BEFORE THE
NEW YORK STATE
PUBLIC SERVICE COMMISSION

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Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of New York State Electric & Gas Corporation for Electric Service	Case 19-E- ____
Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of New York State Electric & Gas Corporation for Gas Service	Case 19-G- ____
Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Rochester Gas and Electric Corporation for Electric Service	Case 19-E- ____
Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Rochester Gas and Electric Corporation for Gas Service	Case 19-G- ____

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DIRECT TESTIMONY OF ADVANCED METERING INFRASTRUCTURE PANEL

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Stephen S. George
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May 20, 2019

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I. INTRODUCTION

Q. Please state the names of the members on this Advanced Metering Infrastructure Panel (the "Panel").

A. We are Gary R. Fauth, Stephen S. George, Diane M. Schreiner, Paul P. Sisson, Jeri Teller-Kanzler, and Theresa VanBrooker.

Q. Dr. Fauth, please state your title and business address.

A. I am a Principal at Erbridge Incorporated. My business address is 206 Prospect Street, Belmont, Massachusetts 02478.

Q. Please summarize your educational background and work experience.

A. I have a BA degree in Economics from Yale University and a PhD in Economics from Harvard University. My academic teaching career covers ten years and includes appointments as Associate Professor of Planning at both Harvard's Kennedy School of Government and Harvard's Graduate School of Design. I have helped with efforts to develop advanced metering infrastructure ("AMI") and smart grid benefit-cost analyses at many utilities, which collectively maintain over twenty million AMI meters. In particular I have served as a core member of deployment project management offices at Pacific Gas and Electric, PPL Electric Utilities, and Central Maine Power, and tracked actual costs and benefits at these utilities over their entire AMI deployment periods. I have also advised the United Kingdom's Department of Energy and Climate Change, the government of New South Wales in Australia, and the United States Federal Energy Regulatory Commission on smart meter planning issues. A more detailed summary of my experience is contained in my Curriculum Vitae ("CV") set forth in Exhibit __ (AMI-1).

Q. Have you previously testified in other proceedings before the New York State Public Service Commission ("PSC" or the "Commission") or any other state or federal regulatory agency?

A. I have submitted testimony supporting the AMI Petition filed by New York State Electric & Gas Corporation ("NYSEG") and Rochester Gas and Electric Corporation ("RG&E" and together with NYSEG, the "Companies") on December 20, 2016 in Case 17-E-0058 (the "AMI Proceeding"). I have also testified in Maine concerning the AMI business case for Central Maine Power.

Q. Dr. George, please state your title and business address.

A. I am a Senior Vice President at Nexant, Inc. My business address is 101 Second Street, Suite 1000, San Francisco, California 94150.

Q. Please summarize your educational background and work experience.

A. I have a BS in Economics from the University of Santa Clara and an MA and Doctorate in Economics from the University of California, Davis. I have 43 years of experience in the energy field, nearly all of it involving consulting to electric and gas utilities or government entities. My areas of expertise include pricing strategy, pilot and experimental design, benefit/cost analysis, program design and evaluation, electric industry restructuring, strategic and marketing planning, market research, and energy demand modeling.

I have worked extensively on issues associated with electricity pricing, behavioral conservation and advanced metering. I was a member of the DOE/LBNL Technical Advisory Group overseeing the design and evaluation of pilot studies of time-varying rates conducted by a number of United States utilities. I was the lead evaluator of the

Sacramento Municipal Utility District's ("SMUD") SmartPricing Options pilot, which is widely recognized as one of the best pricing pilots ever done in the electricity industry. I have worked extensively throughout the United States as well as internationally on issues related to advanced metering, time-based pricing and electricity market restructuring, including projects in New Zealand, Australia, Singapore, Hong Kong, Canada, Spain, England, and Scotland. A more detailed summary of my experience is contained in my CV set forth in Exhibit __ (AMI-1).

Q. Have you previously testified in other proceedings before the Commission or any other state or federal regulatory agency?

A. Yes, I have testified a number of times before the California Public Utilities Commission on behalf of San Diego Gas & Electric Company and Pacific Gas and Electric Company, before the Illinois Commerce Commission on behalf of Commonwealth Edison Company, before the Oklahoma Public Service Commission on behalf of Oklahoma Gas & Electric, and before the Maine Public Utilities Commission on behalf of Central Maine Power. I recently provided testimony in the AMI application by Nova Scotia Power, which was approved, and I provided input to Consolidated Edison Company of New York's ("Consolidated Edison") successful AMI application in New York. I was also a member of the witness panel for NYSEG and RG&E in the AMI Proceeding. In all cases, my testimony was provided either in conjunction with applications for AMI or in proceedings associated with electricity pricing.

Q. Ms. Schreiner, please state your title and business address.

A. I am a Program Director, Smart Grids at Avangrid Networks. My business address is 89 East Avenue, Rochester, New York 14649.

Q. Please summarize your educational background and work experience.

A. I have a BS in Business Administration from the Rochester Institute of Technology and an MBA from the William E. Simon School of Business at the University of Rochester. I have 39 years of leadership experience in the utility sector in the areas of Project and Change Management, Customer Service, and Technology. I have implemented multiple large scale projects for both RG&E and NYSEG during my tenure. A more detailed summary of my experience is contained in my CV set forth in Exhibit __ (AMI-1).

Q. Have you previously testified in other proceedings before the Commission or any other state or federal regulatory agency?

A. No, I have not.

Q. Mr. Sisson, please state your title and business address.

A. I am a Program Director, Smart Grids at Avangrid Networks. My business address is 89 East Avenue, Rochester, New York 14649

Q. Please summarize your educational background and work experience.

A. I have a Bachelors of Electronics Engineering Technology (B.E.E.T.) degree from World College and an MBA from New York Institute of Technology. I have held several positions in various departments and project teams over 36 years with the Companies, including: Electric Generation, Meter and Laboratory Services, Meter Reading Systems, and AMI Deployments. A more detailed summary of my experience is contained in my CV set forth in Exhibit __ (AMI-1).

Q. Have you previously testified in other proceedings before the PSC or any other state or federal regulatory agency or court?

A. I have submitted testimony in the AMI Proceeding.

Q. Ms. Teller-Kanzler, please state your title and business address.

A. I am the Director of Cyber Security at Avangrid. My business address is 89 East Avenue, Rochester, New York 14649.

Q. Please summarize your educational background and work experience.

A. I have a BS from Mercy College and an MBA, with a specialization in Management Information Systems, from Pace University's Lubin School of Business. I have over 20 years of experience in information security, privacy, regulatory compliance, and corporate governance, in a variety of industry verticals: financial services, energy providers, health care, insurance, and consumer brands. I am the inventor of record for two patents: the Citigroup Information Security Evaluation Model (Citi-ISEM), a comprehensive methodology that combines in-depth analysis, business risk assessments, and industry best practices, enabling the assignment of maturity levels for consistent security and privacy evaluations and benchmarking, and the Citibank Metrics Program, which provides qualitative and quantitative measurements of key security metrics, enabling informed decision making. A more detailed summary of my experience is contained in my CV set forth in Exhibit __ (AMI-1).

Q. Have you previously testified in other proceedings before the Commission or any other state or federal regulatory agency?

A. No, I have not.

Q. Ms. VanBrooker, please state your title and business address.

A. I am the Director of Customer Service for the Companies. My business address is 89 East Avenue, Rochester, New York 14649.

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Q. Please summarize your educational background and work experience.

A. I have a BA and an MBA from William E. Simon School of Business at the University of Rochester. I have worked for the Companies for 36 years with most of my time in Customer Service operations. During this tenure, I have had a wide variety of responsibilities. A more detailed summary of my experience is contained in my CV set forth in Exhibit __ (AMI-1).

Q. Have you previously testified in other proceedings before the Commission or any other state or federal regulatory agency?

A. Yes. I submitted testimony in NYSEG and RG&E's last rate proceedings, Cases 15-E-0283 et al. I also submitted testimony in Case 02-E-0198, Case 03-E-0765, Case 05-E-0122, Case 07-M-0906, and Cases 09-E-0715 et al.

Q. What is the purpose of this Panel's testimony?

A. The testimony supports approval and cost recovery for full-scale deployment of AMI at NYSEG and RG&E. AMI is a foundational platform in support of New York State energy policy and the objectives of New York's Reforming the Energy Vision ("REV") proceeding. As explained in this testimony, AMI will also generate hundreds of millions of dollars of net benefits to the Companies' customers and provide very significant additional, non-quantifiable benefits in the form of increased customer convenience and product/service innovation.

Q. How is this testimony organized?

A. The testimony begins with a discussion of the primary benefits of AMI. This is followed by a brief summary of the history of the Companies' previous actions to obtain approval for AMI deployment (collectively referred to as the "AMI Settlement Collaborative") and how those efforts have been incorporated into the Companies' current AMI proposal. The history is followed by an overview of the AMI system and capabilities for which the Companies seek approval. Next, the Panel addresses the changes that have evolved in technology and impacts to the benefit-cost analysis ("BCA") presented here compared with prior information submitted to the Commission and the AMI Settlement Collaborative. The testimony then discusses how the Companies incorporated the lessons learned from the Companies' Energy Smart Community ("ESC") demonstration project in this proposal. One of the key lessons learned from the ESC is how to effectively communicate with customers about the changes associated with AMI deployment and the benefits they will derive from it, which is the next topic covered. This section includes a summary of AMI customer outreach efforts and discusses the implementation of Green Button Connect ("GBC"), which will allow customers (and others with customer permission) to access the granular usage data that AMI produces. Next, AMI cybersecurity is discussed followed by a discussion of the provisions that will allow customers to opt-out of AMI metering if they so choose. The final section of the testimony summarizes the quantified AMI benefits and costs that the Companies have estimated and provides a high-level overview of how those estimates were developed.

II. <u>IDENTIFICATION AND SUMMARY OF EXHIBITS</u>

Q. Is the Panel sponsoring any exhibits?

A. Yes, the Panel is sponsoring the following exhibits:

1) Exhibit __ (AMI-1) sets forth the CVs of the witnesses testifying on this Panel;
2) Exhibit __ (AMI-2) includes details of the AMI Benefit-Cost Analysis and the Capital Investments needed to implement AMI;

3) Exhibit __ (AMI-3) contains the Companies' proposed Customer Outreach and Engagement Plan ("AMI O&E Plan");
4) Exhibit __ (AMI-4) includes the Companies' proposed Cyber Security Plan;
5) Exhibit __ (AMI-5) contains the Employee Transition Plan; and
6) Exhibit __ (AMI-6) provides an index of the Panel's workpapers. A copy of the workpapers will be provided to the New York State Department of Public Service Staff ("Staff").

III. AMI PROPOSAL

A. General Overview of the AMI Project (the "Project")

1. What is AMI?

Q. Please provide a general description of AMI.

A. AMI is an integrated system of smart meters, communication networks, and data management systems that enables two-way communications between utilities and customer locations.

2. AMI should be deployed.

Q. Why do the Companies propose to deploy AMI?

A. Deploying AMI is in the best interest of customers, New York State, and the Companies. This proposition is clearly demonstrated by the quantified benefits of AMI, which are projected to exceed the costs of AMI implementation and operation over the life of the investment. Analysis shows operational business savings from deploying AMI for NYSEG and RG&E combined, in the form of reductions in capital and operating costs, which exceed the full costs of the AMI system. Over the 20-year AMI life cycle, the present value of costs of AMI total $551.5 million and the present value of the capital and operating savings from the investment totals $576.4 million.[1] That is, the AMI system produces enough savings to pay for itself and generates an additional $24.9 million in capital and operational savings over the life of the investment.

In addition to these net operational benefits, AMI provides a platform for achieving very significant societal benefits in the form of reductions in customer outage costs, reductions in carbon emissions, avoided generation, transmission and distribution investments, and reduced fuel costs. The Companies estimate that the present value of societal benefits (excluding operational benefits) will total approximately $263.7 million over the life of the AMI investment, bringing the total gross benefits to $840.1 million. The present value of net benefits (e.g., benefits minus costs) including both operational and societal gains, is estimated to equal $273.4 million. In addition, as discussed later in our testimony, delay in implementation will impose significant costs on customers that could be avoided by deploying AMI now.

Q. Are there other benefits associated with AMI that are not captured by the Panel's BCA?

A. Yes. Among these are "fairness benefits," which have been quantified at $156.8 million, but were not included in the societal BCA calculation because they represent income transfers. Fairness benefits represent better alignment of costs of service and customer bills. These benefits include improvements in meter accuracy, which reduces unaccounted for energy, fewer write-offs for delivery and energy charges, and reductions in theft of service. These fairness benefits reduce the extent to which costs generated by some customers are redistributed across the entire customer base.

[1] All costs and benefits included in this section are expressed in present value terms, which summarize the benefits and costs over the life of the investment in present-day dollars.

In addition to fairness benefits, there are also customer benefits that are not quantified in the BCA. For example, customers with inside meters will no longer need to provide utility company access to obtain meter reads or supply meter reads by calling in to the Companies or submitting reads online. As a result, estimated bill inquiries from customers will be reduced. In addition, service activation and account transfers will be easier through a remote meter service switch.

Q. How does the extensive deployment of AMI in North America improve AMI's value in New York and make this an opportune time to deploy AMI?

A. AMI is no longer cutting-edge; it is proven technology and is the dominant meter platform deployed throughout North America. Utilities that have deployed AMI have extensive operating experience and have generated a wide variety of applications that create significant benefits for customers. In addition, the related AMI communications mesh technology that collects the smart meter data has an extensive experience base and has matured such that it can handle more difficult topology and lower densities while providing reliable communications for AMI data. Today, there are almost 80 million AMI electric meters in the United States and smart meter penetration continues to grow. Only 29 million conventional, non-communicating meters remain in use. Over the last nine years, an average of 8 million smart meters has been deployed each year. Smart meters are also the dominant meter technology in Canada with current penetration reaching roughly 70 percent of all meters.

Q. Why is AMI essential to achieving the Commission's and New York State's REV objectives of market enablement, planning improvement and support for Distributed Energy Resources ("DER")?

A. AMI is an essential foundation for grid modernization and for achieving the Commission's and New York State's grid objectives. For example, AMI helps the Companies avoid future costs for line sensors that would be needed to manage DER loads, and that avoided cost is counted as one of the operational benefits. In addition, installation of smart meters helps DER customers who require measurement of both energy use and generation to avoid the cost of high end meters that would otherwise be needed, adding to the cost of DER installation; that avoided cost is also counted as an AMI operational benefit. AMI also provides detailed data on circuit loads that are needed to support integrated system planning, including the development of non-wires alternatives where appropriate.

Q. Does AMI also provide other customer benefits in the REV context?

A. Yes, AMI data provides customers with usage data that enables them to better manage their electricity consumption and bills. Customers also can choose to share their energy usage data with energy suppliers, facilitating the REV objectives of animating localized energy markets and improving product/service innovation.

Q. How does AMI help achieve the Companies' goal of improving resiliency?

A. The Companies are proposing a Resiliency Plan that includes infrastructure, enhanced vegetation management, automation of substations and reclosers to shorten outage durations, and topology changes to sectionalize circuits, thus reducing the number of customers impacted by any given fault/outage. The Resiliency Plan Panel provides additional details concerning the Companies' proposed Resiliency Plan. AMI complements the Companies' efforts by providing power on and off messaging for customers on smaller or more distant sections of the electric system protected by fuses (which are not automated and therefore have no remote monitoring). This messaging ability is particularly critical for improving system performance and expediting service restoration during outages for these customers. Power off messaging will help crews locate the fault faster, and power on messaging will help deploy crews efficiently in the field to confirm that power has been restored to all customers.

Q. Has AMI been approved previously in New York?

A. Yes. The Commission approved requests by Consolidated Edison and Orange and Rockland Utilities ("O&R") to fully deploy AMI. Consolidated Edison alone has installed more than a million meters to date. The Long Island Power Authority was also recently approved for AMI deployment. Deploying AMI now takes advantage of this experience base.

Q. Has the Commission recently reiterated its overall support for AMI?

A. Yes. On February 8, 2019 in Cases 18-E-0595 et al., the Commission issued an Order Terminating Metering Programs ("Meter Order") that terminated competitive retail Meter Service Provider ("MSP") and Meter Data Service Provider ("MDSP") programs. The Commission noted at page 6 of the Meter Order that it has "ensured the intended goals of the MSP and MDSP programs are being met through other means, including AMI implemented by the electric distribution utilities." The Commission went on to state that it is satisfied with the results gained through utility deployments of AMI toward the original goal of promoting advanced metering. The Companies' AMI program directly furthers that goal and is consistent with the Commission's directive for utilities to "develop and deploy, to the extent feasible and cost effective, advanced metering systems for the benefit of all customers." (Meter Order at p. 3).

Q. What other factors support moving ahead with AMI at this time?

A. Delaying AMI further could significantly reduce net benefits from AMI deployment because the Companies' Distribution System Platform ("DSP") obligations will require certain very substantial capital investments to support REV that can be avoided if AMI is installed. These capital expenditures include the installation of line sensors to monitor voltage on the system, which is critical for system stability as DERs continue to penetrate the market, and the installation of meters that are capable of measuring bidirectional flows on DERs. If AMI deployment is delayed, these investments will need to be made and the sunk costs of these investments will not be offset by AMI.

3. Corporate History with AMI

Q. What is the history of AMI at the Companies?

A. The Companies have been developing and refining plans for AMI continuously since 2015. The Companies filed an AMI narrative as part of an update filing submitted August 5, 2015 for inclusion in the then pending rate case. Subsequently, following Staff's recommendation, the Companies incorporated AMI into their Distribution System Implementation Plan ("DSIP"), filed June 30, 2016 in Case 14-M-0101. The Companies DSIP included a detailed AMI Benefit Cost Analysis and Business Plan.

In addition, on December 20, 2016, the Companies filed a separate petition in Case 17-E-0058 seeking approval of the AMI Business Plan. This filing initiated an extensive process and Settlement Collaborative during 2017 and 2018 to discuss the overall AMI Business Plan, answer questions, and receive feedback from Staff and interested parties. Despite extensive and productive effort, the Settlement Collaborative has been overtaken by the 2019 rate cases.

Q. Please address how the Settlement Collaborative efforts in the AMI Proceeding have influenced or been reflected in this proceeding.

A. The Companies' and the parties' participation in the Settlement Collaborative allowed the Companies to focus on the planning that will be necessary to make the AMI deployment successful and resulted in more detailed plans for AMI security, employee transition, AMI customer outreach and engagement, and GBC capability for the Customer Web Portal being included in the Companies' current AMI proposal. Having these more detailed plans in place better positions the AMI deployment for success.

4. AMI Scope

Q. What is the scope of the AMI proposal?

A. AMI will include: i) installation of approximately 1.9 million smart devices, comprised of 1.3 million new electric meters and 600,000 modules to be retrofitted on existing gas meters (together, "AMI meters"); ii) support of a telecommunications network that will include diverse media solutions (i.e., radio frequency, cell, dark fiber, equipment etc.); and iii) availability of information technology ("IT") infrastructure and software applications to process data and interact with field devices. In addition, the network will provide a telecommunications channel for DER and Demand Response ("DR"). AMI will further enable the DSP to provide granular data, visibility, and situational awareness to customers, third party market participants, and the Companies to inform and enhance decision making. The DSP also will support the generation of new solutions to achieve REV objectives.

Q. How quickly will customers begin to see the benefits of AMI and have access to the enhanced functionality that AMI will provide?

A. Upon installation of a smart meter, customers will have access to the Energy Manager online portal. This will provide customers with the following innovative features:

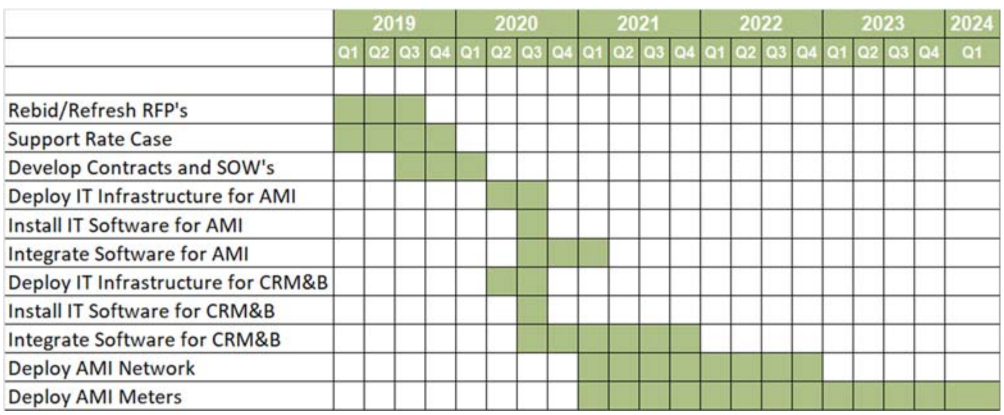
- Access to hourly usage data and energy efficiency tips to see how they can save energy by installing energy efficient products and/or make changes in their usage;
- Ability to download usage data, create an action plan by selecting from a checklist of ways to save money, and reduce their carbon footprint;
- Access to GBC, an online platform that gives customers the ability to share usage data with third parties who will increase opportunities for customers to make smarter energy choices and investment decisions; and
- Facilitate greater customer participation in the Companies' DR programs, increasing access to energy efficiency tools, and provide for other energy management opportunities.

In addition, once meters are installed, voltage monitoring, power on and power off messaging for outage detection, remote turn on and turn off of electricity, and off-cycle reads will all be available to support the changes in business operations that generate many of the benefits discussed later in this testimony. The AMI platform will also allow the Companies to offer innovative rate programs through their respective tariffs and behavioral conservation programs such as weekly usage alerts. The timing for these new tariffs and programs will depend, in part, on planning cycles and regulatory approval. For purposes of the BCA conducted in support of this filing, we have assumed that there is a one-year lag between when meters are installed for each customer and when they will have access to time-varying tariffs and behavioral conservation programs that are dependent on the interval data provided through AMI. This lag allows customers to have a year's worth of usage data to rely upon for deciding whether to select an alternative tariff or participate in behavioral conservation programs.

Q. What deployment schedule is proposed for AMI?

A. Smart meters and the necessary communication network will be deployed across the Companies' service areas over a 36 month period beginning in the first quarter of 2021. Scheduling of specific areas is dependent on approval to proceed and engagement with third party installers. The Companies plan to deploy simultaneously in the NYSEG and RG&E service territories per the schedule shown in Table 1 below.

Table 1: Deployment Schedule



5. Progress since the 2016 AMI Petition Filing

Q. What progress has been made in terms of the planning and analysis of AMI since the Companies filed their petition in the AMI Proceeding?

A. As we explained previously, there have been numerous updates to the analysis and results summarized here compared with prior filings. With the passage of time, the Companies have continued to refine their BCA calculations and, as a result, have even stronger evidence that the installation of AMI now is beneficial and should be approved. These include: i) better estimates of deployment costs obtained through an extensive procurement process with bids for nearly all major cost drivers; ii) the inclusion of new benefit streams that improve the accuracy of the BCA; iii) updates of all assumptions and inputs to the benefit analysis based on more recent Company data and industry findings as they relate to key benefit streams; iv) inclusion of key findings from the Companies' Energy Smart Community demonstration project, and v) advancements in meter functionality.

Q. Please summarize the procurement process that supports the current estimation of deployment costs.

A. The Companies issued multiple RFPs in 2017 and in 2018, to ensure current pricing of required products and services to complete the AMI deployment and update the BCA. The schedule of RFPs is described in Table 2 below. Bid responses were received for each of the RFPs, ensuring a strong basis for the costs included in the BCA.

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Table 2: AMI RFPS

RFP	N	Description
AMI Solution	1	This is a comprehensive RFP that covers all needed electric and gas meters, electric and gas communications modules, communications network, head end software, meter installation, and meter data management (MDM) software. This RFP provides the core infrastructure needed to measure, collect, and manage both customer consumption data and also meter monitoring data to support enhanced grid operations.
PMO	2	This RFP provides resources to support the internal project management office (PMO), and also resources for managing and handling data exceptions that arise during AMI deployment.
IT System Integrator	3	This RFP provides the programming and testing expertise needed to integrate AMI and MDM software, and connect to the customer information system and Spectrum Platform including the Outage Management System (OMS).
Energy Manager Web Portal	4	This RFP solicits software to present AMI data to the customer in a consumer friendly format including connection to Green Button Connect (GBC). The software will be a web-based tool that can also be used by Customer Service Representatives to help answer customer questions.
Network Canopy	5	This RFP solicits hardware and installation services to expand the New York communications network (WiMax, Cell, Fiber) to connect to the AMI network and provide information backhaul services for AMI.
AMI Network Solution	6	This RFP solicits services for installing AMI communications network devices to distribution poles and towers across the service area.
Meter Accessories	7	This RFP solicits meter seals for all the electric meters and A-based adapters for approximately 2.5 percent of the electric meter sockets. (meters must be onsite prior to deployment)
Meter Panel Repairs	8	This RFP solicits electrician services to complete minor repairs on customer meter panels to facilitate AMI meter deployment.
Customer/ Community Outreach	9	This RFP solicits services to design a strategy and for executing the AMI Customer Outreach and Engagement Plan.
CRM Integration	10	This will involve multiple RFPs and IT services to integrate an upgrade to the customer information system. The SAP CRM&B suite of services supports time variable rates.
Network Trouble-shooting	11	This RFP solicits analytical and field services to refine and improve the performance of the installed AMI communications network. The services would include network performance analysis, field trips to reposition, service, or upgrade the communications network with additional equipment.

Q. What additional benefits have been added to the BCA?

A. As discussed previously, two new benefits added are avoided line sensor costs and avoided solar meter costs. A third new benefit that has been added is the avoided cost of field services associated with outage restoration. The integration of AMI-OMS reduces the average time required to restore electricity supply when outages occur, which creates substantial customer and societal benefits in the form of reductions in customer outage costs, as discussed later in this testimony. The reduction in average outage time also reduces field service time and costs. The prior BCA included a reduction in storm-related restoration costs, but it did not include cost reductions associated with non-storm related outages. That benefit has been added to the updated BCA presented here.

Q. Have any new cost categories been incorporated into the analysis?

A. Yes, to ensure that customers can take advantage of new AMI technology and the information that it produces, the Companies substantially expanded their customer outreach and engagement plan and increased their proposed budget for these efforts. Exhibit __ (AMI-3) includes the AMI O&E Plan. We more fully discuss the AMI O&E Plan later in the Panel's testimony.

Q. Have there been any changes to key input assumptions?

A. Yes, many input values have been updated to reflect more current data and industry findings. All input assumptions associated with the BCA are documented in detail in Exhibit __ (AMI-2) and Exhibit __ (AMI-6). A few key assumptions that have had substantial impacts on the overall net benefits and benefit cost ratio are summarized below.

There has been a very substantial drop in the value used for the avoided cost of generation capacity in upstate New York, which is a key driver of societal benefits. We have used the official CARIS forecast[2] as directed in the BCA Handbook 2.0 submitted to Staff July 26, 2018. A new forecast of generation capacity costs is not expected to be available before this filing.

Additional changes include but are not limited to: a revised meter deployment schedule and updates in outage cost reductions due to AMI-OMS using more recent outage data (2016-2018), which more accurately reflect increases in long-term outages as well as the current state of the distribution system.

Q. Please describe the Companies' experience and accomplishments with the ESC and REV Demonstration projects.

A. The ESC has operated for over a year, and important lessons have been learned that will result in increased efficiencies for the full deployment of AMI. Significant progress has been achieved in the successful deployment of AMI in the ESC. NYSEG has installed approximately 12,400 electric meters and 7,600 gas smart meters with a 99.5 percent meter reading rate since deployment completion. AMI's telecommunication system is also deployed across all ESC circuits. The AMI system has already been, or will be, integrated into a number of systems, including the Outage Management System ("OMS") and Energy Manager Customer Web Portal. The information from the system is currently used for billing and is also used as the basis for customer engagement, including segmentation, energy usage information, and new rate design options. The Companies will continue to integrate AMI data into additional systems and initiatives,

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2 New York Independent System Operator, 2017 Congestion Assessment and Resource Integration Study (Apr. 2018).

including time-varying rates, Smart Home vehicle charging pilots, and updated Hosting Capacity and Interconnection portals.

B. <u>Technology Elements to Ensure Value Creation and Realization of Benefits</u>

Q. How does the current AMI technology allow for sustainable benefits?

A. The AMI technology has the ability to be continually updated. As AMI technology has evolved, new capabilities have been realized. These include: i) shorter data latency and information delivery response time; ii) industry standards development to achieve interoperability of vendor solutions, network resiliency and reliability improvements; and iii) increased capacity to ensure effectiveness and less risk of obsolescence.

Q. Would the Panel please describe the current capability of information delivery latency?

A. Until recently, the specifications for interval granularity and delivery frequency were hourly consumption data delivered four times per day. Today's AMI systems have more network and processing capacity and, as a consequence, we anticipate deploying a system that can deliver consumption data every 15 minutes back to the operations center. The higher capacity networks will support more finely tuned time-varying rates and will provide customers with more real-time data to help them manage their electric bills.

Q. What is the state of AMI systems interoperability?

A. The AMI industry in conjunction with standards bodies continues to move toward true equipment interoperability between vendors. The goal being that smart meter and network communications equipment and interfaces manufactured by one vendor can be used in AMI systems from another vendor. This interoperability lessens the risk of dependency on one vendor for acquisition of equipment. This allows for the use of multiple vendors, creates a more competitive environment, and leads to lower post-deployment equipment and maintenance costs. Thus, the Companies have required interoperability capability from each of the vendors being considered as suppliers for full AMI deployment. This will ensure post-deployment equipment replacement and system expansion can be completed as efficiently and cost effectively as possible.

Q. How will the Companies ensure AMI metering equipment compliance?

A. Prior to deployment, all metering devices (i.e., smart meters and gas modules) used for Customer billing will be vetted through the Staff testing process and will be approved by the Commission.

Q. What options are available to improve AMI network resiliency?

A. The Companies' proposed AMI system will be "hardened" to support communications through multi-day power outage situations and through the use of larger battery packs and/or solar power backup at key network locations. Accordingly, our current AMI specifications require that multi-day power backup be provided for network communication nodes. This multi-day backup will allow communications with smart meters upon power restoration. Extended backup power to AMI network devices with no system power during outages enables communication of power restoration messages and will improve the situational awareness and efficiency of the overall storm restoration process during multi-day outages. In addition, the selected network will be strategically deployed with high redundancy and dual communications (WiMAX, Cell, etc.) to provide a failover channel if primary communication is disrupted.

Q. How can the AMI system be updated over the life of the system?

A. Today's smart meters have exponentially more computing power and memory compared with earlier generation AMI meters. They have the ability to download applications Over the Air ("OTA") similar to an iPhone, to enhance and upgrade functionality and capabilities as new requirements emerge. These meters will also provide the additional capacity required to adopt new technologies well into the project lifecycle.

Q. What are some examples of the latest smart meter applications?

A. The most recent generation of AMI smart meters can process information collected in real time, sending the pre-processed information back to the operations center. In addition, the meters can integrate directly collected meter data with data from nearby meters to provide situational awareness and react accordingly. For example, meters can interpret their own power off messages with messages from nearby meters to communicate outage scope more effectively. In addition, the meters can identify which circuit power phase they are connected to and transmit this information back to the operations center to support more accurate load flows and circuit balancing in support of DER growth. The emergence of edge computing will create future AMI benefits for customers as new applications are developed.

Q. Will the implementation of AMI require the Companies to replace the customer billing system?

A. No, the Companies will continue to utilize SAP as its billing system. A technical upgrade is planned to the customer billing system to add functionality. Upgrading the existing SAP Customer Care System ("CCS") to a Customer Relationship Management & Billing ("CRM&B") system will provide an individualized customer experience, which the Companies expect will increase customer engagement and satisfaction. The CRM&B component of the AMI system will enable more comprehensive billing options and the flexibility to report price and billing data to customers on a more real time basis.

It will also enable time varying pricing ("TVP") rate design programs, behavioral conservation programs, improved outage management, and faster response times for service change requests.

Q. Are there additional benefits of implementing SAP CRM&B?

A. CRM&B will also be a foundational system in support of the DSP and will accommodate complex transactions to enable new market functionality in support of REV initiatives.

Q. How does CRM&B support customer and third party engagement?

A. CRM&B will provide the ability to create and manage programs and constraints for all customer classes, for both economic and reliability dispatch, as well as integration into business processes for managing customer and third party service provider enrollments. With appropriate permissions/consents from customers, energy service companies ("ESCOs"), DER providers, and others can use customer-specific interval usage data to tailor supply contracts, PV bids and other product and service offerings to better meet the needs of individual customers.

Q. Why are the Companies' upgrading the existing SAP CCS by implementing SAP CRM&B rather than utilizing some other system?

A. The SAP CRM&B system is a contemporary, vendor-supported, commercially available solution which has been successfully implemented at many utilities industry-wide. CRM&B is a highly configurable system and can be tailored to specific requirements. In addition, SAP provides continuous upgrades to minimize the risk of obsolescence. Utilization of CRM&B also provides the opportunity for the Companies to leverage existing technical expertise. The system flexibility and resource base will allow CRM&B to cost-effectively keep pace with industry and regulatory changes.

Q. What is the scope of the technical upgrade?

A. The technical upgrade is to move the SAP system onto the latest enhancement pack ("EHP8"), convert the database to Unicode, move onto HANA (High-Performance Analytical Appliance) and implement the SAP CRM&B module. The enhancement pack brings many system features to support AMI metering in SAP, including time of use support, gateways to support head end system ("HES") integration, simplified approach for master data integration between SAP and the meter data management ("MDM") system. Converting to Unicode provides standardization to the code in SAP, giving better performance of any system developments. HANA provides in-memory processing, allowing large amounts of data to be managed more efficiently by the SAP system.

Q. What additional systems/modules are being implemented?

A. The SAP CRM&B module introduces additional functionality, with new processes available to the customer service centers handling calls from customers. This system will integrate AMI features into key processes, including but not limited to: on-demand meter read; remote disconnect/reconnect; and move-in/move-out.

Along with SAP CRM&B, additional systems are required to manage the AMI meters, communication, data storage, and provision of meaningful consumption/cost data to customers. These systems are all integrated with the core SAP system. There are also a number of peripheral systems that will require upgrades to support the new versions and the AMI processes. For example, Click Software is the work order mobility solution used to optimize scheduling and completion of work orders across jobs, resources and locations simultaneously.

C. <u>Outreach and Engagement</u>

Q. Have the Companies developed a plan to engage customers and communicate the benefits of AMI?

A. Yes. As we stated above, to achieve a high level of awareness during AMI implementation, the Companies developed the AMI O&E Plan, included in Exhibit __ (AMI-3). The AMI O&E Plan focuses on customer benefits (identifying how AMI enhances the customer experience) as well as leveraging research and best practices. The AMI O&E Plan incorporates lessons learned from the ESC and key stakeholders in Tompkins County, and implementation of AMI by our affiliate companies. The AMI O&E Plan also utilizes the Voice of the Customer ("VOC") to understand and address customer expectations. The AMI O&E Plan has several key components, including: i) a marketing, education and outreach communication plan; ii) the implementation of GBC to engage customers with the enhanced information provided through AMI and to help animate distributed markets; and iii) deployment of enhancements to the Companies' customer portal, Energy Manager, to take advantage of the capabilities of the AMI platform.

Q. How has the knowledge you have gained from the ESC helped improve the AMI O&E Plan?

A. Lessons learned from the ESC related to communications and outreach have helped inform and improve the AMI O&E Plan for full roll out of AMI within New York. Key lessons learned that are highlighted in the AMI O&E Plan are:

- Clearly defined collaboration;
- Ensure transparency with stakeholders;

- Connect early with local municipal officials;
- Connect with community organizations to help educate and inform;
- Protect low income customers;
- Focus on customer education and increase energy literacy; and
- Educate employees as ambassadors.

Q. What are the key components of the AMI O&E Plan?

A. The AMI O&E Plan is focused on informing customers about AMI and the associated benefits, ensuring an effective meter installation process and engaging with customers to provide access to information and products that will enable them to better control energy usage. The AMI O&E Plan will be implemented in three phases:

- **Aware:** A series of communication campaigns designed to create excitement and interest, while educating customers and the community about smart meter benefits and the general scope and timing of the deployment;
- **Informed:** A series of communication campaigns designed to prepare customers for deployment, reiterate meter benefits, and provide information on available program opportunities for each customer; and
- **Engaged:** Ongoing communications, starting from the day of meter installation, to provide individual customers with the knowledge and insights to participate in smart meter opportunities.

Q. In addition to customers, what other stakeholders will be involved in the AMI O&E Plan?

A. While customers are of paramount importance to the Companies, outreach to other constituents is included in planned activities. These constituents include elected and municipal officials (state, county and local), business groups, and key community groups such as environmental groups, neighborhood organizations and interest groups.

Q. How do the Companies plan to prepare customers and the communities served for AMI?

A. The Companies propose that upon approval, a thoughtful and comprehensive period of education will begin with the goal of increasing acceptance and understanding of AMI capabilities. This will precede the three formal phases of the AMI O&E Plan outlined above which will be designed to be more customer/region specific.

Q. Does the AMI O&E Plan identify specific actions to help change customer behaviors related to energy usage?

A. Yes. During the Engagement phase of the AMI O&E Plan, the Companies will focus on how customers can utilize Energy Manager to modify their energy usage through tools such as bill alerts and analytics of usage data. The Companies will make it clear to customers that there are benefits through access to data, availability of DER products and services and GBC.

Q. What is Green Button Connect?

A. GBC is an industry-led effort to provide utility customers with easy and secure access to energy usage information in a consumer-friendly and computer-friendly format. Using GBC will allow utility customers to automate the secure transfer of their own energy usage data to authorized Third Parties, based on affirmative (opt-in) customer consent and control. The Companies propose using a Third Party portal to download data, manage customer lists, and send customers personalized results of services. Third Parties will collect energy usage data in a standard format to promote their services and platforms. The Companies will use standardized and secure means (.CSV and .XML) to share customer energy usage information. The Green Button Alliance, a non-profit corporation formed to foster adoption of standards for the provision of customer information from AMI, has created a standard process for providing this functionality.

Q. What is the Green Button Alliance?

A. The Green Button Alliance is a non-profit corporation formed in 2015 to foster development, compliance and widespread adoption of global Green Button electricity, natural gas and water data standards known as the ASESB Energy Service Provider Interface ("ESPI") for electricity and natural gas. The Green Button My Data initiative was started through the efforts of the U.S. Department of Energy, the U.S. National Institute of Standards and Technology, and the White House in concert with smart-grid efforts of various consortia, utilities, solutions providers and regional governments throughout North America.

Q. What are the Green Button Alliance Standards for Data Transfer?

A. The Green Button Alliance requirements for data transfer are as follows:

- .XML and .CSV file formats for energy usage information;
- A data exchange protocol which allows for the automation transfer of data from a utility to a third party based on customer authorization;
- Flexibility to handle different types of energy data and time interval usage;
- Data provided in 5-minute, 15-minute, hourly, daily or monthly intervals depending on what a utility decides to make available; and
- Data requests and responses are made using the secure Hyper Text Transfer Protocol ("HTTPS") and authenticated via a two-way certificate exchange (Open Authorization 2.0).

Q. What data intervals do the Companies propose for New York AMI?

A. The Companies propose 15-minute data intervals for commercial and industrial ("C&I") customers and hourly intervals for residential customers. Full deployment of AMI will provide opportunities to offer TVP to customers, which can improve economic efficiency by sending more appropriate price signals to customers regarding their consumption decisions.

Q. What are examples of customer use cases for GBC?

A. Current customer use cases for GBC include, yet are not limited to: i) customizing weather-related settings for comfort and cost; ii) projecting energy costs for renters and new home owners for whom historical data does not exist; iii) assisting ESCOs in developing time sensitive rates for customers to lower costs; iv) improving quotes and system design of solar panels; and v) checking and analyzing customers' returns on energy efficient investments.

Q. How does GBC work?

A. Third parties are approved by the utility, and then customers authorize the utility to share data with their selected third parties.

Q. How will the Companies mitigate third party risk?

A. The Companies' third party risk management process includes a standardized procedure for identifying, assessing, and mitigating security risks. All third parties are assessed for cyber and information security controls, based on the Companies' cybersecurity controls framework, including operational, technical and administrative controls. The third party risk management process includes a data security rider/data services agreement that provides, among other things, the right to audit any third party processing, handling, and transmitting, of non-public information.

Q. Does GBC support New York State Energy Policy Goals?

A. GBC facilitates DER adoption and supports market animation, AMI value for customers, and growing markets, all of which support New York State Energy Policy goals.

Q. How does the Panel propose to address the separate GBC collaborative/proceeding directed by the Commission in its December 13, 2018 Order Adopting Accelerated Energy Efficiency Targets issued in Case 18-M-0084??

A. The Companies have incorporated terms and conditions into the GBC provisioning process for both third parties and customers. The Companies are participating in the collaborative in Case 18-M-0084, which is developing universal terms and conditions for third parties and customers.

Q. How will the Companies' customers access GBC?

A. Customers can access GBC through rge.com or nyseg.com from a computer or mobile device.

Q. What metrics are being proposed by the Companies to determine the effectiveness of the AMI Outreach and Engagement Plan?

A. Proposed metrics related to the AMI O&E Plan are shown in Table 3 below. We have reviewed metrics utilized at affiliates as well as those proposed by peer utilities to develop these metrics. These metrics will measure progress through all three phases of the Companies' AMI Outreach and Engagement Plan.

Table 3: Proposed Measurements of NYSEG and RG&E Outreach and Engagement Plan

	Measure	Frequency	Description
Aware	Customer awareness of AMI	Semi-annually	Customer awareness of AMI technology, features and benefits measured by surveys of customers in each region. Baseline established on a regional basis prior to roll-out of AMI in each area.
	Targeted energy briefings	Annually	Company-hosted forums providing information on the AMI plan, features and benefits; two events per region.
	Community outreach	Annually	Organizational events attended by the company where information on the AMI plan, benefits and features are presented; four events will be attended during deployment for each division.
Inform	% of deployments completed	Quarterly	The number and % of AMI meters installed and working by division.
	% of customers opting-out	Quarterly	Number of opt-outs as compared to the meter deployments by region.
	Appointments kept	Quarterly	Number of appointments kept as compared to appointments scheduled by region.
Engage	Customers utilizing Energy Manager	Semi-annually	% of customers in each region with AMI meters that log into Energy Manager at least once during the reporting period.
	Green Button Connect My Data	Semi-annually	% of customers in each division that utilize Green Button Connect My Data. The largest % will be set once baseline information is available for each division.
	Usage alerts	Quarterly	% of customers enrolling in usage alerts. The largest % will be set once baseline information is available for each division.
	Adoption of time-varying rates	Semi-annually	Number of customers with AMI meters that adopt TOU or TVP tariff expressed as a number and % of each by rate. This information will be provided for track purposes only.
	Targeted energy saving messaging	Semi-annually	% of customers with AMI that are targeted during the reporting period with messages regarding their energy savings tools, personalized usage and/or savings tips. Target TBD.

D. Security (Physical, Cyber and Personally Identifiable Information ("PII"))

Q. In addition to the GBC standards discussed previously, please describe the Companies' cybersecurity and privacy plans related to AMI implementation.

A. The Companies are committed to implementing a secure and reliable AMI system. The Companies have a formally implemented Cybersecurity Program and a Controls Framework, governed by a Board of Directors, an approved Cybersecurity Risk Policy, Personal Data Protection Policy and Unified Incident Response Plan. These documents are included in Exhibit __ (AMI-4).

The Cybersecurity Program is continually evolving in concert with advances in technology, threat detection and intelligence gathering methodologies and the changing risk landscape. The Companies have expanded the scope of the Cybersecurity Program to specifically address AMI physical and cyber risks. The Companies cybersecurity and privacy Subject Matter Experts ("SMEs") actively participate in stakeholder and industry Cybersecurity, Data Security, Electronic Data Interchange ("EDI"), Customer Data, Information Sharing, Retail Access and Supplier Relations working groups. The Cybersecurity Program includes on-going collaboration with cybersecurity authorities and industry working groups, including: Electricity Information Sharing and Analysis Center ("E-ISAC"), Edison Electric Institute ("EEI"), Electric Power Research Institute (EPRI), Industrial Control Systems Cyber Emergency Response Team ("ICS-CERT"), InfraGard, and The United States Computer Emergency Readiness Team ("US-CERT").

Q. Please provide additional details regarding the Controls Framework.

A. The Controls Framework creates a common language for identifying and addressing cybersecurity and privacy threats. The Controls Framework is periodically reviewed and assessed to effectively address changes in risk posture, laws, regulations and industry best practices. Industry standards of best practice guidance used in the development and maintenance of the Controls Framework include, for example: NIST Cybersecurity Framework; NIST SP 800-53: Security and Privacy Controls for Federal Information Systems and Organizations; NIST SP 800-30: Guide for Conducting Risk Assessments; NIST SP 800-161: Supply Chain Risk Management Practices for Federal Information Systems and Organizations; NIST SP 800-144: Guidelines on Security and Privacy in Public Cloud Computing; NISTIR 7628: Guidelines for Smart Grid Security; and NIST

SP 800-171: Protecting Controlled Unclassified Information in Nonfederal Systems and Organizations.

Specific to AMI architecture design and deployment is the integration and implementation of a controls effectiveness assessment and reporting process. Cybersecurity SMEs actively monitor and monthly report progress towards the implementation of security deliverables defined by NIST SP 800-171 (Protecting Controlled Unclassified Information in Nonfederal Systems and Organizations). This process addresses the security plan for each network segment of the AMI architecture, including, the HES, MDMS, vendor remote access, physical security network, and customer facing applications.

The Companies' Cybersecurity Program and Controls Framework includes industry best practice and guidance for the protection of customer and system information/data. Technical, physical and administrative controls are in place to protect personal information that is collected or maintained by the Companies against loss, unauthorized access or disclosure. The Companies have implemented and integrated processes and procedures for data classification, data protection and the treatment of PII. Planning and response to privacy incidents complies with New York State law as appropriate.

Q. Will the Companies train their employees on the AMI cybersecurity controls?

A. Yes, the Cybersecurity Program includes on-going cybersecurity training and awareness for all of the Companies' personnel. Cybersecurity training and awareness focuses on the risks of cyber threats; training personnel to detect and recognize threats as they occur; and educating personnel on their roles and responsibilities should cyber threats or incidents arise. Personnel also receive role-based cybersecurity training, addressing specific areas of increased risk or concern. For example, Human Resources employees receive privacy training. Specific to the Companies' AMI deployment, managers, system administrators and users will be made aware of the security risks associated with their activities and advised of the applicable Company policies, rules and controls related to the security of each network segment of the AMI architecture.

E. <u>Employee Transition</u>

Q. The Companies' AMI business case indicates there will be employees who will be impacted by AMI implementation. Have the Companies determined how this will be addressed?

A. To the extent possible, yes. While new requirements and opportunities for our employees' skills will be created with this technology, certain positions will no longer be required. The Companies will ensure impacted employees are informed of the changes and will work to provide training to enable redeployment, or, where necessary, facilitate departure.

Q. How do the Companies propose to do this?

A. The Companies will engage impacted employees through various channels to ensure employees understand the expected timing of AMI implementation, the impacts on their position and the potential opportunities and skills required for redeployment. This engagement work will continue as the Companies further develop the employee transition plans included in Exhibit __ (AMI-5). Additionally, the Companies will identify the business and employee needs, working alongside our Human Resources team and the International Brotherhood of Electrical Workers ("IBEW"), and create plans which will address and support affected employees. The Companies will continue to offer training and development for impacted employees which will include a specific focus on ensuring that employees are able to continue to pursue careers at NYSEG and RG&E with improved, enhanced or new skills as appropriate.

F. Opt-Out Provisions

Q. Are the Companies allowing customers to opt-out from having an AMI meter?

A. Yes, customers billed with standard residential rates will have the option of receiving service with non-communicating meters, instead of service with AMI communicating electric meters and AMI smart gas modules. Specifically, electric customers can elect to have the radio frequency ("RF") devices in the AMI smart meters turned off, thereby opting out from the communication capabilities of the meters. In addition, gas customers can request that the communicating AMI module for their gas meters not be installed.

Q. How are the Companies offering customers the opportunity to opt out of having an AMI meter?

A. Through outreach and customer communications, the Companies will provide customers with information to assist in making an informed decision. For those who choose to opt out, there will be a process in place to facilitate this request.

Q. Are the Companies proposing that customers pay charges for "opting-out"?

A. Yes, all customers who opt-out of the communicating smart meter program will have extra charges on their bills reflecting the incremental costs of serving opt-out customers relative to communicating smart meter customers. Specifically, there will be on-going monthly costs to cover the cost of field visits to read the non-communicating meters and provide for the expected number of customer premise visits to read meters for move-in and move-out purposes, and to connect or disconnect service when needed. These costs will be included in the Companies' respective tariffs.

Q. Have the Companies projected the number of customers expected to opt-out of the communicating smart meter program?

A. The Companies anticipate approximately one percent of customers may choose to have non-communicating meters to measure their consumption. This expectation is based on two different experiences. At Central Maine Power in Maine, the Companies' affiliate, the opt-out percentage is 0.9 percent, reflecting a gradual reduction from a 1.3 percent opt-out rate in December 2012 when the system was first completed. The opt-out rate in the ESC has been less than 1 percent of the customers in the ESC service area.

G. Customer Benefits Summary

Q. What are the primary benefit streams that have been included in the BCA?

A. There are three broad categories of benefits that are discussed below. The first category concerns benefits that arise from changes in business operations and reductions in capital purchases stemming from AMI deployment. We refer to these as operational savings even though they include both O&M and capital reductions.

The second category consists of societal benefits resulting from the implementation of new rates and programs designed to modify consumer behavior in ways that reduce costs such as capital investments in generation, transmission and distribution, reduce fuel use or reduce carbon emissions. This second benefit category also covers benefits deriving from AMI-driven operational improvements such as reductions in outage duration through AMI-OMS integration and reductions in fuel use through conservation voltage reduction/volt-var optimization (CVR/VVO). These produce benefits in the form of outage cost reductions for consumers, carbon emission reductions and avoided generation, transmission and distribution investments.

The final quantifiable category of benefits is what we refer to as fairness benefits that do not improve economic efficiency (and, therefore, are not included in the societal cost test) but do lead to a more equitable allocation of costs to consumers who cause them. This category includes improvements in meter accuracy, theft reduction and reductions in write offs. Each of these benefits is explained more fully below and in much more detail in Exhibit __ (AMI-2).

Q. How does AMI reduce capital and operating costs for the Companies?

A. Table 4 summarizes the capital and operating cost benefits associated with AMI deployment. As seen in the table, there are eleven cost categories in which AMI deployment can reduce or eliminate expenditures over time. The cost categories are discussed below.

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Table 4: Present Value of Operational Benefits ($ Millions)

#	Benefit Category	Life Cycle Savings ($ Millions NPV)
1	Reduced meter reading costs	$193.7
2	Avoided sensors	$109.9
3	Reduced field work costs	$93.2
4	Avoided meter purchases	$80.0
5	Reduced incremental major storm costs	$37.0
6	Reduced T&D operational costs for non-storm restoration events	$17.8
7	Reduced call center costs	$13.5
8	Improved cash flow (reduced working capital)	$10.3
9	Avoided solar meters	$9.5
10	Reduced billing costs	$9.0
11	Avoided service costs from voltage monitoring	$2.5
	Total benefits	$576.4

Q. Please explain how AMI reduces meter reading costs.

A. AMI is expected to remotely read 99.5 percent of all meters accurately on a daily basis, thus eliminating the need for nearly all manual meter reading. The vast majority of savings for this category arise from meter reader work force reductions. Cost reductions also result from the elimination of meter reading vehicle purchases, maintenance, and fuel. Average annual savings were estimated based on actual costs for meter readers, vehicles and other cost components over the prior year plus inflation for each forecast year.

Q. What is meant by the term "avoided sensors?"

A. As distributed energy resources and electric vehicle charging stations proliferate, it will be increasingly difficult to maintain voltage levels on the grid. The Companies will need voltage and load sensors on the distribution circuits to carefully monitor performance in near real time so that adjustments can be made as necessary to maintain voltage. AMI meters can provide this information but if they are not in place, line sensors would need to be deployed. As such, the base case scenario against which AMI should be judged is one where line sensors are in place since they are needed for DSP.

Q. What is meant by reduced field work costs?

A. In addition to eliminating the need for customer premise visits on a bi-monthly basis to collect consumption information for billing purposes, AMI meters will support remote connection and disconnection of service and will also provide move-in /move-out reads when needed without requiring a customer premise visit. Consequently, the work load of the field service representatives will decline by approximately two-thirds.

Q. What is meant by avoided meter purchases?

A. If AMI were not deployed by the Companies, the Companies would need to gradually replace existing electric meters. By deploying AMI, these replacements will be unnecessary, and the avoided costs of replacement are a benefit provided by AMI. The assumption for the replacement cycle is that all meters currently in the field would be replaced over the next 20 years if AMI were not deployed. In addition, there are roughly 30,000 gas meters in the field that are scheduled for replacement over the next nine years, so that those future replacement costs are also avoided through AMI deployment.

Q. What is meant by reduced storm restoration costs?

A. The integration of AMI with OMS allows for granular information on which customers are and are receiving electricity service at any given time and has been shown to shorten the time that crews are in the field when outages occur. The Companies estimate that using the AMI system to “ping” meters and direct the outage restoration crews more efficiently can reduce incremental storm restoration costs by 10%, which leads to significant annual savings attributable to AMI.

Q. Are there also savings from reductions in outage restoration field time associated with non-storm related outages?

A. Yes. AMI allows field crews to more quickly identify where outages have occurred and to determine if nested outage remain after initial repair is done. The Companies expect that the average reduction in field service time required to identify the initial fault per non-storm related outage is 12 minutes in the NYSEG service area and 8 minutes in the RG&E service area. An additional reduction of 12 minutes and 8 minutes, respectively, is achievable by eliminating the need to look for nested outages. With many thousands of outages occurring each year, this reduction in field service time can translate into reductions in field service staff and supporting equipment and produce substantial cost savings each year.

Q. Please explain what is meant by avoided call center handling costs and avoided billing rework.

A. Savings in billing and call center activities occur because customer questions about billed usage, estimated bills and billing rework to address anomalies will drop dramatically after AMI implementation. Currently, customers receive bills every month but meters are typically only read every other month, so the percent of total bills that are estimated is quite high. In addition, the manual meter reading process sometimes produces misreads, which can lead to call center inquiries as well as manual bill adjustments.

Q. Please explain what is meant by improved cash flow.

A. AMI offers the opportunity to reduce the time between meter reading and bill mailing by 1.5 days. Effectively, this reduction will result in payments consistently being received 1.5 days earlier than before AMI. This reduction in collection time improves cash flow and reduces working capital needs.

Q. Please explain what is meant by reduced solar meter expenditures.

A. The number of customers deploying rooftop-solar systems is expected to increase in the future. Without AMI deployment, these customers would need to have their meters replaced with meters that can measure bi-directional loads. AMI meters measure bi-directional loads, so meter replacements for projected new solar installations can be avoided.

Q. Please explain what is meant by avoided service costs from voltage monitoring?

A. AMI meters provide voltage measurements and alerts for high voltage and low voltage situations. The Companies can use this information to proactively address customer voltage problems and issues with transformer loads. The proactive actions will reduce the number of calls into the customer service center. In addition, proactive action will reduce the cost of upgrading or replacing transformers, since that work can be completed on a scheduled basis rather than an emergency overtime basis.

Q. How did the Companies' derive the estimated benefits for the second benefit category?

A. The second benefit category involves the implementation of new rates and programs and changes in business operations that produce societal benefits. Table 5 provides a brief summary of the three primary societal benefits that have been quantified and what underlies those benefit estimates. The power-on and power-off messaging provided by

AMI shortens the length of customer outages through faster outage detection and more efficient management of restoration crews, helping reduce the time needed to get all customers back on line following an outage. Outages impose costs on consumers in the form of lost retail sales and lost service and production output for commercial and industrial customers. For residential consumers, outage costs take the form of inconvenience, lost wages, extra expenditures due to food spoilage, lodging, dining out and others. These outage costs have been quantified through dozens of surveys and other forms of analysis over decades of research. Data from these surveys have been used to quantify the benefits from estimated reductions in outage duration through the integration of AMI with the Companies' outage management system. The estimated benefits in the form of reductions in outage costs to customers have a present value of approximately $96 million over the AMI forecast horizon.

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Table 5: Non-operational Societal Benefits

#	Benefit	Benefit Description	Benefit Result	Present Value of Benefit ($ Millions)
1	Reduced Customer Outage Time	AMI meter power on and power off messaging help identify outages faster and deploy restoration crews more efficiently	Customers have less time without power	$91.9
2	Reduced Costs of Supplying Electricity and Gas	Time variable pricing, bill alerts, and CVR help shift and reduce demand, saving generation and transmission capacity needs, reducing generation operating costs and generation fuel costs	Customers are empowered with information that can help them reduce their energy bills significantly.	$131.0
3	Reduced Carbon Emissions	Time variable pricing, bill alerts, and CVR help reduce demand, which reduces generation of electricity and thus reduces CO2 emissions	Customers have reduced impact on climate change	$40.7
	Total Quantified Societal Benefits	n/a	n/a	$263.6

AMI will also allow the Companies to deliver new rate options and information services to customers that, in turn, lead to changes in consumer behavior in the form of shifting usage from high to low cost usage periods and overall conservation.

AMI also provides data that can be used in conjunction with CVR/VVO systems to maintain required voltages throughout the distribution system while reducing generation output. These changes in behavior and system operations create societal benefits in the form of reductions in the need for new generation, transmission and distribution capacity, reductions in fuel use and lower carbon emissions. Collectively, these benefits from new rate and behavioral conservation programs, AMI-OMS integration and CVR/VVO are estimated to have a present value of $263.6 million over the life of the AMI investment.

Q. How did the Panel quantify these benefits?

A. The changes in usage behavior that generate benefits in the form of reductions in future capacity needs and fuel use are based on stylized TVP and information feedback programs. These programs are patterned after tariffs and programs implemented by other utilities around the country. The TVP program benefits are based on an opt-in, critical peak pricing/time-of-use tariff and a participation rate of 15 percent of residential customers, which has been obtained in a number of jurisdictions. The present value of benefits for this opt-in TVP program is estimated to equal \$28.7 million and the net benefits (benefits minus costs) are estimated to equal \$16.1 million. Benefits would be significantly higher if TVP were implemented on an opt-out basis, as is now underway in California and that has been in place in Ontario, Canada for many years. Estimated net benefits for an opt-out TVP program are \$77.9 million.

The information feedback benefits are based on sending weekly usage alerts to customers through email on a default basis. It is patterned after a similar default program in Southern California. Estimated benefits from the provision of usage alerts equal \$61.2 million and net benefits for this low cost program are estimated to equal \$59.4 million. Estimates of customer response to these pricing and feedback programs are based on evaluations of numerous pilots and programs implemented elsewhere. The assumed behavior changes were adjusted for the usage patterns, load shapes, and other characteristics of the Companies' customers.

The incremental CVR/VVO benefits attributable to AMI deployment assume a very modest incremental reduction of 0.5 percent of energy usage attributable to the enhanced visibility of line voltage provided by AMI. The estimated reductions in use were valued using CARIS forecasts for marginal capacity and energy costs and the avoided carbon emissions were valued based on estimates provided in the BCA Handbook version. 2.0 submitted to Staff on July 26, 2018. CVR/VVO estimated benefits equal $81.9 million.

Q. Would the Panel please explain fairness benefits?

A. The societal benefits discussed above represent reductions in the use of society's resources. They are considered true economic benefits. Fairness benefits do not involve a reduction in the use of economic resources but involve improvements in the alignment of costs with those who impose those costs. For example, improvements in meter accuracy help ensure that all consumers pay for the energy they use. Reductions in energy theft mean that honest consumers are not forced to cover costs for others who do not pay for what they use. Additionally, reductions in delivery and energy bill write-offs through faster disconnections for non-payers and inactive meters mean that the cost of the unpaid-for energy is not incorporated in rates and spread among all other customers. In total, we estimate that AMI can reduce cross subsidies between those who pay for all the electricity they use and those who do not by nearly $157 million as shown in Table 6.

Table 6: Present Value of Fairness Benefits

#	Benefit	Benefit Description	Benefit Result	Present Value of Benefit ($ Millions)
1	Improved Meter Accuracy	Electromechanical meters can slow down with age and under-register usage. Older three-phrase meters may not measure all phases accurately. Electronic meters can measure lower load levels more accurately than electro-mechanical meters.	Reduced cross subsidies by customers who pay for all energy that they use and those who don't	$21.1
2	Energy Theft Reduction	AMI provides tamper alarms and produces granular usage data that can be analyzed for reasonableness in order to identify unusual patterns that may reflect theft of service.		$40.0
3	Reduced Delivery Write Offs	With AMI meters, customers that do not pay can be shut off faster (while adhering to regulatory rules), thus reducing write offs, and inactive meter consumption can be reduced through remote disconnect provided by AMI meters.		$51.9
4	Reduced Energy Write Offs			$43.8
	Total Quantified Fairness Benefits	n/a	n/a	$156.8

Q. What additional, non-quantified benefits does AMI produce?

A. AMI improves customer service/convenience in a variety of ways, including: i) the elimination of the need for indoor meter reads; ii) customized choices in billing date and pay cycle that better fit with individual financial needs; iii) fewer estimated bills and associated disputes due to increased meter reading accuracy; iv) easier service activation and account transfer through a remote meter service switch; and v) customers' actual usage billed monthly instead of bimonthly. The AMI platform will also provide the foundation for a new, advanced customer portal through which customers can monitor energy use in near real time and view more detailed and actionable information to help active energy consumers control usage and costs. AMI will also provide the information necessary for DER providers to engage more effectively with consumers in the REV market place, thus driving greater penetration of distributed resources and animating localized markets to improve economic efficiency and drive product/service innovation.

H. <u>Summary of Costs</u>

Q. What is the initial capital cost of the Companies' AMI roll out?

A. All of the estimates presented above have represented the present value of benefits and costs over the life of the investment. This section presents estimates of the cash expenditures that will be required over the deployment period from 2020 to 2024. The AMI project is projected to cost $498 million. Five major cost categories are discussed in more detail in Exhibit __ (AMI-2). Table 7 summarizes these deployment capital costs.

<u>Table 7: Deployment Capital Costs</u>

Capital Cost Category	2017-2019	2020	2021	2022	2023	2024	Total
IT Hardware	$0	$28.9	$10.8	$0	$0	$0	$39.8
IT Software and Integration	$0	$46.2	$55.8	$1.3	$0.7	$0	$104.0
Meters	$0	$0	$67.1	$89.3	$89.6	$23.0	$269.0
Network	$0	$0	$20.0	$20.2	$0	$0	$40.2
PMO and Other Deployment Costs	$2.8	$5.3	$10.6	$10.8	$10.9	$4.2	$44.6
Total	$2.8	$80.5	$164.3	$121.6	$101.2	$27.3	$497.5

Note: IT Integration costs reflect operational costs and costs for AMI-OMS Integration

The AMI meters, including installation and field troubleshooting during deployment, have a cost of $269 million. The installed AMI meters represent the single biggest category of costs.

The communications network to collect and distribute information between the AMI control center and the AMI meters is projected to cost $40 million. These network costs include $16.1 million to build out a WiMAX information backhaul network to move information back and forth between the AMI control center and the AMI network collectors.

The costs for project management staff, external legal support, systems testing, exceptions handling, and customer outreach and education, total $45 million.

IT costs for computer hardware platforms, software licenses, and integration of the new and existing systems total $144 million. About 50 percent of the IT costs are associated with a new CRM&B system, which is necessary, in part, to support future rates and other customer services that develop as REV evolves. All of the cost estimates described above include project contingency, which averages 10 percent.

Q. What are the on-going O&M costs of the AMI system over the project life cycle?

A. There are two principal on-going AMI costs, which are the costs of the 24-person staff in the AMI operations center, and the costs of maintenance on the AMI software licenses. The staff costs, including overheads, amount to approximately $3 million per year, and the software maintenance costs amount to approximately $4.5 million per year.

Q. What additional capital expenditures will be needed during the 20-year AMI project life?

A. There are three kinds of capital expenditures that will be required over the course of the AMI system's 20-year lifespan. First, every five years, the IT hardware platforms need to be replaced to maintain reliability and performance. Each of these replacements is projected to cost $10 million in nominal dollars. Second, the communications network requires a two percent replacement of equipment each year due to normal unit equipment failures, and one major refresh of all of the network equipment half way through the project to introduce technology improvements. The annual network capital costs are

$250,000 per year and the major network refresh is $14 million. Finally, expected meter failures of 0.5 percent per year translate to an annual capital cost of $700,000 per year.

Q. In addition to the costs summarized above, are there additional costs incorporated into the BCA?

A. Yes, costs must be incurred to obtain the substantial benefits generated by TVP, behavioral conservation and, outage cost reductions through AMI-OMS integration.

Q. What are the estimated costs for the TVP program?

A. The present value of costs associated with the TVP program incorporated in the BCA analysis equals $12.6 million. These include marketing and acquisition costs equal to $6.3 million, fixed overhead costs of $4.0 million and ongoing variable costs equal to $2.3 million. The cost estimates are patterned after a successful pricing pilot implemented by SMUD in California that achieved participation rates similar to the 15 percent participation level assumed for this analysis.

Q. What are the estimated costs for the information feedback program incorporated in the analysis?

A. Estimated costs for the weekly usage alert program included in the BCA are modest because it is a default program delivered via email. The total present value of costs equal $1.8 million and are comprised of program start-up costs, ongoing fixed costs associated primarily with program management, and the variable costs associated with delivering weekly emails to roughly 33 percent of residential customers.

Q. What are the estimated costs for AMI-OMS integration?

A. The Companies estimate that AMI-OMS integration will require upfront costs of roughly $0.8 million on an NPV basis, and this cost is included in Table 7. This estimate covers integration costs of the AMI software and the Companies' OMS. Today's Spectrum OMS automation is at the transmission and distribution ("T&D") or substation level via Supervisory Control and Data Acquisition ("SCADA"). The AMI-OMS integration will provide outage detection at a customer level adding another level of automation.

Q. Were any costs included in the BCA associated with the estimated CVR benefit?

A. The Companies plan to implement CVR/VVO independent of AMI deployment. As such, the costs for developing and operating CVR/VVO are not included in the AMI benefit-cost analysis. However, AMI provides enhanced visibility into voltage at the end-use customer level that will allow NYSEG and RG&E to produce incremental reductions in energy production through CVR/VVO at no incremental cost.

I. <u>Benefit-Cost Analysis Results</u>

Q. Please summarize the BCA analysis for AMI utilized in this filing.

A. Table 8 shows the net benefits and the benefit/cost ratio for the societal cost test, which is the primary cost test perspective required by the BCA Handbook.[3] As seen, the AMI investment is estimated to produce $273.4 million in net benefits to society. The societal B/C ratio of 1.48 is a robust indicator that AMI will deliver significant economic value to the Companies' customers.

<u>Table 8: Societal Benefit/Cost Analysis (PV $millions)</u>

BCA Perspective	Societal Test
Benefits	$840.1
Costs	($566.7)
Net Benefits	$273.4
B/C Ratio	1.48

[3] The BCA Handbook also indicates that the Ratepayer Impact Test and the Utility Cost Test should be estimated. Results associated with these test perspectives are included in Exhibit 2.

Figure 1 provides more detail about the components underlying the societal cost test. Importantly, the operational benefits of $576.4 million, comprised of reductions in capital and operating costs (shown at the bottom of the stacked bar chart on the right of the figure), exceed the sum of the operational costs. Operational costs equal $551.5 million and are comprised of the hardware and installation costs, IT costs, PMO, operations and maintenance of the AMI system, and refresh capital costs on the left-hand side of the figure. That is, the operational benefits exceed the operational costs by $24.9 million in present value dollars when viewed from the societal perspective. Furthermore, a relatively small proportion of the overall net benefits are tied to behavioral changes by customers. Out of the total net benefits of $273.4 million, $75.5 million, or 28%, are reliant on programs designed to drive changes in customer behavior. The remaining $197.9 million result from changes in business practices and system operations that are enabled by AMI.

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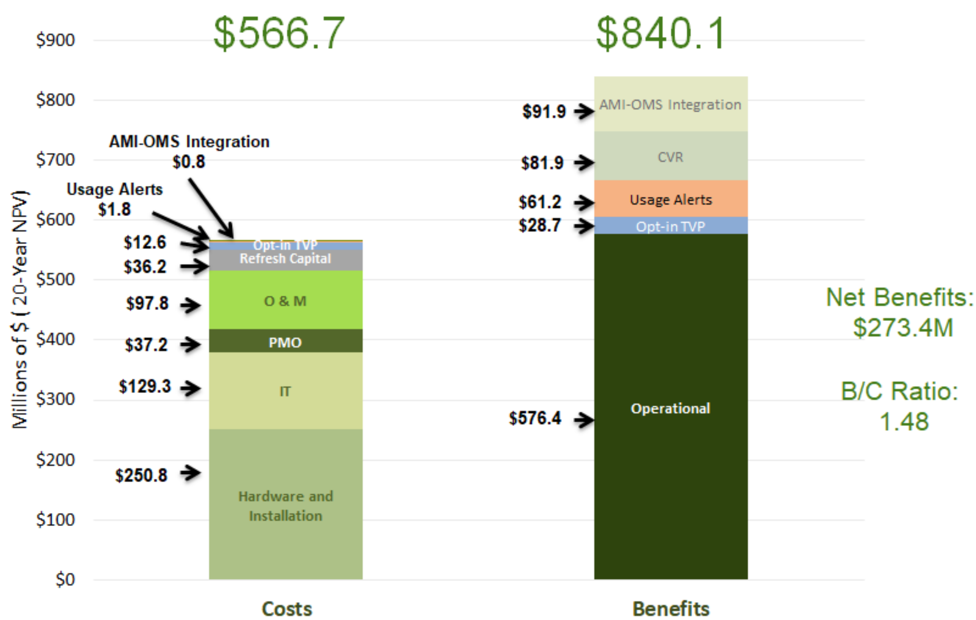
Figure 1: Societal Benefit-Cost Analysis



Q. Are the net benefits positive for NYSEG and RG&E individually?

A. Yes. Table 9 summarizes the societal benefits, costs and net benefits for each Company and for the Companies combined. As seen, the societal net benefits are positive for both Companies although they are larger for NYSEG than for RG&E. The primary reasons for this disparity across the two companies include: i) differences in the number of customers across the Companies; ii) lower manual meter reading costs (and therefore lower avoided costs) at RG&E compared with NYSEG; iii) much fewer outage hours per customer at RG&E than at NYSEG due to the much more compact and urban nature of the distribution system; and iv) higher meter and meter installation costs per customer at RG&E compared with NYSEG because of the greater overlap between electricity and gas service at RG&E.

<u>Table 9: Societal Cost Test by Company</u>

	NYSEG	RGE	Combined Companies
Benefits	$609.4	$230.7	$840.1
Costs	($373.0)	($193.6)	($566.7)
Net Benefits	$236.4	$37.1	$273.4
B/C Ratio	1.63	1.19	1.48

Q. Does this complete the Panel's testimony at this time?

A. Yes, it does.