STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

At a session of the Public Service Commission held in the City of Albany on July 24, 2009

COMMISSIONERS PRESENT:

Garry A. Brown, Chairman
Patricia L. Acampora
Maureen F. Harris
Robert E. Curry, Jr., with concurring opinion
James L. Larocca

CASE 09–E–0310 – In the Matter of the American Recovery and Reinvestment Act of 2009- Utility Filings for New York Economic Stimulus

CASE 09–M–0074 – In the Matter of Advanced Metering Infrastructure

ORDER AUTHORIZING RECOVERY OF COSTS
ASSOCIATED WITH STIMULUS PROJECTS

(Issued and Effective July 27, 2009)

BY THE COMMISSION:

INTRODUCTION

The American Recovery and Reinvestment Act of 2009 (ARRA) (Public Law 111-05) was signed into law on February 17, 2009 by President Obama. The purpose of the ARRA is to reinvigorate the American economy by, among other things, investing in projects that test and deploy smart technology for the electric grid, promote investment in renewable energy sources, drive innovation in the fossil energy industry, and adapt electric facilities to the needs of the future. The ARRA provides funding to the U.S. Department of Energy (DOE) to award grants to various entities to facilitate such projects. These grants are provided either through formulas set forth in the ARRA or through competitive grant programs administered by the DOE.

Several New York electric utilities, seeking to take advantage of competitive grant programs administered by DOE, submitted project proposals to us. Due to the cost sharing requirements of these programs – grants only cover a portion of eligible project costs – utilities require another source of funding for these projects, and they filed their project proposals with us seeking ratepayer funding for the balance of project costs. The timing of the utilities' project submissions for our review was designed to provide the utilities sufficient time to demonstrate on application to the DOE a ratepayer commitment to fund the eligible project costs not covered by the grant. The expectation is that this commitment may place our New York electric utilities in an advantageous position at DOE to secure a portion of the available competitive grants.

In this order we approve certain of the project proposals filed by the utilities, and authorize the recovery by utilities of eligible project costs through the imposition of a surcharge, while reserving our ability to judge the prudence of the project expenditures. Certain conditions apply to our approval, as described below. Finally, we will require the utilities to file reports on the progress of the projects, and we allow the filing of tariffs for the imposition of surcharges, along with the appropriate justification, and tariffs for the implementation of rate design trials as described below.

BACKGROUND

ARRA provides approximately $463 billion in appropriations in several categories including, agriculture, commerce, defense, government services, labor, health and human services, housing and urban development, and health information technology. Appropriations to specific programs are each administered by a federal agency, which either determines the entities that will receive program funds via a competitive grant program and/or allocates a share of the funds to states based upon a statutorily provided formula. New York is expected to receive approximately $24.6 billion in ARRA funding that is distributed through these programs pursuant to the formula. New York also has an opportunity to receive several hundred million dollars in additional ARRA funding through competitive grant programs administered by various federal agencies.

Electricity Delivery and Energy Reliability

Among the competitive programs funded by the ARRA is the Electricity Delivery and Energy Reliability (EDER) Program, funded at approximately $4.5 billion nationwide. The EDER Program is administered by the DOE. ARRA required DOE to develop, within 60 days of the Act's passage, rules and procedures, including eligibility criteria, for awarding grants for electricity delivery and energy reliability projects.

The EDER Program promotes programs authorized under title XIII of the Energy Independence and Security Act of 2007 (42 U.S.C. §17381 et seq.) (EISA).

EISA Section 17381 defines smart grid as technology that: (1) increases the use of digital information and controls technology; (2) provides dynamic optimization of grid operations & resources, deployment of "smart" technologies (real-time, automated, interactive technologies to optimize physical operation) for metering, communications concerning grid operations and status; (3) allows integration of "smart" appliances and consumer devices; (4) facilitates deployment and integration of distributed generation and demand response, including renewables; (5) permits deployment and integration of electricity storage and peak-shaving technologies; (6) provides timely provision of information to consumers and control options; (7) facilitates development of standards for communication and interoperability of appliances and equipment; and (8) minimizes unreasonable or unnecessary barriers to adoption of smart grid technologies.

Federal grant programs to promote smart grid technologies were originally established under EISA. Such programs under 42 USC §17384 included (1) development of advanced techniques for measuring peak load reductions and energy-efficiency savings from smart metering, demand response, distributed generation and electricity storage systems; (2) research and development for wide-area measurement and control networks, including data mining, visualization, advanced computing; (3) new reliability technologies - communications network capabilities, in a grid control room environment against a representative set of local outage and wide area blackout scenarios; (4) time-of-use and real-time electricity pricing; (5) development of algorithms for use in electric transmission system software; (6) interconnection protocols to enable electric utilities to access electricity stored in vehicles. These programs include a requirement that applicants provide a certain level of non-federal funds to match the federal grant.

ARRA expanded upon and enhanced the grant program commenced by EISA. The maximum grant for qualifying investments for the federal matching fund increased from 20 percent under EISA to 50 percent under ARRA. Qualifying Smart Grid investment costs include: (1) appliances that engage in smart grid functions; (2) motors and drives, installed in industrial or commercial applications; (3) transmission and distribution equipment fitted with monitoring and communications devices to enable smart grid functions; (4) metering devices, sensors, control devices, and other devices integrated with and attached to an electric utility system or retail distributor; (5) software that enables devices or computers; (6) entities that operate regional electric grids - costs for equipment that allow smart grid functions; (7) distributed generation costs for monitoring, controlling or integrating with grid operations; and (8) all other projects designated by the Secretary of DOE.[1]

Due to the cost sharing provisions of the EISA, applicable successful applicants will need to find other sources to cover the remaining costs of the investments. Applicants that do not yet have regulatory approvals are eligible for receiving an award; however, we anticipate that applications filed under the EDER program will have a greater likelihood of success if the applicant has already secured the non-federal funding sources for its projects. As further discussed below, several electric utilities have proposed projects for which they intend to seek a DOE grant, and request the contribution of ratepayer funds to comply with the matching requirement of EISA.

On April 16, 2009, DOE issued its initial guidance for the EDER Program. DOE established two specific competitive grant opportunities for the EDER program: the Smart Grid Investment Grant Program (Investment Grant Program)[2] funded at $3.375 billion and the Smart Grid Demonstration Program (Demonstration Grant Program)[3] funded at $600 million. As indicated above, these two programs provide grants of up to 50% of the costs of qualifying projects.

The Investment Grant Program is open to electric utilities, both publicly and privately owned, load serving entities, including retail marketers, system operators,

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1 42 USC § 17386.

2 DOE Notice of Intent to Issue a Funding Opportunity Announcement for the Smart Grid Investment Grant Program (DE-FOA-0000058) (SGIG-NOI), issued April 16, 2009.

3 DOE Draft Financial Assistance Funding Opportunity Announcement for the Recovery Act – Smart Grid Demonstrations Program (DE-FOA-0000036)(SGD-Draft FOA), issued April 16, 2009.

such as the NYISO, and manufacturers of appliances and equipment to enable smart grid. Qualifying projects may receive up to 50% cost matching, with a funding range for each grant of $500,000 to $200 million. DOE issued a final funding announcement for the Investment Grant Program on June 25, 2009, and set an initial application deadline of August 6, 2009.[4] Subsequent application deadlines of November 4, 2009 and March 3, 2010 are also included, however, DOE cautions that it is unable to predict if funds will remain beyond the initial awards provided after the August 6, 2009 application due date.

The purpose of the Investment Grant Program is to accelerate the modernization of the nation's electric transmission and distribution systems and promote investments in smart grid technologies, tools, and those techniques which increase their flexibility, functionality, interoperability, cyber-security, situational awareness, and operational efficiency. Its stated goal is to enable measurable improvements that can result from accelerated achievement of a modernized electric transmission and distribution system. The Investment Grant program is intended to enable smart grid functions on the electric system as soon as possible. It therefore provides grants to support manufacturing, purchasing, and installation of existing smart grid technologies that can be deployed on a commercial scale.[5]

On June 25 DOE also issued the final funding opportunity announcement (FOA) for the Demonstration Program.[6] The Demonstration Grant Program[7] is also open to all types of entities. Funding under the Demonstration Grant Program is intended to demonstrate how emerging technologies can be applied in innovative ways within the electric delivery system to provide integrated and economically-feasible solutions. The

[4] DOE Investment Grant Program – Funding Opportunity Announcement (DE-FOA-0000058)(SGIG-FOA), issued June 25, 2009.

[5] SGIG-FOA, pp. 6-7.

[6] DOE Demonstrations Grid – Funding Opportunity Announcement (DE-FOA-0000036) (SGD-FOA), issued June 25, 2009.

[7] SGD-FOA, pp. 6-7.

Demonstration program is aimed at identifying and developing new and more cost-effective smart grid equipment, tools, techniques, and system configurations that can significantly improve upon today's technologies.

Other Competitive Grant Programs

DOE has also issued several other FOAs for competitive grant programs focused on the development of clean energy technologies and the efficient use of energy. On May 29, 2009, DOE issued an FOA for the Wind Energy Consortia,[8] which is a grant opportunity funded at $24 million and designed to focus on the development of critical information that may promote the construction of off-shore wind turbines. The Wind Energy Consortia FOA anticipates awarding two to three grants with grant a ceiling of $12 million and a grant floor of $8 million, and all recipients are required to provide non-federal funds to cover at least 10% of the total allowable costs.

An FOA for a High Penetration Solar Deployment Program was issued by DOE on May 27, 2009, and modified on June 4, and provides a total of $37 million for available grants.[9] The goal of this program is to fund projects that will demonstrate the impacts from photovoltaics (PV) sourced solar electricity on the reliability and stability of the electric power system in general, and specifically its impact on the distribution system. While there is no grant floor for this program, the maximum grants expected to be awarded by DOE for the High Penetration Program range from $1.75 to $7.5 million depending on the topic area, which includes improved modeling tools development, field verification of high-penetration levels of PV into the distribution grid, modular power architecture, and demonstration of PV and energy storage for smart grids. Applicants to this program are required to provide a non-federal funding source to cover at least 25% of

[8] DOE Funding Opportunity Announcement – Wind Energy Consortia between Institutions of Higher Learning and Industry (DE-FOA-0000090), issued May 29, 2009.

[9] DOE Funding Opportunity Announcement – High Penetration Solar Deployment (DE-FOA-0000085), issued May 27, 2009.

the total allowable costs or for private industry applicants for demonstration of PV and energy storage for smart grids. Con Edison intends to pursue this topic area, as discussed more fully below.

DOE also issued an FOA for the Transportation Electrification Program on March 19, 2009.[10] This Program provides grants to projects that conduct development, demonstration and data collection on a wide-range of electric drive transportation technologies. The main purpose of the Program is to accelerate the market introduction and penetration of advanced electric drive vehicles. Applicants are required to provide a non-federal funding source to cover at least 50% of total allowable costs, however, the Secretary of Energy, at his discretion, may reduce this responsibility to 25%.

Electric Utility Filings

Department of Public Service Staff asked all major electric utilities planning to apply to DOE under the EDER program or other ARRA funded DOE grant programs to file preliminary project proposals with the Secretary to the Commission by April 17, 2009.[11] For each project proposed, the utilities were asked to include: a detailed project description; a project milestone schedule; an estimate of the number of jobs created by the project; detailed cost estimates; the rationale/justification for the project, given all known and anticipated criteria for project selection; and a statement as to the potential availability of EDER funds, any other non-ratepayer funds that may be applied, an estimate of the net costs that must be recovered from ratepayers, and a proposed method for recovering those costs.

Consolidated Edison Company of New York, Inc./Orange and Rockland Utilities, Inc. (Con Ed/O&R), New York State Electric and Gas Corporation/Rochester

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[10] DOE Funding Opportunity Announcement – Transportation Electrification (DE-FOA-0000028), issued March 13, 2009.

[11] Letters from Mr. Michael Corso, Director of Industry and Government Relations, to Con Edison/O&R, Central Hudson, National Grid, NYSEG/RG&E, dated April 3, 2009.

Gas and Electric Corporation (NYSEG/RG&E), Central Hudson Gas and Electric Corporation (CH) and Niagara Mohawk Power Corporation d/b/a National Grid (National Grid) filed over 100 projects at an estimated total cost of approximately $1.3 billion (April 17 filings). Projects included proposals for deployment of smart meters and home area networks, demonstration of green energy technologies, and modernization of the transmission and distribution system. By letter dated May 26, 2009, utilities were requested to update their April 17 filings to reflect the final criteria for the Investment Grant Program, ultimately released by DOE on June 25, and the utilities submitted their updated filings on July 2, 2009. A notable change in the update filings was that NYSEG and RG&E withdrew their proposals for full service territory deployment of Advanced Metering Infrastructure (AMI). The withdrawal of these projects, coupled with other minor cost revisions resulted in an estimated cost of all proposed projects as of the July 2, 2009 update filings of approximately $1 billion.

The Department Staff Team met with the utilities on several occasions in order to discuss the requirements of the ARRA and various aspects of projects under consideration. In order to better inform Staff's understanding of the filings, Staff also maintained a continuing dialogue with the utilities, and submitted numerous interrogatories.

To obtain additional information on smart grid in general, and how it relates to the ARRA, the Commission convened a Smart Grid Technical on June 11, 2009. The Conference provided an opportunity for entities from the government, industry, and utility sectors to address various smart grid topics including the current state of technology, and technology obsolescence; the role of communication networks and facilities; development of standards and protocols; and cyber-security issues.

Staff initially evaluated the filings pursuant to the criteria contained in the DOE guidance documents. The purpose of this evaluation was to assess each project's compliance with the requirements of the program FOA. The DOE Investment Grant Program criteria included numerous requirements grouped in the following areas: technical approach, project plan, interoperability and cyber security, and data collection and analysis. The DOE Demonstration Program criteria covered the following areas: project approach, significance and impact, interoperability and cyber security, and project team.

Detailed descriptions of the project proposals are provided in Appendix A. Those project proposals for which we authorize ratepayer support are further discussed below.

PARTIES COMMENTS

In accordance with the State Administrative Procedure Act (SAPA) §202(1), the utility stimulus filings were noticed in the New York State Register on May 6, 2009 [I.D. No. PSC-18-09-00014-P]. The deadline for comments expired on June 20, 2009. Comments were received from EnerNOC, Inc.,[12] Multiple Intervenors (MI),[13] Verizon, National Energy Marketers Association (NEM),[14] and the New York State Reliability Council (NYSRC) and focus on the utility April 17 utility filings. The comments can be summarized as: (1) no ratepayer assistance should be provided for utility Stimulus Plans during this period of economic hardship without demonstrable benefits for ratepayers; (2) any commitment of ratepayer funds for the Stimulus Plans should be conditioned on the use of open standards and architectures that enable all energy providers to equally compete with and utilize the investment, as well as compliance with the AMI Minimum Functional Requirements; and (3) the utilities should focus on the use of and expertise that can be derived from leveraging existing resources that operate backbone facilities for smart grid projects.

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[12] EnerNOC Inc. is a provider of demand response resource and energy management services in New York.

[13] MI is an association of New York based industrial, commercial and institutional energy consumers.

[14] NEM is a non-profit trade association of suppliers and consumers of natural gas and electricity, energy-related products, services, information and advanced technologies.

MI, in general, does not oppose recovery of costs associated with cost-effective, proven smart grid technologies from consumers in a fair manner. MI contends, however, that the utility Stimulus Plans provide inadequate information regarding the cost effectiveness of the proposed projects to allow the Commission to make a reasonable decision. MI requests that the Commission reject the utility Stimulus Plans, thereby refraining from imposing significant additional costs upon ratepayers at a time of an economic recession and high electricity costs for businesses and residents of the State.

In addition, MI explains that DOE may award grants for less than 50 percent of eligible costs, thus potentially increasing significantly the amount of costs ratepayers may shoulder. MI notes that even with a grant for DOE that covers 50 percent of the eligible costs, some utilities, such as NYSEG and RG&E, have proposed projects that would result in ratepayers being responsible for close to $200 million in associated capital costs alone, not reflective of the incremental costs associated with rate of return, operations and maintenance for the projects. MI further contends that the magnitude of the utility Stimulus Plans may trigger the requirements of the Public Service Law §66(12)(f) to hold an evidentiary hearing.

The competing policy initiatives of the Commission, MI states, also appear to weigh against any favorable treatment by the Commission of the utility Stimulus Plans. According to MI, the mandate in the Austerity Proceeding[15] for utilities to eliminate discretionary spending to minimize ratepayer costs stands in direct contravention to the utility Stimulus Plans, especially if those plans lack supporting analyses for how the projects would result in net benefits for ratepayers. MI, moreover argues that a cost-benefit methodology, which was recently released for comment in the AMI proceeding, is critical in assessing the cost-effectiveness of AMI deployment, and that a decision regarding the AMI projects contained in the utility Stimulus Plans should be postponed

[15] Case 09-M-0435, Proceeding on Motion of the Commission Regarding the Development of Utility Austerity Programs, Notice Requiring the Filing of Utility Austerity Plans (issued May 15, 2009) (Austerity Proceeding).

pending final determination by us on the methodology, and should be relegated to the AMI proceeding.

MI requests, to the extent cost-recovery for the proposed utility Stimulus Plans is approved, that the Commission limit such cost recovery to the highest priority, lowest cost projects that will produce immediate, demonstrable benefits for ratepayers. According to MI, any authorization for cost-recovery should be accompanied by a requirement that: (1) utilities supplement smart grid project proposals with detailed information regarding cost effectiveness and (2) allow parties an opportunity to submit additional comments regarding those supplemental filings. Any approval for cost-recovery should also be contingent upon the receipt by the utility of grant funding from DOE.

EnerNOC supports development of a smart grid network for New York State and requests that any smart grid investment that includes installation of AMI should comply with the minimum functional requirements adopted by the Commission in the AMI proceeding. EnerNOC contends that minimum functional requirements ensure: (1) ability of customers to participate in NYISO demand response programs; (2) future upgradeability of meters in order to facilitate participation in the NYISO ancillary service markets; and (3) customers and agents will be able to effectively exchange data. EnerNOC, consequently, requests that the Commission condition any cost-recovery by utilities from ratepayers upon full adherence to the minimum functional requirements.

In addition, EnerNOC states that utilities should be required to use the latest open, advanced protocols. Noting its own experience with moving dynamic data from customers to its operation center for participation in the PJM Synchronized Reserves market, EnerNOC recommends the use by utilities of Extensible Messaging and Presence Protocol (XMPP), which is the core protocol of instant messaging for Google Talk and Yahoo Messenger. According to EnerNOC, XMPP devices can autonomously and automatically report their current state to one or more collection centers, while using minimum bandwidth.

NEM requests that any smart grid investment be conditioned on inclusion of opens standards and information protocols that minimize duplicative, non-interoperable, closed or proprietary infrastructure investments. NEM is concerned that utility investment in smart grid technology, if not done in a manner that implements open technology, will result in the creation of a new information and/or demand or demand response-related monopolies. If the Commission authorizes “open” non-discriminatory access to the new data produced by AMI, smart thermostats, and other smart grid equipment, NEM asserts, a new level of services to customers will develop in the areas of demand response, information technologies and price offerings. NEM also states that open standards for smart grid/AMI infrastructure will minimize the potential for future stranded costs.

Verizon notes that advanced communications technology is necessary for any development and deployment of smart grid technology, and as such, established communications providers can provide experience and capabilities to assist utility smart grid projects. Verizon asserts that leveraging existing facilities of companies like itself will ultimately save ratepayers from having to pay to “re-create the wheel.” Verizon, consequently, requests the Commission condition cost-recovery for utility smart grid projects on the utilization by the projects of wireline and wireless technologies. Moreover, it argues that the Commission should give preference to utility projects that partner with a communications provider like Verizon, that have experience in moving vast amounts of a data quickly and securely over network facilities.

NYSRC states that after the August 2003 blackout, NYSRC created a Defensive Strategies Working Group (DSWG) to evaluate ways to mitigate major disturbances on the New York Control area. Participants in the DSWG include New York State Transmission Owners, the Northeast Power Coordinating Council’s (NPCC) System Studies Task Force, New York Independent System Operator’s Operations Engineering group, outside consultants, and Department Staff is part of DSWG. NPCC through its studies has determined that underfrequency load shedding (UFLS) will be its first line of defense within NPCC, including New York, to mitigate major disturbances.

The UFLS program, however, is predicated on the ability of the system operator to island or separate automatically to protect healthy portions of the system from areas that are experiencing difficulties or under threat of collapse. NYSRC advocates for the installation on the transmission system of Phasor Measurement Units's (PMU) because such devices may offer a simpler method, at reduced costs, for islanding or separating sections of the transmission system. PMUs offer the opportunity for more vision into the surrounding control areas and the ability of the operator to position the system to respond to disturbances in other transmission areas. Moreover, NYSRC states that ongoing studies indicate that PMUs, when strategically located, may enhance the reliability of the New York bulk power system by allowing "controlled separations" around and/or within the New York Control Area. NYSRC, consequently, supports Commission approval of utility cost-recovery for the PMU program.

DISCUSSION

The electric transmission and distribution grid of the future will be integrated with two-way communications systems and sensors, enabling utilities to optimize grid performance in real-time. It will provide incentives to consumers for reducing energy consumption through demand response and it will help integrate renewable energy resources into grid operations. We conclude that there are substantial benefits to be gained by beginning to invest in the use of advanced technology and communication to improve grid operations. Many of these benefits are difficult to quantify, particularly for the small-scale deployments proposed by the utilities, where the initial benefit may be the knowledge and experience gained. For this reason, we reject MI's proposal to apply a formal benefit-cost analysis, such as the draft AMI benefit-cost methodology, to the project proposals. As a condition of receiving grants under either the Investment Grant Program or the Demonstration Grant Program, the DOE requires proposers to agree to stringent data collection and reporting requirements, to facilitate an ex-post benefit-cost analysis. We agree with the DOE that the appropriate time to evaluate the net benefits of these projects is at their conclusion.

Furthermore, with the EDER programs, the federal government offers a unique opportunity to stimulate the development of the Smart Grid. In light of the economic recession, in the Austerity Proceeding we encouraged the utilities to, among other things, examine the potential to safely defer capital expenditures that might otherwise take place in the present. The prospect of the considerable financial leverage offered by the EDER programs, however, prompts us to encourage the utilities to examine the prospect to accelerate those qualifying investments that are likely to be made in the near future. If such projects are likely to be undertaken within the next several years in any event, ratepayers clearly benefit from implementing the project at a 50 percent cost match. This principle in fact forms one of our key criteria in evaluating these projects. The ability to leverage significant federal support for valuable projects is not inconsistent with the principles we established in the Austerity Proceeding. Thus, we reject MI's objections in this area.

Criteria for Project Selection

We have evaluated whether each project met DOE's criteria for federal funding. Having narrowed our consideration to only those projects that pass this initial screen, we have identified our own set of criteria to judge each project's consistency with our goals and objectives. This evaluation served as the primary basis, but not the sole basis, for our decision whether to approve a project. While, as previously noted, a formal quantitative analysis is not feasible, we can qualitatively assess whether a particular project is likely to provide significant ratepayer value. In an effort to consistently make such judgments, we applied a set of criteria that identify some important and valuable potential outcomes. In order to demonstrate such potential, a project must exhibit one or more of these qualities. Those criteria are as follows:

- *Expansion of Existing Programs:* Projects that expand or extend existing projects that the Commission has previously authorized for ratepayer recovery. As the Commission has approved similar projects in the past, such programs have already undergone an examination of their net benefits, and therefore represent expenditures that could be incurred sometime in the future, even if economic conditions may make it less likely in the near term. As explained above, implementing such projects at a 50 percent cost match is in itself a strong ratepayer benefit. There are several examples of such programs, as further discussed below.

- *Leveraging Other Funds:* Projects that leverage other funding sources, minimizing the needed ratepayer contribution. Besides improving the prospect for net ratepayer benefits, such arrangements implicitly require the cultivation of project partners. Future uses of the Smart Grid, such as electric vehicles and home automation will involve utility alliances with unaccustomed partners, including auto makers and appliance manufacturers. Projects that begin to forge such relationships thus provide intrinsic value in addition to improving the leverage of ratepayer dollars.

- *System-Wide Benefits:* Projects that are part of a portfolio of projects that potentially yield system-wide benefits and require broad coverage across utility territories to yield such benefits. By their nature, such cooperative ventures are more difficult to accomplish. The prospect of EDER Program funding provides a unique opportunity to motivate all of the stakeholders to act in concert. The NYISO PMU and capacitor bank initiatives are prime examples. These are discussed in detail below.

- *Net Benefits:* Projects that are supported by a completed benefit-cost study that demonstrates net benefits for such projects. This characteristic is largely limited to the capacitor bank proposals.

- *Foundational Information:* Projects that are designed to collect fundamental information to enable utilities and the Commission to identify those smart grid investments that produce net ratepayer benefits, and/or how to implement such projects in the most cost-effective manner.

  Critical peak pricing is a good example of this. Our Staff and the utilities have expended considerable time and effort on a statewide coordination of dynamic pricing trials, in a manner that recognizes the statutory and regulatory environment in which New York utilities operate, rigorously adheres to the fundamentals of test design and statistical validity, and is designed to produce a set of data on customer acceptance of and response to dynamic prices that will be of value to utilities across the country. This area is discussed in greater detail below.

> Another consideration is whether each utility should have the opportunity to gain experience with deployment of smart grid technologies, and to collect some demand response data from its own customers. There are some things that cannot be learned by reviewing another utility's experiment. A critical objective of these projects is for technicians and engineers at each utility to begin to gain hands-on experience with new technologies, for IT managers to begin developing strategies for managing vastly increased data flows and their integration with legacy systems, and for customer-facing organizations to begin to understand how to introduce customers to new products and services. In addition, the collection of utility-specific demand response data will limit questions about the replicability of results that have been obtained elsewhere.

- *Enabling Technologies:* Projects that enable a wide variety of Smart Grid capabilities. Several utility filings point out that the unit cost for a small scale deployment is greatly reduced in a mass deployment, thereby improving benefit-cost ratios. To some degree, this reflects the economics of the smart grid communication network, -- communication infrastructure costs generally reflect the size of territory to be covered, and are independent of the number of connected devices. Each utility proposes a grid enablement project that involves construction of a robust two-way communications network. The network alone provides no specific enhancement, but lays the groundwork for a multiplicity of potential future uses.

Approved Projects

The project proposals discussed below appear to qualify for the DOE SGIG and SGD Programs, and upon applying our criteria above, we also conclude they provide a reasonable investment in technology that improves the efficient and intelligent operation of the electric grid in New York.

Based on our review of the filed projects in light of, all of the projects listed below are approved:

Projects That Expand or Extend Existing Projects

Con Edison has proposed a series of projects that expand or extend existing projects that the Commission has previously authorized for ratepayer recovery. All of these projects have been determined to be appropriate projects in past cases for ensuring that Con Edison's infrastructure is maintained and, as necessary, upgraded to provide reliable service. These projects have clear and direct value to ratepayers.

Con Edison Dynamic Secondary Network Modeling and Visualization – Since the 1999 Washington Heights network shutdown and more recently the 2006 Long Island City (LIC) network outage, Con Edison has been working to develop and improve its ability to simulate, model, and understand in real time the electrical characteristics and loading occurring in the secondary network grids within its system. Con Edison does not currently have real time communications capability or loading information from within its secondary networks available to the Company's control centers and operators. The only line of communications for loading information comes from the network transformers within each network. This inability to obtain real-time operational information was a major contributor for the Company's delayed response, and consequently the large amounts of damage to the secondary network system, during the LIC network outage.

Due to the complexity of the secondary network grids, previous attempts to accomplish these goals have shown limited success and only since the 2006 LIC network outage have some measurable strides been made. This project therefore represents an advancement of an ongoing project which originated from the LIC outage.

The project includes the integrated development and operation of distributed secondary network load flow models. Data is provided by remote devices installed at strategic customer locations. The project will provide near real-time load profiles for customer locations and help validate predicted load flows from the models. Additionally, it will improve secondary modeling and load flows to better target grid reinforcement efforts, which can be expected to minimize risks of secondary cable failures during peak loading conditions and network outages due to secondary events. It will also provide a state of the art training tool for Control Center Operators to develop, and maintain situational awareness skills, and for system contingency planning to help improve emergency response.

Overhead (OH) Distribution Sectionalizing Switches – This project includes the installation of 750 supervisory control and data acquisition (SCADA) controlled primary underground sectionalizing switches on targeted network feeders, replacing old motor operated three phase SF6 (sulfur hexafluoride) gas insulated switches to improve the reliability of the overhead distribution systems. The benefits of the project include enhanced reliability by enabling rapid isolation of faulted segments of primary feeders and re-energizing the non-faulted portion of the feeder. It also includes advanced distribution automation and enhances system reliability by creating a more adaptive, integrated, flexible, interactive and optimized grid.

Underground (UG) Distribution Sectionalizing Switches – This project includes installing a combination of 100 automatic and manual sectionalizing overhead switches, to improve the reliability of the overhead distribution systems. The benefits of the project are the same as those for the overhead switches discussed above.

4 kV Grid Modernization – This project modernizes the 4kV grid, which is the backbone of supply to the majority of the non-network customers in the Con Edison system. It will include additional distribution capacitor banks, installation of central load tap change (LTC) controller software for all 4kV grids, installation of SCADA equipment for all 4kV grids, and the development of 4kV grid modeling software. Upgrading the 4kV Grids will increase efficiency by reducing losses and reliability by mitigating grid cascades through automated load shedding.

Remote Monitoring System (RMS) – This project provides an upgrade to the RMS that includes installation of RMS transmitters on network transformer vault locations throughout all service territories to allow operators and engineers to dynamically monitor transformer tank pressure, oil temperature and the oil level. This would enhance the reliability of the Remote Monitoring System and enables rapid operator response to changes in system conditions.

High Tension (HT) Monitoring – This project upgrades the existing meters associated with High Tension feeders on the system with a RF communication module. This enables improved system monitoring thereby improving the reliability and operation of the distribution grid. This project also supports remote metering of high tension customers and critical load data during contingency situations.

Projects That Demonstrate State-Wide Benefits

These projects are part of a portfolio of projects that potentially yield system-wide benefits, but require broad coverage across utility territories to yield such benefits. The NYISO-sponsored PMU and capacitor bank initiatives are prime examples. Demonstration of net benefits is largely limited to the capacitor bank proposals, but underscores that some projects already demonstrate strong potential for system benefits.

Grid Enhancement/Bulk Power System – PMU Statewide Project – In August of 2003, the Eastern United States and Canada experienced a large scale blackout. Through investigations that followed, it was identified that operators could have been forewarned of the evolving situation, and therefore, could have taken action to preserve their systems or to enhance their system capabilities. Many industry experts have concluded that additional PMUs on the system would have allowed operators to foresee the situation in other operating areas, and could have prevented or at least reduced the severity of the 2003 North East Blackout.

The New York Independent System Operator (NYISO), in collaboration with the New York Transmission Owners (TOs) and Rensselaer Polytechnic Institute (RPI), has developed a plan to install PMUs throughout the New York Control Area.[16] This project includes the deployment of a significant number of PMUs throughout the state, offering precise measurements of the electricity grid. Installation of PMUs would improve the ability of the NYISO and utilities to assess conditions of the bulk power

[16] A PMU is a high-speed, time-synchronized digital recorder that measure voltage, current and frequency on the electric power transmission system and calculates voltage and current magnitudes, phase angles and real and reactive power flows.

system by providing data on a real-time basis thereby improving system reliability and enabling creation of on and off line applications.

The statewide PMU network would provide a wide area and local region visualization of the transmission system. The system would be set up with alarms to notify operators of possible voltage violations and angular separation of generators in other control areas and to be able to take preventive measures. In addition, the system would provide a history for event re-creation following an event. Each utility is expected to retrieve the data and have one or more phasor data concentrators to pick up the data and forward the data to the NYISO. In concert with the NYISO project, RPI will develop software to collect the data, screen for bad data, alarm for conditions that could lead to a system collapse, and enable the users to work with information received from other ISO control areas.

The full scale application of PMU is expect to take several years to accomplish and develop the analytical tools to work with it. Because this project provides *system-wide benefits*, *expands* an existing program, and provides *foundational information* for the development of more advanced operational systems, we will approve it.

Con Ed has already installed several PMUs on its system and data is transmitted to the Con Ed control center to a phasor data concentrator[17] using Con Ed corporate fiber. The data is utilized to collect voltage and frequency phasor measurements at a high sample rate per second. Con Ed and O&R would add approximately 11 new PMU units to the system, and their outputs would be sent to the corporate phasor data concentrator. The data would be screened, processed and sent on to the NYISO for use in on-line analysis tools. Con Ed would also have the capability to

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[17] The phasor data concentrator (PDC) is a collector of data from the PMUs which are located at particular substations. The PDC collects all the data from the PMUs in a region, checks the data for validity, processes it to check for situation awareness, and then sends the collected data on to the NYISO for further analysis.

receive data collected by the NYISO operations center. The total cost of the Con Ed PMU project is projected to be $6.5.

The estimated cost of the PMU project for National Grid is approximately $2 million. These costs reflect all the installation cost and the software to make them operate. National Grid states that it will install them at 11 locations which include 230 kV and 345kV substations on their system. National Grid will collect the data in a central phasor data concentrator and forward the information to the NYISO for processing by their analytical tools.

Central Hudson proposes to install one PMU unit at a substation. The data would be sent directly to the NYISO control center and Central Hudson would have the capability to receive data from the NYISO. Central Hudson estimates the total project cost to be $185,000. NYSEG has been working on the deployment of 5 additional PMU resources within its service territory, with an approximate capital cost of $2.1 million. RG&E is planning the deployment of one additional PMU resource within its service territory at an approximate capital cost of $820,000.

Statewide Capacitor Project to Improve Voltage Support and Reduce Losses – The statewide capacitor program is designed to provide for the reactive power requirements and keep transmission voltage up so that the transfer capability remains high. Installation of these automatically controlled and/or switched capacitors would help to optimize the operation of the electrical system and reduce system losses by correcting the power factor and thereby reducing the flow of reactive power through transmission lines, cables, and transformers.

As part of a statewide effort to produce and deliver energy as efficiently possible the NYISO performed a study of actions that could be taken to improve the efficient operation of the bulk electric system. The study concluded that the addition of capacitors in strategic locations would: raise voltage levels on the bulk system; reduce the amount of reactive power required to be produced by generators; reduce system losses; and free up transfer capacity on the bulk transmission system. The study results show that the addition of about 950 MVARs (Mega Volt Ampere Reactive) of capacitance would provide total energy and capacity savings on the bulk system of at least $9.7 million per year. These estimates are considered extremely conservative because the starting assumption for the study is that all existing equipment on the system is operating at optimal levels simultaneously, which is not physically possible, and the savings on the distribution system from reduced losses, which can be considerable, are not included,. In addition to efficiency gains, the capacitor banks would reduce CO_2 output by 58,440 tons/year.

After the ARRA funding was announced, the TOs and NYISO worked to refine the locations and sizes of capacitors to provide optimum system-wide benefits. Based on the refined analysis, it was determined that capacitors were needed as follows: 286 MVAR at a cost of $ 17 million for National Grid, 320 MVAR at a cost of $ 9 million for NYSEG, 98 MVAR at a cost of $2.8 million for RG&E, 35 MVAR at a cost of $ 3.1 million for Central Hudson, and 42 MVAR at a cost of $ 1.9 million for ORU.

Distribution Capacitor Banks – In addition to the bulk transmission study, the NYISO also commissioned a supplemental study that addressed the benefit of capacitor banks to the distribution system. By addressing losses on the distribution system, it attempts to address the issue at a point closer to its source, i.e., the customer, which is beneficial in terms of saving losses. Reduced losses and optimizing the operation of the electrical system through additional capacitor banks offers not only reliability benefits, but economic and environmental benefits as well. By optimizing the operation of the electrical system and reducing losses, the cost of operating the electrical system is reduced due to freed up capacity previously not available, and in turn reduces the amount of generation and associated emissions needed to support the electrical load. There are additional operational benefits to installing capacitors on the distribution system: voltage levels, system power factor, and loading constraints are also improved or corrected with the installation of capacitor banks. Two of the New York State utilities proposed adding capacitor banks to the distribution system as a valuable and effective means to reducing system losses. The proposed projects submitted by RGE and O&R for ARRA funding include the installation of automatically controlled and/or switched capacitor banks at several locations throughout their respective service territories to address system losses and other system constraints within each area.

RG&E Distribution Capacitor Installation – These proposed projects by RG&E are a direct outgrowth from the NYISO study and will reduce system losses on the distribution system and improve voltage control. RG&E has been installing capacitor banks for several years now. With the retirement of Russell Station, the need for capacitors in RG&E's service territory has increased, along with the need for a static VAR compensation to solve other contingencies on its system. In addition, in the event of certain outages, RG&E needs additional capacitor banks and phase shifters on the system to keep the Ginna nuclear station operating at peak capacity.

O&R Distribution Capacitor Installation – This project includes the installation of approximately 120 new capacitor banks and the relocation of approximately 30 existing capacitor banks to optimize distribution system VAR support for both on peak and off peak conditions. Benefits include reducing system losses by correcting the power factor and thereby reducing the flow of reactive power through transmission lines, cables, and transformers.

Grid Modernization and Reliability Enhancement Projects

Con Edison has proposed several smart grid related projects that are designed to modernize and enhance its existing electrical distribution system by making it smarter and more flexible in reacting to system conditions and emergencies, with the least amount of impact or disruption on the system and customers. These projects are all a form of distribution automation, which is not conceptually new, although these projects will be addressing needs that are not currently being addressed. The projects are intended to provide *foundational information and enable* other technologies in order to enhance system reliability, improve demand response, and allow for better integration of renewable resources. One project, referred to as command and control also *leverages* other funds.

Distributed Generation (DG) Interconnection – Network protectors and their operation within a network grid continue to be a major hurdle for both Con Edison and its customers who wish to install renewable sources of distributed generation (DG). The amount of DG installed within a Con Edison network can be very limited due to the design and protection schemes of the network protector units. There has been a large increase in interest and actual deployment of renewable DG, particularly solar resources, in the Con Edison service territory, with recently passed legislation that increased the availability of net-metering for both residential and non-residential customers. The advanced automation and communications proposed for the network protectors would allow a large increase in available DG onto the network without the existing network protector operational concerns previously seen. This would also allow the deployment of targeted DG in areas where it is needed the most during high load periods, and possibly avoid system emergencies and equipment failures.

Demand Response Initiatives – This program includes the implementation of a Demand Response (DR) monitoring system and deployment of innovative controllable technologies. The DR monitoring system will be a comprehensive software deployment that will aggregate all DR participation in real time during events. The second component of the DR program will incent the purchase and installation of innovative utility controllable technologies. This will include such technologies as controllable room air conditioning, controllable rooftop air conditioning, home area network (HAN) systems and Auto-DR enabled building management systems. The program will increase the reliability, utility and scope of Con Edison's DR programs. The DR monitoring system will enhance the use of DR as a truly dispatchable resource. Incenting new technologies will allow penetration of DR into New York City residential markets that have previously been unable to participate in DR. Additionally, it will provide DR resources to the utility that are extremely reliable and verifiable.

Monitoring Based Commissioning – This project utilizes a combination of commissioning activities, coupled with ongoing, technology-based monitoring to create benchmarks for optimal building operations and ensure the persistence of savings. Monitoring building operations will allow the system to alert building managers of deviance from optimal performance, ensuring achievement of energy savings, and achieving benefits normally associated with energy efficiency and demand response (lower energy costs, lower peak demands, and reduced emissions).

Con Edison - Command and Control – In partnership with Boeing, Columbia University, and The Prosser Group, Con Edison proposes to design and deploy intelligent network centric command and control system-of-systems in conjunction with demand management, distributed generation, and energy efficiency projects. This project will provide real time situational awareness and transparency via an Integrated System Model of the electric transmission grid will enable targeted management and intervention to resolve issues as they arise. It will also accommodate effective, plug-and-play compatibility amongst new, green technologies that have the potential to disrupt grid function. Additionally, due to contributions from the partners associated with this project, Con Edison is requesting funding for only 25 percent of the total project cost from ratepayers instead of the 50 percent requested in most other project areas.

Con Edison - Grid Support – This project will facilitate the integration of renewable resources by developing storage capabilities. It includes demonstration of customer on-site energy storage and other distributed energy resources (DER). It will demonstrate the capability of Con Ed to control and dispatch disparate customer energy storage and other DER assets to the grid for load leveling / peak shaving.

The ability to develop storage capabilities along side new distributed generation facilities offers great benefits when high load periods or equipment failures occur, by allowing the Company to dispatch these resources on an as needed basis. Optimizing the full potential of these new renewable sources of power is valuable to the Company, the system, and the environment.

Intelligent Underground (UG) Automatic Loop – This project will provide a demonstration of an underground automatic loop design in a large distribution network using remotely controlled and automated switches to reduce the risk of a large network outage and improve reliability. This reduces the size of a large network and thereby reduces risk of major network outage and improves the reliability of the grid, saving societal costs associated with such outages.

Non-Smart Grid Project Proposals

The specific details of the non-smart grid project proposals from Con Edison were submitted with the July 2, 2009 update filing, and thus, were not specifically detailed enough in the April 17, 2009 Stimulus Filings to provide adequate notice to the public. Consequently, we review Con Edison's request for approval of the non-smart grid project proposals on an emergency basis. Adoption of this Order is needed to assure the Company is fully compliant with the requirements of the various DOE grant opportunities discussed above. Approval of the projects, and subsequent award by DOE of matching funds for the projects, would promote and encourage economic development, job growth, and a possible reduction in air emissions through the promotion of renewable electric generation resources and introduction of electric vehicles to the market. In view of the fact that these benefits may not be realized, the immediate adoption of this Order, under SAPA §202(6)(a) and (b), is necessary for the preservation of the general welfare of Con Edison ratepayers and compliance with the advance notice and publication requirement of SAPA §202(1) would be contrary to the public interest.

Specifically, Con Edison intends to apply to the three non-smart grid grant opportunities discussed above – High Penetration Solar Deployment, Wind Energy Consortia, and Transportation Electrification. In addition to promoting the development of foundational information, these projects leverage non-ratepayer funds. Con Edison's smart solar project, with a cost-share responsibility of $1.2 million (approximately 25% of the total project costs), calls for the deployment of 2,250 solar panels at its Astoria complex, and is designed to test the Company's system for the integration of solar resources and battery storage.

While we still prefer that New York utilities refrain from either acquiring or constructing generation due to the associated vertical market power constraints, we also are well aware of the public policy benefits that accompany Con Edison's proposed test. This project, if successful, may provide Con Edison with the tools to achieve system integration of greater electricity generation from solar resources. In addition, the project will assist the State of New York in meeting its Renewable Portfolio Standard goal of

25% of electricity consumed in New York State generated from renewable resources by 2013.

The Off-shore Wind Study will be performed by Con Edison in cooperation with the New York Power Authority, the Long Island Power Authority, New York City, IBM, Clipper Wind Power, and SUNY Stony Brook. The Wind Study provides an important opportunity for the measurement of wind resources located off the shores of New York. This study may provide insight into the value that can be derived from construction of off-shore wind turbines, which in turn could trigger the construction of those resources to the benefit of reaching the renewable energy goals for the State. Moreover, because of the partners involved in this project, Con Edison's cost responsibility is estimated at only 10% of the total project costs, or $1.2 million.

The Electric Vehicle Demonstration Project proposed by Con Edison offers a unique opportunity, at very little cost, for Con Edison to partner with Chrysler and the U.S. Postal Service. The project proposes to test new technologies that ultimately may promote the reduction of greenhouse gases in a nonattainment area, through the introduction of electric vehicles for the U.S. Postal Service. With the introduction of electric vehicles for the U.S. Postal Service, or mass market customers in general, the electric utilities will need to be ready to handle the unique challenges that are presented by the introduction of this new load to the system. Con Edison's proposed project provides an initial foray into the challenges that may face Con Edison in the near future as the move to electric vehicles gains momentum.

In total the above-described projects would amount to an approximate ratepayer cost of $2.5 million[18] and offer a unique opportunity for Con Edison to test technologies that will ultimately promote important public policy initiatives at minimal cost to ratepayers.

Integrated Smart Grid and/or AMI Projects

The projects we are approving in this category meet several of our criteria for project selection. First, these projects include AMI technologies that potentially enable the expansion of demand response resources and opportunities for mass market customers to manage energy costs. Effective trials of these technologies, particularly when associated with dynamic pricing trials as discussed in greater detail below, will provide foundational information and greatly improve our ability to reach conclusions regarding the cost-effectiveness of these approaches to expanding resources on the "demand" side of the meter.

Additionally, these projects enable other technologies by providing investments in the basic communications infrastructure that forms an integral part of the architecture of the smart grid. Without this basic component, the grid cannot be made "smart" -- information provided by meters and sensors on the transmission and distribution system cannot be efficiently collected by the utility, nor acted upon by sending signals or instructions back to the devices connected to the system.

[18] The Hydra – Secure Super Grids Project, initially proposed by the Company, is not sufficiently along in the process at DOE to warrant a determination regarding ratepayer funds. Con Edison has not been authorized by DOE, which is a requirement of the program, to file an application for the Advanced Research Projects Agency – Energy (ARPA-E) Grant Program, and thus, we need not address this request. Two other projects have also been withdrawn. The District Energy Project proposal is an application to DOE to cover the entire costs associated with the expansion of the Company's steam system. Consequently, no ratepayer funds are being requested for this project. In addition, one of Con Edison's partners for the Data Center Energy Efficiency Program withdrew support, resulting in the Company's withdrawal of the proposed project.

Finally, even after questions about the basic viability of smart grid technologies are answered, each utility will face decisions regarding which applications make the most sense for its particular circumstances, and how to most effectively integrate those technologies with its legacy systems. These projects not only provide valuable information that will help validate the viability of a variety of smart grid technologies, they provide each utility the opportunity to gain experience with their deployment, and to collect demand response data from its own customers. For these reasons, the projects listed here are approved.

As these projects involve installation of AMI, several provisions of our various orders in the AMI proceeding are applicable here.[19] We have previously noted that the Public Service Law and our regulations require that only Commission-approved devices should be deployed. If the devices selected by each utility have not been submitted for Commission review and approval, the company must do so before moving forward with implementation. We are aware that several utilities have already submitted meters for Staff review; and depending on the outcome of those reviews, further orders may be issued concerning approval to use such meters.

Con Edison/O&R and Central Hudson were required to file revised AMI pilot proposals in the AMI case. It appears to us that the projects those utilities have submitted in this case are consistent with their filings in the AMI case, and comply with our directives in that case. To the extent that these project plans duplicate or improve upon the filings made by Con Edison/O&R and Central Hudson in that case, those plan filings are also approved.

Our February 2009 order in the AMI case adopted certain minimum functional requirements for AMI meters.[20] That order allows utilities flexibility in

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[19] Case 09-M-0074, In the Matter of Advanced Metering Infrastructure, Order Adopting Minimum Functional Requirements For Advanced Metering Infrastructure Systems And Initiating An Inquiry Into Benefit-Cost Methodologies, (issued February 13, 2009) (AMI Order).

[20] Id.

meeting AMI minimum functional requirements; however, if a utility believes that it can achieve the same result through a different route, or if it believes that adherence to a particular requirement would not be cost-effective in its particular circumstances, it must seek waiver of the applicable functional requirement. Utilities are reminded of the need to adhere to these requirements in their selection of meters, or seek the appropriate waiver. We note that Con Edison sought specific waiver of certain requirements for the meter type that it intends to employ in the Westchester portion of its pilot. For the limited purposes of conducting this pilot, such waiver is hereby granted.

Finally, several utilities included proposals to install automated meter reading capability on its gas meters in the project areas, and/or to upgrade those gas meters to furnish automated reading capability. While we understand the potential for operational savings produced by automation of meter reading functions, we are doubtful that the limited installations involved in these deployments will produce appreciable savings. Furthermore, the operational savings achievable with full installation of automated meter reading capability for both electric and gas service are relatively certain, and are not properly a subject of inquiry in these projects. Finally, neither the DOE smart grid funds, nor the surcharges to recover the ratepayer funded portion of project costs, are intended to apply to gas service. For these reasons, the portion of the costs of these projects relating to gas meters and other apparatus related to gas service is denied. The utilities are directed to provide updated estimates of project costs at the time that each makes the surcharge tariff filings discussed below.

Central Hudson Smart Grid/AMI – This project creates ten “intelligent” circuits from source to end user combining AMI technologies, distribution equipment upgrades and automation, and data system modernization to enhance operational efficiency in the distribution grid, and, when coupled with dynamic rate offerings, will allow greater energy consumption control by consumers. Installation of meters and associated communications technology will accommodate data collection for approximately 13,500 “smart” endpoints and facilitate demand response programs. Approximately 2,000 home area networks (HANs) will be installed to facilitate customer response, as well as display devices which can communicate meter data, and other devices that can control appliances to aid in demand response.

The two-way communication system will incorporate a two-tiered radio frequency (RF) mesh design. Communication modules will allow for real-time voltage and current readings and control of equipment, which will aid in reducing system loss. The meter data management system (MDMS) will integrate with the existing legacy Customer Information System as well as the Outage Management System and provide real time data from endpoints on the grid to the load flow program for circuit modeling and analysis functions.

Central Hudson intends to deploy technologies in multiple areas of its service territory, representing two percent of its total customers and approximately five percent of its electric distribution circuits. The areas chosen incorporate the diversity of its customer population, as well as the various geographic characteristics of its service area.

Importantly, the Company has designed customer surveys and focus group activities to study and evaluate customer reactions and explore the possibility of creating new services. Education and outreach initiatives will be developed to guide consumers through the transition to Smart Grid and how to take advantage of dynamic rate offerings.

Con Edison / O&R Smart Grid/AMI – Con Edison and O&R have proposed four AMI deployment projects throughout its service territory. Three of which are in Con Edison's Westchester, Manhattan, and Long Island City (LIC) operating areas. The last is O&R's Eastern operating division. The deployment projects will include approximately 42,000 electric meters. This includes approximately 20,000 electric meters in Westchester; 7,500 electric meters in Manhattan; 10,000 electric meters in LIC; and 4,300 electric meters in O&R.

These AMI projects are proposed to evaluate, in actual field conditions, technologies from different vendors of AMI equipment and communications and home area network providers. Demand Response and Energy Efficiency programs in the deployment will be used to evaluate the responses of mass market customers to price sensitive rates and their acceptance of AMI technologies. The AMI project will enhance information sharing and communications between the utility and its customers.

None of these projects are exactly the same, and each of them offer different technologies and characteristics specific to the location and customers served. O&R and LIC will expand on communications infrastructures and Smart Grid projects already established and previously approved by the Commission. The Con Edison Manhattan project would be deployed in an area that offers diverse operational challenges and opportunities for the Company to address, in an environment not like any other in the country or the world. The Westchester program plans to extract AMI functionality from already existing Automated Meter Reading (AMR) meters, in an attempt to avoid any possible stranded costs from investments already in place.

Each of these programs will improve upon or introduce new technologies, such as more accurate meter reading, better outage management, and will eliminate most estimated bills and associated customer concerns. Additionally, they will provide customer specific hourly usage information for use in new rate forms and verification of customer participation in demand response (DR) and energy efficiency (EE) programs to be offered. They will identify customer acceptance of HANs and in home display (IHD) technologies as well as changed customer behavior in response to electric price signals, energy usage, automated appliance control, and incentives to reduce energy usage. The projects will implement dynamic pricing for certain customers whose service is measured by AMI meters resulting in improved information with which to perform more reliable cost benefit analyses of AMI deployment and associated customer side technologies.

These advancements will collectively provide major benefits and improvements to both the Con Edison and O&R distribution systems. Real time information transmitted to system operators from customers improves the operator's ability to react to system conditions as needed and the overall reliability of the system. Real time price and consumption information coming to customers allows them to consume electricity in a smarter, more efficient manner. A substantial body of knowledge and information is expected to be gained with these initial deployments that should prove beneficial in future deployment projects.

National Grid Smart Grid/AMI – The Company proposes to deploy Smart Grid technology at two locations in New York, one in the Syracuse area and one in the Capital District area, located north of Albany. The Syracuse Smart Program area will include approximately 40,000 customers, while the Capital District Smart Program area will include approximately 42,000 customers.

A two-way communications platform forms the backbone of National Grid's proposal. The Company is investigating a variety of wireless technologies to support this approach, but promises to leverage existing National Grid assets, new wireless technologies, and public networks. Advanced meters will be implemented that can support interval measurements, remote firmware upgrades, track both voltage and power factors, and serve as a gateway for communications into the home. Finally, National Grid proposes to integrate a set of clean energy modules into its program. These will include photovoltaics, plug-in hybrid electric vehicles, energy storage, wind power, micro-CHP, micro-grids, and holistic homes.

The Company states that the customer demographics and associated meters, feeders, and substations represent a cross-section of the Company's customers and electric grid equipment, which is an essential element for any test to be both statistically valuable and procedurally useful in informing its broader strategic decision related to smart grid and clean energy.

In addition to deploying the Smart Grid/AMI technology "spine", National Grid proposes to demonstrate the effects of combining Smart and Green by integrating a robust set of clean energy modules into its Smart Program. The Smart Program will demonstrate the integration of a number of clean energy technology modules with the Smart Grid spine. The clean energy technologies that National Grid intends to integrate with the Smart Grid include photovoltaics, plug-in hybrid electric vehicles, energy storage, wind power, micro combined heat and power, microgrids, and holistic homes.

NYSEG Smart Grid/AMI – NYSEG proposes to submit two Smart Grid/AMI projects, at an approximate combined capital cost of $28.4 million for the Horseheads and Cooperstown regions in its service territory. Each of the projects will improve upon or introduce new technologies to advance areas such as accurate meter reading, outage management, and the elimination of estimated meter reads and associated customer concerns. Customers will additionally be provided with information on their energy usage on a real time basis allowing them the opportunity to modify their usage and reduce costs. These projects will allow reclosing, sectionalizing and monitoring, which will allow the utility to minimize the number of customers impacted by an outage and increase its ability to maintain service to a larger number of customers during adverse circumstances. Also, the inclusion of an energy management system will permit the utility and customers to manage their load during peak periods as well as immediately notify the utility of outages which will reduce customer restoration time and complaints.

The projects will also provide the ability for coordination between wind farms and grid operators, as well as operators of the proposed compressed air energy storage facility near Watkins Glen, NY. This coordination will make the wind farms more effective as an asset for the Transmission Grid. These programs will allow the utility to evaluate if the use of distributed generation on specific selected circuits is a cost effective method of reducing load pockets, as opposed to constructing new transmission and distribution infrastructure. Lastly, the projects will allow the utility to test dynamic pricing for certain customers whose service is measured by AMI meters. The utility will randomly select a statistically valid number of customers who will be charged on a dynamic price on a mandatory basis with assurance that their bill will be no higher than the bill they would have received under the otherwise applicable standard tariff.

RG&E Smart Grid/AMI – RG&E proposes to apply to DOE for a Smart Grid/AMI project in the Canadaigua/Bloomfield area of its service territory at an approximate capital cost of $37 million. RG&E's proposed projects are identical to the projects proposed by NYSEG other than the locations to be demonstrated; therefore they share the same strengths. Each of the following projects will improve upon or introduce new technologies to advance areas such as accurate meter reading, outage management, and eliminate estimated meter reads and associated customer concerns. Customers will additionally be provided with information on their energy usage on a real time basis allowing them the opportunity to modify their usage and reduce costs. These projects will allow reclosing, sectionalizing and monitoring, which will allow the utility to minimize the number of customers impacted by an outage and increase its ability to maintain service to a larger number of customers during adverse circumstances. Also, the inclusion of an energy management system will permit the utility and customers to manage their load during peak periods as well as immediately notify the utility of outages which will reduce customer restoration time and complaints.

These projects fall well within the scope of the DOE overall purpose to accelerate the modernization of the nation's electric transmission and distribution systems and promote investments in smart grid technologies, tools, and techniques which increase flexibility, functionality, interoperability, cyber-security, situational awareness, and operational efficiency. They will also be of great benefit to the customers of NYSEG and RG&E in the project areas and possibly beyond in the future.

RG&E Mandatory Hourly Pricing (MHP) – New York has led the country in exposing its largest customers to dynamic pricing. New York's largest utility customers have been on MHP rates since 2007. On April 24, 2006, the Commission issued an Order[21] directing utilities to file Hourly Pricing tariffs, outreach and education plans and plans for making meters available to implement MHP for their largest customer classes. The Commission has found the benefits of MHP to be: potential bill savings due to reductions to peak period prices, enhanced peak period reliability, wholesale market power mitigation, and producing more equitable customer bills than does the existing, less exact, average energy rate.

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[21] Case 03-E-0641 - Expedited Implementation of Mandatory Hourly Pricing for Commodity Service, Order Denying Petitions for Rehearing and Clarification in Part and Adopting Mandatory Hourly Pricing Requirements (issued April 24, 2006).

The MHP project at RG&E will consist of installation of an estimated 250 new meters for 2010 and 250 more for 2011. The costs include the installation of a new recording meter, but the customer also has to provide a phone line to the meter. RG&E's proposed expansion of MHP would expose more customers to hourly prices and bring further benefits to customers and the electric system. One of the most thorough studies of the benefits of MHP, completed in 2004, was based on data from National Grid's SC-3A customers.[22] This project could provide similar evidence on the benefits of MHP for lower demand thresholds.

RG&E has also proposed to implement a reactive power tariff for this same group of customers. RG&E proposes to integrate the Reactive Metering project with the MHP project. While implementation of a reactive power tariff could provide benefits to the electric system, we are not prepared to recommend implementation of a reactive power tariff at this time. We understand that interval meters used for the MHP program have the capability to measure reactive power. RG&E should file for recovery of MHP meters only. The Company should choose MHP meters that are capable of recording reactive power, so if the Commission chooses to implement reactive power rates in the future, there will be no additional metering cost to implement that change.

Interoperability/Cyber Security

The smart grid has often been referred to as a "system of systems". The Smart Grid Investment Program FOA describes interoperability as:

> "the capability of two or more networks, systems, devices, applications, or components to share and readily use information securely and effectively with little or no inconvenience to the user."[23]

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[22] C. Goldman, Hopper, M. Moezzi,R. Bharvirkar, B. Neenan, R. Boisvert,P.Cappers, D. Pratt, "Customer response to day-ahead wholesale market electricity prices: Case study of RTP program experience in New York" (July 1, 2004). *Lawrence Berkeley National Laboratory.* Paper LBNL-54761.

[23] DE-FOA-0000058 at pg. 8, which refers to "Introduction to Interoperability and Decision-Maker's Interoperability Checklist, v1.0." by the GridWise Architecture Council.

The expectation of seamless integration of new “smart” technologies with legacy systems and devices cannot be achieved without great attention to the principal of interoperability. The National Institute of Standards and Technology (NIST) has been tasked to coordinate the “development of a framework that includes protocols and model standards for information management to achieve interoperability of smart grid devices and systems.”[24] NIST has selected the Electric Power Research Institute (EPRI), in collaboration with industry representatives, other standards bodies and government stakeholders to draft an interim “roadmap” to guide the development of Smart Grid interoperability standards. EPRI’s initial report[25] on an interim roadmap has been released to elicit public comment, to be evaluated by NIST for its anticipated completion of the interim roadmap in the fall of 2009, addressing smart grid architecture issues and priorities for interoperability standards, including cyber security.

Interoperability promotes technology innovation, operational efficiency and facilitates the scalability, security, and reliability of smart grid deployments. Although development of a comprehensive set of smart grid standards is not entirely complete, the principals of interoperability, standards-based communication protocols, and open architecture must be incorporated in current smart grid deployments. It is essential that the concept of interoperability not be limited to informational compatibility between smart grid systems. Greater interoperability and standards development should also drive innovation and competition among device manufacturers, increasing vendor choice and communications technology alternatives, ultimately leading to more cost-effective deployments.

The DOE criteria include detailed interoperability and cyber security requirements. We have, moreover, issued our own minimum functional requirements

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[24] Energy Independence and Security Act, Title XIII, Section 1305.

[25] See http://www.nist.gov/smartgrid/InterimSmartGridRoadmapNISTRestructure.pdf

relating to AMI, a key smart grid technology.[26] EnerNOC agrees that projects that include AMI should comply with the Commission's minimum functional requirements. While adopted only for AMI, the minimum functional requirements provide a specific set of interoperability and cyber security functions that are readily adaptable to other smart grid technologies.

First and foremost, we are keenly interested in ensuring that our expected investments in the Smart Grid will not lead to a decrease in the safety and reliability of the transmission and distribution system. NIST's cyber security and interoperability standards will have specific requirements for electricity producers, system and transmission operators and other system users to ensure the security of their systems and infrastructure; however, these important standards will not be available in time for use in these proposals. In the absence of the NIST standard, we rely on the DOE criteria, which we believe the projects we approve will meet, and we commend the cyber security and interoperability requirements contained in our AMI minimum functional requirements as a reference for the utilities' final planning and design phases of their smart grid projects. It is our expectation that smart grid systems being approved here may contain some proprietary elements, but will incorporate standards-based communications protocols, be flexible to accommodate future standards development, such as what is being produced by NIST.[27] Approved deployments must be adaptable to incorporate future technology innovations which support choice among devices, vendors and alternative, cost-effective communications solutions.

We acknowledge NEM's concerns regarding the creation of an information monopoly through the deployment of AMI that is proprietary and closed to outside

[26] Case 09-M-0074, In the Matter of Advanced Metering Infrastructure, Order Adopting Minimal Functional Requirements for Automated Meter Infrastructure Systems and Initiating and Inquiry Into Benefit-Cost Methodologies, (issued February 13, 2009).

[27] We expect that the utilities will continue to keep abreast of the development of NIST Standards, and adhere to those standards as appropriate.

providers. We do not support the creation of an information monopoly through our approval of these smart grid projects, and thus, require utilities to take all steps appropriate, including adherence to the AMI minimum functional requirements, to prevent such monopoly from being created. Consequently utilities, unless otherwise waived, shall adhere to the AMI minimum functional requirement that customers or their competitive providers will be able to access meter data in an open, standard, non-proprietary format, as both NEM and EnerNOC suggest.

EnerNOC's proposal to adopt the XMPP protocol is premature, as the NIST process is ongoing. We are disinclined to adopt a particular protocol before NIST has drafted its standard.

Leveraging Public Communications Networks

In developing minimal functional requirements for AMI, we addressed interoperability by adopting the use of standards based protocols and open communications architecture.[28] The Commission also recognized the potential of commercial broadband in AMI deployments and encouraged utilities to investigate opportunities to leverage existing communications networks. At the June 11, 2009 Technical Conference in this proceeding, various aspects of smart grid development were presented to and discussed by the Commission, including the role of existing communications providers. Verizon and Cablevision made presentations to the Commission and were participants in a panel discussion on their companies' potential contributions to smart grid development.

On June 22, 2009 Verizon also submitted written comments for the Commission's consideration when evaluating the utility proposals. Citing the size, scale, and reliability of its wireline, wireless and private networks, and its expertise in managing complex and voluminous data systems with a priority on security and integrity, it argued that it and other communications providers offer all the services needed to support various smart grid communications applications. It recommends that the

[28] Id., p.12.

Commission favor proposals that leverage these existing resources; not approve deployments that create new broadband networks; and, encourage utilities to work closely with communications providers in their deployment of smart grids.

The communication components of the project proposals submitted by the utilities are mainly comprised of private, focused communications systems for meter data with very little committed use of established wired or wireless networks, except to fill in gaps where coverage is poor. Some project proposals commit to explore commercial offerings to back-haul accumulated meter data to the utility as a choice among other alternatives. We are aware that smart grid deployments in other parts of the country have successfully leveraged existing wireless networks for end-to-end communications. While it appears that the current industry preference is deployment of private smart grid communications networks, we need to continue examining whether there are opportunities to leverage public communications networks as these communications systems are expanded. We strongly encourage utilities to work with established network providers to leverage their available infrastructure and operational expertise in deploying smart grid communications solutions. Approved deployments must be adaptable to incorporate technology innovations which support cost-effective communications solutions, including existing broadband communication networks.

With regard to the possibility that deployments funded here could one day be used for public broadband offerings, our approval is consistent with policy established in Case 06-M-0043,[29] which recognized the public interest in exploring alternative broadband technologies, in that case broadband over powerline (BPL), but which also sought to mitigate the potential of undue risk for electric utility customers. That policy permits the deployment of economically viable BPL technology by electric companies solely to support electric system operations because it does not raise subsidization or cost

[29] Case 06-M-0043, Niagara Mohawk Power Corporation and New Visions Powerline Communications, Inc., Statement of policy on Deployment of Broadband Over Powerline Technologies, issued October 18, 2006.

allocation issues. Our presumption here is that all broadband technologies, such as BPL and WiMAX, being deployed in the projects meet that limitation, i.e., they will be utilized to support smart grid operations only. Further, we require that the principals established in the Case 06-M-0043 policy statement with regard to third-party or separate affiliate operation, associated affiliate transaction, cost allocation and related business rule requirements to prevent subsidization by regulated electric utility rates, be extended to deployments here for any technology investments that are subsequently utilized for the provision of public broadband.

Projects Not Approved

Both NYSEG and RG&E proposed several projects under the title of Grid Enhancement that they state should be considered for application to DOE's Investment Grant Program. A description of the projects is provided in Appendix A to this Order. The projects include replacement of bulk transformers and installation of efficient transformers, as well as replacement of general transmission and distribution infrastructure equipment.

The overall purpose of the EDER programs is to accelerate the modernization of the nation's electric transmission and distribution systems and promote investments in smart grid technologies, tools, and techniques which increase flexibility, functionality, interoperability, cyber-security, situational awareness, and operational efficiency. The projects listed under the Grid Enhancement category proposed by RG&E were originally submitted to Staff as part of its January 2009 rate case filing. That case has since been dismissed. These projects are considered typical capital improvement projects and not the type of smart grid advanced technology driven projects requested by the DOE and its Investment Grant Program FOA. In addition, while the Commission views installation of interval meters for MHP to be a valuable step toward a smart grid, NYSEG's proposed MHP expansion is identical to the project they proposed in Case 07-

E-0479, and that the Commission already approved.[30] This project does not appear to meet the DOE's goals of incenting new projects or incremental expansion of existing projects.

Therefore, we will not include these projects in those for which we allow cost recovery pursuant to the DOE's EDER program.

Rate Design

In our advanced metering infrastructure AMI Order, we said:

> An advanced metering infrastructure and use of new intelligent technology provide the foundation for electric utilities and consumers to make informed choices about energy suppliers and usage on the basis of price and time-of-use of energy. Use of advanced electric metering systems enables electric utilities and consumers to manage the need for additional supplies to satisfy growing demand, to avoid use of high priced fuels, and to moderate pricing volatility associated with use of expensive generation in times of peak demand.[31]

In the absence of time-differentiated pricing information, average energy pricing insulates customers from a full understanding of the relationship between hourly varying energy costs and retail prices. By providing customers with more information about peak prices, we expect that customers can better manage their electric bills by better managing their electricity usage.

A key component of a smart grid is therefore the empowerment of customers through the installation of AMI in homes and businesses. Among the many abilities of AMI is the ability to measure the electricity usage of customers on an hourly basis. The existence of hourly usage data creates the possibility for time-variant rate designs, including rates that correctly signal the actual costs of electricity usage during peak times.

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[30] Case 07-E-0479, New York State Electric and Gas Corporation, Order Establishing Commodity Program, (issued August 29, 2007).

[31] Case 00-E-0165, et al., In the Matter of Competitive Metering, Order Relating to Electric and Gas Metering Services (issued August 1, 2006), pp. 1-2.

A key question is whether such rate designs can induce enough reductions in the on-peak usage of residential customers to justify the cost of fully deploying AMI. In the AMI proceeding, several utilities have filings pending before us that propose pilot programs to help answer this question. The ARRA gives New York an opportunity to address this question with the help of federal stimulus money.

Some of the utilities included rate design proposals in their April 17 filings. DPS staff, in an effort to insure that a coordinated, statewide approach is taken to addressing the testing of rate designs, met with all of the utilities several times, both one-on-one and as a group. As a result, adjustments were made by the utilities in their rate design proposals to fill gaps and to add several dimensions. The utilities' updated rate design proposals were filed on July 2 as part of their smart grid stimulus projects.

We have not yet made a decision on full deployment of AMI in New York. To a large extent, the key to this decision is in projecting the benefits from demand response that is enabled by this technology. The tests of rate designs we approve now must provide the necessary information regarding demand response benefits that will help us make decisions about long-term full deployment of AMI. Moreover, we need to understand the possible ways in which rates can be implemented over time that reach large numbers of residential customers and give them meaningful incentives to change their consumption patterns. Opportunities may exist across the entire range of customer classes for promotion and adoption of demand reduction measures.

The Utilities' Rate Design Proposals

The various rate designs proposed are listed and briefly described below.

- Standard Rate – Price is the standard residential energy charge (cents per KWh). It collects energy costs and generation capacity costs in a single KWh charge that does not vary by time-of-use (TOU).

- Peak Time Rebate (PTR) – Price is the standard residential energy charge. The utility provides rebates to customers who reduce their KWh usage when the utility calls a critical peak event. Customers are informed about critical peak events one day ahead of time. For each customer, an estimate of what the customer would have used during each critical peak event must be made, so that reductions from that level can be measured.

- Critical Peak Pricing (CPP) – Price is designed to recover all or most of the generation capacity costs over a fairly small number of days/hours in which system load is at or near system peak. The prices are set for a minimum of two components. The first component is an energy only price (no generation capacity costs). The second component is the price that recovers the generation capacity costs. The utility will only charge this second component of the rate when it has informed the customers (one day ahead of time) of a critical peak event. The utilities have split the energy component into two or more blocks per day similar to Day/Night rates.

- Hourly Pricing Program (HPP) – Price changes hourly based on the NYISO day-ahead market prices for energy. The cost of generation capacity is recovered through a capacity adder, which can be static over time, or can be dynamic. The dynamic form involves signaling the cost of generation capacity over a fairly small number of days/hours when the utility calls a critical peak event, exactly as in critical peak pricing. Each day’s 24 hourly prices are provided to customers one day in advance.

- Dynamic Block Time-of-Use (TOU-DB) – Rate is designed with three separate blocks, Off-Peak, On-Peak and Super-Peak. The prices in each block change every day based on NYISO day-ahead market prices for energy. Generation capacity costs are added into the On-Peak and/or Super-Peak blocks. Each block corresponds to specific hours in a day, for example, Off-Peak – 8:01pm to 6:00am, On-Peak – 6:01am to 4:00pm, Super-Peak 4:01pm to 8:00pm. Customers are provided each day’s prices one day ahead of time.

- Static Block Time-of-Use (TOU-SB) – Rate is designed with two separate time-of-use blocks, peak and off-peak, and sometimes a third, Super-Peak block. Each block has its own price and the price in each block is a single, average price across many months/days. These block prices do not change day to day, and therefore do not reflect changing day-to-day demand/supply conditions.

The rate designs proposed by each New York utility are shown in the following table:

		Utility					
		Con Edison	Orange and Rockland	Central Hudson	National Grid	RG&E	NYSEG
Rate Design[1]	PTR	X			X		
	CPP	X			X		
	HPP	X		X	X[2]		
	TOU-DB	X	X				
	TOU-SB			X			

PTR = Peak Time Rebate
CPP = Critical Peak Pricing
HPP = Hourly Pricing Program
TOU-DB = Dynamic Block Time-of-Use
TOU-SB = Static Block Time-of-Use

[1] For any given rate design label, there are some differences from one utility to the next in terms of the details.

[2] For non-residential customers only.

The utilities plan to test the extent to which the response to smart rates is enhanced by in-home devices. These include in-home displays (IHDs) that provide detailed information about prices and the customer's usage; HANs that allow the customer to automatically adjust appliances in response to signals sent to the home by the utility; and equipment that allows direct control by the utility of the customer's key energy using appliances. The test design will also allow a test of the response to time varying rates of low income consumers. Con Edison also proposed the testing of the effectiveness of direct utility control of room air conditioners for customers that remain on the standard rate.[32]

Finally, several utilities propose to test information-only programs, i.e., whether and to what extent enhanced information about energy consumption, in the absence of any price signals, brings about a change in the total consumption or pattern of consumption of customers. Examples of enhanced information are IHDs that continuously show usage, either in total, or for specific appliances; information about the amount of carbon emissions caused by the customer's electricity consumption; and continuous calculations of the effect on the monthly bills of customers caused by the customers' current rates of consumption.

U. S. Department of Energy's Randomized Control Trial Design

In its Funding Opportunity Announcement for the Smart Grid Investment Grant Program, the U.S. DOE describes mandatory, randomized control trial design and emphasizes its importance to the DOE in gauging the merits of dynamic pricing:

> DOE is interested in advanced metering projects that involve dynamic pricing and use a randomized control trial design. Randomization is important for conducting cost-benefit analysis of dynamic pricing because it allows for unbiased comparisons across customers…
>
> In the ideal randomized control trial involving smart meters and dynamic pricing, smart meters would first be installed for all customers within a particular geographic area. This might be any well-defined part of the applicant's service area or, alternatively, a set of zip codes. Selection of this area would be at the discretion of the applicant and could be based on where it would be easiest to install smart meters. Next, customers within this geographic are would be randomly assigned start dates for dynamic pricing. There would probably need to be a significant period of time between start dates. For example, a randomly-selected sample of 50% of all customers might begin dynamic pricing on March 1, 2010, while the other 50% begins on March 1, 2012. The DOE is most interested in applications in which some customers would remain on default tariffs for at least two years. The randomization would need to take place at the customer level

[32] Con Edison has an on-going program that performs direct control by the utility of central air conditioners.

> so all customers within the geographic area are equally likely to be in each group…
>
> It is critical that smart meters be installed in the entire geographic area prior to the beginning of dynamic pricing because program evaluation depends on comparing hourly consumption between customers with and without dynamic pricing….
>
> DOE understands that there may be concerns from some customers about dynamic pricing. In order to avoid introducing selection bias that would hamper analysis of project costs and benefits it is critical that dynamic pricing be applied on a mandatory basis….
>
> Applications should include a plan that addresses the requirements of the ideal randomized control design to the best extent possible… [33]

Approaches to Testing Rate Designs

We agree with the DOE's goal of assessing the effect of dynamic rates by using a randomized control trial design. Given the modifications in the New York rate design testing that we direct in the detailed utility-by-utility sections below, randomized control trial designs will be substantially accomplished by New York's utilities. Our Staff and the utilities have expended considerable time and effort on the statewide coordination of dynamic pricing trials, in a manner that recognizes the statutory and regulatory environment in which New York utilities operate, rigorously adheres to the fundamentals of test design and statistical validity, and is designed to produce a set of data on customer acceptance of and response to dynamic prices that will be of value not only to New York, but to utilities across the country.

Although time-varying rates can be offered on a voluntary basis, mandatory time-varying rates may not be imposed on residential customers in New York.[34] New

[33] DOE SGIG-FOA, p. 23.

[34] Chapter 307 of the Laws of 1997 amended Public Service Law §66(27)(a) to delete a provision authorizing the Commission to mandate time-of-use rates for residential customers.

York's utilities are well aware of this, and their proposed rate designs reflect several strategies for the deployment of time-varying rates for residential customers.[35]

Several different dynamic rate strategies will be tested. First is to offer dynamic rates on a strictly voluntary basis. Customers would be given the option to enroll in a time-varying rate. Equipped with hourly meters, customers can be shown, with some precision, how they would fare were they to switch to a voluntary time-varying rate. This is a vast improvement over today's setting, in which a customer must make an educated guess about his or her own load shape and how it might translate into a bill under a voluntary time-varying rate. The time-varying rate would allow customers to make informed decisions regarding whether such rates would be to their benefit. All of the utilities have proposed voluntary dynamic rate designs, except for NYSEG and RG&E, which don't propose any residential trials.

A second strategy is the use of a Peak Time Rebate. Under this approach, at all times the utility charges a single, non-time varying rate, and the customer is free to ignore the rebate feature and just pay the standard rate. The rebate feature can be expected to entice many customers to change their behavior during critical peak events, primarily during summer heat waves, to the benefit of themselves and the electric system. The Peak-Time Rebate requires no customer enrollment – as a practical matter, every customer equipped with an AMI meter can participate – and the only possible consequence of participation is a saving on consumption costs: customers can receive a rebate for reducing consumption when an event is called, but are not charged more than the standard rate in any event. Both Con Edison and National Grid have proposed Peak-Time Rebate rate designs.

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[35] No such restriction exists respecting nonresidential customers, and we made hourly pricing mandatory for all of the state largest customers. See, Case 03-E-0641 – Proceeding on Motion of the Commission Regarding Expedited Implementation of Mandatory Hourly Pricing for Commodity Service, Order Denying Petitions for Rehearing and Clarification In Part and Adopting Mandatory Hourly Pricing Requirements (issued April 24, 2006).

A third strategy is to place customers on a time-varying rate, but provide each such customer with bill protections that guarantee that his or her annual bill be no higher than it would have been under the standard rate. This is equivalent, from the customer's perspective, to being given an opportunity to volunteer for the dynamic rates, without taking any risk at all that he or she will pay more as a result of that action. National Grid proposes to stage a limited duration trial of this approach.

Because of the guarantees for customer bill protection inherent in the Peak Time Rebate and in National Grid's proposal for Critical Peak Pricing, the following utilities and dynamic rates will strictly satisfy the DOE's statistical goal of a randomized control design:

- Con Edison – Peak Time Rebate
- National Grid – Peak Time Rebate
  – Critical Peak Pricing (with bill protection)
- NYSEG – Peak Time Rebate
- RG&E – Critical Peak Pricing (with bill protection)

Central Hudson and O&R propose to implement dynamic rates on a strictly voluntary basis, without bill protection. Con Edison also proposes a number of voluntary dynamic rates in the same manner. Each voluntary rate will be tested against a control group that consists solely of customers that volunteer for dynamic rates, but are randomly placed in a control group and are required to remain on the regular rate. This approach permits a true estimate of the demand response for the subset of customers that are inclined to volunteer for dynamic rates, were such rates to be fully implemented on a voluntary basis. As described in greater detail below, and in Appendix B, Central Hudson, O&R, and Con Edison are directed to implement the DOE's randomized control trial design within the constraints of their all-volunteer pools of customers. This trial design will best meet the DOE's goal of randomization for these programs within the constraints of New York law. Also as described in greater detail below, RG&E is directed to include a Critical Peak Pricing program, and NYSEG is directed to include a Peak Time Rebate.

It is our intent that these trials will be useful not only for New York, but for utilities across the country that may consider implementing such programs. We are mindful that DOE has indicated a strong preference for randomized, mandatory testing of dynamic rates, in an effort to produce statistically valid results. We note that our utilities' programs must recognize the statutory and regulatory environment in which they operate, and encourage DOE to take such factors into account in awarding funding under the SGIG and SGD programs.

Moreover, while DOE's preferred approach will likely produce a prodigious set of data that will guide the evaluation of mandatory programs, it will be less useful for consideration of programs that employ a voluntary approach because, among other things, mandatory trials will provide little information regarding customer enrollment rates. To the best of our knowledge, no utility anywhere in the nation has yet implemented a mandatory dynamic rate program for residential customers. New York's program trials thus could provide valuable information regarding the effectiveness of voluntary programs that may not be replicated elsewhere.

Modifications to the Statewide Portfolio of Rate Designs

The rate designs proposed by the New York utilities were summarized in a table above. While they do a reasonably good job of covering the State's needs for obtaining information about the amount of demand response that can be expected from the various relevant rate designs, they can be improved.

Con Edison's proposal could be strengthened if it contained more data points, especially in the sizes of control groups it uses for its voluntary rate designs. Larger sample sizes may be difficult to achieve, however, given the potential difficulty of recruiting volunteers. In order to provide a greater potential pool of volunteers for its rate programs, Con Edison is directed to eliminate its Hourly Pricing Program from its proposal, and eliminate certain of the non-price mechanisms it plans to test. These changes can double the size of its control groups and increase the size of each of the remaining treatment groups. More detailed guidance is provided in Appendix B, attached to this Order. Dropping the Hourly Pricing Program is acceptable since Con Edison's

Dynamic Block Time of Use rate is quite similar, yet easier for residential customers to digest: the former presents the customer with 24 prices each day whereas the latter presents customers with just three, per day. Moreover, the statewide portfolio of rate designs will continue to contain a residential Hourly Pricing Program at Central Hudson. As noted in Appendix B, if Con Edison gets an unexpectedly large number of volunteers, it may add the Hourly Pricing Program back into its mix of rate designs to be tested.

Central Hudson is directed to delete one of its two Hourly Pricing Program rates, specifically, the critical peak pricing version. The price signal Central Hudson proposed to add on critical days is so small, that little is likely to be learned from it. The expanded pool of participants can be employed to increase the sample size used by Central Hudson to test its Hourly Pricing Program.

Similarly, Orange and Rockland is directed to delete one of its two Dynamic Block Time of Use rates. The two rates that Orange and Rockland proposes to test are so similar, that little will be lost by this deletion. The freed-up pool of participants should be used to boost the size of the control group and the treatment groups.

National Grid's limited duration trial will include randomly selected groups within the trial locations including 800 customers in a control group, 500 customers on Peak Time Rebate and 500 customers on Critical Peak Pricing. These customers have the price protection that National Grid originally proposed but will also have the option of switching to the utility's existing Time of Use rate as that exists for all customers. Furthermore, since the customers in the Critical Peak Pricing group may be exposed over the year to prices higher than the standard rate (at least until the annual reconciliation takes place), no disconnections will be permitted for these customers during the trial to the extent the customer pays what would be due assuming they were on standard rates. In addition, a customer on Critical Peak Pricing shall not be subject to late payment charges as long as the customer remits an amount to the utility that is at least equal to the amount that would be due assuming standard rates. Moreover, should a customer leave during the trial period, they will be afforded the price protection reconciliation upon departure. In addition, we will require the Company to provide with interest at the customer deposit rate for the bill credits earned in connection with reconciliation during the pilot. As recognized by the DOE, it is important that some customers be placed on certain rates for the usefulness of these programs to be evaluated. With the additional modifications we impose here, we increase the chances of obtaining useful information while still recognizing our responsibility to protect all New York ratepayers.

NYSEG is directed to add a proposal to test a Peak Time Rebate. In developing the rebate price, and in defining the rules that govern the number of critical peak days/hours that will get triggered per year, assume an annual market price of generation capacity that is at the level that would exist in a tight market. Assign all, or nearly all, of the annual cost of generation capacity to the summer period for purposes of developing the rebate price. This rate will yield valuable information about the demand response that can be expected when a Peak Time Rebate is in effect during a period in which a tight market prevails. This added rate test will also provide a valuable comparison to the Peak Time Rebate of National Grid, which will contain a lower priced rebate, reflecting current market conditions.

RG&E is directed to add a proposal to test two versions of Critical Peak Pricing, having different concentrations of capacity costs during critical peak events that reflect tight market conditions. For the first version, in developing the generation capacity component of the critical peak price, and in defining the rules that govern the number of critical peak days/hours that will get triggered per year, assume an annual market price of generation capacity that is at the level that would exist in a tight market. Assign all, or nearly all, of the annual cost of generation capacity to the summer period for purposes of developing the critical peak price. The second version should have a capacity component that is based on a market price of generation capacity that lies between the current price level and a tight market price level. Having both levels of price signals in the same AMI deployment area will allow the test of the effect that raising the price has on the amount by which customer demand responds. When combined with National Grid's Critical Peak Pricing proposal, these additional RG&E tests will provide the State with 3 different levels of prices, which will allow valuable comparisons. RG&E is also directed to provide customers with a bill protection guarantee similar to that provided by National Grid, plus the additional bill protections described above.

Given the above modifications, along with some other adjustments shown in Appendix B, the portfolio of statewide rate designs to be tested is shown in the following table:

		Utility					
		Con Edison	Orange and Rockland	Central Hudson	National Grid	RGE	NYSEG
Rate Design[1]	PTR[2]	X-high			X-low		X-high
	CPP[2]	X-high			X-low	X-high X medium	
	HPP			X	X[3]		
	TOU-DB	X	X				
	TOU-SB			X			

PTR = Peak Time Rebate
CPP = Critical Peak Pricing
HPP = Hourly Pricing Program
TOU-DB = Dynamic Block Time-of-Use
TOU-SB = Static Block Time-of-Use

1 For any given rate design label, there are some differences from one utility to the next in terms of the details.

2 High, medium and low are relative terms that show the size of the price signal during critical peak periods.

3 For non-residential customers only.

The portfolio of rate designs should yield a set of valuable information about dynamic pricing and the size of the demand response of customers. Among the things learned will be the following comparisons:

- A full range of rate forms will be tested, including all rate forms known to be in use or under consideration for residential customers in the U.S.

- New York City demand response versus upstate demand response, in order to determine whether significant differences in demand response exist between customers located in these broad geographic areas.

- Each rate design trial will include control groups whose behavior will form baselines against which the target customers' demand responses will be measured. The specific selection processes utilized to assign customers to "control" or "treatment" groups will vary depending on the specific nature of the rate to be tested.

- Each utility's control and treatment groups are designed to be appropriately sized and selected to produce statistically valid data, which can be utilized by other utilities in New York or elsewhere to evaluate the potential for demand response from these rate designs.

- Low income customer demand response versus non-low income demand response, in order to evaluate the impacts of these programs, and the demand response behaviors, of this important demographic segment. We are keenly aware that many consumer advocates fear that dynamic rates will adversely affect low income customers, but there has been little research to prove or disprove this concern. Producing valid results that could lead to conclusions on this matter is among our top priorities for this project.

- Room air conditioning demand response in New York City and how it compares to central air conditioning demand response there. Since a large segment of New York City residents utilize room air conditioners, Con Edison's program will test the effectiveness of load control of these devices (most previous programs have focused on central air conditioning, which is much easier to apply direct load controls).

- Room air conditioning, versus central air conditioning, versus no air conditioning responses upstate.

- Response to high, versus low, versus medium sized price signals during critical peak events.
- Response of volunteers versus response of those that are randomly assigned to a rate.
- Customer acceptance of simple rate designs (Peak Time Rebate), versus moderately complex (Critical Peak Pricing), versus very complex (Hourly Pricing Program).
- Amount of added demand response one gets to dynamic pricing from added in-home devices, to determine the benefits of using such technologies to improve demand response.
- Amount of demand reduction one gets, in the absence of dynamic pricing, solely from adding in-home devices.

The utilities' need to file tariff amendments for rate design is dependent upon a favorable outcome of their applications to DOE. Consequently, we direct the utilities, where appropriate, to file within 30 days of DOE's determination on their application for the Investment Grant Program or the Demonstration Program, which ever is relevant, tariff amendments for the implementation of the rates. In addition, each utility tariff amendment shall not become effective on less than 90 days notice, to allow Staff an initial review of the proposed rates. Each utility in its tariff filing must include in all supporting documentation.

Requirements of PSL §66(12)

MI raises the concern that the utility plans may be of a magnitude that would trigger the requirements of Public Service Law, section 66(12) to hold a hearing. Section 66(12) requires, *inter alia*, that any increase in rates or charges which would increase the aggregate revenues of a utility by more than two and one-half percent requires a hearing. As shown on Appendix C, the total revenue impacts for each of the utilities does not exceed that threshold. Thus, no evidentiary hearing is required.

Issues Related to Surcharges

Several utilities requested Commission authorization for the recovery of costs related to the proposed projects through the imposition of a surcharge. The certainty and availability of utility funding sources for the costs not funded by the DOE (50 percent or more) may also be considered by the DOE when it makes final award decisions. Since the Commission's authorization of either a surcharge or deferral funding mechanism could be viewed as adding funding certainty, we will now consider funding options.

A surcharge mechanism would charge customers for the incremental costs (including depreciation, taxes, operating expenses, and return on capital, net of any federal grants, in-kind or matching funds received) associated with the projects, adjusted for any operational savings or other benefits once the project is placed in-service. The surcharge would cease when a company's overall rates are reset and the on-going costs are reflected in its base rates. Alternatively, a deferral mechanism, as requested by Central Hudson, would accumulate on the companies' balance sheets the incremental capital costs and the associated carrying costs, together with any incremental on-going costs, net of savings or other benefits until base rates are reset through a rate proceeding. At that time, rates would be adjusted to reflect the accumulated deferred costs together with the on-going costs. A deferral approach would have no immediate rate impact, but recovery would be required in a future rate case. The deferral approach could compound the rate impacts since a utility would have to recover both the current costs of the project in rates together with the amortization of the prior deferred costs.

Under a surcharge mechanism, the companies are provided the benefit of receiving recovery of incremental depreciation, O&M expenses, taxes, and a return on their investments once projects are placed in-service, or relatively soon thereafter.[36]

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[36] It is expected that the surcharges would be updated no more frequently than semi-annually to reflect the additional projects placed in-service and allow an adequate time for Staff review prior to effectuation.

Similarly, a surcharge can and should be adjusted to reflect any cost savings or other benefits. This results in benefits to both the utilities and ratepayers. Ratepayers benefit from: (1) a lower rate increase due to not continuing to accrue carrying charges on the projects costs after its completion,[37] and (2) not having to simultaneously pay in the next rate case both the current year's costs of the project plus the amortization of the project's prior periods costs, which were deferred. Also, since the utility is being made whole for project impacts through the surcharge, there is less pressure on a utility to file for an increase in base rates. Finally, a surcharge can easily be tailored to charge each class of customers an appropriate amount. From the utility's standpoint, it improves cash flow and the related cash flow metrics, relied upon by analysts and credit rating agencies in assessing the utility's credit worthiness, immediately upon completion of a project. This occurs since the surcharge provides cash flow to cover the project's on-going costs, depreciation and return requirements.

With the use of a surcharge we will have the ability to review the reasonableness of the amounts spent on the projects, as they become known and final. In order to mitigate ratepayer impacts, we expect the utilities requesting DOE grants avail themselves of the maximum amounts available, including seeking in-kind grants where possible.[38]

We expect the Staff to review the reasonableness of the amounts spent on each project no later than the first rate case in which the utility seeks to place the project into rate base. Moreover, so that we may have confidence in the appropriateness of the

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[37] On a net present value basis, ratepayers should be indifferent if the ratepayer's cost of capital is comparable to the utility's cost of capital.

[38] In-kind contributions represent non-cash contributions provided by the performing contractor or a non-Federal third party who is participating with DOE in a co-sponsored project or contract. In-kind contributions may be in the form of personal property (equipment and supplies), real property (land and buildings) or services which are directly beneficial, specifically identifiable and necessary to performance of the project or program.

costs for these projects and that the projects are progressing in a timely manner, we require each utility to provide progress reports on the projects to the Director of the Office of Electric, Gas and Water on a quarterly basis commencing with an award by DOE of a grant for the project.[39] DOE funding for the ARRA projects also requires the utilities to collect data for the performance of a cost benefit analysis. As a result of our review of these analyses, any operational or cost benefits from these ARRA projects that may accrue will be returned to ratepayers. Any adjustments required to return these benefits to ratepayers will be addressed in establishing the surcharges or when rates are reset.

In this instance, we conclude that a surcharge mechanism is appropriate. Since the facts and circumstances may differ significantly at each utility, we will require that each company proposing a surcharge mechanism do so in future filings, which will be noticed for public comment, that will consider the impact of the proposed surcharge on customers, as well as the impacts of the any other new surcharges (i.e., 18-a, EEPS, etc.) which are already putting upward pressure on customers' bills. The surcharge tariffs shall contain an identification of the individual projects, including their capital and operating costs, and estimated in-service dates. A final implementation decision will be made after the DOE grants are approved, consideration is given to the parties' inputs, customer impacts are considered, and the individual company's facts and circumstances are analyzed. This is a unique situation and does not represent precedent for the recovery of future anticipated costs via a surcharge. The unique opportunity presented by the ARRA provides ratepayers with the potential to receive the benefits of investments in the electric system that may improve the efficiency and reliability of the system at a reduced cost.

Content of Surcharge Proposals

[39] We expect that any cash flow benefits resulting from the receipt of DOE grants in advance of the expenditure of such funds will inure to the benefit of ratepayers.

Surcharge proposals will be designed to collect only the incremental project costs, net of taxes, other benefits and grants obtained or requested after projects are placed in-service.[40] Surcharge proposals must include a showing that utilities have considered and moderated, where appropriate, customer impacts. This can be achieved through surcharge proposals that consider approaches to useful life selection that match the costs and benefits of the projects. In addition, surcharge tariff proposals should address rate design and revenue allocation proposals that consider customer impacts.

In addition, because the ARRA is designed to be a stimulus measure, it is important to ascertain how approval of cost-recovery of these projects may benefit the State economy. Consequently, utilities shall include in their surcharge filings data regarding the total number of jobs created or retained and to what extent New York State businesses were utilized for each completed project.

Finally, we will require that any utilities that are authorized to implement surcharges include additional information in the above referenced quarterly reporting requirement. Such surcharge information will be reported quarterly until a rate order is issued in the utilities next major rate case. Such reports will include all relevant details including: surcharge revenue collection, project in-service dates, incremental costs incurred, operational savings, taxes, grants (including in-kind or matching grants) and all other benefits. Incremental capital and operating expenses associated with these projects will be accumulated in separate sub-accounts. Grants will be credited against the incremental capital costs at the time they are received. Carrying charge proposals will consider the timing of the capital expenditures and grants received. Annually, each utility will submit a reconciliation between authorized surcharge amounts and actual collections. Authorized surcharge amounts will take into account the information provided in the quarterly reports concerning project costs, benefits, grants, taxes and any

[40] Should the DOE provide funding for overheads or common costs in excess of project proposal amounts under consideration here, ratepayers will only match amounts in excess of what is currently in rates and the DOE amounts provided for overheads that are already in rates will be used as an offset to the surcharge.

other relevant information. Any over or under collections will accrue interest and after review and approval, be included in the next year's surcharge.

Although we now authorize the use of a surcharge to collect the costs associated with eligible projects, we reserve on the matter of how the surcharge should be applied to ratepayers. In general, the record on this issue is not sufficient to determine now what classes of ratepayers should pay, and how the surcharge should be levied, e.g., flat charge or volumetric charge. The utilities' need to levy surcharges is dependent upon a favorable outcome of their applications to DOE. Consequently, we direct the utilities, where appropriate, to file within 30 days of DOE's determination on their application for the Investment Grant Program or the Demonstration Program, which ever comes first, tariff leaves for the imposition of the surcharge. In addition, each utility surcharge tariff shall not become effective on less than 90 days notice, to allow Staff an initial review of the projects' costs. The tariff leaves must include in its filing all supporting documentation, which supports the final project costs and its rationale for both the rate classes that will be levied and the manner upon which the levy is to be done.

Conditions for Approval

Given the time constraints for this proceeding dictated by DOE's process, the Staff Team, although doing a reasonable amount of investigation of utility project proposals through numerous meetings with utilities and Staff issued discovery, did not have the opportunity to give these proposals the level of scrutiny that ordinarily would be provided to such projects. Therefore, our approval of these projects is conditioned. First, the utilities shall file with the Secretary their applications, any amendments thereto, and supplemental information provided in any form, they submit to DOE for any competitive grant opportunity in order to ensure the utility has applied for substantially the same projects that were filed with the Commission for cost-recovery. Second, the utilities are required to submit quarterly reports to the Director of the Office of Electric, Gas and Water detailing the project milestones, including which milestones that have been reached, the associated costs for each project milestone as well as documentation supporting the associated costs (e.g. vendor invoices). These quarterly reports should incorporate any reports submitted by the utilities to DOE for each project.

In addition, the surcharges will be subject to refund. If after review, the project costs are found to be imprudent or if the surcharge calculations are later found incorrect (e.g., costs and/or benefits are misstated), monies paid by consumers will be preserved for their benefit. Also, the authorization to surcharge is limited to no more than the project cost estimates submitted by the utilities in their July 2 update, and as listed in Appendix C to this Order. Our approval is also contingent upon DOE awarding a 50 percent matching federal grant for substantially the same project that was filed by the utilities with the Secretary. Therefore, utilities that receive less than a 50 percent matching federal grant or have agreed to a DOE request to substantially revise the scope of the project, from the April 17 and July 2 filings, will need to resubmit their projects for our approval.

In addition, although we approve in this Order the projects that are being proposed by the utilities, we retain the right to review the reasonableness of the costs associated with each project, prior to or at the time of the utility's next rate case when the projects are considered for inclusion in rate base. At such time, the utilities are required to file evidence demonstrating the reasonableness of costs associated with each project.

If any of the above conditions are not met, the utilities are required to file an update of their project with us for approval prior to commencing collection of or adjusting the surcharge.

CONCLUSION

New York's competitiveness and quality of life depend upon a reliable and adequate supply of electric power. Our aging power delivery infrastructure needs to be modernized to address today's needs. We, along with utilities and many other stakeholders across the State are looking towards making the Smart Grid a reality, which why we approve cost-recovery for the projects, including smart grid and non-smart grid project proposals as discussed in the body of this Order, totaling approximately $825 million, for an approximate ratepayer cost-responsibility of $391 million.

The competitive grant programs administered by DOE offer a unique opportunity to begin to make these investments now. There are substantial benefits to be gained by leveraging these federal dollars to invest in the use of advanced technology and communications to improve the grid's operation. Moreover, the non-smart grid competitive grant opportunities provide an opportunity for Con Edison to participate in partnerships designed to further research and understanding of integration and utilization of renewable energy resources and energy efficiency.

New York State is an ideal laboratory for national smart grid implementation since the state represents a microcosm of the US grid challenges. Upstate New York has widely distributed power consumers and access to generation from diverse sources such as hydro, nuclear, and wind. Conversely, downstate faces some of the nation's most serious congestion and capacity challenges, due to the difficulties in adding new generation or transmission capability. Also, the heavily populated downstate area is environmentally challenged to comply with air quality attainment standards.

With this order, we approve certain of the project proposals filed by the utilities. This will allow New York's utilities to demonstrate, on application to the DOE, a ratepayer commitment for the portion of eligible project costs not covered by the grant, with the expectation that this commitment will place our electric utilities in an advantageous position to secure a fair portion of the available competitive grants.

The Commission orders:

1. The utility projects listed and described in the body of this order, as shown in Appendix C, are approved, subject to the modifications described herein.

2. With respect to Con Edison's Smart Solar Project, Off-shore Wind Study, and Electric Vehicle Demonstration Project, this order is adopted pursuant to SAPA §202(6)(a) and (b), is necessary for the preservation of the general welfare of Con Edison ratepayers, and compliance with the advance notice and publication requirement of SAPA §202(1) is hereby waived.

3. If not previously approved by the Commission, any metering devices installed as part of these projects must be submitted for Commission review and approval.

4. For the limited purposes of the meters utilized in its Westchester territory in the project proposed herein, Consolidated Edison Company of New York, Inc. is hereby granted a waiver of the requirement for two-way communications capability contained in the minimum functional requirement adopted in our AMI Order.

5. Requests for the recovery of those portions of project costs relating to gas meters and other apparatus related to gas service are denied. The utilities are directed to provide updated estimates of project costs at the time that each files its surcharge tariff filings for recovery of final project costs.

6. Rochester Gas and Electric Corp.'s proposal to implement a reactive power tariff for certain customers is denied; however, in implementing its MHP program as approved herein, the Company is directed to install MHP meters that are capable of recording reactive power, in order to accommodate any prospective implementation of such tariffs.

7. The principals established in the Case 06-M-0043 policy statement with regard to third-party or separate affiliate operation, associated affiliate transaction, cost allocation and related business rule requirements to prevent subsidization by regulated electric utility rates, are extended to deployments approved consistent with the body of this Order.

8. Consolidated Edison Company of New York, Inc., Orange and Rockland Utilities, Inc., New York State Electric and Gas Corporation, Rochester Gas and Electric Corporation, Central Hudson Gas and Electric Corporation and Niagara Mohawk Power Corporation d/b/a National Grid are directed, where appropriate, to file within 30 days of DOE's determination on their application for the Investment Grant Program or the Demonstration Program, which ever is relevant, tariff amendments, to

become effective on 90 days' notice, for the implementation of the rate designs, consistent with the body of this Order and Appendix B.

9. Consolidated Edison Company of New York, Inc., Orange and Rockland Utilities, Inc., New York State Electric and Gas Corporation, Rochester Gas and Electric Corporation, Central Hudson Gas and Electric Corporation and Niagara Mohawk Power Corporation d/b/a National Grid are directed, where appropriate, to file within 30 days of DOE's determination on their application for the Investment Grant Program or the Demonstration Program, which ever is relevant, tariff leaves, to become effective on 90 days' notice, for the imposition of the surcharge, as authorized in the body of this Order.

SUMMARY OF UTILITY PROJECTS

Below is a summary, by utility, by project type of the projects that were submitted on April 17, 2009 and updated on July 2, 2009.[41] These project summaries pertain to the smart grid funding opportunities for investment and demonstration available through the U.S. Department of Energy. There are also several non smart grid projects submitted by Con Edison on June 24, 2009 that the company intends to submit under different funding opportunity announcements.

Con Edison / Orange & Rockland

Grid Enhancement – Distribution

A. **Dynamic Secondary Network Modeling and Visualization** – This project proposal includes integrated development and operation of distributed secondary network load flow models; provides near real-time load profiles for customer locations; validates model load flows from secondary models, provided by installation of new remote devices at strategic customer locations; helps Control Center Operators develop, maintain, and sharpen their situational awareness skills. Additionally, it will improve secondary modeling and load flows to better target grid reinforcement in the networks, minimizing secondary cable failures during peak loading conditions and network outages due to secondary events in the summer. It will also improve the accuracy of the calculated coincident demand for peak summer days. The project will provide a state of the art training tool for the operators for system contingency planning which will help to improve emergency response. This project is a combination of newly proposed projects along with other advancements of ongoing projects that will create additional 14-20 new jobs and cost an estimated $19.0 million.

B. **Overhead (OH) Distribution Sectionalizing Switches** – This project includes the installation of SCADA controlled primary underground sectionalizing switches on targeted network feeders, replacing old motor operated three phase SF6(sulfur hexafluoride) gas insulated switches to improve the reliability of the overhead distribution systems. The benefits of the project include enhanced reliability by enabling rapid isolation of faulted segments of primary feeders and re-energizing the non-faulted portion of the feeder. It also includes advanced distribution automation and enhances system reliability by creating a more adaptive,

[41] All numbers contained herein are total numbers, and thus, the proposed ratepayer portion of project costs would be one-half the total project cost unless otherwise specified.

integrated/flexible, interactive and optimized grid. The OH Distribution Sectionalizing Switches project is advancement to the existing OH sectionalizing efforts that will create additional 21 to 24 new jobs and cost an estimated $46.0 million.

C. **Underground (UG) Distribution Sectionalizing Switches** – This project includes installing a combination of automatic and manual sectionalizing overhead switches, to improve the reliability of the overhead distribution systems. The benefits of the project include enhanced reliability by enabling rapid isolation of faulted segments of primary feeders and re-energizing the non-faulted portion of the feeder. It also includes advanced distribution automation and enhances system reliability by creating a more adaptive, integrated/flexible, interactive and optimized grid. The UG Distribution Sectionalizing Switches project is advancement to the existing UG sectionalizing efforts that will create additional 14 to 16 new jobs and cost an estimated $40.0 million.

D. **Intelligent Underground (UG) Automatic Loop -** This project will provide a demonstration of an underground automatic loop design in a large distribution network using remotely controlled and automated switches to reduce the risk of a large network outage and improve reliability. This reduces the size of a large network and thereby reduces risk of major network outage, also improving the reliability of the grid. This is a new project that will create additional 18 to 20 new jobs and cost an estimated $72.0 million.

E. **4 kV Grid Modernization** – This project modernizes the 4kV grid, which is the backbone of supply to the majority of non-network customers in the Con Edison system. It will include additional distribution capacitor banks, installation of central load tap change (LTC) controller software for all 4kV grids, installation of SCADA equipment for all 4KV grids, and the development of 4kV grid modeling software. Upgrading the 4kV Grids will increase efficiency by reducing losses and reliability by mitigating grid cascades through automated load shedding. This is a new project that will create additional 10-12 new jobs and cost an estimated $21 million.

F. **Remote Monitoring System (RMS)** – This project provides an upgrade to the RMS system that includes installation of RMS transmitters on network transformer vault locations throughout all service territories to allow operators and engineers to dynamically monitor transformer tank pressure, oil temperature and the oil level. This would enhance the reliability of the Remote Monitoring System and enables rapid operator response to changes in system conditions. This is an advancement of an ongoing project that will create additional 16 to 18 new jobs and cost an estimated $48 million.

G. **High Tension (HT) Monitoring** – This project upgrades the existing meters associated with High Tension feeders on the system, with an RF communication module. This enables improved system planning thereby improving the reliability and operation of the distribution grid. Supports remote metering of HT customers and critical load data during contingency situations. This is an advancement of an ongoing project that will create additional 1 to 2 new jobs and cost an estimated $2.0 million.

H. **O&R Capacitor Installation and Phase Balancing** – This project includes the installation of new area substation capacitor banks and the relocation of existing capacitor banks to optimize distribution system VAR support for both on peak and off peak conditions. Benefits include reducing system losses by correcting the power factor and thereby reducing the flow of reactive power through transmission lines, cables, and transformers. This is an advancement of an ongoing project that will create additional 4 new jobs and cost an estimated $1.8 million.

Grid Enhancement – Transmission

A. **Phasor Measurement Units (PMU)** – In collaboration with all the New York State utilities and the New York Independent System Operator (NYISO), this project includes the deployment of a significant number of Phasors throughout the state, offering precise measurements of the electricity grid. Installation of phasors would improve the ability to assess condition of the bulk power system on a real-time basis thereby improving system reliability and enabling creation of on and off line applications. For Con Ed, this is an advancement of an ongoing project that will create one additional new job and cost an estimated $6.5 million.

B. **O&R Capacitor Bank Installation for Losses Reduction** – This project includes the installation of transmission capacitor banks at strategic O&R locations as identified in a NYISO report on the benefits of additional capacitors. These capacitor installations would reduce system losses by correcting the power factor and thereby reducing the flow of reactive power through transmission lines, cables, and transformers. This is a new project that will cost an estimated $1.9 million.

Customer Enablement / Grid Enhancement

A. **Advanced Metering Infrastructure (AMI)** – Con Edison and Orange and Rockland have proposed four AMI pilot projects throughout its service territory. Three of which are in Con Edison's Westchester, Manhattan, and Long Island City (LIC) operating areas. The last is in Orange and Rockland's (O&R) Eastern operating division. The pilot projects will include approximately 58,000 electric and gas meters. This includes approximately 20,000 electric meters in Westchester; 7,500 electric meters in Manhattan; 10,000 electric meters in LIC; and 4,300 electric meters in O&R. These AMI pilot projects are proposed to evaluate in actual field conditions technologies from different vendors of AMI equipment and communications and home area network providers. Demand response and energy Efficiency programs in the pilot will be used to evaluate the responses of mass market customers to price sensitive rates and their acceptance of AMI technologies. The AMI pilot project will enhance information sharing and communications between the utility and its customers. All four AMI projects will create approximately 4 to 6 new jobs and cost an estimated $44 million.

B. **Demand Response Initiatives** – This program includes the implementation of a Demand Response (DR) monitoring system and deployment of innovative controllable technologies. The DR monitoring system will be a comprehensive software deployment that will aggregate all DR participation in real time during events. The second component of the DR program will incent the purchase and installation of innovative utility controllable technologies. This will include such technologies as controllable room A/Cs, controllable rooftop A/Cs, HAN systems and Auto-DR enabled building management systems. Increase the reliability, utility and scope of Con Edison's DR programs: the DR monitoring system will enhance the use of DR as a true dispatchable resource. Incenting new technologies will allow penetration of New York City residential markets that have previously been unable to participate in DR. Additionally, it will provide DR resources to the utility that are extremely reliable and verifiable. This is an advancement of an ongoing project that will create additional 56 to 62 new jobs and cost an estimated $9.0 million.

C. **Monitoring Based Commissioning** – This project utilizes a combination of commissioning activities, coupled with ongoing, technology-based monitoring to create benchmarks for optimal building operations and ensure the persistence of savings. Monitoring building operations will allow the system to alert building managers of deviance from optimal performance, ensuring achievement of energy savings, and achieving benefits normally associated with energy efficiency and demand response (lower energy costs, lower peak demands, and reduced emissions). This is a new project that will create additional 46 to 52 new jobs and cost an estimated $6.0 million.

D. **Distributed Generation (DG) Interconnection** – This project will include smart communications between the network protectors and distributed generation such that the Network Protector (NWP) would not operate when sensing back feed from exporting customer owned DG. This allows Con Edison to accommodate large deployment of Distributed Generation into its networks. This is a new project that will create additional 1 to 2 new jobs and cost an estimated $4.0 million.

E. **Command and Control** – In partnership with Boeing, Columbia University, and The Prosser Group, Con Edison proposes to design and deploy intelligent network centric command and control system-of-systems (C2SOS) in conjunction with demand management, distributed generation, and energy efficiency projects. This project will provide real time situational awareness and transparency via an Integrated System Model of the electric transmission grid enables targeted management and intervention to resolve issues as they arise. Accommodated effective, plug-and-play compatibility amongst new, green technologies that have the potential to disrupt grid function. This is a new project that will create 90 to 100 new jobs and cost an estimated $61.7 million. Due to additional funding from the associated partners listed above, Con Edison is only asking for 25% (approximately $15.4 million) funding for the project.

F. **Grid Support -** This project will facilitate the integration of renewable resources by developing storage capabilities. Includes demonstration of customer on-site energy storage and other distributed energy resources (DER). It will demonstrate the capability of Con Ed to control and dispatch disparate customer energy storage and other DER assets to the grid for load leveling / peak shaving. This is a new project that will create additional 8 to 10 new jobs and cost an estimated $2.0 million.

NON SMART GRID PROJECTS

A. **Smart Solar** – This project will demonstrate the integration of PV and battery storage into Smart Grid applications. It will demonstrate how large scale resources can be integrated with battery technology into a robust Smart Grid project including a substantial number of AMI meters. This is a new project that will create additional 36 new jobs and cost an estimated $4.7 million. Due to additional funding from a partner institution, Con Edison is only asking for 25% (approximately $1.2 million) funding for the project.

B. **Off-Shore Wind Study –** This project will validate off-shore wind resource study tools and develop models and parallel algorithm organization tools for operational generation planning and scheduling of distributed energy resources into the electric power systems. This is a new project that will create additional 97 new jobs and cost an estimated $12.0 million. Due to additional funding from associated partners, Con Edison is only asking for 10% (approximately $1.2 million) funding for the project.

C. **Electric Vehicle Demonstration** – Con Edison joined with Chrysler for a large scale transportation electrification program demonstration in its service area. The program will demonstrate the use of plug-in electric delivery vehicles for the US Post Office. The Company will provide charging infrastructure and related metering for these vehicles, at various Post Office locations in Queens and the Bronx. This is a new project that will create one additional new job and cost an estimated $546 thousand. Due to additional funding from associated partners, Con Edison is only asking for 25% (approximately $123 thousand) funding for the project.

National Grid

Customer Enablement/Grid Enhancement

Smart Grid/AMI -- The Company proposes to deploy Smart Grid technology at two locations in New York, one in the Syracuse area and one in the Capital District area, located north of Albany. The Syracuse Smart Program area will include approximately 40,000 customers, while the Capital District Smart Program area will include approximately 42,000 customers. The Company states that these customers and associated meters, feeders, and substations represent a cross-section of the Company's customers and electric grid equipment, which is an essential element for any test to be both statistically valuable and procedurally useful in informing its broader strategic decision related to smart grid and clean energy. The Smart Program is broken down as follows:

A. **Communications Backbone** –National Grid proposes to implement a robust, two-way communications platform as the backbone of the Smart Program. The stated objective is to deploy a communications backbone capable of moving both data and commands at sufficient bandwidth and speed to enable an integrated, interactive approach to smart energy technologies in the home, at the meter, along the electric grid, in the substation and potentially beyond. The Company is investigating a variety of wireless technologies to support this approach, but promises to leverage existing National Grid assets, new wireless technologies, and public networks.

B. **Advanced Digital Meters** – National Grid proposes to use advanced digital meters that can support interval measurements, remote disconnects and remote firmware upgrades, track both voltage and power factors, and serve as a gateway for communications into the home. The Company views smart meters as a critical component of the system in order to provide timely data for use by the customer, the grid operator, and possibly, third party service providers.

C. **In-Home Energy Management** – Three levels of in-home energy management technology are proposed to be provided to customers based upon the service offerings in which they elect to participate. At each level of participation, customers will be provided with energy consumption and pricing data to inform their decision making processes. As customers elect to become more engaged, the information and tools available to them to actively manage their energy consumption and usage will become increasingly detailed, timely and interactive, with more options and greater flexibility for the customer.

D. **Technology Deployment** – Six categories of technology are proposed for deployment on the grid as part of the Smart Program: (1) new monitoring devices mounted directly on feeders; (2) retrofit communication devices installed on existing grid control and switching equipment to enable his equipment to be monitored and controlled remotely; (3) new grid control and switching equipment added to feeders in the Program area; (4) software applications that provide distribution grid operators with improved visibility and operational flexibility; (5) new substation monitoring and control that will provide a broader view of the entire operational system; and (6) digitally controlled sub-transmission breakers to extend the smart system beyond the substation.

The total projected cost of National Grid Smart Grid/AMI Initiative is $189.9 million.

Clean Energy Modules – In addition to deploying the Smart Grid/AMI technology "spine", National Grid proposes to demonstrate the effects of combining Smart and Green by integrating a robust set of clean energy modules into its Smart Program. The Smart Program will demonstrate the integration of a number of clean energy technology modules with the Smart Grid spine. Each technology is summarized along with the rationale for its inclusion below:

> **Photovoltaic** systems convert solar energy from the sun directly into electricity. Key barriers to photovoltaic deployment include high installation cost and the intermittent and variable nature of the output. This module will focus on demonstrating how the Smart Grid can manage high concentrations of photovoltaic on the grid and how the Smart Grid can help unlock additional value by having photovoltaic on the grid.

> **Plug-In Hybrid Electric Vehicle** (PHEV) is a hybrid vehicle which has additional battery capacity and the ability to be recharged from an external electrical outlet. Electric vehicles are likely to play a major role in achieving greenhouse gas reductions and reducing dependence on foreign oil. The objective of this project is to understand the interface between PHEVs and the Smart Grid. Combining PHEV with the Smart Grid will

allow for system optimization and create opportunities to take advantage of significant distributed energy storage on the grid.

Energy Storage has many different applications and benefits, but the most promising applications require close integration with utility operations and assets. Energy Storage coupled with Smart Grid sensing and controls can provide asset deferral, peak shaving, voltage support, and improve reliability for the distribution system. It would also be important for managing increased penetration of intermittent renewable generation and charging of PHEV.

Wind Power taps wind energy and converts it to mechanical energy for driving electric power generators. The Smart Grid can help optimize the integration of distributed wind power, and provide asset deferral, load management, voltage support, and improved reliability.

Micro Combined Heat and Power (Micro-CHP) is the simultaneous production of useful heat and electric power within the home. Utilizing Micro-CHP may result in a more than 30% reduction in fuel required for residential electricity generation and produce enough electricity in a thermal load following configuration to reduce a homeowner's annual electric consumption by about half. Micro-CHP may also reduce emissions associated with global warming by 60% and help electric utilities meet mandates requiring them to meet emission reduction targets.

Micro-Grids are self-sufficient power systems that do not need to be connected to a larger utility grid, but often are connected. This module is different in that it will combine all the preceding modules into a single locally operated system. Opportunities exist to demonstrate that this local energy network can disconnect and operate independently from the rest of the distribution system and can resynchronize with the grid.

Holistic Homes This module seeks to integrate the individual technologies described in the preceding modules into an existing home. A holistic building will lead ultimately to a zero-net carbon building as renewable energy technology continues to develop. This evaluation will lead directly to economically framing the possibilities and costs for utility customers.

The total projected cost of National Grid Clean Energy Modules is $80.7 million.

Statewide Phasor Measurement Units Program

National Grid proposes to participate in a statewide program, developed in coordination with the NYISO and other New York utilities, to install Phasor Measurement Units (PMUs) at locations across New York in an effort to provide appropriate visibility for the transmission network. As part of this program, National Grid anticipates installing approximately twelve PMUs, primarily at the major 345 kV and 230 kV stations on the Company's transmission system that already have data fault recorders which can be easily upgraded to provide PMU capabilities. A location list for the PMUs will not be finalized until the NYISO and transmission owners complete a comprehensive review of the New York State transmission system. The cost of the PMU project as $2 million, including initial engineering design, procurement and installation costs and the ongoing cost of operations and maintenance.

Statewide Capacitor Bank Program

National Grid states that the installation of capacitors on both the transmission and distribution system for increased reactive power support and improvement of voltage profile is an approach that it has adopted for a number of years. National Grid says that it is working in collaboration with the NYISO and the New York transmission owners to understand the needs, costs and benefits of a statewide capacitor bank investment program. The Company explains that the NYISO recently completed a "Benefits of Reducing System Losses" study (the Study) to update the optimal power flow assessment they performed earlier in the year. Based on a preliminary review of the Study, National Grid estimates that its project costs for participation in the Capacitor Bank program would total $17 million, of which $4.5 million would be for equipment installed on the Company's transmission system, and $12.5 million for equipment installed on its distribution system.

Central Hudson Gas & Electric

Smart Grid Initiative

The Smart Grid Initiative project encompasses many Smart Grid/AMI elements and technology applications. It creates ten "intelligent" circuits from source to end user combining AMI technologies, distribution equipment upgrades and automation, and data system modernization to enhance operational efficiency in the distribution grid, and, when coupled with dynamic rate offerings, allow greater energy consumption control by consumers.

CHG&E's Smart Grid Initiative project seeks to deploy systems that are cost-effective, scalable, adaptable, open to technology and vendor neutrality, and which provide reliable and secure transmission of data. Technology applications of the CHG&E Smart Grid Initiative include:

A. **Advanced Meter Infrastructure (AMI):** Installation of meters (both electric and gas) and associated communications technology to accommodate data collection for approximately 13,500 "smart" endpoints and facilitate demand response programs. The two-way communication system will incorporate a two-tiered radio frequency (RF) mesh design. For meter data communication, the system will incorporate a 2.4 GHz platform to allow for "hopping" of data among meters to a collection point for backhaul to the utility. A higher priority tier (at 5.8 GHz) will be established for electric distribution equipment applications that have higher bandwidth and speed requirements.

B. **Home Area Networks (HAN):** Creation of 2,000 HANs to gauge customer response to electric usage. Installation of display devices which can communicate meter data, and other devices that can control appliances to aid in demand response. Conduct surveys and focus group activities to study an evaluate customer reaction to HANs and explore the possibility of creating new services.

C. **Meter Data Management System (MDMS):** Adoption of a Meter Data Management System (MDMS) and near real-time load flow data analysis tool. The MDMS will integrate with the existing legacy Customer Information System as well as the Outage Management System and provide real time data from endpoints on the grid to the load flow program for circuit modeling and analysis functions. The analysis tool will be used to perform load flow scenarios as well as provide both engineering and system operations with timely and accurate simulation capabilities for improved operation of the electric system. In conjunction with smart meter and the HAN deployment, the MDMS will facilitate consumer-friendly interfaces for access to usage and rate information allowing for educated choices in terms of rate offerings and energy usage.

D. **Electric Distribution Automation, Data Monitoring and Engineering Analysis Software Tool:** Installation of substation relaying equipment, switched capacitor banks (SCBs), and electronic reclosers. Also includes integration of communication modules into existing equipment control panels such as automatic load transfer switches (ALTs), SCBs, and voltage regulators. The project will create ten “smart “distribution circuits. The communication modules will allow for real-time voltage and current readings and control of equipment, which will aid in reducing system loss by utilizing installed SCBs. Data will be collected and integrated into an engineering analysis tool to determine overall health of the circuit, predict overload conditions, high and low voltage conditions, and power factor discrepancies

E. **Distributed Resources:** Installation of sensors and communication equipment on Distributed Generation (DG) circuits, as well as the integration of collected data into systems, to monitor and control the impact of distributed generation interconnection on the overall system and protect against undesirable events. In one area with a high concentration of DG interconnection, CHG&E proposes the installation of SCBs to compensate the system to enhance reliability and optimize the voltage profile of the feeder circuit. The Investment Program also includes the installation of a PHEV charging station.

F. **Natural Gas Equipment Monitoring:** Installation of communication modules to investigate the feasibility and applicability of transferring gas pressure and flow data from electronic monitors at regulator station and low points through the mesh network.

G. **Customer Programs:** Development of education and outreach initiatives to guide consumers through the transition to Smart Grid and how to control energy consumption. Establishment of voluntary dynamic rate offerings and introduction of demand response and load control initiatives, which include the installation of energy usage displays, customer web access to usage information and energy saving techniques designed to reduce energy demand.

CHG&E intends to deploy technologies in multiple areas of its serving territory, representing two percent of its total customers and approximately five percent of its electric distribution circuits. The areas were chosen incorporate the diversity of its customer population, as well as the various geographic characteristics of its service area, which includes densely treed areas, mountainous, and sparsely populated regions. Specific areas for deployment include the Knapps Corners Substation (Duchess County), the Saugerties Substation (Northern Ulster County), and the Modena Substation (Southern Ulster County).

The CHG&E Smart Grid Initiative envisions a two-year deployment timeline and an additional two-year period for system integration, data evaluation and study of customer behavior. The projected cost of CHG&E Smart Grid Initiative is $17.3 million.

Statewide Capacitor Bank Installation

Deployment of additional reactive resources, i.e., capacitor banks, in the CHG&E service territory, as recommended in the recent study by the NYISO (pursuant to requirements of Case 08-E-0751) to reduce system losses, improve reliability by improving system voltage profile, increase generator reserve, and improve interface transfer capability. CHG&E proposes installations in North Catskill, Lawrenceville, Reynolds Hill and West Balmville at an estimated cost of $3.1 million.

Statewide Phasor Monitoring Unit Deployment

In collaboration with the NYISO and other transmission operators, CHG&E has been working on the deployment of additional PMU resources within its service territory to improve monitoring and situational awareness of the transmission network. Benefits of a PMU network include enhancements to: network situation alarming; oscillation detection; power plant integration, monitoring and control; planned system separation, reclosing and restoration; and, post-event analysis. CHG&E's Roseton 345kV Switchtyard as a possible location for PMU deployment and estimates the cost to be $185 thousand.

NYSEG

Grid Enhancement

A. **SmartGrid – MHP metering** ($0.25 M, O&M – $0.011 M/yr) – This project compliments the Mandatory Hourly Pricing initiative ordered by the PSC. By providing large C&I customers (>300KW) with access to real-time energy prices the expectation is that they will shave their peak loads and reduce costs. NYSEG is scheduled to install 500 more MHP customers in 2009. NYSEG estimates that this project would retain 2 jobs.

B. **Bulk Transformer Replacement Initiative** ($70.0 M, O&M - $3.15 M/yr) - Purchase spare transformers for the bulk power system; purchase replacements for transformers near end of life. NYSEG estimates that 2 jobs would be retained and an unknown number of transformer manufacturing jobs would be created.

C. **Efficient Transformers Distribution Projects** ($31.5 M, O&M – $1.42 M/yr) - Purchasing core efficient transformers will reduce losses and associated system costs. Loss reductions range from 25-50% depending on transformer characteristics and loading. New transformers will contain environmentally friendly, non-oil based dielectric fluid to reduce impacts in the event of fluid spill. NYSEG estimates that 2 jobs would be retained and an unknown number of transformer manufacturing jobs would be created.

D. **Transmission and Distribution Infrastructure Replacement Program** (TDIRP) ($ 10.0 M, O&M - $0.45 M/yr) - Program started in 2005 and is intended to replace distribution, transmission, and substation equipment to sustain reliability through targeted replacement of aged or unreliable equipment. NYSEG estimates that 25 jobs will be retained and an unknown number of wire and pole manufacturing jobs created.

Statewide Capacitor Bank Installations

Statewide Capacitor Bank Installations ($9 M, O&M - $0.41 M/yr) – Install capacitor banks at locations as determined by the NYISO system losses study (pursuant to requirements of Case 08-E-0751) to reduce system losses, improve reliability by improving system voltage profile, increase generator reserve, and improve interface transfer capability. NYSEG proposes installation of a total of 320 MVARs at 121 locations.

Statewide Phasor Monitoring Unit

Statewide Phasor Monitoring Unit ($2.1 M, O&M - $0.35 M/yr) - In collaboration with the NYISO and other transmission operators, NYSEG has been working on the deployment of 5 additional PMU resources within its service territory to improve monitoring and situational awareness of the transmission network.

Customer Enablement

SmartGrid/AMI Demonstration and Technology Comparison ($28.4 M, O&M - $1.2 M/yr) – Horseheads/Cooperstown.

A. **Phase I - Expand WIMAX** – Expand the existing WIMAX communications system to provide smart metering with electric and gas meters and upgrade selected control points for the electric and gas system within the WIMAX communications "cloud." Communicate all the data on a real time basis to the Elmira Service Center. Compare the performance and cost of a WIMAX system to an upgrade of the existing digital radio system that would allow data transmittal from the same smart meters and system control points.

B. Phase 2 – Evaluation – Consisting of 4 parts: 1) Evaluate the potential use of SmartGrid with WIMAX to optimize transmission grid performance by integrating real-time wind turbine information with the proposed compressed air energy storage facility near Watkins Glen, NY. 2) Evaluate the use of DG on selected circuit in the Horseheads area versus upgrading to respond to peak loading. 3) SmartGrid/AMI Demonstration of the Cooperative Use of Broadband WIMAX in Cooperstown for Community and Utility Services. This would provide a comparative demonstration to the proposed installation in the Horseheads area, expand on the number and type of meters and devices as well as compliment the interests that exists in many upstate communities to have broadband capability where it currently does not exist. 4) A dynamic pricing rate option evaluation that will include control and test groups. The pilot pricing program will randomly select a statistically valid number of customers who will be charged at either real-time pricing, critical peak pricing, time-of-use rates, or peak-time rebates in conjunction with the deployment of smart meters. NYSEG estimates that this project would create or retain 31 jobs.

RG&E

Grid Enhancement

A. **Smart Grid - MHP Metering** ($0.1875 M, O&M - $0.0084 M/yr) and Reactive Metering ($0.1875 M, O&M - $0.0084 M/yr) - RG&E proposes to integrate the Reactive Metering project with the MHP project. The MHP project at RG&E will consist of 250 new meters in estimated for 2010 and 250 more estimated in 2011. The costs include the installation of a new recording meter, but the customer also has to provide a phone line to the meter. These meters will be capable of measuring reactive power as well as recording the active kwhs for the MHP program. RG&E estimates that 4 jobs will be retained by these projects.

B. **Bulk Transformer Replacement Initiative** ($22.0 M, O&M - $0.99 M/yr) - Purchase spare transformers for the bulk power system; purchase replacements for transformers near end of life. RG&E estimates that 2 jobs would be retained and an unknown number of transformer manufacturing jobs would be created.

C. **Efficient Transformers Distribution Projects** ($10.7 M, O&M - $0.482 M/yr) - Purchasing core efficient transformers will reduce losses and associated system costs. Loss reductions range from 25-50% depending on transformer characteristics and loading. New transformers will contain environmentally friendly, non-oil based dielectric fluid to reduce impacts in the event of fluid spill. RG&E estimates that 2 jobs would be retained and an unknown number of transformer manufacturing jobs would be created.

D. **Transmission and Distribution Infrastructure Replacement Program** (TDIRP) ($5.0 M, O&M - $0.225 M/yr) – Program provides for the replacement of distribution, transmission, and substation equipment to maintain reliability through targeted replacement of aged or unreliable equipment. RG&E estimates that 25 jobs will be retained and an unknown number of wire and pole manufacturing jobs created.

Capacitor Bank Projects:

A. **Station 42 Capacitor Banks** ($2.1 M, O&M - $0.095 M/yr) - Add four (4) 20MVAR capacitor banks at Station 42. One capacitor bank will be located on each of the four 34.5kV buses. Station 42 uses approximately 60MVAR of reactive supply. Presently this reactive capability must be brought through the two (2) 115kV cables and 115/34.5kV transformer that supply the station. This heavy VAR flow uses the limited capacity of the cable and the transformers especially under contingency conditions of loss of one of the cables or one of the transformers. Adding the reactive support will provide significant voltage benefits to Station 42 which will ripple back to Station 13A which supplies Station 42. This area is very sensitive to the 115kV source voltage which is most predominate during high loads and most notably if Ginna Station trips off line. The capacitor bank additions should increase post-contingency voltages at Station 13A by approximately 2%. RG&E estimates that 2 jobs will be retained and an unknown number of capacitor and associated equipment manufacturing jobs created.

B. **Station 42 115kV SVC** ($ 17.5 M, O&M - $0.788 M/yr) - Add a +/- 150MVAR SVC on the 115kV system near Station 42. Station 42 uses approximately 60MVAR of reactive supply and is a low-point for voltage in the Rochester area.

Dynamic voltage support is required for voltage transient stability for large contingencies which include the tripping of Ginna. Adding the dynamic support where it is needed will provide significant voltage stability to the entire Rochester area. RG&E estimates that 4 jobs will be retained and an unknown number of SVC/capacitor and associated equipment manufacturing jobs created.

C. **Station 56 Capacitor Banks** ($ 0.8 M, O&M - $0.036 M/yr) - Add an additional 9MVAR to both 34.5kV 9MVAR capacitor banks at Station 56. Station 56 serves approximately 92MW of load which is 4,427 customers. During high load periods, loss of one of 115/34.5kV transformers results in significant MVAR through the transformer and overloading the transformers. This would result in shedding approximately 40MW of load to relieve the over load. The period of exposure is approximately 90 hours per year. RG&E estimates that 2 jobs will be retained and an unknown number of capacitor and associated equipment manufacturing jobs created.

D. **Station 48 Capacitor Banks** ($0.5 M, O&M - $0.0225 M/yr) - Add an additional 16MVAR capacitor bank to the 34.5kV at Station 48. Station 48 serves approximately 100MW of load which is 2327 customers which includes Rochester Products. During high load periods, loss of one of 115/34.5kV transformers results in significant MVAR through the transformer and overloading the transformers. This would result in shedding approximately 10MW of load to relieve the overload. The period of exposure is approximately 30 hours per year. RG&E estimates that 2 jobs will be retained and an unknown number of capacitor and associated equipment manufacturing jobs created.

E. **Station 198, 218, 194, and 181 Capacitor Banks** ($ 2.7 M, O&M - $0.122 M/yr) - Add 34.5kV (2) - 1.5MVAR capacitor bank at Wolcott (181), (1) - 1.5MVAR capacitor bank at Station 198, a (1) - 4.0MVAR capacitor bank at Station 218, and a (1) - 1.5MVAR capacitor bank at Station 194. All would be voltage controlled. Clyde 34.5kV substation serves approximately 25MW of load which is 9217 customers. During high load periods, the region served by Clyde substation will have low-voltages. This would result in shedding approximately 10MW of load to relieve the low-voltage. The period of exposure is approximately 175 hours per year. RG&E estimates that 2 jobs will be retained and an unknown number of capacitor and associated equipment manufacturing jobs created.

F. **Station 180 and 128 Capacitor Banks** ($ 2.2 M, O&M - $0.1 M/yr) - Add a 115kV capacitor bank at Station 180 and a 115kV 20MVAR capacitor bank at Station 128. The Genesee region services approximately 55MW of load which is 13,188 customers which includes Angelica municipal. During high load periods and with local generation off, the Genesee region will have low-voltages. This would result in shedding approximately 10MW of load to relieve the low-voltage.

The period of exposure is approximately 300 hours per year. RG&E estimates that 2 jobs will be retained and an unknown number of capacitor and associated equipment manufacturing jobs created.

G. **Station 168 Capacitor Banks** ($ 1.0 M, O&M - $0.045 M/yr) - Add a 12MVAR capacitor bank to both 34.5kV buses at Station 168. Station 168 serves approximately 70MW of load. During high load periods, loss of one of 115/34.5kV transformers results in significant MVAR through the transformer and overloading the transformers. This would result in shedding approximately 10MW of load to relieve the overload. The period of exposure is approximately 90 hours per year. RG&E estimates that 2 jobs will be retained and an unknown number of capacitor and associated equipment manufacturing jobs created.

H. **Station 127 and 125 and 120 Capacitor Banks** ($2.5 M, O&M - $0.1125 M/yr) - Add 34.5kV (2) - 3.0MVAR capacitor bank at Station 127, (2) - 3.5MVAR capacitor bank at Station 125, and a (1) - 7.2MVAR capacitor bank at Station 120. All would be voltage controlled. Station 121 serves approximately 48MW of load which is 8321 customers. During high load periods, Station 121 and surrounding substations will have low-voltages. This would result in shedding approximately 15MW of load to relieve the low-voltage. The period of exposure is approximately 175 hours per year. RG&E estimates that 2 jobs will be retained and an unknown number of capacitor and associated equipment manufacturing jobs created.

I. **Station 121 Capacitor Banks** ($ 1.2 M, O&M - $0.054 M/yr) - Add a 115kV 75MVAR capacitor bank at Station 121. Station 121 serves approximately 38MW of load which is 8300 customers and several key 115kV transmission lines. During high load periods, loss of Ginna results in instantaneous low-voltages at Station 121 and adjacent substations including Station 13A. The period of exposure is approximately 90 hours per year. RG&E estimates that 2 jobs will be retained and an unknown number of capacitor and associated equipment manufacturing jobs created.

J. **Station 71 Capacitor Banks** ($ 1.2 M, O&M - $0.054 M/yr) - Add a 115kV 50MVAR capacitor bank at Station 71. Station 71 serves approximately 38MW of load which is 6779 customers. During high load periods, loss of the 917 line source from Station 7 results in low-voltages at Station 71 and adjacent substations. This would result in shedding approximately 20MW of load to relieve the low-voltage. The period of exposure is approximately 90 hours per year. RG&E estimates that 2 jobs will be retained and an unknown number of capacitor and associated equipment manufacturing jobs created.

Statewide Capacitor Bank Installation

Statewide Capacitor Bank Installations ($2.8 M, O&M - $0.126 M/yr) – Install capacitor banks at locations as determined by the NYISO system losses study (pursuant to requirements of Case 08-E-0751) to reduce system losses, improve reliability by improving system voltage profile, increase generator reserve, and improve interface transfer capability. RG&E proposes installation of a total of 98 MVARs at 35 locations.

Statewide Phasor Monitoring Unit Deployment

Statewide Phasor Monitoring Unit ($0.82 M, O&M - $0.07 M/yr) - In collaboration with the NYISO and other transmission operators, RG&E has been working on the deployment of 1 additional PMU resources within its service territory to improve monitoring and situational awareness of the transmission network.

Customer Enablement

SmartGrid/AMI Demonstration and Technology Comparison ($37 M, O&M - $1.67 M/yr) – Canandaigua/Bloomfield.

A. **Phase I - Expand WIMAX** – Expand the existing WIMAX communications system operated by NYSEG and located in Horseheads, NY to provide smart metering with electric and gas meters and upgrade selected control points for the electric and gas system within the WIMAX communications "cloud". Communicate all the data on a real time basis to the Canandaigua Service Center. Compare the performance and cost of a WIMAX system to an upgrade of the existing digital radio system used by the NYSEG natural gas operations group that would allow data transmittal from the same smart meters and system control points.

B. **Phase 2 – Evaluation** – Consisting of 4 parts: 1) Evaluate the potential use of SmartGrid with WIMAX to optimize transmission grid performance by integrating real-time wind turbine information with the proposed compressed air energy storage facility near Watkins Glen, NY. 2) Evaluate the use of DG on selected circuit in the Canandaigua area versus upgrading to respond to peak loading. 3) SmartGrid/AMI Demonstration of the Cooperative Use of Broadband WIMAX in Canandaigua for Community and Utility Services. This compliments the interest that exists in many upstate communities to have broadband capability where it currently does not exist. 4) A dynamic pricing rate option evaluation that will include control and test groups. The pilot pricing program will randomly select a statistically valid number of customers who will be charged at either real-time pricing, critical peak pricing, time-of-use rates, or peak-time rebates in conjunction with the deployment of smart meters. RG&E estimates that this project would create or retain 29 jobs.

COMMISSION REQUIREMENTS GOVERNING RATE DESIGNS

This appendix contains, in general, the directives by the Commission that apply to the Utilities' proposals to deploy and test rate designs.

Con Edison

1. Eliminate either the Hourly Pricing Program (in the Con Edison filing, this is labeled "Real Time Pricing" or "DAP (Hourly)"), or the Time-of-Use (TOU) pricing, unless a sufficient number of volunteers exists to populate additional trials at the level of 150 data points each.

2. Eliminate the following treatment groups that were under the "Standard Rate" category (page references are to the Company's July 2, 2009 filing):

   (a) HAN with utility and Customer Controlled Load (DR2), utility control (page 101 of Attachment 1);
   (b) HAN with utility and Customer Control Load (DR2), Customer Control (page 101 of Attachment 1); and
   (c) HAN-Customer Controlled Load with AMI (EE2) (page 102 of Attachment 1).

3. Increase the number of data points in each of the three control groups in the voluntary package of proposals from 125 data points to approximately 250 data points. These control groups are: (1) Control Group, with AMI (DR Control) – Low Income (page 100 of Attachment 1); (2) Control Group, with AMI (DR Control), Non Low-Income (page 100 of Attachment 1); and, (3) Control Group with AMI (Control EE) (page 102 of Attachment 1).

4. Increase the number of data points in each of the voluntary treatment groups from 125 to approximately 150.

5. Within the voluntary suite of rates, ensure that at least 100 room air conditioning equipped residences appear in each of the control groups and the treatment groups used for Critical Peak Pricing. If the initial random assignment approach fails to accomplish the above, use a second random assignment to obtain additional room-air conditioning- equipped residences, to be added to the control groups and/or the treatment groups. For the non-voluntary Peak Time Rebate, ensure that at least 100 room air conditioning equipped residences appear in both the randomly selected control group and the randomly selected treatment group.
6. For the 10,000 customers that are proposed to be placed on a Peak Time Rebate, establish a random control group of at least 800 customers and a random treatment group of at least 800 customers, as follows. Prior to assigning any customers from the targeted testing population for the purposes of the voluntary rate programs, use a randomized control trial design to randomly populate the control group of at least 800 customers and to randomly assign at least 800 customers to the Peak Time Rebate ("treatment") group. The customers assigned by the above process shall not be eligible to volunteer for any of the company's other rate design programs that are being tested in this project. They will retain the option to volunteer for the company's regular Voluntary Time of Use rate. Only after this randomized process is completed shall additional customers be assigned to either: (a) the non-voluntary Peak Time Rebate program to the 10,000 customer level or; (b) any of the voluntary rates or the voluntary control groups.

7. After the step described in (6) above is completed, and after the general pool of volunteers is established, randomly assign customers to each of the voluntary trial designs, including the control groups. The control groups will consist of customers that volunteered for dynamic pricing, but remain on the standard rate. These customers will retain the option to volunteer for the company's regular Voluntary Time of Use rate.
8. For the Peak Time Rebate, in developing the rebate price, and in defining the rules that govern the number and duration of critical peak events that will be triggered annually, assume an annual market price of generation capacity that is at the level that would exist in a tight market. Assign all, or substantially all, of the annual cost of generation capacity to the summer period for purposes of developing the rebate price.
9. For the Critical Peak Pricing rate, in developing the capacity component of the critical peak price, and in defining the rules that govern the number and duration of critical peak events that will be triggered annually, assume an annual market price of generation capacity that is at the level that would exist in a tight market. Assign all, or substantially all, of the annual cost of generation capacity to the summer period for purposes of developing the generation capacity component of the critical peak price. The prices charged to Critical Peak Pricing customers during the non-summer months should be designed, or adjusted, to reflect the difference between the Critical Peak Pricing customers' contribution to the cost of

generation capacity and the actual cost of generation capacity incurred by the Company based on the current annual market price for generation capacity.

10. All customers that are placed on either a control group or a treatment group shall retain the option to volunteer for the company's regular voluntary Time of Use rate.

National Grid

1. Add a randomly selected control group consisting of 800 customers that are drawn from within the same geography as the treatment groups.
2. Prior to mailing out any letters that involve placing customers into the Critical Peak Pricing Program and inviting them to opt-out into the Peak Time Rebate, use a randomized control trial design as follows:

   (a) Randomly place at least 800 customers in a control group;
   (b) Randomly place at least 500 customers in a Critical Peak Pricing program; and
   (c) Randomly place at least 500 customers in a Peak Time Rebate Program.

   The customers assigned by the above process shall not be eligible for any other rates, except that they will retain the option to volunteer for the company's regular Voluntary Time of Use rate. Only after this randomized process is completed shall the remaining customers be offered the choice of the Critical Peak Pricing program or the Peak Time Rebate.

3. For purposes of the Peak Time Rebate, the Customer-Specific Reference Level ("CRL") defined in the company's July 2 filing shall not be used (New York

Smart Program Proposal, Attachment 18, page 5 of 7). The company shall consult with staff and develop and alternative definition for the CRL.

4. With respect to National Grid's proposal, which provides each Critical Peak Pricing customer a bill protection guarantee that ensures that, on a twelve month basis, the customer pays the lower of his or her Critical Peak Pricing bill, or the bill that he or she would have received under the company's standard rate; the following provisions and/or protections shall apply: (a) no customer on the Critical Peak Pricing rate shall be disconnected during the trial to the extent the customer pays what would be due assuming they were on standard; (b) no customer on the Critical Peak Pricing rate shall be charged late payment fees during the trial to the extent the customer pays what would be due assuming they were on standard; (c) budget billing must be permitted; (d) the bill protection guarantee shall apply on a pro-rated basis to any customers that leave the service territory, switch energy providers, or otherwise terminate participation in the program before the end of the twelve month period; and (e) the bill protection guarantee shall apply on a pro-rated basis to any customers that begin service from National Grid, or arrive to National Grid from an alternative energy provider, and enter the program during the middle of a twelve month period.

5. All customers that are placed on either a control group or a treatment group shall retain the option to volunteer for the company's regular voluntary Time of Use rate.

Central Hudson

1. Eliminate the rate labeled, "HPP/Critical Peak Pricing (CPP) capacity", as described on Table 2 of Page 24 of Central Hudson's July 2, 2009 document titled, Central Hudson Gas and Electric Smart Grid Initiative: An Investment Program Project." Assign volunteers only to the remaining Hourly Pricing rate labeled, "HPP/summer peak capacity."
2. Add two randomly selected control groups, as described in greater detail below. Each control group should be approximately 50% larger than the treatment groups that are placed on the HPP rate.
3. Obtain the first control group as follows. Prior to assigning any customers to the voluntary HPP rate, randomly assign customers to the first control group. The customers assigned by this process shall not be eligible to volunteer for the company's HPP rate. They will retain the option to volunteer for the company's regular Voluntary Time of Use rate. Only after the above randomized process is completed shall additional customers be assigned to the HPP rate or the voluntary control group.
4. Obtain the second control group as follows: For the customers that have volunteered to be placed on the HPP rate, after the step described in (3) above is completed, and after the general pool of volunteers is established, randomly assign customers to the voluntary trial design, including the control group. The control group will thus consist of customers that volunteered for dynamic pricing, but were told that they must remain on the standard rate. They will retain the option

to volunteer for the company's regular Voluntary Time of Use rate. The customers in the control group should be provided with no enhanced equipment, other than the smart meter.

5. All customers that are placed on either a control group or a treatment group shall retain the option to volunteer for the company's regular voluntary Time of Use rate.

Orange and Rockland

1. Eliminate one of the Dynamic Block Time of Use Rates (TOU – DB). Increase the number volunteers for testing the remaining Hourly Pricing rate labeled, "HPP/summer peak capacity."
2. Add two randomly selected control groups, one that is established without regard to whether the customer has volunteered for the TOU-DB rate, and one that is drawn from among the volunteers. Each control group should be approximately 50% larger than the treatment groups that are placed on the TOU-DB rate.
3. Obtain the first control group as follows. Prior to assigning any customers to the voluntary HPP rate, randomly assign customers to the first control group. The customers assigned by this process shall not be eligible to volunteer for the company's TOU-DB rate. They will retain the option to volunteer for the company's regular Voluntary Time of Use rate. Only after the above randomized process is completed shall additional customers be assigned to the TOU-DB rate or the voluntary control group.

4. Obtain the second control group as follows: For the customers that have volunteered to be placed on the TOU-DB rate, use a randomized control trial design. Specifically, after the step described in (3) above is completed, and after the general pool of volunteers is established, randomly assign customers to voluntary trial design, including the voluntary control group. The control group will thus consist of customers that volunteered for dynamic pricing, but were told that they must remain on the standard rate. They will retain the option to volunteer for the company's regular Voluntary Time of Use rate.
5. All customers that are placed on either a control group or a treatment group shall retain the option to volunteer for the company's regular voluntary Time of Use rate.

New York State Electric & Gas

1. Add a test of a Peak Time Rebate. In developing the rebate price, and in defining the rules that govern the number of critical peak days/hours that will get triggered per year, assume an annual market price of generation capacity that is at the level that would exist in a tight market. Assign all, or substantially all, of the annual cost of generation capacity to the summer period for purposes of developing the rebate price.
2. Use a random process to assign customers to the control group and to the treatment groups.
3. For purposes of the Peak Time Rebate, a Customer-Specific Reference Level (CRL) must be defined from which to measure each customer's demand reduction

during critical hours. The company shall consult with staff and develop a definition for the CRL.

4. All customers that are placed on either a control group or a treatment group shall retain the option to volunteer for the company's regular voluntary Time of Use rate.

Rochester Gas and Electric

1. Add a proposal to test two versions of Critical Peak Pricing. One version should have a price signal for capacity cost during critical peak events that reflects tight market conditions. In developing the generation capacity component of the critical peak price, and in defining the rules that govern the number of critical peak days/hours that will get triggered per year, assume an annual market price of generation capacity that is at the level that would exist in a tight market. Assign all, or substantially all, of the annual cost of generation capacity to the summer period for purposes of developing the critical peak price. The second version should have a capacity component that is based on a market price of generation capacity that lies between the current price level and the tight market price level. The critical peak events of the two rates should be identical.
2. The prices charged to Critical Peak Pricing customers during the non-summer months should be designed, or adjusted, to reflect the difference between the Critical Peak Pricing customers' contribution to the cost of generation capacity and the actual cost of generation capacity incurred by the Company based on the current annual market price for generation capacity.

3. Each customer placed on either version of Critical Peak Pricing shall be given a bill protection guarantee that ensures that, on a twelve month basis, the customer pays the lower of his or her Critical Peak Pricing bill, or the bill that he or she would have received under the company's standard rate.
4. The following additional provisions and/or protections shall apply to all customers placed on the Critical Peak Pricing rate: (a) no customer on the Critical Peak Pricing rate shall be disconnected during the trial to the extent the customer pays what would be due assuming they were on standard rates; (b) no customer on the Critical Peak Pricing rate shall be charged late payment fees during the trial to the extent the customer pays what would be due assuming they were on standard; (c) budget billing must be permitted; and (d) the bill protection guarantee in (3) above will apply on a pro-rated basis to any customers that leave the service territory, switch energy providers, or otherwise terminate participation in the program before the end of the twelve month period; and (e) the bill protection guarantee shall apply on a pro-rated basis to any customers that begin service from RG&E, or arrive to RG&E from an alternative energy provider, and enter the program during the middle of a twelve month period..
5. Use a random process to assign customers to the control group and to the treatment groups.
6. All customers that are placed on either a control group or a treatment group shall retain the option to volunteer for the company's regular voluntary Time of Use rate.

Company	Project	Total Project $ (Millions)	NYS Project $ (Millions)	Estimated Revenue Increase (Millions)	Estimated % Increase (incl. Commodity)	Estimated % Increase (excl. Commodity)
Smart Grid & Other Stimulus Project List & Rankings - Case 09-E-0310 - By Company						
7/23/2009						
Approved Projects						
N. Grid	Smart Grid / AMI - Syracuse & Capital	$189.9	$95.0	$16.9	0.51%	0.85%
N. Grid	Clean Energy Modules	$80.7	$40.4	$7.2	0.22%	0.36%
N. Grid	State Wide Capacitors / NYISO	$17.0	$8.5	$1.5	0.05%	0.08%
N. Grid	State Wide PMU's / NYISO	$2.0	$1.0	$0.2	0.01%	0.01%
	Total N. Grid	**$289.6**	**$144.8**	**$25.8**	**0.78%**	**1.29%**
CHGE	Smart Grid / AMI Poughkeepsie Saugerties	$13.0	$6.5	$1.2	0.19%	0.47%
CHGE	Smart Grid / AMI - Modena	$4.3	$2.2	$0.4	0.06%	0.16%
CHGE	State Wide Capacitors / NYISO	$3.1	$1.6	$0.3	0.05%	0.11%
CHGE	State Wide PMU's / NYISO	$0.2	$0.1	$0.0	0.00%	0.01%
	Total CHGE	**$20.6**	**$10.3**	**$1.8**	**0.30%**	**0.75%**
Con Ed	Smart Grid / AMI Manhattan Long Island City Westchester	$38.5	$19.3	$3.5	0.05%	0.08%
Con Ed	Smart Solar	$4.7	$1.2	$0.2	0.00%	0.00%
Con Ed	Off-shore Wind Study	$12.0	$1.2	$0.2	0.00%	0.00%
Con Ed	Electric Vehicle Demonstration	$0.5	$0.1	$0.0	0.00%	0.00%
Con Ed	Command and Control	$61.7	$15.4	$2.8	0.04%	0.06%
Con Ed	State Wide PMU's / NYISO	$6.5	$3.3	$0.6	0.01%	0.01%
Con Ed	Dynamic Modeling & Visualization	$19.0	$9.5	$1.7	0.02%	0.04%
Con Ed	UG Sectionalizing Switches	$40.0	$20.0	$3.7	0.05%	0.08%
Con Ed	4 kV Grid Modernization	$21.0	$10.5	$1.9	0.02%	0.04%
Con Ed	OH Sectionalizing Switches	$46.0	$23.0	$4.2	0.05%	0.09%
Con Ed	Remote Monitoring System	$48.0	$24.0	$4.4	0.06%	0.09%
Con Ed	High Tension Monitoring	$2.0	$1.0	$0.2	0.00%	0.00%
Con Ed	UG Automatic Loop	$72.0	$36.0	$6.6	0.08%	0.14%
Con Ed	DG Interconnection	$4.0	$2.0	$0.4	0.00%	0.01%
Con Ed	Grid Support	$2.0	$1.0	$0.2	0.00%	0.00%
Con Ed	Demand Response Initiative	$9.0	$4.5	$0.8	0.01%	0.02%
Con Ed	Monitoring Based Commissioning	$6.0	$3.0	$0.5	0.01%	0.01%
	Total Con Ed	**$392.9**	**$174.9**	**$32.0**	**0.41%**	**0.69%**
ORU	Smart Grid / AMI	$5.5	$2.8	$0.5	0.10%	0.23%
ORU	State Wide Capacitors / NYISO	$1.9	$1.0	$0.2	0.03%	0.08%
ORU	Distribution Capacitor Banks	$1.8	$0.9	$0.2	0.03%	0.08%
	Total ORU	**$9.2**	**$4.6**	**$0.8**	**0.16%**	**0.38%**
NYSEG	Smart Grid / AMI - Horse Heads / Cooperstown	$28.4	$14.2	$2.5	0.18%	0.33%
NYSEG	State Wide Capacitors / NYISO	$9.0	$4.5	$0.8	0.06%	0.11%
NYSEG	State Wide PMU's / NYISO	$2.1	$1.1	$0.2	0.01%	0.02%
	Total NYSEG	**$39.5**	**$19.8**	**$3.5**	**0.25%**	**0.46%**
RGE	Smart Grid / AMI - Canandaigua	$37.0	$18.5	$3.3	0.48%	0.85%
RGE	State Wide Capacitors / NYISO	$2.8	$1.4	$0.2	0.04%	0.06%
RGE	State Wide PMU's / NYISO	$0.8	$0.4	$0.1	0.01%	0.02%
RGE	Distribution Capacitor Banks	$31.7	$15.9	$2.8	0.41%	0.73%
RGE	MHP Metering	$0.4	$0.2	$0.0	0.01%	0.01%
	Total RGE	**$72.8**	**$36.4**	**$6.5**	**0.95%**	**1.67%**
		$824.6	**$390.8**	**$70.5**	**0.49%**	**0.85%**
Not Approved Projects						
NYSEG	MHP Metering	$0.3	$0.2	$0.0	0.00%	0.00%
NYSEG	Bulk XFMR Replacement	$70.0	$35.0	$6.2	0.44%	0.82%
NYSEG	Efficient Dist. Transformers	$31.5	$15.8	$2.8	0.20%	0.37%
NYSEG	TDIRP	$10.0	$5.0	$0.9	0.06%	0.12%
	Total NYSEG	**$111.8**	**$55.9**	**$10.0**	**0.70%**	**1.31%**
RGE	Bulk XFMR Replacement	$22.0	$11.0	$2.0	0.29%	0.51%
RGE	Efficient Dist. Transformers	$10.7	$5.4	$1.0	0.14%	0.25%
RGE	TDIRP	$5.0	$2.5	$0.4	0.07%	0.11%
	Total RGE	**$37.7**	**$18.9**	**$3.4**	**0.49%**	**0.87%**
		$149.5	**$74.8**	**$13.3**	**0.09%**	**0.16%**

STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

CASE 09–E–0310 – In the Matter of the American Recovery and Reinvestment Act of 2009- Utility Filings for New York Economic Stimulus

CASE 09–M–0074 – In the Matter of Advanced Metering Infrastructure

ROBERT E. CURRY, JR., concurring

I concur in the majority's opinion in these cases, but do not agree to:

(a) approve authorizing matching ratepayer funds for Consolidated Edison of New York's Smart Solar, Off-Shore Wind Study and Electric Vehicle Demonstration projects, as (1) these projects are unrelated to the US Department of Energy Smart Grid programs which in my view are the reason for this Order, and (2) the first two projects involve partial funding of electrical generation by a distribution company, a policy change the Commission has yet to formally address; and,

(b) approve the proposed rate design for AMI projects set forth in the Order as its mechanics may yield unintended consequences.