Company has proposed and expects to test TVP options that can form the basis of such a package in Clifton Park and more broadly once it begins deploying AMI across its service territory.

After the Commission approves a territory-wide TVP rate on either an opt-in or opt-out basis, the Company will need to undertake a series of steps the length of which will vary depending on a number of factors including the complexity of the TVP rate, its similarity to other already programed rates and programs, and the underlying technology and processes in place at the time of approval. The steps are described below:

- Program the new rate in the Company's billing system, including relevant Customer Information System enhancements (complete 9-12 months after approval depending on rate complexity);
- Develop back-office processes, including system integration and customer enrollment, to administer the new rate (complete 9-12 months after approval);

- Refine customer engagement strategies, including new TVP-related CEMP features, and develop collateral specific to the new rate including marketing materials and campaigns (9-12 months after approval);
- Train employees to administer the rate and answer customer questions (6-9 months before launch); and
- Implement the new rate structure on an opt-in or opt-out basis with implementation timeline and availability to customers depending on whether rate is on opt-in or opt-out basis (0 to 10 months after completion of above steps).
- Track customer adoption and performance metrics.

The Company anticipates that the benefit of a TVP rate will start to be realized on a one-year delay after adoption, and that it will take the benefits four years to reach a steady state for benefit realization. The numbers below reflect assumptions included in the BCA, and are subject to change based on the timing and structure of the TVP rate approved by the Commission.

SCT	UCT	RIM	Nominal	Priority	First Benefit Year	Steady State Year	Annual Steady State Benefit
$46.38M	$30.15M	$30.15M	$108.03M	Medium	TBA	TBA	$6.71M

4.2.4. Electric Vehicle (EV) Pricing

The Company expects the introduction of AMI and TVP to enable avoided energy charges. The estimate for the EV integration benefit assumes a certain percentage of EV charging is currently done during on-peak periods; however, with the introduction of TVP enabled by AMI, an increased share of charging is expected to move off-peak, thereby lowering the costs for customers to charge EVs.

Benefit Components

To find the amount of load shifting possible, the Company used the EV load shape tool (RESHAPE) to generate hourly electric load from charging EVs for a population of drivers. RESHAPE uses detailed trip data to simulate driving and charging behavior of thousands of drivers under different EV and charging access scenarios. Specifically, the RESHAPE tool considered four different EV types and six different charging access scenarios to output a normalized load shape for 24 different customer types. The normalized load shapes are then scaled by the number of drivers in the population that fall into each customer type. The final load shape therefore captures the diversity of driving behavior, charging access, and EV type adoption across a population.

Steps to Benefit Realization

The following are the key high-level milestones for realizing the EV pricing benefit:

- In the absence of an approved TVP rate design, the Company will propose a rate that unlocks the TVP benefit. The rate need not be EV-specific in the sense that it is available only to EV customers. Rather, the proposed rate must sufficiently induce customers to shift their charging to lower-cost periods to realize the benefits of such lower pricing;
- The Commission must approve a specified TVP rate structure;
- Upon determination of a specific TVP structure, the Company will implement the TVP plan, programming the rate and updating the CIS and billing systems, as necessary (complete 9-12 months after approval depending on rate complexity);
- Develop Platform features to help EV customers understand and adopt TVP, such as a rate calculator to compare rate plans and options to enroll in new TVP rates, in addition to features describing the TVP features described above, including targeted marketing, education, and outreach to EV customers (9-12 months after approval);
- Train employees to administer the rate and answer customer questions (6-9 months before launch);
- Coordinate with other offerings for EV customers, such as EV Smart Charging managed charging (continuous);
- Implement the new rate structure on an opt-in or opt-out basis with implementation timeline and availability to customers depending on whether rate is on opt-in or opt-out basis (0 to 10 months after completion of above steps); and
- Track customer adoption and performance metrics.

The Company anticipates that the benefit of a TVP rate and the corresponding EV Pricing benefit will start to be realized on a one-year delay after adoption, and that it will take the benefits four years to reach a steady state for benefit realization. The numbers below reflect assumptions included in the BCA, and are subject to change based on the timing and structure of the TVP rate approved by the Commission.

SCT	UCT	RIM	Nominal	Priority	First Benefit Year	Steady State Year	Annual Steady State Benefit
$4.41M	$3.66M	$3.66M	$10.44M	Low	TBD	TBD	$0.51M

4.3. Avoided Program Costs

The total avoided AMR Program Cost benefit is $354.39 million and is comprised of four elements: 1) Avoided AMR Program Capital Costs; 2) Avoided AMR Program O&M Costs; 3) Avoided VDER Metering Costs; and 4) DSP Costs. Table 4-3 summarizes the benefit for avoided AMR and VDER costs.

Table 4-3: Avoided AMR Program Costs ($M)

Component	20-Year NPV (FY20$M)
Capital	$245.35
Operations & Maintenance	$13.08
VDER Metering	$10.58

DSP Platform	$85.38
Total	$354.39

4.3.1. Avoided AMR Capital

Without the implementation of an AMI program, the Company would be required to continue its AMR program. This would result in capital costs to replace meters reaching the end of their useful life, meter installation, field equipment upgrades and project management. Thus, the AMI program avoids the need to replace the existing AMR meters and associated systems. The avoided cost of these activities is categorized as a benefit in the AMI BCA model. The Company assumed the electric AMR meters and gas modules would be replaced when they reach 20-years of age, the manufacture projected life. The avoided capital costs are a one-time cost and, unlike other benefits, do not have an associated annual benefit, which is shown as N/A below.

SCT	UCT	RIM	Nominal	Priority	First Benefit Year	Steady State Year	Annual Steady State Benefit
$245.35M	$228.68M	$228.68M	$335.50M	High	2021	N/A	N/A

4.3.2. Avoided AMR O&M

The AMI program also avoids the associated O&M costs of the life-cycle replacement program for the existing electric AMR meters and gas modules, such as call center calls and customer communications. The BCA assumed similar program cost elements between an AMR replacement program and the proposed AMI program. The avoided AMR O&M costs are a one-time cost and, unlike other benefits, do not have an associated annual benefit, which is shown as N/A below.

SCT	UCT	RIM	Nominal	Priority	First Benefit Year	Steady State Year	Annual Steady State Benefit
$13.08M	$12.29M	$12.29M	$17.30M	Medium	2021	N/A	N/A

4.3.3. VDER Metering

The compensation mechanisms for DERs with in-service dates after January 1, 2020, are expected to require hourly meter usage data. Without AMI, the Company or customers would incur additional costs to implement an alternative metering method. Specifically, National Grid would extend the program implemented as part of the Clifton Park demonstration project to support VDER. The Clifton Park system utilizes cellular interval meters, which cost approximately four times the standard AMI mesh meters. Thus, the benefit recognizes that the Company would avoid the VDER metering program costs if AMI is implemented.

Benefit Components

To forecast DER adoption (Figure 4-2), the Company analyzed the historical trends beginning in 2014 while incorporating various market conditions such as:

- VDER meter forecast beyond 2024 held constant at 2024 level;
- 2018 (96 projects) & 2019 (80 projects) value stack forecast is based on complex projects connecting under Value Stack;
- 2018 & 2019 overall forecast is number of DG projects connecting in those respective years; this forecast is based on number of applications in the Company's queue and assuming only 70 percent will connect;
- Seasonality assumption of two months into the forecast, as most of the residential systems are constructed during the summer, resulting in higher volumes in those months;
- All meters installed for all types of DG systems after 2019 are assumed to be interval meters;
- 2014 through 2017 are actual number DG applications connected and not necessarily total interval meters installed; and
- The Company has approximately 70 percent confidence in its forecast as DG installations in New York have not reached a steady state so as to rely on mathematical formulas.

SCT	UCT	RIM	Nominal	Priority	First Benefit Year	Steady State Year	Annual Steady State Benefit
$10.58M	$8.74M	$8.74M	$25.34M	Medium	2027	2027	$1.17M

4.3.4. Distributed System Platform (DSP) Feeder Sensors

This benefit assumes that the presence of AMI metering obviates the need for approximately two-thirds of the feeder monitoring sensors required to assume the role of DSP provider. The calculation assumes four feeders per substation and two end-of-line sensors per feeder. The O&M cost is calculated at 10 percent of the capital cost.

Steps to Benefit Realization

Realizing the DSP benefit, will require the following key actions:

- Provide initial integration between MDMS and ADMS (Q3-Q4 2023); and
- ADMS enhancement to incorporate voltage readings in state estimation and power flow module (Q4 2023 to Q4 2027).

Because the DSP feeder sensor costs will be avoided based on approval of the AMI program, the benefit is realized in the first year of the project and the benefits accumulate as meters are deployed, reaching steady state in 2027.

SCT	UCT	RIM	Nominal	Priority	First Benefit Year	Steady State Year	Annual Steady State Benefit

$85.38M	$0.00M	$0.00M	$154.37M	Medium	2021	2027	$7.72M

4.4. Rate Impact Mechanism (RIM-Only) Benefits

4.4.1. Benefit from Improvement in Bad Debt Write-Offs

Bad debt is incurred when National Grid customers are unable or unwilling to pay their billing obligations. National Grid makes every reasonable attempt to collect those outstanding bills. Eventually, this unrealized revenue is classified as a loss and is written off and spread across all customers. A smart meter's ability to remotely disconnect service, within the existing approved parameters and in consideration of all consumer protection processes, will reduce these socialized costs. Although the smart meters cannot eliminate bad debt write-offs, the remote disconnect function can reduce the period between when an electric customer defaults on payment to when their meter is disconnected, thus reducing the loss incurred. In time the impact of this functionality will prompt a change in customer behavior, resulting in a significant reduction in overall bad debt and operational expense. This will result in fewer collection activities such as mailings, phone calls, and field visits.

Benefit Components

This benefit calculation takes the cumulative AMI deployment and multiplies it by the total residential and commercial growth in bad debt mitigation attributable to AMI data to identify the total incremental annual bad debt mitigation.

Steps to Benefit Realization

For Steps to Realize the Benefit From Improvement in Bad Debt Write-Offs, please refer to Section 4.1.3 above.

SCT	UCT	RIM	Nominal	Priority	First Benefit Year	Steady State Year	Annual Steady State Benefit
$0.00M	$0.00M	$30.72M	$84.83M	Low	2027	2027	$5.28M

4.4.2. Benefit from Reduction of Theft of Service

Smart meter technology combines greater frequency of readings with sophisticated algorithms to ensure that electric and gas consumption is accurate. AMI provides tamper alarms after detecting usage that attempts to bypass the meter, and also produces customer level data that can be analyzed for reasonableness in order to identify unusual patterns that may reflect theft of service. If discrepancies are proven to be theft, the Company can take action to address the situation, thus minimizing a cost that would normally be socialized across the customer base, thereby saving other customers money.

Benefit Components

In this benefit, National Grid also assumed a conservative theft recovery benefit of 0.25 percent of annual electric revenue.

Steps to Benefit Realization

Realizing the reduction of Theft of Service benefit, will require the following key actions:

- Build processes for monitoring theft of service and undermetering (e.g., tamper alarms) using the AMI network as part of Business Integration workstream (Q1-Q2 2023).
- Train employees on processes to monitor theft of service and undermetering using the AMI network (Q2 2023 to Q2 2026).
- Track use of AMI network to identify theft of service and undermetering.

SCT	UCT	RIM	Nominal	Priority	First Benefit Year	Steady State Year	Annual Steady State Benefit
$0.00M	$0.00M	$53.19M	$136.74M	Medium	2024	2027	$7.73M

5. Unquantified Benefits

The following section aims to provide a description of the unquantified benefits that AMI can enable. Some benefits require follow-on investments, technology advancements, or evolution of internal processes and may be further developed in future regulatory proceedings. In addition, some benefits included below may not be feasible or prudent to pursue and are included for completeness.

5.1. Expanded AMI Network Use Cases

The AMI communications network and back-office systems can be leveraged over time to integrate other end-point devices to provide additional customer value that is not quantified in the BCA. The Company is open to exploring the use cases in ongoing and/or future forums with the Commission and interested stakeholders. Execution of these and/or other new functionalities that demonstrate ongoing utilization of the AMI network and are BCA positive could be part of future proposals. A non-exhaustive list of potential future opportunities is included below.

5.1.1. Water Utility/Municipality Revenue Opportunities with Joint Use

Water utilities could leverage the technical umbrella of the Company's proposed AMI infrastructure to support overlapping metering efforts, with the Company offering "Metering-as-a-Service" to interested jurisdictions. The Company's platform could serve as the wireless FAN, backhaul, and back-office validation systems for a smart water metering capability.

5.1.2. AMI for Street Lights and Ancillary Devices

The integration of AMI metering, wireless communications, and lighting control technology have fostered an expanding array of ancillary device deployments in support of customer-centric services. Many vendors have developed proprietary platforms that combine a photoelectric control having dedicated solid-state AMI chip-meter technology and varied forms of wireless communication modes incorporated within a small form-factor for use in conjunction with street lighting infrastructure. The advent of these collective technologies was initially promoted for the energy efficiency and environmental benefits achievable through remote controlled light emitting diode (LED) technology applications in street lighting. The opportunity for customer specified operating schedules was further enabled by using the AMI chip metering for the energy consumption measurement of the individual street light. This advancement could allow the lighting control device to integrate with the AMI electric metering mesh network to transition street lighting from an unmetered to a metered billing application. Additionally, the lighting control devices provide electric power quality monitoring, operational performance, maintenance diagnostics of the luminaire, global positioning (GPS), structure inclination and other lighting system data unavailable without a site investigation assessment.

The further advancement of these technologies has been expanded within the street lighting industry and other business use cases under the "Smart City" moniker. The small form factor and wireless communication capability in conjunction with the availability of electric service voltage on potential vertical real estate has fostered a ground swell of innovative and complementary applications. The combined technologies have included video streaming, asset detection (*e.g.*, license plate reader, parking management), environmental sensors (*e.g.*, climatology, pollution and hazardous chemicals), gunshot detection, traffic management, emergency services, waste management and other internet of thing (IoT) devices. Additionally, the control and metering capabilities are considered the prospective solution to managing the expansive deployments of community Wi-Fi applications, EV charging facilities, and mobile communication infrastructure (*e.g.*, 4G LTE and 5G). The Company's proposed communications infrastructure and potential back-office systems could be leveraged to support network services to interested third parties.

However, the metering and lighting industries continue to address the need for established industry standardization of meter accuracy testing and application performance criteria. Additionally, the adoption of uniform industry communication standards for this technology segment will minimize the limitations imposed by proprietary protocols, further expanding interoperability and end-use opportunities.

5.1.3. "Smart" Gas Meters

Advancements in meter technology have developed gas meters with multiple safety functionalities, including temperature sensing, overpressure protection, excess flow monitoring and air-detection tamper alerts. "Smart gas meters" are battery-powered and include the gas metering and communication components in a single assembly, eliminating the need for a separate gas communication module. Each of these attributes will trigger the meter to potentially shutoff gas to prevent emergency situations from occurring. The smart gas meters also have the potential to shutoff gas to the customer proactively through the AMI network if an external safety event is occurring nearby, such as a fire, gas leak or other unplanned emergency. Having the AMI mesh network in place enables the Company to advance this emerging technology quickly to enhance customer safety as smart gas meters become available. Smart gas meters require back-office integration to enable full end-to-end operability. The Company's recent testimony in the 2020 Rate Case (*see* Gas Infrastructure Operations Panel (GIOP)) proposes to follow the AMI back-office integration, with field deployment planned once back-office integration is complete.

5.1.4. “Smart” Residential Methane Detectors (RMD)

Residential methane detectors (RMD) equipped with communication devices, also known as smart RMDs, are currently in research and development for AMI deployment. In the event the smart RMD senses methane at a customer location, it would be able to send a notification to the Company through a fixed communication network, expediting the Company’s response even if a customer has not called to report the issue. In partnership with smart gas meter implementation, services could be closed remotely upon receiving a methane alarm through the AMI network. Similar to smart gas meters, a complete Smart RMD program is proposed as part of the GIOP testimony in the Company’s 2020 Rate Case; RMD deployment would follow AMI back-office integration.

5.1.5. Improved Gas Reliability

Integration of gas end-point devices into the AMI network will improve forecasting, response to events, and the scale at which demand response (DR) could be deployed in the gas distribution system. Accuracy and efficiency of long-term and emergency planning processes are improved when informed by high-resolution data. Event tracking and interruption isolation would benefit from high-resolution data combined with smart meter sensing and an ability to remotely disconnect service. As mentioned in Section 5.4.2, below, AMI would enable gas DR, which could reduce peak demands and mitigate high- or low-pressure conditions to prevent interruption events.

5.2. Distributed Computing Apps

Another key design attribute of the AMI solution is the flexibility and adaptability of the solution to meet evolving customer and grid needs. The solution the Company proposes to implement represents the latest generation of maturing AMI technology; its capabilities include over-the-air firmware upgrades and grid-edge computing platform functionality. Supporting software applications will be deployable to the meters for both grid- and customer-facing use cases ranging from integration of additional DER and EVs on the grid to providing more choice, conveniences, and control through additional information. The meter technology allows the Company to upgrade the operating system and upload applications remotely.

The vendor solution chosen by the Company has application development tools and ecosystems to support applications. The capabilities of the meters and the application development environment provide risk mitigation against technology obsolescence. The Company believes the grid-edge computing platform will enable significant future customer- and grid-facing capabilities. The Company will also look to work with stakeholders and third parties to identify and consider new capabilities to ensure that evolving customer and grid needs continue to be met in the future.

As shown in Table 5-1, the near-term functionalities will likely lead to the development of AMI-enabled future functionalities capable of delivering additional benefits. The Company divided these potential future applications into two groups: 1) those functionalities that may be available in 5-10 years; and 2) those functionalities that are on a longer development path (*i.e.*, greater than 10 years). In addition, Table 5-1 links these potential future functionalities to near-term enablers. For example, the future functionalities described in Table 5-1 would utilize the grid-edge computing platform capabilities enabled by near-term AMI functionalities that support deploying software applications to the meters for both grid-facing and customer-facing use cases. The future functionalities are based on the Company's evaluation of the AMI solution vendor's capabilities and development roadmaps as part of the competitive request for solution process.

The Company will further evaluate the future functionalities (*e.g.*, proof of concept) as the Company implements the AMI solution. To the extent the functionalities merit implementation, the Company will include incremental funding requests and justification, as appropriate, in future proceedings.

Table 5-1: AMI-Enabled Future Functionalities

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

Active Demand Response	Autonomous demand management locally and intelligently by integrating with customer HAN devices to support demand reduction in accordance with utility demand events. Integration with EV charging stations can provide additional demand benefits while facilitating electrification.	Grid-edge computing application with HAN integration	>10 years

Beyond the items listed above, the Company believes data analytics is an area expected to provide additional functionality in the future. As the industry continues to evolve, the number and types of data analytics use cases, as well as the extractable value of available data from grid-edge devices (*i.e.*, meters and sensors), will continue to increase. Using data analytics, the Company can turn this data into actionable insights, increasing benefits for customers and core utility business functions. Potential use cases include improved mapping capabilities, distribution planning and asset management, enhanced functionality for EVs, and DER adoption/deployment.

5.3. Enhanced Planning and Operation Capabilities

A key application for AMI data will be in generating improved forecasts, which the Company can incorporate into planning and operations. Leveraging the AMI data will demand new tools and processes. For example, the Company plans to procure a software module to help integrate AMI load data into the CYME DIST tool to update its load models. It is expected the data from AMI will play a key role in integrated planning. The initial AMI business case and subsequent updates highlighted the following key benefits to improved grid planning:

- Enhanced data availability;
- Improved forecasting of load and DER behind-the-meter assets (*i.e.*, load disaggregation);
- Support for planned VVO/CVR program and AMI-ADMS-CVR via voltage feedback and fault location isolation and service restoration (FLISR) programs via meter status and load data for fault location and optimal switching, respectively;
- Phase connectivity and improved models;
- Service transformer loading;
- Avoided sensor costs via voltage and load readings;
- Greater use of EE and DR to support targeted grid load relief; and
- Improved load balancing and reduction in losses.

5.4. Enhanced Customer Capabilities

5.4.1. Program Design and Optimization

The Company recognizes the deployment of smart metering as a unique opportunity to accelerate the innovation and delivery of its existing portfolio of customer-facing programs and services, ranging from offerings such as residential and commercial EE and DR programs to its comprehensive electric transportation initiative. The deployment of AMI will also animate the market for third-party technologies and services, providing opportunities for third-party innovation and delivering additional benefits for customers under policies and programs set forth by state laws and regulations.

AMI can also facilitate the strategic use of customer consumption data by enabling new program offerings to customers including Pay for Performance (P4P),[18] Metered Energy Efficiency Transaction Structure (MEETS),[19] Non-Pipe Alternatives, and potentially helping to lower the cost of weatherization programs. Furthermore, AMI data enhances data sharing capabilities of Green Button Connect My Data, improves customer insights and market intelligence, facilitates data driven propensity modelling for streamlined EE delivery, supports evaluation of cost/benefit of downstream versus upstream measure opportunities, and enhances coordination with other National Grid clean energy initiatives such as DER integration, Smart Cities, Buildings to Grid, and Vehicles to Grid.

AMI also opens the door to increasingly sophisticated demand-side management programs. Hourly and 15-minute interval data and highly accurate load disaggregation capability enables deeper customer engagement as part of behavioral EE and DR programs, remote home energy audits, continuous whole-home energy optimization and contributes to improving program outcomes. Granularity in data also contributes to higher accuracy in the evaluation, measurement and verification of EE and savings accuracy, and contributes to higher energy savings and administration cost savings to customers and the utility.

In summary, AMI deployment can support EE programs by facilitating the:

- Identification and enrollment of customers that provide the biggest program benefits and energy savings opportunity (factors may include site location, large consumption size, weather correlation, past program participation, locational constraints, etc.);
- Improved marketing metrics by reducing customer acquisition cost through targeted engagement, improving open/click/conversion rates, and employing data driven sales and communication strategy;
- Improved customer experience, choice, satisfaction, and personalization of offerings and services;
- Improvement in program participation and evaluated program savings;
- Reduced localized peak load due to data availability that could support EE, DR and DER programs targeting specific feeders or geographic regions;
- Employment of performance-based EE technologies and delivery mechanisms like P4P, MEETS, etc., with higher accuracy of energy savings and verification methods; and
- Overall increased cost-effectiveness of DSM programs.

The Company envisions that current and future program offerings will leverage AMI towards delivering data driven programs and increasing program efficiency and portfolio energy savings, thereby facilitating long-term cost effectiveness.

5.4.2. Gas TVP and Demand Response

Historically, discussions of TVP have focused on electricity. Gas markets lack the temporal resolution to pass signals through to rates. However, in the future, sub-daily gas rates may be

[18] https://www.nyserda.ny.gov/About/Newsroom/2020-Announcements/2020-11-05-nyserda-and-national-grid-partner-to-launch-innovative-home-energy-savings-program-in-central-new-york
[19] https://www.meetscoalition.org/

used to create financial signals for customers to efficiently use the gas system. Sub-daily usage is already measured for system operations, which can impact the terms of supply contracts. In addition to making sub-daily rates feasible, an increase in temporal resolution of gas system data could support the expansion gas DR.

The Company and its affiliates are currently engaged in several gas DR programs or pilots. Data is a critical component of those efforts. To capture the data, the Company has installed supplemental metering to gather the necessary information regarding customer participation. If AMI was available, the programs could be deployed more efficiently, as there would not be a need for supplemental metering. Also, AMI could potentially allow for additional tiers of participation in the programs/pilots providing flexibility for customers. One learning from the DR pilots is that customers assign a significant value to having access to granular usage data. Many of the participants in the programs have stated that this has more value to them than the incentives they receive.

One of the Company's downstate New York affiliates was the first utility in the country to explore incentivized gas DR for firm commercial and industrial (C&I) customers as part of a pilot that began in 2017. The pilot will run for three years and includes 16 facility-participants with a goal of shifting gas load outside the peak hour (*i.e.*, changing the shape of the load profile). Events within the pilot are called for three hours between 6 a.m. and 9 a.m. from December through March. The pilot was approved as part of the affiliate's 2016 rate case and the company was awarded the inaugural Utility Industry Innovation in Gas award by the National Association of Regulatory Utility Commissioners. Additionally, the Company's downstate New York affiliate launched both incentivized Bring Your Own Technology (BYOT) and non-incentivized behavioral residential and small and medium business (SMB) gas DR programs for winter 2019-2020.

Though same-day incentivized gas DR programs are a relatively new offering, tariffed rates that create peak-day reductions via customer behavior have been a critical component of system planning and design for many decades. Specifically, National Grid and its affiliates have operated both interruptible (customer-controlled curtailment for events called at the utility's discretion) and temperature-controlled (utility-controlled curtailment for events initiated based on air temperature) rates for large C&I customers. Nearly 3,000 customers are on these rates in downstate New York. However, based on the market response for the DR pilot, the Company's affiliates proposed expanding their DR portfolios in downstate New York as part of their pending rate case with a modified version of the current DR program and two new programs to reach the SMB and residential classes. Customer participation in the rates requires additional metering to track usage and, if necessary, calculate bills for non-compliance. Full-scale AMI deployment would enable wider rollout of similar programs in New York without requiring additional metering. Also, the presence of more granular usage data from AMI would facilitate program deployment and evaluation, helping the Company better understand usage and reward customers.

In addition, another Company affiliate has partnered with Fraunhofer Center for Sustainable Energy Systems to conduct a pilot in Massachusetts. The Company is also piloting two DR programs in New York – a short event program called Peak Period Demand Response (three-hour events) focusing on daily peak, and a longer event program called Extended Demand Response (twenty-four-hour events) focusing on reducing daily load. There are currently two facilities participating in the Peak Period Demand Response program, and one facility participating in the Extended Demand Response program.

6. Conclusion

The AMI Order represents a once-in-a-generation opportunity to drive approximately $700 million (20-year NPV) in benefits for customers, the system, and the environment. National Grid continues to believe AMI is a foundational investment for achieving the shared vision of the clean-energy future, in support of the aggressive carbon reduction and equity goals outlined in the CLCPA. The Company appreciates the opportunity to share this Plan, as it seeks to transform the way customers interact with their energy through the functionalities enabled by AMI.

7. Appendix

7.1 Summary of AMI Program Costs by Category

Category	20 Year NPV SCT	20 Year NPV UCT	20 Year NPV RIM
AMI Meter and Installation Cost			
AMI Electric Meter Equipment and Installation	$213.71	$200.96	$200.96
AMI Gas ERT Equipment and Installation	$65.38	$61.46	$61.46
AMI Inventory	$5.02	$4.72	$4.72
Support Infrastructure	$17.54	$16.50	$16.50
Total	**$ 301.64**	**$ 283.64**	**$ 283.64**
Communications Network Equipment and Installation			
Network Equipment and Installation	$17.46	$15.55	$15.55
Communication Network Installation Management	$4.20	$3.83	$3.83
Backhaul	$2.64	$2.25	$2.25
Total	**$ 24.30**	**$ 21.63**	**$ 21.63**
Platform and Ongoing IT Operations Costs			
AMI Head-end and Meter Data Management Systems	$81.33	$71.84	$71.84
Customer Service System	$20.16	$19.52	$19.52
Customer Engagement Products and Services	$7.69	$6.78	$6.78
IS Infrastructure	$68.48	$61.07	$61.07
Cyber Security	$33.03	$29.94	$29.94
Total	**$ 210.69**	**$ 189.15**	**$ 189.15**
Project Management and Ongoing Business Operations Cost			
Equipment and Installation Refresh Cost	$11.23	$9.52	$9.52
Ongoing Business Management	$22.16	$19.25	$19.25
Customer Engagement Cost	$26.11	$24.33	$24.33
CPP and TOU Pricing Cost	$8.41	$6.98	$6.98
Project Management	$32.28	$31.09	$31.09
Total	**$ 100.18**	**$ 91.18**	**$ 91.18**
Revenue Benefits (Negative Cost)			
Reduction in Theft of Service	$0.00	$0.00	$53.19
Reduction in Write-offs	$0.00	$0.00	$30.72
Total	**$0.00**	**$0.00**	**$83.90**
Total Cost	**$ 636.81**	**$ 585.59**	**$ 501.69**