BEFORE THE
NEW YORK STATE
PUBLIC SERVICE COMMISSION

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Proceeding on Motion of the Commission as to the
Rates, Charges, Rules and Regulations of
Rochester Gas & Electric Corporation
for Electric Service — Case 09-E- ____

Proceeding on Motion of the Commission as to the
Rates, Charges, Rules and Regulations of
Rochester Gas & Electric Corporation
for Gas Service — Case 09-G- ____

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# DIRECT TESTIMONY OF THE CAPITAL EXPENDITURES, RELIABILITY, AND OPERATIONS PANEL

**Michael H. Conroy**
**Jeffrey L. McKinney**
**Michael D. Eastman**
**Alan L. Matthews**
**Hugh J. Ives**

September 17, 2009

# DIRECT TESTIMONY OF THE CAPITAL EXPENDITURES, RELIABILITY, AND OPERATIONS PANEL

Q. Can you please state the names of the members of this Capital Expenditures, Reliability, and Operations Panel (the "CRO Panel" or "Panel")?

A. We are Michael H. Conroy, Jeffrey L. McKinney, Michael D. Eastman, Alan L. Matthews, and Hugh J. Ives.

Q. Mr. Conroy, please state your current position and business address.

A. My title is Senior Vice President and Chief Operating Officer for Rochester Gas and Electric Corporation ("RG&E") and New York State Electric and Gas Corporation ("NYSEG") (together the "Companies"). My business address is 89 East Avenue, Rochester, New York 14649.

Q. Please summarize your educational background and work experience.

A. I received a B.S. degree in Electrical Engineering from Cornell University, and an M.B.A. from the University of Southern Maine. I was employed by Central Maine Power Company ("CMP") from 1979 through 2002, serving in a variety of technical, supervisory and managerial positions. I left CMP as Vice President of Marketing and Economic Development to RG&E and NYSEG in January 2003 as Vice President – Electric Technical Services. In September 2003, I was assigned the added responsibility of Gas Technical Services. I assumed the position of Vice President, Operations in 2004 and my current position in August 2009.

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

A. Yes. I have previously testified before the Maine Public Utilities Commission. I testified before this Commission in Case 07-M-0906, the acquisition by Iberdrola, S.A. of Energy East Corporation, and most recently I sponsored testimony in Cases 09-E-0082, 09-G-0083, 09-E-0084, and 09-G-0085.

Q. Mr. McKinney, please state your current position and business address.

A. I am currently Manager – System Planning for NYSEG and RG&E. My business address is 18 Link Drive, P.O. Box 5224, Binghamton, NY 13902-5224.

Q. Please summarize your educational background and work experience.

A. I graduated from Pennsylvania State University in 1982 with a B.S. degree in Electrical Engineering. In 1987, I completed the General Electric Power Systems Engineering Course. I received an M.B.A. from Syracuse University in 1999. I have been employed by NYSEG in the transmission planning and services area for over 27 years and assumed similar responsibilities for RG&E in January 2003.

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

A. Yes. I testified before the Commission in Case 92-T-1081, and sponsored testimony in Cases 09-E-0082, 09-G-0083, 09-E-0084, and 09-G-0085. I testified before the Federal Energy Regulatory Commission ("FERC") in Docket Numbers

OA96-195-000, ER97-2353-000, ER97-1523-000, ER97-4234-000, OA97-470-000, EC00-001-000, and EC01-97-000.

Q. Mr. Eastman, please state your current position and business address.

A. My current position is Vice President – Gas Assets for NYSEG and RG&E. My business address is 1300 Scottsville Road, Rochester, NY 14624.

Q. Please summarize your educational background and work experience.

A. I have an A.S. degree in Engineering Sciences from Broome Community College and a Bachelor of Mechanical Engineering Technology degree from the State University of New York at Binghamton. I have 28 years of utility gas experience in field operations, field and corporate engineering and gas business management functions. In addition, I was U.S. Business Development Manager for natural gas materials manufacturer UPONOR Aldyl of Oklahoma.

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

A. Yes, I have previously testified in other gas proceedings before the Commission, the Maine Public Utilities Commission and the Vermont Public Service Board. I most recently sponsored testimony before the Commission in Cases 09-E-0082, 09-G-0083, 09-E-0084, and 09-G-0085.

Q. Mr. Matthews, would you please state your current position and business address?

A. I am currently Director – Gas Engineering for NYSEG and RG&E. My business address is 1300 Scottsville Road, Rochester, NY 14624.

# DIRECT TESTIMONY OF THE CAPITAL EXPENDITURES, RELIABILITY, AND OPERATIONS PANEL

Q. Please summarize your educational background and work experience.

A. I graduated from Pennsylvania State University with a B.S. degree in Civil Engineering. In addition, I have an M.B.A. from Alfred University. I am a licensed Professional Engineer in New York State. I have been employed in the utility operations and engineering field for over 30 years. I have worked in gas operations and engineering for 18 years, including management positions in field operations, field engineering and corporate engineering. In addition, I worked in the electric generation field for 12 years at NYSEG and the Pennsylvania Electric Company.

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

A. Yes. I testified before the Commission in Case 07-M-0906, the acquisition by Iberdrola, S.A. of Energy East Corporation, and most recently I sponsored testimony in Cases 09-E-0082, 09-G-0083, 09-E-0084, and 09-G-0085.

Q. Mr. Ives, please state your current position and business address.

A. I am currently the Manager – Fossil/Hydro Operations for NYSEG and RG&E. My business address is 89 East Avenue, Rochester, New York 14624.

Q. Please summarize your educational background and work experience.

A. After serving three years in the U.S. Army as a radar technician, I was hired by RG&E on July 27, 1981. During my 28 years with RG&E, I have served in a variety of technical, supervisory and managerial positions including: seven years in Electric T&D and Production (fossil, hydro and nuclear) maintenance, two

years as a Technical Instructor for the Ginna Nuclear Power Plant ("Ginna"), 16 years as a Project Electrical Engineer and three years as Manager of NYSEG and RG&E Fossil/Hydro Operations. I received an A.A.S. degree in Electrical Engineering Technology from Rochester Institute of Technology ("RIT") in 1990. I am currently pursuing a B.S. degree from RIT Business Management. From June 1999 to November 2006, my engineer responsibilities expanded to include coordinating Hydro license related matters with local, state and federal agencies as well as Hydro license compliance. In March 2003, my responsibilities expanded to include supervision of Hydro licensing matters for the NYSEG electric production facilities. From November 2006 through April 2008, I was the Manager of Fossil/Hydro Operations for RG&E electric production facilities. I assumed my present position in April 2008 and now have responsibility for management of operations, maintenance, engineering, regulatory compliance and administration for both NYSEG's and RG&E's electric production facilities.

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

A. No. I have not previously testified in any other proceedings.

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

A. The CRO Panel supports the Company's request for electric and gas capital expenditures and incremental operating and maintenance costs necessary for the Company to continue to provide safe and reliable service to its customers while meeting all regulatory requirements and mandated standards of service. The

Company undertakes a variety of projects required by regulation to relocate or replace the Company's facilities such as projects resulting from municipal highway work or projects necessary to comply with the North American Electric Reliability Corporation ("NERC") reliability standards for bulk power transmission. The Company also undertakes projects related to business operations and growth such as construction of new or upgraded transmission and distribution facilities, services and meters to serve new customers or to increase supply to existing customers. The Company also initiates projects to enhance infrastructure, including replacing Company facilities due to various criteria such as age, obsolescence, condition, capacity, reliability, performance, or relative consequences of failure. These projects are planned, designed, prioritized, and approved specifically to maintain safe and reliable service. This Panel describes the capital projects that have met these criteria and the incremental O&M costs required by the Company to ensure safe and reliable electric and gas service. This Panel also addresses line clearance resources required to maintain reliable service. Finally, this Panel addresses the Rochester Transmission Project ("RTP") and identifies and discusses the local reliability need in the Greater Rochester Area beginning in approximately 2014 and demonstrates that a transmission project is needed to address that local reliability need.

Q. Is this Panel sponsoring any electric exhibits?

A. Yes. The Panel will sponsor electric exhibits RGECRO 1 through RGECRO-18: Exhibit __ (RGECRO-1) is a detailed listing of RG&E's current and proposed

electric capital projects that have an estimated total cost of at least $1 million. Exhibit __ (RGECRO-2) is a summary of RG&E's total capital forecast by type of expenditure, which includes the cost of the major projects listed in Exhibit __ (RGECRO-1) and expenditures for other projects with total costs that are less than the $1 million threshold. Exhibit __ (RGECRO-3) contains a map of various project locations and detailed project summary sheets. Exhibit __ (RGECRO-4) is a summary of RG&E's actual electric capital expenditure history for 2007-2009. Exhibit __ (RGECRO-5) is summary of RG&E's Transmission and Distribution Infrastructure Reliability Program ("TDIRP") investments. Exhibit __ (RGECRO-6) is a summary of customer hours of outage related to equipment problems. Exhibit __ (RGECRO-7) is a flow chart that depicts the Company's capital forecast process. Exhibit __ (RGECRO-8) is a summary of the Company's 2010 forecast of Common Capital total expenditures and allocations to electric and gas capital. Exhibit __ (RGECRO-9) is an electric franchise area map. Exhibit __ (RGECRO-10) is an index of this Panel's electric workpapers. Exhibit __ (RGECRO-11) is the RTP metals rate analysis. Exhibit __ (RGECRO-12) is an excerpt from Platts, Electric Power Daily. Exhibit __ (RGECRO-13) is an analysis of Article VII estimates. Exhibit __ (RGECRO-14) is an RTP updated cost analysis. Exhibit __ (RGECRO-15) is an excerpt from the RTP Joint Proposal at pages 14-15. Exhibit __ (RGECRO-16) is an estimate summary of RGE electric Reliability Organization ("ERO") "bright line" estimated costs. Exhibit __ (RGECRO-17) sets forth incremental positions and the related cost.

Exhibit __ (RGECRO-18) identifies incremental Operation and Maintenance ("O&M") costs.

Q. Does this Panel also sponsor any gas exhibits?

A. Yes. This Panel sponsors gas exhibits RGECROGAS-1 through RGECROGAS-9 Exhibit __ (RGECROGAS-1) is a gas service territory map. Exhibit __ (RGECROGAS-2) sets forth gas safety performance measures for 2009. Exhibit __ (RGECROGAS-3) is RG&E's gas capital budget history, proposal and forecast. Exhibit __ (RGECROGAS-4) contains project summary forms. Exhibit __ (RGECROGAS-5) sets forth incremental positions. Exhibit __ (NYSEGRGECROGAS-6) contains a NYSEG and RG&E gas Research and Development ("R&D") budget history, proposal and forecast. Exhibit __ (RGECROGAS-7) sets forth the Integrity Management budget history, proposal and forecast. Exhibit __ (RGECROGAS-8) identifies O&M incremental programs. Exhibit __ (RGECROGAS-9) is an index to this Panel's gas work papers.

Q. Is the Panel also submitting its work papers?

A. An index to the Panel's work papers is set forth in Exhibit __ (RGECRO-10) and Exhibit __ (RGECROGAS-9). Copies of the actual work papers will be provided to New York State Department of Public Service Staff ("Staff") contemporaneously with the Company's rate filing.

# DIRECT TESTIMONY OF THE CAPITAL EXPENDITURES, RELIABILITY, AND OPERATIONS PANEL

## ELECTRIC RATE PROCEEDING

Q. Can you describe the purpose of the Panel's testimony as it relates to the electric rate proceeding?

A. In our testimony, we present details of RG&E's forecasted capital expenditures for Electric Transmission and Distribution ("T&D"), Generation and Common Capital, including descriptions of a number of representative major projects for 2010 and 2011 within the RG&E electric franchise area as shown on Exhibit __ (RGECRO-9). We also discuss the need for increased distribution vegetation management, transmission right of way maintenance, electric system maintenance, generation system maintenance, and other resources to provide safe and reliable service. We discuss the cost impacts of compliance with regulatory mandates, including the Electric Reliability Organization ("ERO") standards, and increased stray voltage requirements.

Q. Can you please briefly summarize the overall levels of electric capital investment and operating expenditures that you support in your testimony?

A. We support an RG&E capital investment plan for electric and allocated general capital of $80.8 million in 2010 and $188.2 million in 2011. The Company's capital investment plan funds projects that are required by regulation, required to meet our obligation to serve customers, and that are necessary to provide safe and reliable service. We also we also support $16.6 million of incremental O&M requirements in the rate year to maintain reliable service. These costs are summarized in Exhibit __ (RGECRO-18).

Q. What has been the Company's historical capital expenditures?

A. The Company's historical capital expenditures are set forth in Exhibit __ (RGECRO-4).

## RG&E CAPITAL PLAN

Q. Would you please describe the Company's capital forecast for the electric division?

A. The capital forecast is a multi-year projection of the investment needed to serve incremental electric load growth, to fulfill regulatory obligations and to maintain the electric system infrastructure. It consists of specific projects and lesser-defined expenditures that are estimated based largely on historical trends.

Q. How is the capital forecast prepared?

A. Exhibit __ (RGECRO-7) depicts the Company's process for developing its capital forecast. The capital forecast is prepared as a collaborative effort with contributions from subject matter experts representing all affected areas of the Company. Proposals are developed by the functional areas, including, system and distribution planning, maintenance engineering, field engineering and field operations as well as by areas with a focus on investments that are applicable across gas and electric.

Q. Did the Company follow the exact details set forth in the normal capital budget approval process reflected in Exhibit ___ (RGECRO-7) for the 2009 capital plan?

A. No. Given the historic turmoil in the financial markets and the resulting cash flow challenges faced by the Companies in late 2008 and 2009, a formal capital

budget was not approved by the Boards of NYSEG and RG&E for 2009. Rather, the Companies utilized a more flexible approach that focused on scrutinizing every capital project as it arose in order to conserve cash and minimize spend, all the while addressing critical safety and reliability needs and meeting the Company's obligation to serve customers. We anticipate that the normal capital budget approval process set forth in Exhibit ___ (RGECRO-7) will be followed for 2010.

Q. In what manner are specific projects initiated?

A. Projects are initiated from a number of internal and external entities, including, large and small customers, municipalities, and Company resources. Customer requests include new services, line extensions and reinforcements intended to support the addition of incremental new electric load. Government agencies annually provide a list of proposed highway improvements that require the relocation of Company electric facilities. The Company also generates projects that are driven by regular inspections that identify areas of concern, are the result of system planning studies or are needed to correct degradation in system or equipment performance.

Q. Once initiated, how are project proposals developed?

A. Project proposals are developed by the subject matter experts from various areas of the Company. The Company's distribution planning group conducts circuit analyses, load flow and other studies to identify which circuits have reached, or are close to reaching, loading limits or have the potential to create reliability

issues. This information is used to develop alternatives to relieve the system constraints and reliability concerns. The Company's system planning function also analyzes the demands expected of the electric transmission system over a longer term period and proposes projects that are forecast to be needed to alleviate issues at a system wide level. An example of the type of issues addressed is the ongoing analyses associated with Electric Reliability Standards, which we will address in more detail later in our testimony. The Company's field engineering function, which has a focus on specific division operations, prepares maintenance projects and communicates with customers to identify needs and problem areas, performs field investigations and proposes solutions to address concerns. Information gained from regular inspections conducted by field maintenance staff and as specified within the Company's Standard Operating Procedures is also used to support the development of projects.

Q. Can you explain how proposed projects are analyzed?

A. All proposed projects require the development of alternatives as well as the preparation of cost estimates. Projects with estimates that exceed $100,000 are evaluated via use of the Company's capital project analysis or CPA model. This model provides for a consistent and uniform basis for major project evaluation and comparison. Projects are submitted to an Electric Review Panel which consists of subject matter experts representing various technical functions. The Electric Review Panel conducts a preliminary review of project reasons, the proposed solution, cost estimate and benefits. Once screened by the Electric

Review Panel, projects are submitted to the Capital Review Team for review and selection as part of a portfolio of projects to be included in the Company's proposed electric capital plan. The members of the Capital Review Team currently include: the Director – Electric Distribution Engineering, the Director – Gas Engineering, the Director – Field Operations, the Manager – Performance and Budgets, and the Manager – Electric System Engineering, and the Manager – Fossil/Hydro Operations. Final review and submittal of all projects and the proposed forecast is completed through the Company's Capital Allocation Team which formulates a proposed total capital plan including projects from all areas of the Company. The members of the Capital Allocation Team currently include the Manager – Performance and Budgets, the Manager – Electric System Engineering, and the Manager – Fossil/Hydro Operations.

**Electric Transmission and Distribution**

Q. What is the current status of the electric T&D system?

A. The Company's T&D system has been performing within the existing reliability measures. The system, however, is facing challenges as it ages and additional expenditures to maintain and improve reliability are required.

Q. Can you identify the objective of the Company's electric T&D planning and expenditures process?

A. Electric T&D planning and spending are focused on compliance with all regulatory standards and mandates and achievement of reliability performance measures. These objectives are met by reviewing current operations and

maintenance records, projecting forecasted loads, evaluating reliability standards, and reviewing reliability performance across the T&D system.

Q. What is the process used by the Company to determine T&D expenditures?

A. The Company builds its annual capital and O&M plans from proposed projects which best meet mandatory reliability standards and established levels of service.

Q. Can you briefly explain the mandatory reliability standards?

A. In addition to the Commission's requirements, mandatory reliability standards include the National Electric Reliability Council ("NERC") reliability standards, Northeast Power Coordinating Council ("NPCC") criteria, New York State Reliability Council ("NYSRC") rules and New York Independent System Operator ("NYISO") procedures. NERC serves as the FERC authorized Electric Reliability Organization pursuant to the Energy Policy Act of 2005 and is responsible for developing and enforcing reliability standards for the bulk electric system. There are currently approximately 100 NERC reliability standards. NERC standards are the minimum mandatory and enforceable requirements and NPCC, NYSRC, and NYISO reliability rules may be more specific or stringent than NERC standards.

Q. What significant transmission and distribution (T&D) expenditures are planned by the Company?

A. The Company has numerous T&D projects underway to meet minimum operating criteria and to improve customer service. Attached as Exhibit __ (RGECRO-1) is a listing of projects with total estimated costs of at least $1 million that are

expected to be initiated within the next five years. Detailed project summary forms for those projects listed in Exhibit __ (RGECRO-1) that have planned expenditures in 2010 or 2011 are included in Exhibit __ (RGECRO-3).

Q. Are there also significant electric T&D expenditures planned for the years 2010 through 2014?

A. Yes. The RG&E Electric Capital Investment Spending Plan for 2010 through 2014 is presented in Exhibit __ (RGECRO-2). Significant expenditures are anticipated during this time period for major transmission projects including, for example: University of Rochester New 115 kV/34.5 kV Substation, New Station 137, New 115 kV Source, Station 124 New Phase Shifter Transformer, Station 124 New SVC Project, New 115 kV Transmission Line (Station 13A to Station 135), New Downtown 115 kV Substation, New 345 kV Source and 115 kV Transmission Lines, Rochester DCADA Project, and the Grid Modernization Initiative ("GMI").

Q. Can you describe the University of Rochester New 115 kV/34.5 kV Substation project?

A. This project fulfills the Company's obligation to serve its customers and involves the construction of a new 115 kV to 34.5 kV substation with two 75 MVA transformers which are needed to provide capacity to serve the University of Rochester's planned load growth. The new substation will connect to RG&E's 901 and 902 115 kV transmission lines.

Q. Why is the University of Rochester New 115 kV to 34.5 kV substation necessary?

A. The University of Rochester has projected that its loads will increase from 24 megawatts ("MW") to 47 MW within the next five (5) years and will possibly continue to grow to 90 MW within the next 20 years. The University of Rochester is currently served from RG&E's Station 33, which can not accommodate this additional load. The best long term solution to serve the University's needs is to construct a new 115 kV substation. The University's load currently served out of Station 33 will be transferred to the new substation.

Q. Can you briefly describe the New Station 137 project?

A. The New Station 137 project involves replacing the substation equipment at RG&E's Station 3 (Beebee Station) with new substation 137 equipment at a new location. It also involves installing two (2) 34.5 kV/11 kV, 37 MVA transformers, one 9 MVAR capacitor, equipping the switchgear building with eighteen 11 kV circuits, and preparing for the addition of four (4) 34.5 kV circuits.

Q. Why is the New Station 137 project necessary?

A. The New Station 137 Project fulfills the Company's obligation to maintain its system in a safe and reliable condition. The equipment at RG&E's Station 3 is beyond its useful life and is in poor condition. This project continues from prior years and will eliminate aging and over taxed 11 kV and 34.5 kV breakers and deteriorating structures, improve safety and ensure compliance with electric standards and codes.

Q. What is the New Downtown 115 kV Source Project?

A. The New Downtown 115 kV Source Project includes the construction of a new 115/34.5 kV source near the existing Station 3 substation and installing two (2) 115/34.5 kV transformers at the new substation and two (2) 34.5 kV circuits to the new Station 137. It will also involve connecting RG&E's 901 and 920 lines that originate from Station 82 and Station 42, respectively, to the new 115 kV transformer, upgrading the 901 line to 400 MVA capacity, and adding a phase-shifting transformer on the 920 line.

Q. Why is the New Downtown 115 kV Source Project necessary?

A. The New Downtown 115 kV Source project fulfills the Company's obligation to provide for long-term reliable system operation. RG&E's Station 3, which is currently being replaced as part of the Company's New Station 137 project, is a 34.5 kV/11 kV substation that serves approximately 50 MW of load and is an important source for the 11 kV network system. This project will eliminate overloads to the 34.5 kV lines feeding Station 137 under contingency conditions, overloads of the 115 kV/34.5 kV transformers at Station 33, and overloads on the 115 kV cables that supply RG&E's Station 42 under contingency conditions.

Q. What is the Station 124 New Phase Shifter Transformer project?

A. The Station 124 New Phase Shifter Transformer project involves the installation of a phase-shifting transformer with appurtenant facilities on each of RG&E's 911 and 932 lines at Station 124.

Q. Why is the Station 124 New Phase Shifter Transformer project necessary?

A. The Station 124 New Phase Shifter Transformer project fulfills the Company's obligation to reliably serve the load connected to its system. RG&E's Station 42 serves over 275 MW of load through various distribution circuits out of Station 42 and through its 34.5 kV transmission system. Station 42 presently has two primary sources into the substation. Loss of one of these sources will result in the other source being loaded to a level above its STE limit, which could result in the potential loss of one circuit and dropping 120 MW of load until repairs could be made. The phase-shifting transformer will provide the ability to manage the power flow on each of the circuits so that this situation can be mitigated.

Q. Can you please describe the Station 124 New Static VAR Compensator ("SVC") Project?

A. The Station 124 New SVC project involves the installation of a 200 MVAR – 115 kV SVC in RG&E's Station 124.

Q. Why is the Station 124 New SVC project necessary?

A. The Station 124 New SVC project fulfills the Company's obligation to reliably serve the load connected to its system. RG&E's Station 42 uses approximately 60 MVAR of reactive supply to maintain adequate operating voltage. This substation is currently supplied from two sources: the lines 911 and 932 cable circuits. Dynamic voltage support is required for voltage transient stability during large contingencies which might include the tripping of Ginna. Adding dynamic

system support through this SVC will provide significant voltage stability to the entire Rochester area.

Q. Can you briefly describe the New 115 kV Transmission Line (Station 13A to Station 135) project?

A. The New 115 kV Transmission Line (Station 13A to Station 135) project includes the construction of a new 115 kV transmission line rated for 240 MVA on the existing right-of-way ("ROW") between RG&E's Stations 13A and 135. It also involves the installation of new terminals and appurtenant facilities in both substations.

Q. Why is the New 115 kV Transmission Line (Station 13A to Station 135) project necessary?

A. The New 115 kV Transmission Line (Station 13A to Station 135) project fulfills the Company's obligation to reliably serve the load connected to its system. This project will eliminate overloading of RG&E's line 909 during certain double contingency outages of lines out of Station 13A.

Q. What is the New 345 kV Source and 115 kV Transmission Lines project?

A. The New 345 kV Source and 115 kV Transmission Lines project involves the installation of a new 345 kV breaker and a half substation connected NYPA's 345 kV cross-state transmission. It will also include the installation of two (2) 250 MVA 345 kV/115 kV transformers, one (1) 115 kV transmission line to Station 418, and one (1) 115 kV transmission line to the new Station 3 115 kV substation.

Q. Why is the New 345 kV Source and 115 kV Transmission Lines project necessary?

A. The New 345 kV Source and 115 kV Transmission Lines project fulfills the Company's obligation to provide for long-term overall electric system reliability. The Rochester electric system normal source capability is limited by the sources into the system. The significant load growth in the Rochester area requires an additional bulk power source to ensure that the load can be served and system reliability can be met for loss of any bulk power system transformer or generation element. The Company discusses this need in more detail below.

Q. What is the Rochester Supervisory Control and Data Acquisition ("SCADA") NERC Compliance project?

A. The Rochester SCADA NERC Compliance project will convert the existing RG&E SCADA to a NERC regulation compliant configuration with the necessary security complaint hardware, software, databases, and communication protocols.

Q. Why is the Rochester SCADA NERC Compliance project necessary?

A. The Rochester SCADA NERC Compliance project fulfills the Company's obligation to meet mandated operating requirements. RG&E must comply with NERC regulations CIP-002 through CIP-009 effective beginning in 2010 which specify the requirements to protect the Company's cyber assets within its operations control centers.

Q. What is the GMI?

A. The GMI is a program designed to systematically replace aging infrastructure while injecting newer technology where appropriate to support the improved operation and reliability of the electric system.

Q. Does the GMI support the goals of the new draft State Energy Plan ("Plan")?

A. Yes, the GMI is consistent with the Plan because it supports the systematic investment in replacement and modernization of the Company's infrastructure. The Plan recognizes in Section 1.1.1 at page 2 that New York's businesses and residents depend on reliable energy and transportation systems and that "[f]or energy systems, reliability is contingent on adequate supplies of fuel, as well as a robust delivery infrastructure. Investments made in these systems help ensure that the systems remain resilient, flexible, and adaptable to accommodate new technologies. The ability to construct new, and maintain existing delivery infrastructure is key to maintaining reliability."

Q. How does the GMI support reliability?

A. The objective of the GMI is to systematically replace infrastructure within a structured and focused program with the goal of reducing the average age of the Company's T&D system. By removing older equipment, RG&E believes that it will improve its overall system reliability through a reduction in equipment-related outages.

Q. How will the Company select assets that will be replaced under the GMI?

A. RG&E will utilize its asset information to prioritize replacement projects to be undertaken during the subsequent budget period. Prioritization will be based on age as the primary characteristic and would use other criteria including condition, customer impact, maintenance test results, equipment loading, short circuit duty (breakers only), design obsolescence, and restoration time to further prioritize assets that would be replaced. The Company determined the base number of units that would be expected to be replaced annually by dividing the total number of units of a specific type of equipment installed on the system by the depreciable life for that equipment type.

Q. In addition to the base number of units needing replacement, did the Company identify additional units of a specific type of electric equipment that would need replacement?

A. Yes. Utilizing the Commission-approved depreciable life for each type of equipment, the Company calculated an 'ideal average age' equal to half of the depreciable life for the equipment. The Company then selected the number of units needing to be replaced to adjust the current average age of the equipment to the ideal average age.

Q. How did the Company calculate the capital investment for the GMI?

A. The Company determined the GMI capital requirements utilizing the average replacement cost for each type of equipment and assuming a ten (10) year period to complete the initiative.

Q. Why did the Company select a ten (10) year period to complete the GMI?

A. The ten (10) year period selected represents a reasonable balance between the large capital expenditure that would be necessary to immediately move the Company's system to the ideal average age and a more sustainable pace of capital expenditure with an accompanying slower replacement schedule. The Company is proposing a ten (10) year program starting gradually and increasing 20% per year, with the program estimated to be at its full spending level in 2015.

Q. What experience does RG&E have with infrastructure replacement investment programs?

A. In 2007, RG&E initiated an infrastructure reliability program to begin the replacement of aging assets. Since that time, the Company has invested approximately $47.6 million in the program. The Company's investment in this area since 2005 is summarized in Exhibit __ (RGECRO-5)

A. Q. What benefit has RG&E realized as a result of its past investment in infrastructure replacement?

A. RG&E has experienced a decreasing trend in customer hours of outage due to equipment problems. This trend is demonstrated in Exhibit __ (RGECRO-6). RG&E recognizes that its continued investment in infrastructure replacement is needed to continue this positive and necessary trend.

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Q. Why does RG&E consider the replacement of aging infrastructure to be an important investment?

A. RG&E believes that increasing equipment age is the factor that contributes the most to decreasing performance of that equipment and, consequently, to a reduction in the reliability of RG&E's electric system as a whole.

Q. What are the Company's plans related to continuing an infrastructure reliability program?

A. The Company plans to maintain its focus on modernizing its infrastructure through the GMI so that it can continue to improve electric system reliability through a reduction in equipment-related outages.

Q. Has RG&E performed a system assessment that supports continued investment in aging infrastructure?

A. Yes. In the Abbreviated Iberdrola/Energy East Merger Order, Appendix 2, at 1-2, the Commission directed RG&E to file within ninety (90) days a report including: "an assessment of the physical conditions of all elements of its electric system; and repair plans, remedial actions, and monitoring programs for correcting problems with facilities found deficient." Accordingly, RG&E submitted its required assessment and report ("Report") on December 8, 2008.

Q. What did the Report indicate with regard to aging infrastructure?

A. The Report indicated that the average age of RG&E's substation, transmission, and distribution system infrastructure is increasing.

Q. What conclusion do you draw from the assessment with respect to the importance of the GMI?

A. RG&E currently provides safe and reliable service, as measured through its achievement of established Customer Average Interruption Duration Index ("CAIDI") and System Average Interruption Frequency Index ("SAIFI") performance targets. However, given the amount of aging equipment across its system, GMI is needed to systematically replace aging infrastructure, maintain system reliability and use modern technology to enhance the operation of the Company's system. This initiative, however, requires appropriate rate support to ensure that the Company is able to continue replacement of its aging infrastructure at a sufficient pace to assure continued reliable high quality system performance.

Q. What are examples of technology that RGE might interject in its system?

A. RG&E intends to apply advances in designs and materials across its system including, for example, accelerated use of microprocessor-based control, fiber-based communications, modern cable systems, transformers, breakers, sectionalizers, and surge protection.

Q. Are there other significant expenditures planned for 2010 and 2011 that the Company will describe?

A. Yes. The descriptions provided above are for projects that are illustrative of the important investments proposed to be made by the Company. Detailed information including descriptions for these projects and for all other projects

with total costs of at least $1 million and with expenditures expected in 2010 or 2011 are included in Exhibit __ (RGECRO-3) which is attached.

## ELECTRIC GENERATION

Q. Can you please describe the purpose of this part of the Panel's testimony?

A. In this part of our testimony, we present details of RG&E's forecasted capital expenditures and incremental O&M for the Company's fossil/hydroelectric production facilities. We also support the need to construct and maintain recreational, environmental and project safety related systems and processes to comply with regulatory mandates associated with the Company's FERC hydro licenses.

Q. Does this Panel support the incremental O&M associated with the Company's generating facilities?

A. Yes. The O&M cost reflects normal escalation from the amounts already included in rates for the test year with the exception of the combustion turbine-generator maintenance at Allegany Station and the dredging of river silt at Station 5 and Station 26.

Q. What is the baseline O&M work related to the natural gas fired Allegany Station?

A. The baseline O&M work includes labor and administrative functions, routine maintenance, testing, inspections, permitting, and reporting related to: (1) safety systems; (2) one combustion and one steam turbine-generator; (3) a heat recovery/steam boiler; and (4) ancillary equipment such as cooling water intake and water treatment systems, a continuous emissions monitoring system (per

Clean Air Act regulations), fuel delivery systems, plant AC and DC electrical distribution systems, control systems, and building and grounds.

Q. Are there incremental O&M costs in 2010 and 2011 other than normal escalation related to the Allegany Station?

A. Yes, the incremental O&M work includes re-wedging the stator coils on the gas turbine generator, repairing the boiler duct burners, and performing a control battery discharge test at a total estimated incremental cost of $234,500 dollars.

Q. Will you please provide a short summary of the incremental O&M work related to the dredging of river silt at Station 5?

A. A dive inspection of the tailrace of the powerhouse revealed a heavy buildup of compacted rivers silt from the discharge to the confluence of the river. This buildup impedes the flow of water through the turbines and will reduce energy output. To comply with the project's FERC license and for environmental reasons, the silt must be removed rather than flushed downstream. The initial dredging of the silt will be done during the tunnel project outage during 2011-2012 at an estimated cost of $500,000. To maintain efficient operation of the turbines silt removal will need to be done every 7-10 years at an estimated cost of $150,000.

Q. Please describe the incremental O&M work related to the dredging of river silt at Station 26.

A. A dive inspection of the intake revealed a heavy buildup of compacted rivers silt across the entire intake to Gate No. 4 at the dam. This buildup impedes the flow

of water to the turbines and reduces energy output. To comply with the project's FERC license and for environmental reasons, the silt must be removed rather than flushed downstream. The initial dredging will be done in 2010 at an estimated cost of $125,000. To maintain efficient operation of the turbines silt removal will need to be done every 3-5 years at an estimated cost of $40,000.

Q. Would you briefly summarize the levels of capital investment you are supporting for hydro facilities for the years 2010 through 2014?

A. As shown in Exhibit __ (RGECRO-2) the Company is seeking $11.4 million for 2010; $42.9 million for 2011; $20.4 million for 2012; $6.0 million for 2013; and $6.2 million for 2014.

Q. How is the Company's hydro generation capital budget developed?

A. The Hydro generation capital budget is prepared as a collaborative effort with contributions from various subject matter experts within the Company. Projects are initiated based on input from a number of internal and external entities. For example, projects are driven by regular inspections that identify areas of concern or that identify actions that are necessary to correct degradation in the system or in individual equipment performance. A project may also replace infrastructure that has reached end-of-life, or implement a system upgrade or modification to improve plant efficiency and reliability. In addition, many Hydro generation projects are the result of regulatory mandates imposed by FERC, the United States Fish & Wildlife Service ("USFWS"), the New York State Department of Environmental Conservation ("NYSDEC"), and other governmental entities.

Each project is evaluated by Engineering and Operations management to determine the necessity and cost effectiveness of the project and, if the project passes that review, it is placed in the long term capital forecasts.

Q. In what manner is the Company's Hydro capital budget generally organized?

A. The Hydro capital budget is organized into general categories relating to safety, efficiency, reliability and regulatory, although a particular project may fit in more than one category. Safety projects address public, work or plant safety concerns. Efficiency or growth projects improve the utilization of available water to maximize the electrical output of the Company's hydro generation. Reliability or infrastructure type projects are implemented to ensure that equipment is reliable and available when required. Regulatory projects are those projects required by governmental requirements or regulations. For example, our FERC licenses and associated New York State permits require that the Company meet various standards and operational requirements. FERC and the NYSDEC conduct routine inspections, typically on an annual basis, of our hydro stations. The results of these inspections may result in regulatory agency directives that require "regulatory" capital investments.

Q. Can you identify some representative major projects during the years 2010 and 2011?

A. During this period there are four major hydro and generation projects planned. These projects are: (1) Station 5 Tunnel Relining; (2) Station 5 Unit 1, Unit 2 and

Unit 3 Major Rebuild and Upgrade; and (3) Station 2 Unit 1 Upgrade and Generator Rewind.

Q. What is the largest Hydro generation project in the capital forecast?

A. The Station 5 Tunnel Relining project is the largest Hydro generation project in the forecast.

Q. Would you please provide a brief history of the Station 5 hydroelectric plant?

A. The Station 5 hydroelectric project was constructed in 1916-1917. The project footprint, from the intake structure to the tailrace, spans the Middle Falls and Lower Falls on the Genesee River and is located approximately two miles north of downtown Rochester. The 1,350 foot long, horseshoe shaped tunnel at Station 5 was originally constructed using early 1900s technology and methods (e.g., concrete mixed on site). The tunnel liner was originally constructed with un-reinforced (no steel re-bar) concrete of varying compressive strength. Tunnel maintenance was conducted in 1939 and again 1986 to spot repair liner damage.

Q. What is the current Station 5 Tunnel Relining project?

A. The Station 5 Tunnel Relining project was initiated to install a reinforced concrete lining inside of the original tunnel liner, which has deteriorated. A visual engineering inspection was conducted in late 2004. From that inspection, a liner design, work scope and cost estimate were developed. The relining project employs modern designs and methods (e.g. codes, quality control, materials) to construct a steel reinforced concrete liner with embedded and grouted rock anchors. The project was originally planned to be completed in three phases

beginning in 2007. However, during the initial tunnel entry in August 2007, a new unexpected 125 foot long partial liner collapse was found. As a result, the entire underground water conveyance system needed to be inspected and made secure for entry and construction. The collapsed area was stabilized in preparation for tunnel relining and a series of sixteen safety inspections of the tunnel system were performed by an outside consultant, Hatch Energy, which identified additional deterioration in the existing liner. The original scope of the project was therefore expanded to include relining additional areas of the tunnel and the project schedule and costs were revised. In addition, given the level of deterioration found, a change in the original tunnel design from an oval cross sectional liner to a "best-fit" circular cross sectional liner was implemented to minimize excavation and structural reinforcement costs.

Q. What is the current scope of the Station 5 Tunnel Relining project?

A. The current project scope includes relining the entire tunnel system along with numerous structural reinforcements including the construction of a 15-inch thick reinforced concrete lining inside of the original tunnel liner to assure the long term integrity of the tunnel.

Q. Was the Station 5 Tunnel Relining project halted in December 2008?

A. The Station 5 Tunnel Relining project was temporarily halted in December 2008 as a result of the worldwide financial crisis and financial pressures on the Company. The Company anticipated restarting the project in April 2009.

Q. Have there been any intervening natural events?

A. In February 2009, a large rock slide behind the powerhouse resulted from natural causes. The rock slide caused extensive damage and blocked access to the tunnel through the normal entry point. The rock slide destroyed the tunnel access facilities that had been constructed over the Unit 1 penstock access hatch and brought into question the security of that area for future tunnel entry. Debris from the slide is being cleared and a new entry point into the tunnel is being designed to avoid the danger of future rock slides. The rock slide has delayed construction access to the tunnel into the first quarter of 2010.

Q. Is the Company taking appropriate steps to move forward with this project?

A. The Company is proceeding diligently on remedying the rock slide situation and is presently about fifty percent done with this necessary process. The Company's best estimate is that it will regain access to the tunnel for construction in the first quarter of 2010.

Q. Are there negative consequences for retiring the plant by shutting it down, decommissioning it and demolishing the facilities?

A. Abandoning the project would impose significant additional costs. Retiring the plant would entail a number of activities going forward. First, we would need to negotiate license surrender with FERC at an estimated cost of $1.7 million. As a part of these negotiations, FERC would almost certainly require the Company try to sell the plant to an alternate operator, which would entail completion of environmental studies at an estimated cost of $1.1 million. The license surrender

order would likely require that the Company fill in the tunnel because of the environmental contamination present in the rock that leaks into the tunnel at an estimated cost of $23.9 million. The license surrender order may also require the demolition of the Station 5 powerhouse and surge tank at an estimated cost of $2.2 million. Additional environmental clean-up and site remediation at an estimated cost of $11.0 million and the relocation of an existing 11 kV distribution substation at a cost of $5.5 million may also be required. The total cost for abandoning the project is estimated to cost $45.4 million.

Q. If the tunnel relining project was terminated and Station 5 decommissioned, would there still be ongoing O&M costs associated with Station 5?

A. Yes. There would be ongoing O&M costs to maintain the headgates and dam in order to maintain impoundment levels above the Middle Falls in accordance with state and federal requirements.

Q. Does it make sense for the Company to complete the Station 5 Tunnel Relining project?

A. Yes. The Company has expended approximately $34.5 million on the project through December 2008. The projected total cost to complete the project is $93.0 million, with an estimated incremental cost of completing the project of $58.5 million. This incremental cost must be compared with the estimated $45.4 million cost of decommissioning Hydro Station 5. Restoring the hydro facility's 45 MW of renewable generation with no fuel cost for the incremental cost of $13.1 million will provide ratepayer benefits.

Q. Can the Panel please summarize its conclusions regarding this project?

A. The Station 5 Tunnel Relining project should be completed because: (1) it enhances reliability by maintaining generation in a load center; (2) it is the best economic choice for customers; and (3) it retains a renewable energy source for New York (45 MW capacity; 156,000 MWhrs/year on average) in support of New York's goal of 25% renewable energy use by 2013. The current project schedule is to return the station to service by July 2012. Accordingly, the Panel supports the inclusion of funds in the Capital Budget to complete the Tunnel 5 Relining project.

Q. You previously mentioned a Station 5 Unit 1, Unit 2 and Unit 3 Major Rebuild and Upgrade project. Can you please elaborate on this project?

A. The three generating units have a combined installed capacity of approximately 45 MW and historically produce an average of 156,000 MWhrs per year of clean renewable energy. This work is necessary to ensure unit performance and reliability. This project encompasses the major rebuild and upgrade of all three hydro turbines. The existing wickets gates, bearings, bushings, turbine guide bearings, shafts and associated components of all three units are original equipment and are reaching end of life. Each turbine and generator will be completely disassembled, and all major components replaced with new equipment.

Q. Has any work been started on this project?

A. Work on Unit 1 began in the fall of 2007 and approximately 50% of the work on this unit has been accomplished. Unit 1 work was temporarily suspended at the same time as the Tunnel Relining project in December 2008. We anticipate resuming that work in the third quarter of 2010.

Q. Is the work on Unit 2 and Unit 3 different than the work on Unit 1?

A. No. The same work will be performed on Unit 2 and Unit 3 in years 2011 and 2012. All three units must be completed in order to be ready for efficient and reliable service upon completion of the tunnel relining project in July 2012. In addition, with the tunnel drained and the plant out of service, we will perform other related projects that are necessary for sustaining and/or improving plant safety, performance, reliability and compliance, including such projects as powerhouse foundation restoration, Unit 1 and Unit 2 butterfly valves and bearing lube oil system work. Completing all necessary work during this one extended outage is being done to eliminate the need for additional and extended plant/unit outages in the years immediately following the completion of the tunnel relining project. Completing this related work to the Station 5 Tunnel Relining project essentially completes the restoration of the energy production infrastructure.

Q. What is the proposed capital expenditure for the Station 5 Unit 1, Unit 2 and Unit 3 Major Rebuild and Upgrade project?

A. The total capital cost for this project is $7.1 million. To date, $1.2 million has been invested in this project. The remaining amount to complete this project is

estimated at $5.9 million and is shown in Exhibit __ (RGECRO-1) (Station 5 Wicket Gate Upgrades) and is included in the amount shown in Exhibit __ (RGECRO-2) (Production Hydro).

Q. Given that the turbine upgrades and the tunnel relining are both proposed concurrently, how does the cost of generation from Station 5 compare with new hydro generation?

A. The cost to finish the tunnel relining of $58.5 million and the cost of the turbine project of $5.9 million results in a cost of $1,431/ kW to retain this baseline renewable energy source, which is less than the cost of new hydro generation.

Q. Please describe the upgrade of Unit 1 at Station 2 in Rochester New York.

A. The existing Unit 1 at Station 2 was installed in 1960 and its maximum rated capacity is 6.5 MW. Engineering studies have shown that Unit 1's capacity could be increased to about 8.4 MW with the addition of a new, higher efficiency runner and an upgraded generator to capture the higher output of the turbine. This upgrade would provide another 6,400 MWH/year for the station. The current schedule for installation of this project is from July 2010 through November, 2010.

Q. Can you identify the proposed capital expenditures for the Station 2 Unit 1 Upgrade project?

A. The total capital expenditure for this project is $3.9 million. To date, $1.2 million has been invested in the project. The incremental capital expenditure to complete the project is therefore $2.7 million and is shown in Exhibit __ (RGECRO-1)

(Station 2 Runner Upgrade and generator Rewind) and is included in the amount shown in Exhibit __ (RGECRO-2) (Production – Hydro).

**COMMON CAPITAL**

Q. Will the Panel please summarize the Company's Common Capital forecast, including the allocation of Common Capital to the electric and gas divisions?

A. The Company's Common Capital includes forecasted expenditures for General Equipment, Fleet, Information Technology, and Facilities including Security. These expenditures are typically for projects that provide benefits to both the electric and gas operations of the Company. Common Capital expenditures are generally allocated 65% to electric capital and 35% to gas capital. Exhibit __ (RGECRO-8) is a summary of 2010 Common Capital proposed expenditures.

Q. How was the capital forecast for General Equipment developed?

A. The Company's General Equipment capital forecast is developed based on General Equipment needs identified by all areas of the Company.

Q. What General Equipment expenditures are planned?

A. The investment identified in the Company's Exhibit __ (RGECRO-8) for General Equipment is a total forecast for expenditures needed to provide the tools and work equipment that are necessary to support effective construction and maintenance of the Company's facilities?

Q. How was the capital forecast for Fleet developed?

A. The forecast for Fleet replacements is the result of an analysis comparing the "Current" average age of the fleet to the "Ideal" average age, identification of the

"Normal" annual capital required to maintain the current average age and the "Additional" annual capital required to achieve the "Ideal" average age. All Fleet vehicles and equipment have an established life cycle (Years, Mileage and/or Hours). Life cycles are based on industry standards and benchmarked each year. During the capital planning phase, the Fleet management system generates a list of units that have achieved their life cycle years. This establishes the proposed capital dollars required for Fleet replacements.

Q. What capital expenditures are planned for Fleet replacements?

A. The collective expenditure for the replacement of individual vehicles is identified in Exhibit __ (RGECRO-8).

Q. How was the forecast for Information Technology ("IT") projects developed?

A. The Company's IT capital forecast includes expenditures for information system improvements that support targeted operational processes. IT projects are developed collaboratively between the Company's operating staff and Utility Support Services' IT organization. The IT organization leads the project formulation including development of the necessary specifications and cost estimates.

Q. What IT capital expenditures are planned?

A. The investment identified in the Company's Exhibit __ (RGECRO-8) is a collection of projects needed to support the Company's IT network.

Q. Are there significant expenditures planned within the IT forecast?

A. Yes. The Company plans to implement enhancements to its internet site based on recommendations it received from the Staff.

Q. What were the Staff recommendations to the Company and its affiliate regarding web-based outage information?

A. The recommendations made by Staff to the Company concerning its website include providing a highly visible and easily identifiable link on the Company's home page to internal page(s) which would be dedicated to information about outages. The information provided should be the most up-to-date information on outages and restoration times and prioritization and it should include outage location maps.

Q. Was there other information that Staff recommended be provided via the web site?

A. A. Staff recommended that the web site provide information about the location of dry ice and bottled water distribution centers, listings of the Company's storm-related news releases, and other pertinent information such as safety tips about, for example, the danger of downed wires and recommendations for preparing for a storm. Finally, the web site should focus on and reinforce the importance of contacting the Company to report outages and it should provide the necessary information for making that contact.

Q. Has RG&E begun implementation of the recommendations?

A. RG&E has already made many revisions and enhancements to its web site for outage information based upon Staff's original recommendations and subsequent discussions with Staff. For example, the Company has enhanced its exiting web site home page and links to include more prominent identification of links, to dedicate space for storm information and to modify drop down and descriptive text.

Q. Are there elements of Staff's recommendations that the Company has not yet been able to implement?

A. Yes. The Company, through its evaluation of the scope and costs to provide outage location maps, summary level outage and estimated restoration maps and data, has determined that an Enterprise geographic information system ("GIS") is required to properly provide that information.

Q. Can the Company's existing Outage Management System provide outage maps and estimated restoration times on the web?

A. The Company's Outage Management System limits the type of outage information that can be presented to customers on the web. The system lacks the flexibility to model real world restoration events (e.g., dynamic modeling and cut-ins) which results in an over-prediction of the numbers of customers affected in many storm situations. Manual intervention is required to analyze and present information. As such, the information cannot be automatically communicated to

customers via the web in a meaningful format. An Enterprise GIS system would solve this problem.

Q. What other benefits would be derived from the Enterprise GIS?

A. The Enterprise GIS will provide improved outage analysis capabilities, an enhanced mapping solution, an enterprise platform for GIS, and position GIS and the existing Outage Management System for Advanced Metering Infrastructure ("AMI").

Q. What is the schedule for implementing the Enterprise GIS?

A. The project will require eighteen (18) months to complete after initiation and the estimated cost is shown on Exhibit __ (RGECRO-1).

Q. What Facility capital expenditures are planned?

A. The investment identified in the Company's Exhibit __ (NYSEGCRO-8) is a collection of small projects needed to maintain the Company's buildings and property.

Q. What Security capital expenditures specifically related to facilities are planned?

A. The Security investment identified in the Company's Exhibit __ (RGECRO-8) is a collection of small projects needed to comply with security requirements discussed below. Expenditures are anticipated during this time period for hardened security upgrades and lighting and fencing installations at various Company facilities including electric substations and service centers. Closed circuit television upgrades at critical gas and electric substations and overall

security system upgrades for Hydro generating stations and Company facilities are also planned.

Q. Are there any utility critical infrastructure protection orders or regulations directing the Security expenditures described?

A. Yes. The United States Department of Homeland Security has recommended security standards under The Homeland Security Act of 2002. NERC ERO standards under Critical Infrastructure Protection ("CIP") regulations mandate a cyber security framework for the physical and electronic protection of Critical Cyber Assets to support the reliable operation of the bulk electric system. The Commission has also implemented certain actions pursuant to its Orders issued on August 2, 2002, September 22, 2002, December 18, 2002, and September 30, 2003 in Case 02-M-0953.

Q. Has the Company achieved compliance with CIP required security measures?

A. Yes. The proposed investments are to continue implementation of security standards reviewed and encouraged by Staff.

Q. Do these security expenditures include expenditures related to FERC action to expand the definition of the bulk electric system down to 100 kV?

A. No. In the event that the FERC takes such action, additional security expenditures are likely to be required.

# DIRECT TESTIMONY OF THE CAPITAL EXPENDITURES, RELIABILITY, AND OPERATIONS PANEL

## FEDERAL STIMULUS PROJECT OVERVIEW

Q. Can you please describe the purpose of the Panel's testimony as it relates to the American Recovery and Reinvestment Act of 2009 ("ARRA") (Public Law 111-05)?

A. The ARRA ("Stimulus Program") provides in part for approximately $4.5 billion nationwide to fund competitive projects in the Electricity Delivery and Energy Reliability ("EDER") program. The EDER program, administered by the United States Department of Energy ("DOE"), supports technology projects that increase the use of digital information and controls, provides dynamic optimization of grid operations and status, allows integration of smart appliances, provides timely information to consumers and control options, and minimizes unreasonable barriers to adoption of smart grid technologies. The DOE established two specific competitive grant opportunities for the EDER program: the Investment Grant Program funded at $3.375 billion and the Demonstration Program funded at $600 million. These two programs provide maximum grants for qualifying investments between 20% and 50% of the project's cost. The DOE suggested that utilities that had found other non-federal funding sources to cover the remaining costs of the investments would have a greater likelihood of success in their selection process. On July 2, 2009, RG&E filed with the Commission in Case 09-E-0310 – In the Matter of the American Recovery and Reinvestment Act of 2009 – Utility Filings for New York Economic Stimulus and in Case 09-M-0074 – In the Matter of Advanced Metering Infrastructure, for recovery of between 50 percent and 80

percent of 17 projects' costs with an estimated total capital expenditure of $110.5 million and an estimated total annual O&M cost of $5.01 million.

Q. Did the Commission approve the full recovery of costs for the remaining projects identified in the RG&E July 2, 2009 filing through a surcharge?

A. The Stimulus Order was clear that only 50% of the cost of a DOE-approved project would be collected through an RG&E surcharge. If the DOE were to award less than a 50% matching grant, RG&E would need to resubmit their project for Commission approval.

Q. What Commission-approved projects has the Company proposed for funding under the DOE Stimulus Program?

A. RG&E filed on August 6, 2009 for two stimulus investment grants – one for capacitors and a SVC estimated at $31.7 million, and one for the Mandatory Hourly Pricing program estimated at $0.4 million. RG&E is also a party to NYISO transmission owner DOE filings for investment grants for Phasor Monitoring Units estimated at $0.8 million and NYISO supported capacitors estimated at $2.8 million. A Stimulus Program demonstration grant filing was also submitted on August 25, 2009 for a Smart Grid demonstration project in the Canandaigua area estimated at $37.0 million.

Q. What is the status of these projects?

A. RG&E awaits word from the DOE as to the status of any awards. DOE has indicated that it intends to provide a response on these types of projects by November 6, 2009.

Q. Will there be material capital or O&M expense impact on the Company as a result of these projects?

A. The Company expects that any DOE-approved projects will be funded for between 20% and 50% of the estimated project capital costs. Therefore, RG&E may have to resubmit their Commission filing to collect any unfunded capital costs between the 50% that the Commission has already approved and up to 80% of the costs that may remain to be recovered. The Commission Stimulus Order did allow for a surcharge mechanism that would collect incremental depreciation, O&M expenses, taxes, and a return on the investment once the project is placed in-service.

Q. Are the capital and O&M costs for any of the Stimulus Program projects included in Exhibit __ (RGECRO-1)?

A. No.

## NERC ERO STANDARDS OVERVIEW

Q. Can the Panel please provide a brief background on the ERO reliability standards?

A. The U.S. Energy Policy Act of 2005 amended Section 15 of the Federal Power Act ("FPA") to require that FERC adopt mandatory and enforceable reliability standards for the bulk power system ("BPS") and to create a self-regulatory "electric reliability organization," with FERC oversight in the United States. On July 20, 2006, FERC gave the NERC responsibility for developing and enforcing these standards as one means of improving the reliability of North America's BPS.

On March 15, 2007, FERC approved the first set of 83 mandatory and legally enforceable reliability standards. Since that time, additional reliability standards have been submitted and approved by FERC. Currently, there are approximately 100 approved reliability standards, each with multiple subparts. FERC established June 18, 2007 as the effective date of compliance for the approved mandatory and enforceable reliability standards. Since that date, RG&E has operated under mandatory, enforceable reliability standards.

Q. Do these standards have a material capital or O&M expense impact on the Company?

A. The NERC ERO reliability standards require a significant amount of document management and compliance monitoring for annual self-certification of compliance and periodic NERC audits. Several of the standards also have material capital or O&M impacts for implementation. Such standards include:

- CIP standards provide a cyber security framework for the physical and electronic protection of Critical Cyber Assets to support reliable operation of the bulk electric system ("BES"). The additional levels of security, beyond industry standards, result in additional capital and O&M expenses.
- Facilities Design and Maintenance ("FAC") standards establish criteria for facility design and maintenance to help avoid adverse impacts on reliability. Under the FAC standards, RG&E must establish facility connection and performance requirements, effectively manage vegetation in and adjacent to

transmission ROWs, and ensure proper facility ratings in accordance with established rating methodologies.

- Protection and Control ("PRC") standards establish requirements for the installation, maintenance and testing of system protection and control equipment. RG&E has had to upgrade and/or install equipment in substations to meet these standards, including breakers, relays, disturbance monitoring equipment and automation equipment.

**Bulk Electric System Definition Issue (100 kV Bright Line)**

Q. What is the bulk power system or BPS?

A. The BPS consists of the power plants, transmission lines and substations, and related equipment and controls, that generate and move bulk electricity to the points from which local electric companies distribute the electricity to customers. Section 215 of the FPA requires FERC to approve and enforce standards for the reliability of the BPS.

Q. Is there a difference between the BPS and the BES?

A. Yes. The two have different definitions. For purposes of this discussion, the key definition at issue is the BES.

Q. What is the definition of the BES?

A. FERC initially accepted NERC's definition of the BES to apply the mandatory standards. NERC's BES was, as defined by the Regional Reliability Organization ("RRO"), the electrical generation resources, transmission lines, interconnections with neighboring systems, and associated equipment, generally operated at

voltages of 100 kV or higher. Radial transmission facilities serving only load with one transmission source are generally not included in this definition. Because NERC allowed for regional definition, the Northeast NPCC had its own approach to defining the BES; NPCC includes its own definition of "bulk power system" as follows:

> The interconnected electrical systems within northeastern North America comprised of system elements on which faults or disturbances can have a significant adverse impact outside of the local area.

According to NERC, NPCC analyzes all system elements within its footprint regardless of size (voltage) to determine impact based on this definition. NERC's filing included NPCC's "Classification of Bulk Power System Elements" ("BPSE"), which provides further information on the above definition and how it is applied. Each "Area," i.e., balancing authority, within NPCC maintains and updates lists of bulk power system elements. The New York control authority (now called the "balancing authority"), NYISO, has developed multiple lists of BPSE, each with some variation. The NPCC Document A-10 ("A-10 methodology"), Classification of Bulk Power System Elements, listed New York facilities above 200 kV as BPSE.

Q. How has RG&E defined its BES?

A. RG&E has defined its BES with the same definition adopted by the NYSRC for the New York BPS. NYSRC defines the BPS as the portion of the bulk power

system within the New York control area, generally comprising generating units 300 MW and larger and generally comprising transmission facilities 230 kV and above. However, smaller generating units and lower voltage transmission facilities on which faults and disturbances can have a significant adverse impact outside of the local control area are also a part of the New York State BPS.

Q. Is the NPCC definition of BES under review by FERC?

A. Yes. NPCC is the only regional entity in the United States that uses a risk-based assessment methodology. The other seven RROs use a "bright line" test that follow FERC's recommendation that the BES be defined at 100 kV and above. FERC has expressed concern over the A-10 methodology. On December 18, 2008, FERC issued an Order to NPCC and NERC to collect data on the elements included in NPCC's BES, and elements over 100 kV not included in NPCC's BES. FERC stated that the other seven regional entities use either a modified or unmodified definition of the BES at 100 kV and above. FERC has initiated a proceeding under Docket No. RC09-3-000 to review this matter.

**Potential Outcome of FERC Action on BES Definition Issue**

Q. What action may be taken by FERC on the definition of BES?

A. On February 20, 2009, NERC and NPCC submitted a comprehensive list of facilities at 100 kV and above in the United States portion of the NPCC region, including facilities owned by RG&E. Since the February submittal, NPCC has developed a working definition of BES to evaluate the economic and reliability impacts of applying the NERC standards within the U.S. portion of the NPCC

region. The working definition includes all transmission elements of 100 kV or higher, but excludes radial portions of the transmission system.

The findings of NPCC's BES Impact Assessment will be used to develop a recommended BES definition for the United States portion of the NPCC region. As of August 2009, NPCC's draft recommended definition includes all transmission elements of 100 kV or higher, but excludes radial portions of the transmission system and excludes those portions of the transmission system determined by a regionally approved methodology to have a minimum impact on transfers across the BES.

The assessment findings and recommended BES definition will be submitted by NPCC to FERC by September 20, 2009. Following this submittal, FERC will determine the acceptability of the recommended BES definition for implementation in the United States portion of the NPCC region.

Q. What electric system impacts could the potential FERC action have for the Company?

A. The Company has evaluated two potential definitions that FERC could approve: (1) all transmission elements of 100 kV or higher, excluding radial portions of the transmission system; and (2) all transmission elements of 100 kV or higher, excluding radial portions of the transmission system and excluding those portions of the transmission system determined by a regionally approved methodology to have a minimum impact on transfer of power across the BES (such as facilities that have less than a 1% impact on transfers across New York State, based on the

NYISO Transfer Distribution Factor analysis). Definition 1 would include more RG&E transmission facilities than Definition 2.

Q. Can you identify the quantitative impacts on RG&E's facilities?

A. The quantitative impacts on RG&E facilities include:

- An increase by between 10 to 27 substations to meet the new standards. Currently, there are 2 substations that required upgrades to meet the CIP (CIP-002-1 through CIP-009-1).
- Improvements to between 10 and 27 RG&E substations to meet the PRC Standards. This work includes control house expansions, separation of cable systems, addition of battery banks and chargers, relay additions, breaker, trip coil, and current transformer additions.
- Under an expanded 100 kV bright line definition, RG&E would also need to comply with Transmission Operator Standards ("TOP"). Under the current standard, the NYISO is the operator of the defined BPS in New York State. Under the new definition, RG&E would face additional coordination, monitoring and reporting for RG&E System Operations.
- A series of capital projects will be required to meet the expanded Transmission Planning Standards ("TPL") (TPL-001-0 through TPL-003-0) for contingencies in the event of the loss of a single BES element (TPL-002-0), and in the event of the loss of two or more BES elements (TPL-003-0).

- As a transmission operator, compliance with Personnel Standards ("PER") and Emergency Preparedness Standards ("EOP") would require additional training and staffing at the RG&E Energy Control Center ("ECC").
- Additional control house expansions, separation of cable systems, addition of battery banks and chargers, relay additions, breaker, trip coil, and current transformer additions would be required.
- TPL (TPL-001 through TPL-003) for contingencies in the event of the loss of a single BES element (TPL-002), and in the event of the loss of two or more BES elements (TPL-003) would apply.
- Compliance with Communications ("COM"), PER and EOP would require additional training and staffing at the RG&E ECC.

Q. Has the Company prepared capital and O&M estimates in preparation for FERC action on expanding the definition of bulk transmission?

A. The estimated cost impact to RG&E is included in Exhibit __ (RGECRO-16).

Q. What is the time frame for the capital and operating expenses shown in Exhibit __ (RGECRO-16)?

A. The projects shown in the capital forecast are a one-time cost to bring existing facilities into compliance, based on currently approved NERC ERO standards only. Revisions to existing standards or additional standards could add to these cost estimates. It is not known how long FERC would give entities to bring new BES facilities into compliance, but there is likely to be a multi-year phase-in period. If changes occur in the ERO standards at a later date, additional capital

projects may be required. The operating and maintenance costs are annual costs that would continue as long as the ERO standards are considered to be mandatory by FERC.

Q. Why are there differences between the previous estimates provided to the Commission and the current estimates?

A. The original estimates assumed that the 100 kV bright line definition would have no exceptions, thus more substations were included in the original estimates. For example, estimates for PRC standards compliance was based on upgrades at 37 RG&E substations. Current estimates are based on 10 to 27 RG&E substations. In addition, compliance costs for the Vegetation Management Standard (FAC-003) have been reduced because this standard specifically applies to transmission lines over 200 kV. The new BES definition would not change the applicability level for this standard. Finally, estimates for compliance with system redundancy requirements of the TPL (TPL-002-0 and TPL-003-0) are different because of the change in the proposed BES definition, resulting in fewer projects needed to come into compliance. However, the project capital estimates have been updated, resulting in slightly higher estimates.

Q. Are the estimated capital and O&M costs related to redefinition of bulk transmission included in the five year capital plan summarized in Exhibit __ (RGECRO-2), or in the Company's proposed revenue requirements?

A. No. The cost estimates have been updated and presented to the Commission for its information.

Q. In the event that the definition of bulk transmission is modified, will the Company have to recover the related costs?

A. Yes. As the information presented to the Commission demonstrates, the costs associated with such a redefinition will be significant and the Company will need timely recovery of those costs once the standards and a timeline for compliance have been approved.

**RG&E O&M to Maintain Reliable Service**

Q. Can you briefly summarize the areas of increased O&M investments necessary for RG&E to maintain safe and reliable service?

A. Increased investment in distribution vegetation management, transmission right-of-way maintenance, electric system maintenance, and human resources are necessary to maintain safe and reliable service.

**Distribution Vegetation Management**

Q. Can you explain the Company's current distribution vegetation program?

A. The Company has vegetation management programs to provide safe and reliable electric service to its customers. The distribution vegetation management program is referred to as a line clearance program and is managed to maintain the system in accordance with established levels of service reliability.

Q. Can the Panel please elaborate on the need for additional distribution vegetation management?

A. The Company currently performs scheduled cycle line clearance on three phase portions of its distribution system. The balance of distribution circuit line

clearance is prioritized to maximize reliability impact. This approach has allowed RG&E to achieve its established service quality levels (as measured by the CAIDI and SAIFI targets). However, establishing a full cycle line clearance program for all distribution circuits would support continued reliability performance and in the long run be most cost effective. Lines on cleared ROW are less likely to sustain interruptions due to tree contact, and it follows that clearing more ROW on a periodic basis will maintain or improve reliability. Cycle clearing ensures that ROW boundaries are well-established and maintained on a regular schedule, providing consistent visibility and accessibility to inspection and repair crews. This allows for quicker identification and correction of problems and facilitates preventive line maintenance. Cycle clearing also ensures periodic identification and removal of danger trees along the ROW edge. Furthermore, cycle clearing enhances public safety by minimizing the risk that vegetation will become energized, and lessens the system-wide potential for human contact with energized conductors. The reduction in vegetation size, density and proximity to energized conductors that can be achieved with periodic, scheduled clearing, and the reduction in handling costs for the large trees removed during the first cycle can mitigate the cost of subsequent clearing cycles. Further, a comprehensive cycle program would allow for even more efficient planning and contracting of clearing work, reducing per-mile maintenance costs. Cyclical line clearance also helps improve customer satisfaction. Customers are more amenable to frequent cutting of small limbs and trees, and generally view this as acceptable. During the

first cycle, however, customer satisfaction may be expected to decrease as ROW is reclaimed. The incremental annual cost is $3.79 million and the total annual cost for this program would be $6.6 million.

Q. Has the Company utilized a partial clearing cycle in the past?

A. Yes. Distribution line clearance has been funded to achieve established reliability targets. This has resulted in the implementation of a partial clearing cycle. Transition to a full cycle clearing program has multiple benefits as described in the previous response.

Q. Is the Company proposing a change in accounting treatment?

A. Yes. The cost to perform full cycle distribution line clearance is significantly greater than the present spend. Additionally, costs for line clearance can vary based on market conditions and the expected volume of work per mile. The Company proposes that costs to achieve full cycle distribution line clearance be reconciled as part of the deferral recovery mechanism surcharge or surcredit mechanism that is discussed in detail by the Revenue Requirements Panel.

**Incremental Positions**

Q. Are incremental positions necessary to support reliable service?

A. Yes, additional positions are needed to maintain the electric system. These would include workers skilled in overhead lines, underground cables, substations, and system protection.

Q. Are there positions needed beyond the craft positions to support safety and reliability performance?

A. Yes. Additional positions are necessary in distribution engineering to evaluate high priority circuits, plan and design improvements, and maintain effective standards. Positions in maintenance engineering would provide for additional analysis of system performance and inspection results and the development and direction of maintenance plans. Other positions are necessary to support the scheduling, coordination and processing of work. Qualified Security Investigators are important to support the continued protection of employees and Company assets. Replacement positions in the electric test group would improve coverage for substation inspections, tests, and maintenance. Further, increasing customer traffic and transaction times in our customer offices requires additional supervision and customer service positions to enhance training and the customer's experience.

Q. What is the total number of new positions needed?

A. The total number of positions needed is 72 at an annual cost of $5.6 million. Exhibit __ (RGECRO-17) provides additional detail on the number of positions sought by the Company.

**Electric System Maintenance**

Q. What additional incremental electric system inspection and maintenance initiatives would support the desired reliability performance level?

A. RG&E has identified additional incremental inspection and maintenance of T&D lines and electric substations that would further support achievement of reliability goals. Examples include, wood pole inspection and treatment, helicopter inspection process improvements, manhole repair, insulator replacement, fault indicator maintenance, circuit breaker maintenance, animal fence repair, relay maintenance, oil pipe cable maintenance, and network repair. The incremental cost for these activities is $3.7 million per year.

**REGULATORY MANDATES**

Q. What incremental expenses does the Company expect to incur due to regulatory mandates?

A. RG&E expects to incur incremental expenses for compliance with the requirements of: (1) the continued testing and inspection standards established in the Commission's January 5, 2005 Order Instituting Safety Standards in Case 04-M-0159 (the "Stray Voltage Order") and December 15, 2008 Order Adopting Changes to Electric Safety Standards in the same case ("Modified Stray Voltage Order"); (2) Transmission and Distribution Loss and Cost of Losses Study in response to the Order issued on July 17, 2008 in Case 08-E-0751, which directed the utilities to specifically identify all major sources of losses on their

transmission and distribution systems; and (3) additional cost to implement Staff recommendations to improve storm response.

**Stray Voltage**

Q. What are the current costs associated with stray voltage?

A. RG&E's filing contains a rate year expense of $4.4 million. The rate year level of costs associated with stray voltage has been adjusted to include compliance with the inspection and testing requirements in the Stray Voltage Order, the Modified Stray Voltage Order and an estimated increase in contractor costs associated with testing.

Q. What are the major requirements of the Stray Voltage Order?

A. Stray voltage testing must be conducted on all electric facilities that are capable of conducting electricity and are publicly accessible. Testing is required on all facilities annually. Certification for 100% compliance with test requirement must be provided by the utility.

Q. Are there other requirements under the Stray Voltage Order?

A. Inspections are also required on all electric facilities that are capable of conducting electricity and are publicly accessible. All electric facilities shall be inspected at least every five years (a minimum of 20% per year). Certification of compliance with the requirements must be provided by the utility annually.

Q. Has the Commission modified its Stray Voltage Order?

A. Yes. On December 15, 2008, the Commission issued the Modified Stray Voltage Order, which imposed on the Company incremental requirements above those in the initial Stray Voltage Order issued in 2005.

Q. What are the incremental inspection and testing costs associated with compliance with the Modified Stray Voltage Order issued on December 15, 2008?

A. RG&E's estimated incremental inspection and testing costs associated with stray voltage total over $1.25 million annually.

Q. Can you explain the additional increase in Stray Voltage above those imposed by the Stray Voltage Order and Modified Stray Voltage Order?

A. The rate year expense includes an estimated increase in the contractor costs associated with testing.

**T&D Loss and Cost of Losses Study**

Q. Can you briefly describe the need for the T&D Loss and Cost of Losses Study?

A. In Case 08-E-0751, the Commission directed the utilities to specifically identify all major sources of losses on their T&D systems. As directed, RG&E explained in its filing made on December 23, 2008, that data used to quantify the T&D losses was no longer current. RG&E proposed to retain a consultant to perform a loss study based on 2007 system configurations. The estimated cost of that study is $120,000.

**Storm Costs and Recovery**

Q. Is RG&E proposing a change to its annual storm funding in this proceeding?

A. Yes. We are proposing that RG&E's storm funding be modified to conform with NYSEG's process and include both major and minor storms. Based upon RG&E's historical experience with Major and Minor Storms since 2006, RG&E will propose increasing the annual storm reserve funding amount by $2.0 million at this time. Recovery of the deferral for major storm costs incurred in prior periods greater than the amount reserved is addressed by the Revenue Requirements Panel.

**Other Transmission Requirements**

Q. Are there potential transmission-related expenses that are not included in the capital forecast in Exhibit __ (RGECRO-2)?

A. Yes. As a market participant in the electric control area operated by the NYISO, RG&E may be required to incur mandated, incremental transmission-related costs as a result of the NYISO's application of its Comprehensive System Planning Process ("CSPP").

Q. What is the NYISO's CSPP?

A. The CSPP is an independent and comprehensive study of New York's electric delivery system that focuses on the overall reliability of the system in accordance with industry criteria and policy and analysis of the costs and benefits of alternatives to alleviate future transmission congestion.

Q. Has the NYISO CSPP identified any projects that may impact RG&E?

A. No. The annual NYISO CSPPs through 2009 have yet to identify any needs within the RG&E franchise area.

Q. How has the Company treated the potential projects that may emerge from the NYISO CSPP?

A. Such potential projects have not been included in the Panel's forecast. The costs associated with such projects, therefore, should be addressed as mandated costs, the recovery of which will be addressed in a future proceeding.

Q. Are there other potential additional expenditures that are not included in the capital forecast in Exhibit __ (RGECRO-2)?

A. Yes. Certain costs will need to be incurred on National Grid's property to support one or more large scale projects that are in our capital plan. We are seeking Commission authorization to capitalize those improvements on our books.

**Rochester Transmission Project**

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

A. The purpose of this testimony is to address the two items identified by the Commission in footnote 73 of Order Authorizing Acquisition Subject to Conditions, issued on January 9, 2008 in the Iberdrola/Energy East acquisition proceeding in Case 07-M-0906 (the "Long Merger Order"), relating to the RTP. These items are: (1) "publicly available information suggests that the RTP may not provide sufficient transmission reliability in the Rochester area" and (2) "the record indicates that the actual cost of the … (RTP) exceeded the original

estimate by about 60%." To address the first item, we identify and discuss the local reliability need in the Greater Rochester Area beginning in approximately 2013 based on current load forecasts, and will demonstrate that a transmission project, as RG&E, in its role as Provider of Last Resort ("POLR"), proposes, is needed to address that local reliability need.

Q. Do current load forecast demonstrate that there is a local reliability need in the Greater Rochester Area?

A. Yes, beginning in approximately 2013, a local reliability need has been identified, and a transmission project is an alternative to address that local reliability need. RG&E has the responsibility for identifying and addressing local transmission reliability needs as part of their POLR responsibilities. In light of that POLR responsibility, RG&E describes the basis for the local reliability need, the process for evaluating how to best address that need, and concludes that a new transmission project is necessary. Since RG&E is precluded from owning generation, the only option for a generation solution would be to assume the repowering of the existing Russell site by a merchant generator. As this cannot be assumed with any degree of confidence, the POLR responsibility demands that RG&E pursue a transmission solution that will be ready by 2013.

**The Local Reliability Need**

Q. Can you please describe the bulk electrical system serving the Greater Rochester Area?

A. The Greater Rochester Area is a load pocket, which is defined as a region of concentrated electric load with very limited generation in the region and with very limited access to a major electric bulk power transmission system. In the case of Rochester, the only significant generation in the load pocket is the Ginna 590 MW nuclear generating station. The remainder of the load in the Rochester area is currently served from two transmission substations, Station 80 and Station 122 which connect to two 345 kV transmission lines owned by the New York Power Authority. The four 345 kV bulk power transformers at Substation 80 can provide approximately 1,204 MW into the Rochester load pocket, and the three 345 kV bulk power transformers at Substation 122 can provide approximately 711 MW. These sources feed the underlying 115 kV transmission system, which, in turn, provides the source for the 34.5 kV and 11 kV systems that feed the distribution systems in the Rochester load pocket. Combined with Ginna, the total electric capability supplying the Rochester load pocket during Summer Peak Load Periods is approximately 2,505 MW. The current peak load for RG&E is 1,744 MW, which occurred on August 1, 2006.

Q. What planning criteria are used for electric system reliability planning purposes for the Rochester load pocket?

A. The system needs to continue to reliably serve the expected peak load after loss of the largest power source, which in this case would be the loss of Ginna. Therefore, current alternative electrical source capability into the Rochester area, based on the capabilities of Stations 80 and 122 is 1,915 MW. This capability is in excess of the historic peak summer load of 1,744 MW. But with continued load growth in the area, RG&E will soon face peak loads that cannot continue to be served in the event of the loss of the single largest source of supply to the load pocket.

Q. Do you have any reliability concerns for the Greater Rochester Area if additional electric source capability is not added in a timely manner?

A. Yes. Without an adequate source capability within or into the Greater Rochester Area, there would be the risk of thermal overloads on the bulk power transformers and transmission lines during peak load periods. This condition would lead to system wide unacceptably low operating voltages that would result in substation voltages that cause sub-marginal distribution line voltage. This, in turn, could damage customers' electrical equipment and trigger the need for RG&E to shed customer load. Thermal overloads could occur that can lead to electric system equipment failure and attendant loss of service to customers. Additionally, with only one source of generation in the Rochester load pocket to supply voltage control through reactive compensation, the loss of Ginna would result in an

instantaneous loss of the reactive compensation that in itself would cause severe low voltages, including damage to customer equipment in the Greater Rochester Area even at loads below the net input capabilities of Stations 80 and 122. The loss of Ginna during heavy load periods would cause widespread thermal overloads, sub-marginal voltages and the potential for voltage collapse with consequences that could affect not just the approximately 347,000 RG&E customers in the Rochester area, but also may cause interruptions to customers throughout the surrounding region. Time permitting, the response to the conditions noted above would be the shedding of load to relieve the thermal and voltage concerns. Based on an extrapolation of historic coincident peak summer load growth, the amount of load that would need to be shed would be a limited number of MW in 2013 and would grow to nearly 200 MW by 2018.

Q. How many hours would the Rochester load pocket be exposed to the thermal and voltage concerns noted in the scenario described above?

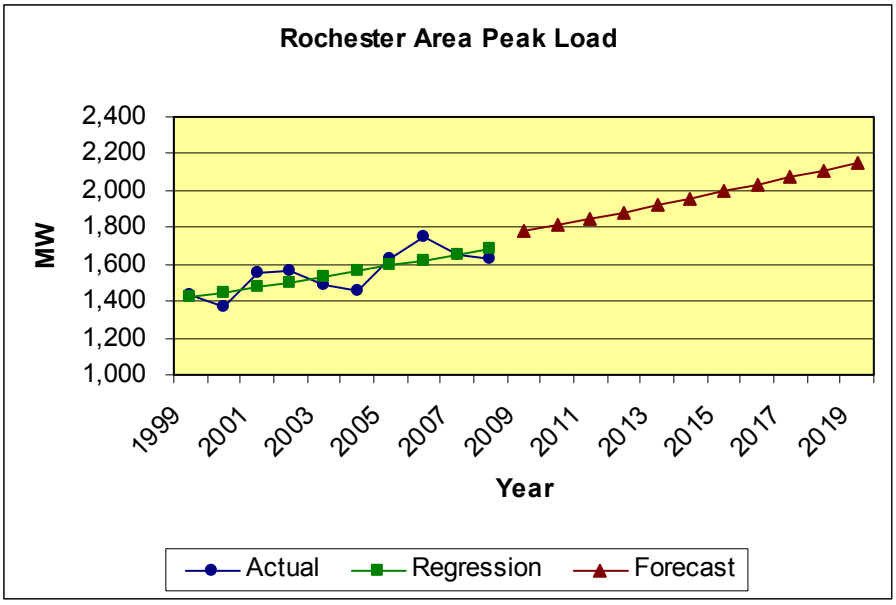
A. Based on RG&E's forecast of load growth, the risk exposure to the loss of Ginna during a peak load period would begin with a limited number of hours starting in 2013, but would be forecast to increase to approximately 100 hours per year in 2018. This forecasting is highly dependent on a number of factors including regional economic activity, weather (including summer thunderstorm activity), customer usage patterns, and the assumed continued reliable performance of the bulk power system and Ginna sources of supply.

Q. What is RG&E's forecast of summer peak load growth, and how was it developed?

A. RG&E uses a regression analysis of actual peak loads in the Rochester load pocket over the past ten years to develop a forecast of future load growth for local reliability planning purposes. Based on this approach and despite declining sales in the near term, RG&E projects a ten-year growth which averages 1.93% per year for coincident peak demand.

Q. Would you please illustrate the actual and forecast peak load growth rates in the Rochester load pocket?

A. The growth rates are illustrated below:




The 2008 NYISO installed capacity ("ICAP") forecast for the Greater Rochester Area is 0.6% starting at 1,638 MW, whereas the RG&E Planning forecast is 1.93% starting at 1,744 MW.

Q. Wasn't the RTP designed to address local reliability issues in the Rochester load pocket?

A. The purpose of the RTP was to address local reliability concerns that would result from the planned shut down of the then existing coal-powered generating units at the Russell Station. The system supply capabilities into the Rochester load pocket noted above are based on the RTP being in service, as a replacement for the retired Russell Station. It must be emphasized that the RTP was designed to replace the Russell Station generation. Even if the Russell Station had not been retired, continued coincident peak demand in the Rochester load pocket would have required the additional system supply by the 2013 time frame that is the subject of this testimony.

Q. Does the proposed transmission project address the local reliability need discussed above?

A. Yes. In the ten-year planning horizon through approximately 2018, with the addition of the proposed transmission project, the loss of Ginna will not cause overloads on the Station 80 and Station 122 source capability in the Greater Rochester Area and the voltages will be within acceptable ranges. Based on RG&E's peak load growth forecasts, the additional transmission capability would solve the anticipated problems projected through 2018.

Q. Do you know if the proposed transmission project will address the local reliability need beyond the ten-year planning horizon?

A. No. Our analysis of the issue was limited to the ten-year planning horizon.

Q. What other reports and options did RG&E evaluate with respect to analyzing and responding to the local reliability need?

A. RG&E reviewed the NYISO Comprehensive Reliability Planning Process ("CRPP") with respect to identifying local reliability needs. It evaluated the possibility of using Demand-Side Management ("DSM") to reduce the local reliability need or whether the Energy Efficiency Portfolio Standard in Case 07-M-0548 ("EEPS") could reduce the identified need for the RTP. It also considered distributed generation ("DG") to address the need.

Q. Is the CRPP responsible for identifying local reliability needs such as the one described here?

A. No. The CRPP is aimed at assessing and addressing emerging reliability issues at the statewide, bulk power transmission level. Individual transmission owners, including RG&E, retain the responsibility for identifying and addressing local transmission reliability needs as part of their POLR responsibility.

Q. Would DSM or the EEPS reduce the identified need for the RTP?

A. No. While DSM is a viable component of electric supply plans, the forecasted significant need of several hundred MW and additional reactive compensation necessitates the development of additional supply sources for the Rochester load pocket. Even though DSM may potentially offset a modest portion of the significant projected load growth in the Greater Rochester Area, DSM alone cannot compensate for all of the projected load growth or the electric system stability concerns discussed above. The EEPS would have to directly reduce

summer peak demand within the Rochester load pocket in order to reduce or eliminate the need for the RTP. General energy consumption reductions occurring during off-peak periods, while providing potential air emissions reductions, would have no effect on the local reliability need. If the EEPS was able to reduce summer peak demand by approximately 15% by 2015, it would delay the need for the addition of new supply into the Rochester load pocket to approximately 2018, which is the end of the ten-year planning horizon. If the EEPS does not reduce coincident peak demand or if it was to result in only a limited amount of demand reduction, then the local reliability need would be unaffected. In addition, given the lead-time to build a new transmission line for the Rochester load pocket, RG&E and its customers could be placed at significant risk if this program were not to achieve significant peak load reductions.

Q. Can you briefly describe RG&E's analysis of DG with respect to being a viable option to solving the local reliability need?

A. As with DSM, DG could be a component of electric supply plans. However, the forecast need for several hundred MW and additional reactive compensation does not allow DG to be considered a viable alternative to the addition of supply into the Rochester load pocket. Typical distributed generation projects range from 2 to 10 MW. With several hundred MWs of load growth, the Rochester area would need to attract and site, at a minimum, over two dozen individual large DG projects. Even assuming that a number of willing hosts and suitable sites could be identified, DG alone is not considered a viable alternative to the proposed

generation considering the difficulties in developing, financing, licensing, and constructing such a large number of generating units throughout the Greater Rochester Area. RG&E cannot be certain that these units would be developed in time to meet the local reliability need, that they would be operated and maintained in a manner that was consistent with the performance requirements needed to support the reliability need, and that the DG units would remain in reliable service for the long term.

Q. Given this uncertainty regarding DG, what steps does RG&E have to take?

A. Because of its continuing POLR responsibility, RG&E would have to ensure that these customer-owned generating units would be available for service during those periods of time in which the reliability need would be at its most critical point. Without direct control of the availability of those units, RG&E could not be assured that they would be available to meet the local reliability need. As a result, RG&E will need to review a new transmission option.

Q. Can you describe the new transmission option that RG&E will need to begin due to its POLR responsibilities?

A. The local reliability needs should be addressed by a transmission option consisting of another tap of the cross-state 345 kV bulk power system with a new bulk power substation. The substation would involve construction of a new 345 kV breaker and a half substation that would tap into the two existing cross state 345 kV lines owned by the New York Power Authority. The new 345 kV substation would have two 250 MVA 345/115 kV transformers with load tap

change capability and tie into a 115 kV breaker and a half scheme on the low voltage side of the substation. There would need to be two 115 kV transmission lines with a capability of 300 MVA each constructed out of the new substation that would interconnect to the existing RG&E electric system at Station 418 and a new downtown substation. The proposed facilities assumed for the purpose of formulating an estimate include: a 345 kV to 115 kV substation at the source end; a 115 kV transmission line approximately 14 miles in length with a mix of overhead and underground designs; and a 115 kV to 35 kV substation in downtown Rochester.

Q. What are the costs for building this transmission alternative?

A. The cost to construct the proposed transmission alternative is currently estimated at approximately $177 million. The cost and schedule estimates are based on preliminary engineering analysis and take into account current conditions in the utility construction markets. These estimates will be subject to further analysis and modification based on future events.

Q. Would Article VII approval be required for the transmission alternative?

A. Yes. The construction of the proposed transmission alternative would require authorization by the Commission via its issuance of a Certificate of Environmental Compatibility and Need for the project.

Q. When could the transmission alternative be ready to be placed in-service?

A. The anticipated duration for completing the transmission alternative is approximately five years and, as such, could be completed by approximately 2015 assuming an expedited Article VII process is started in 2010.

**Actual Costs of the RTP**

Q. What was the originally estimated cost of the RTP?

A. The Article VII application filed on September 30, 2003, listed the estimated cost of the RTP as $75,349,400 in 2003 dollars.

Q. Was the cost of constructing transmission facilities increasing sharply at the time the Article VII certificate for the RTP was issued on December 16, 2004?

A. Yes. During this time, the cost of the commodities used in the construction of transmission facilities was increasing rapidly. Exhibit __ (RGECRO-11) contains graphs that show the increases in the price of copper, steel and aluminum, three of the commodities that most significantly affected the cost of the RTP. Additionally, because many transmission projects were being constructed at the time, the demand for transmission construction services and the cost of those services were being driven up. Exhibit __ (RGECRO-12) is an article from the September 1, 2005 issue of Electric Power Daily reporting that the projected cost of Vermont Electric Power Company's Northwest Vermont Reliability Project increased from a 2003 estimate of $120 million to a 2005 estimate of $228 million. The article ascribes the price increase to "the heightened demand for construction services as utilities nationwide undertake transmission upgrades."

Q. Was Staff aware that the actual cost of the RTP might be different from the estimate set forth in the Article VII application?

A. Yes. The September 28, 2004 RTP Joint Proposal among RG&E, Staff and other parties included, at Staff's request, proposed Ordering Clause 33, which provided in pertinent part, "[o]nce RG&E receives bids for 85% of the RTP's construction costs, RGE shall provide DPS Staff with an updated project cost estimate report ("cost update"). In addition, if at any time after submission of the cost update, RG&E becomes aware that the estimate of the total project costs will vary by $1 million or more from the most recently supplied cost update, RGE shall provide DPS Staff with a report on such further estimated cost variance. Such cost updates shall include costs incurred and an explanation of the reason(s) for the cost variance." This provision was adopted in the Commission's Order Granting Certificate of Environmental Compatibility and Public Need, issued December 16, 2004 in Case 03-T-1385.

Q. Did RG&E provide Staff the cost updates required by Ordering Clause 33?

A. Yes. On August 15, 2005, after an engineer-procure-construct ("EPC") contract for the RTP had been negotiated, and months prior to the start of construction of the RTP, RG&E provided Staff with its first cost update, a copy of which is attached as Exhibit __ (RGECRO-13). That update first used the 2003 cost estimate methodology to show the increases in the various project cost categories that increased the initial estimate to $93,870,000. It then updated the estimate based on the price of the EPC contract and other known increases, resulting in a

total projected cost of $114,123,000. Each cost category is footnoted to describe differences in costs. Thereafter, RG&E provided Staff with updates on January 30, 2007, August 30, 2007, December 12, 2007, and July 31, 2008. The July 31, 2008 update, attached as Exhibit __ (RGECRO-14), reflects a total project cost of approximately $121.2 million, approximately $7.1 million above the post-bid estimate of $114.1 million provided to Staff in August 2005, which was prepared prior to the start of detailed engineering, procurement and construction.

Q. What are the principal causes of the increase from the August 2005 update to the July 2008 update?

A. The cost of Circuit 927 of the RTP increased by about $2 million as a result of the Commission's Order Approving Part of Segment 5 of the Environmental Management & Construction Plan, issued March 28, 2007 in Case 03-T-1385, which required RG&E to obtain additional ROW and perform additional clearing along Circuit 927 of the RTP beyond that specified in the Article VII application. Removal of rock beyond the amount anticipated in the EPC contract added $1,250,000 to the cost. RG&E's decision to reject, for reliability reasons, the use of a new conductor design, which would have allowed the reuse of structures on certain circuits, added $2,250,000 to the cost of the facility. Also, security requirements for transmission facilities that were mandated by regulatory order were increasing significantly as the RTP was being developed, and this increased the cost of the project.

Q. Why did RG&E enter into a fixed-price EPC contract for the RTP?

A. RG&E believed that use of an EPC contract was the best way to protect the Company and its customers from cost overruns.

Q. How did RG&E select the EPC contractor?

A. RG&E selected the EPC contractor through a carefully designed competitive bidding process, followed by extensive negotiations with all bidders to further reduce the cost of the RTP.

Q. What was the purpose of the RTP?

A. As stated on the first page of the Executive Summary included in the Article VII application for the RTP, "the proposed improvements will reinforce the overall RGE 115 kV electric transmission system and its interface with the New York State bulk transmission system and are required to ensure that RG&E will be able to adequately and reliably provide electricity to the Rochester area following the shut down of the Russell Station." The section of the September 28, 2004 RTP Joint Proposal that addresses need for the facility, a copy of which is attached as Exhibit __ (RGECRO-15), demonstrates that the focus of the RTP was to allow RG&E to continue to provide reliable service after Russell Station was closed.

Q. Has Russell Station been closed?

A. Yes, Russell Station was permanently shut down on April 29, 2008.

Q. Is the RTP in service?

A. Yes. All segments of the RTP are in service and operating at their specified ratings.

Q. Has RG&E continued to provide reliable service to the Rochester area despite the closing of Russell Station?

A. RG&E has continued to provide reliable service. With the RTP in service, RG&E has continued to provide reliable service to the Rochester area even though Russell Station has been closed. RG&E anticipates that it will continue to be able to provide reliable service to the Rochester area with the RTP in service, although, as noted previously, load growth in the area will require additional facilities.

## ELECTRIC RELIABILITY PERFORMANCE METRICS

Q. Has the Company been encouraged by Staff to propose additional electric reliability performance metrics?

A. Yes. Staff has encouraged the Company to propose additional electric reliability metrics. CAIDI and SAIFI are currently the sole measures of electric reliability performance. One of the most significant opportunities to support maintenance or improvement in electric reliability is an increase in annual miles of distribution line clearance as proposed in our testimony above. The percentage of cycle trim miles achieved each year would provide an additional electric reliability metric consistent with the proposed direction of the program.

# DIRECT TESTIMONY OF THE CAPITAL EXPENDITURES, RELIABILITY, AND OPERATIONS PANEL

## GAS RATE PROCEEDING

Q. Mr. Eastman and Mr. Matthews, what is the purpose of this portion of the Panel's testimony?

A. The purpose of this portion of the Panel's testimony is to: (1) describe the RG&E natural gas system; (2) discuss the historical and proposed Capital expenditure plans; and (3) discuss incremental O&M programs needed to meet current work tasks and new regulatory requirements and their associated cost.

## NATURAL GAS SYSTEM STATUS

Q. What is the current status of the system operations of RG&E natural gas business?

A. The RG&E natural gas transmission and distribution system infrastructure is in good condition. Systematic replacement programs targeting leak prone main and service piping continues to result in fewer emergency leaks, leaks requiring repair and outstanding leaks each year. Emergency response times are improving and damage prevention and quality assurance programs continue to improve.

Q. Can you please provide a description of the RG&E Natural Gas System?

A. RG&E operates and maintains 4,686 miles of transmission and distribution gas main and 3,929 miles of gas service lateral piping. RG&E has 12 purchase stations, 2 heaters, 12 odorizers, 12 city gate regulator stations, 333 district regulator stations, and approximately 300,000 distribution gas meters.

Q. What tasks must RG&E perform to run its natural gas system?

A. RG&E is responsible to operate, maintain and upgrade all the systems constructed throughout its 117 years of operating history, respond to emergencies 24 hours

per day, seven days per week and 365 days per year, locate facilities for every construction project occurring in seven counties as shown on Exhibit __ (RGECROGAS-1) (Gas Service Territory Map), connect approximately 1,500 new customer gas services annually and relocate facilities in conflict with all street, road and highway rebuilding projects. Employees witness test 30 gas pipeline supply sales meters annually, calibrate 235 industrial meters, exchange approximately 1,500 distribution meters for accuracy testing annually, train 300 contractors in operator qualification skill assessment, construction and safety practices, engineer 3,000 service orders and work orders, maintain all the records associated with all these facilities, and perform corrosion monitoring and corrective work on 14,500 cathodically protected piping systems.

Q. Are there other tasks that the Company must perform?

A. Yes. The Company must perform thousands of mandated operating and maintenance inspections on the infrastructure, calculate gas network studies to correctly size facilities for replacements and load additions, work proactively with 2 local production companies who desire to connect and are connected directly to the distribution facilities, maintain system pressures, monitor district regulator stations and coordinate deliveries from the RG&E gas control center with the interstate pipeline control centers, balance gas deliveries, interact with multiple natural gas marketers, optimize supply for all firm customers, maintain and produce all of the billing documents for all of these transactions, collect payments from customers, and provide RG&E commodity and delivery service as required.

## DIRECT TESTIMONY OF THE CAPITAL EXPENDITURES, RELIABILITY, AND OPERATIONS PANEL

Q. What is the operations business strategy for the RG&E natural gas business?

A. RG&E's operations business strategy is to focus on public safety and system reliability. RG&E is committed to operational excellence, continuous improvement, serving new customers and coordinating activities with municipalities, highway departments, regulatory agencies and jurisdictional and governing bodies to provide safe, reliable, cost efficient natural gas service to many upstate rural businesses and communities. The Company has one of the lowest lost and unaccounted for gas ("LAUF") factors in the State, repairs all leak classifications annually, maintains one of the lowest third party damage rates, and strives to be among the top emergency responders and system safety performance leaders in the State.

Q. Does RG&E currently have mandated service quality performance measures and safety related targets that they are required to accomplish in its current gas rate plan?

A. Yes, RG&E is subject to targets and associated revenue adjustments related to infrastructure enhancements, leak management, damage prevention and emergency response times. Targets for the Company were in effect through December 2008 and were recently modified in the Iberdrola/Energy East Merger Order in September of 2008. They are attached as Exhibit __ (RGECROGAS-2) (Gas Safety Performance Measures 2009).

Q. Do the current mandated service quality performance measures help RG&E to achieve and maintain the Company's infrastructure and current high performance?

A. Yes, these mandated and Commission ordered programs have helped RG&E to systematically identify, prioritize and coordinate upgrades and replacements of aging mains and services, reduce main and service leaks, improve emergency response times, reduce third party system damages, extend the useful life of main, and improve the effectiveness of the quality assurance and employee training programs, thereby improving system safety, reliability and economics.

Q. Based upon RG&E's historic performance under the gas safety performance standards in effect through December 31, 2008, has RG&E ever incurred a revenue adjustment penalty for not performing its duties?

A. No, RG&E has never incurred a performance measure penalty for not meeting its gas safety performance measure targets.

Q. What service performance measures is RG&E planning to accomplish in the near future?

A. RG&E is planning to accomplish the performance measures that were adopted by the Commission in the Iberdrola merger.

# DIRECT TESTIMONY OF THE CAPITAL EXPENDITURES, RELIABILITY, AND OPERATIONS PANEL

## CAPITAL EXPENDITURE PLAN

Q. Can you please summarize the levels of capital investment you are supporting in this testimony?

A. As indicated in Exhibit __ (RGECROGAS-3) (RG&E Gas Capital Budget History, Proposal and Forecast), the proposed investment is $22.0 million in 2010, excluding common capital.

Q. What is the actual RG&E natural gas historical five year capital spending?

A. The historical, proposed and future proposed capital expenditure information is attached as Exhibit __ (RGECROGAS-3) (RG&E Gas Capital Budget History, Proposal and Forecast) and in Exhibit __ (RGECROGAS-4), which contains project summary forms.

Q. How much money has RG&E invested in gas system capital and system improvements since 2004?

A. Since 2004, RG&E has invested approximately $116 million dollars in gas capital and system improvements, excluding common investments.

Q. What are the levels of gas capital required by the Company to perform its service responsibilities?

A. Approximately 85% of the Company's proposed level of annual capital expenditures is spent on mandatory replacement programs, mandated tariff main and service extensions and rate case service quality performance measures.

Q. Has RG&E met its main and service replacement targets during the past five years?

A. Yes, RG&E has met or exceeded the leak prone main replacement and leak prone service replacement targets every year.

Q. Please describe the process that RG&E uses to develop the forecast of its annual gas capital investment requirements.

A. RG&E's gas capital forecast is developed by the Director of Gas Engineering and division operating departments based on forecasted customer additions, gas system performance information and RG&E's business plans.

Q. What are the broad categories of focus used regarding program planning and capital spending?

A. The broad categories of focus used regarding program planning and capital spending are Transmission Mains, Distribution Mains, Gas Services, Meters and Service Regulators, M&R/Gate Stations, Production Plant, Highway Relocations, and General Plant/Miscellaneous.

Q. Can you please describe RG&E's projects that are classified as Transmission Mains?

A. These projects involve relocating or replacing RG&E's gas transmission facilities including mains and cased crossings.

Q. What RG&E projects are classified as Distribution Mains?

A. These projects include the leak prone main replacement program, extension of mains to serve new customers and the installation of new pipe required to support organic growth of existing distribution systems.

Q. What is RG&E's capital forecast for these projects based upon?

A. RG&E forecasts these expenditures based on the projected cost to replace 20 miles of leak prone main, the known development projects such as commercial and industrial development, residential housing development, subdivisions, and historical growth information. Expenditures for the leak prone main and leak prone service replacement programs are based upon historical leak information, risk factors, RG&E O&M procedures and the terms and conditions of the RG&E mandated programs. Economic development driven projects are also included in distribution. The capital requirements for new business are generally dependent upon the economic conditions throughout the service territory. Even though the Company has been experiencing net negative load growth due to equipment efficiencies, a sluggish economy and fluctuating commodity cost, a baseline level of work continues.

Q. Can you please describe RG&E's projects that are classified as gas services?

A. These projects include installation of services to new customers, upgrade of services to supply increased loads to existing customers as required and the replacement of a minimum of 2,000 leak prone services as part of the leak prone service replacement program.

Q. What projects are included in the budget for those RG&E projects that are classified as gas meters and service regulators?

A. The budget for gas meters includes new meters and regulators to serve new customers, upgraded meters for existing customers and the replacement of aging meters identified through the alternative in test program ("AIP").

Q. Can you please describe M&R/Gate Station projects and Distribution Regulator Station projects?

A. The M&R/Gate Station and Distribution Regulator Station projects include the replacement or addition of new gas facilities due to the particular condition or the need to increase system capacity. Examples of these types of programs include obsolete regulator replacements, station replacement programs, and odorizer replacement programs. These facilities are critical components to the safety and reliability of the delivery system. Systematic replacement and upgrade programs similar to the main and service replacement programs should also be included and funded in the annual capital plan.

Q. What are Highway Relocation projects?

A. Regulations and terms of highway access permits allow RG&E's facilities to be located within State of New York ROW, but mandate relocation of those facilities when in conflict with street reconstruction projects. These relocations are Highway Relocation projects. The proposed scope of work includes relocation of all gas facilities in conflict with proposed highway reconstruction. Facilities located in easements on private property generally are reimbursable. Relocation

of the facilities prior to the start of construction reduces the potential for damage to the facilities and prevents unscheduled interruption of service to customers in the affected surrounding area.

Q. What is RG&E's capital forecast of these projects based upon?

A. RG&E forecasts these expenditures based on preliminary project descriptions and schedules provided to RG&E by the New York State Department of Transportation ("NYSDOT"), county and local municipal highway departments, and engineering estimates for other known or anticipated projects. These relocation projects must be completed and schedules are subject to changes due to the availability of federal and state project funding levels.

Q. Do you anticipate that federal stimulus funds will increase the amount of mandatory highway relocation projects?

A. It is possible that federal stimulus funds will result in additional highway repair and construction, which could increase our mandatory highway relocation projects. Should that occur, the current forecast would need to be updated accordingly.

Q. What projects are included in General Plant/Miscellaneous?

A. General Plant/Miscellaneous includes Gas SCADA upgrades and miscellaneous replacement of Remote Terminal Units ("RTUs"), and projects that are not included in the categories described above.

Q. What is RG&E's capital forecast for these projects based upon?

A. RG&E's capital forecast for these projects is based upon anticipated work levels and equipment age.

Q. What was the 2008 gas capital budget and the gas capital actually spent in 2008 at RG&E?

A. The 2008 gas capital budget was $22,287,000 and the actual amount spent was $21,729,000 excluding common capital.

Q. What was the amount of capital spent in the test year?

A. The amount of capital spent in the test year was $20,189,000, excluding common capital.

Q. What is the proposed level of capital expenditures for RG&E gas in 2010?

A. The proposed level of capital expenditure for RG&E gas in 2010 is $22,000,000, excluding common capital, as shown in Exhibit __ (RGECROGAS-3).

Q. Why is the gas capital budget increasing over the next five years?

A. RG&E would like to proactively implement additional systematic infrastructure enhancement programs to replace other critical system facilities in addition to primarily mains and services.

Q. What are the other system facilities that RG&E is proposing to systematically upgrade or replace?

A. Additional system facilities that require attention in addition to mains and services include purchase stations, heaters, regulator stations, odorizers, SCADA/RTU equipment, exposed piping on bridges, and cased crossings. There are no line

item capital dollars budgeted for these facilities in the current rate plans. These facilities are aging and require replacement attention similar to the main and service replacement programs currently in place.

Q. Have RG&E's capital costs, contractor costs, material costs and expenses been increasing?

A. Yes, during the past five years, RG&E's capital costs have been increasing due to various items. Contractor construction costs have continually increased year over year, sometimes as much as 5% to 10% a year. Material costs have increased significantly in the past few years as well as internal cost structure increases. The Merger Order increased the amount of replacement of leak prone main, leak prone services and leak repairs, while increasing the penalties for non-compliance. Therefore, capital expenditures and O&M costs have increased also.

Q. Have you included inflation in your capital cost budget estimates?

A. Yes, we have included 3% inflation per year in our capital cost budget estimates.

## OPERATIONS AND MAINTENANCE

Q. What changes or incremental programs does RG&E propose to include in this rate proceeding that were not included in the test year or require an adjustment in base rates?

A. RG&E is proposing the following changes or incremental programs regarding gas main clearing, integrity management ("IMP") and Distribution Integrity Management ("DIMP"), damage prevention and public awareness enhancements, gas meter relocation revenue recovery program, enhanced maintenance of

exposed piping on bridges, complete the implementation of a GIS mapping system and manpower. DIMP will be required by the U.S. Department of Transportation Pipeline and Hazardous Materials Safety Administration ("PHMSA"). The program cost associated with these initiatives is detailed in Exhibit __ (RGECROGAS-8).

Q. Does RG&E currently perform mandated programs that cause RG&E to incur significant expense as deferral items?

A. Yes, the federal mandated IMP for transmission pipelines has caused RG&E to incur significant expense during the past six years, please refer to Exhibit __ (RGECROGAS-7). RG&E has spent over $2 million to date. RG&E is proposing to include future costs for these programs in base rates. These programs have proven to be very beneficial to RG&E. RG&E has discovered facilities requiring repair due to construction damage and material defects. This program will continue to require additional resources in the future.

Q. What is the proposed level of O&M spending requested each year related to the IMP?

A. The O&M expense to continue the requirements for this program is estimated at $895,000 in 2010.

Q. Are you aware of any future integrity related programs that will cause you to incur significant cost increases?

A. Yes, starting in 2010, all distribution natural gas companies will be required to have a formal DIMP that will address additional operational and safety aspects.

PHMSA is expected to issue the final rule making in the first quarter of 2010. It is anticipated that 18-24 months will be given for program development and implementation. The final details and approvals of Company procedures have yet to be finalized. RG&E has estimated the cost to prepare appropriate documentation and implementation plans to be in compliance with these new federal and state mandates and have included these costs in our O&M plans.

Q. What is the estimated annual O&M spending for DIMP that is being proposed?

A. The estimated amount required is $100,000 per year starting in the last quarter of 2010.

Q. Does the Company currently have a gas main clearing program and budget?

A. Yes, the Company has O&M procedures in place that specify gas main clearing and pipeline marker requirements and the costs to perform the work are included in regional operations budgets. In the future, the Company plans to enhance the gas main clearing and pipeline marker practices to improve damage prevention and public awareness programs.

Q. What is the estimated annual incremental cost of the gas main clearing program?

A. The incremental cost is approximately $250,000, including labor.

Q. What additional initiatives is RG&E planning to accomplish regarding damage prevention and public awareness?

A. RG&E is planning to enhance its outreach and education program with the federal mandated public awareness plan. The goal is to provide a greater understanding and awareness of pipeline infrastructure to our major stakeholders (affected

public, emergency officials, public officials, and excavators). The benefit is improved public safety, pipeline safety, and an enhanced damage prevention program. The additional funding will be used for baseline evaluation surveys, direct mailings to customers adjacent to the transmission ROWs, damage prevention advertising, and outreach.

Q. What is the estimated incremental cost of these programs?

A. The incremental cost is approximately $50,000 for each program, excluding labor.

Q. Is the Panel proposing any programs to help reduce arrears and control uncollectibles?

A. Yes, RG&E proposes the relocation of 1,000 gas meters each year with high arrears from inside locations to outside locations. The relocations will provide easier access to the meters to support ongoing collection activity.

Q. How many meters currently fall within this category?

A. Approximately 10,000 meters are in this category.

Q. In what way does moving meters outside help with arrears and write off expenses?

A. Some customers with indoor meters tend to have poor payment patterns because the threat of disconnection is greatly diminished. An analysis of 90 days or greater arrears showed that customers with indoor meters had 52% higher arrears at RG&E than customers with outdoor meters. Having access to meters allows the Company to disconnect service for non-paying customers while providing

more incentive for customers to make timely payments. Keeping arrears low on accounts has a direct correlation to limiting uncollectible expense.

Q. What factors will be used to select accounts for relocation?

A. Accounts will be reviewed individually based on factors such as arrears, feasibility for relocation, condition of customer equipment, and cost to determine the priority list.

Q. What is the estimated cost of the meter relocation program?

A. The estimated cost is $816,000 per year, including labor.

Q. Has RG&E started to implement a GIS?

A. Yes, a GIS system was started in 2009. Phase 1 of the project was network modeling.

Q. What is a GIS system and what benefits will it provide?

A. A GIS is an integrated system of computer hardware, software and trained personnel linking topographic, demographic, utility, facility, image and other resource data that is geographically referenced. The benefits are increased efficiency regarding storage of data in one location, improved network modeling and mapping processes and an information system that integrates, stores, shares and displays gas system maps.

Q. What is RG&E proposing for the next phase of its GIS program?

A. Phase 2 of the GIS program includes transferring existing map attributes and data to the GIS system. In addition, GPS coordinates for the gas distribution system

will be collected so that the mains can be accurately located on the GIS mapping system.

Q. What is the proposed cost of this work?

A. The estimated cost to GPS gas mains, valves and attributes is $500,000. The collection of field data is scheduled to begin in 2011. Enhanced mapping will allow the Company to update maps quicker, improve engineering efficiency and have timely constructed maps available for field reference and help to further reduce damages.

Q. Why is the Company proposing to remove $351,000 of O&M expense for the Mendon Purchase Station heater fuel from base rates and begin including it in gas supply cost, as discussed in the Gas Supply Panel Testimony.

A. This cost is clearly a gas supply cost because it is fuel used at the purchase station in order to deliver all customers supply. In addition, in the past only $351,000 was budgeted in base rates although in some years the costs have been as high as $500,000 or $600,000 depending upon the highly fluctuating market price of natural gas.

Q. Is RG&E planning to incur incremental expenses in order to repair exposed piping on bridges?

A. Yes, RG&E's cost to maintain exposed piping on bridges is increasing due to facility age, location and accessibility. The estimated cost to repair the piping is approximately $200,000 a year, including labor.

Q. Is RG&E proposing to add additional positions, not included in the test year, to help complete its required work and to continue providing safe and reliable service?

A. As indicated in Exhibit __ (RGECROGAS-5) (Incremental Positions), the Company is proposing incremental positions of approximately 24 gas positions and four electric meter positions. These resources (primarily gas fitters) are needed to complete existing and incremental work requirements, improve meter operations and performance, assist in engineering projects and training employees and contractors.

Q. What is the total number of new gas positions needed to support work requirements and the estimated cost?

A. Approximately 24 gas positions would need to be added at an approximate annual cost of $1.9 million dollars. These positions are needed to be able to sustain the current levels of safety performance and increasing work requirements.

## RESEARCH AND DEVELOPMENT

Q. Does the Company plan to propose any changes in the R&D program and if so please explain?

A. Yes, the Company is proposing a small increase to the funding required for the RG&E R&D program and a reduction to the funding required for the R&D program at NYSEG. The intent of the proposed change is to more equally share the costs and the program benefits between NYSEG and RG&E.

Q. What is the current level of funding for the RG&E Gas R&D Program?

A. The current RG&E funding is provided via an annual surcharge of $314,000. This surcharge is commonly referred to as Millennium funds. Funds required to pay the semi-annual Commission Assessment for the New York State Energy Research and Development Authority ("NYSERDA") statutory program are collected and tracked separately. The historic, current and proposed amounts are set forth in Exhibit __ (NYSEGRGECROGAS-6) (NYSEG and RG&E Gas R&D Budget History, Proposal and Forecast).

Q. How is the funding being provided for the existing Gas R&D Program at RG&E?

A. Funding for the RG&E Gas R&D Program is provided via a surcharge consistent with the Commission's Order in Case 99-G-1369.

Q. What is the proposed funding level for the RG&E Gas R&D Program?

A. The RG&E Gas R&D Program proposal is to increase the internal funding from $0 to $450,000, adding this amount to the existing R&D surcharge used for the Millennium funding and leaving the Millennium funding at $314,000, resulting in the R&D Program funding going from $314,000 to $764,000. Specifically, we propose reducing the NYSEG internal category by $450,000 and transferring that sum to the RG&E internal category. The RG&E and NYSEG gas systems and customer bases are roughly comparable. As a result, the Company is seeking a funding level for the RG&E internal Gas R&D Program that is closer to being comparable to NYSEG's in order to allow the RG&E customers an opportunity to realize a similar level of benefit to that seen from the NYSEG Gas R&D Program.

A fully complementary program would lead to the potential for added collaboration between the NYSEG and RG&E programs. The proposed funding for Millennium expenditures will be $314,000 per year, internal gas R&D expenditures will be $450,000 per year and the NYSERDA payments will vary based upon the annual PSC assessment and will be collected consistent with the current methods. All the funds collected (except NYSERDA) will be dedicated for R&D cost and not be used for any other purpose. Differences between actual expenditures and actual collections will be deferred from year-to-year with any balance available for R&D in subsequent years, used to recover any deferred cost from a previous year.

Q. Are there any restrictions placed on the use of the RG&E Gas R&D funds?

A. Yes. The funds collected via the surcharge are restricted as defined in the Commission's Order in Case 99-G-1369.

Q. How does RG&E manage gas R&D?

A. RG&E does not have a centralized gas R&D group. Instead, project managers are assigned on a project-by-project basis. Executive management provides program direction to maximize the benefits of the program while administrative functions are supported by the NYSEG Energy Technology Group. Frequent communication between RG&E and the NYSEG Energy Technology Group keep the two Companies' programs in alignment with each other and the NYSEARCH Millennium program. Whenever there are sufficient funds, NYSEG and RG&E collaboratively fund projects that provide benefit to both Companies. However,

due to the limits placed on how Millenium funds can be spent and the disparity in funding levels, there are many projects in which RG&E is not able to be a participant.

Q. Can you please provide examples of how the Gas R&D funds have been used by the Company for the benefit of ratepayers?

A. The NYSEG/RG&E gas research and development program has had several significant successes. For RG&E, these successfully deployed technologies come from NYSEARCH and GTI collaboratively-funded projects. Collectively, for NYSEG and RG&E, the combination of millennium funded projects and NYSEG's projects funded via the internal program generate significant cost savings that exceed the annual combined R&D investment of $2,364,000. They also yield positive safety, customer service and environmental benefits. Examples of some of these successful projects include:

- The P&L E-Communications LLC damage prevention and security camera/software project allowed an immediate $8,000,000 cost reduction in 2008 with added savings and safety benefits expected to continue for many years. This was an RG&E innovation that was co-funded by NYSEG and NYSEARCH.
- The NYSEARCH Pipeline Integrity Management portfolio of projects developed a suite of advanced technologies to conduct the direct or remote assessment of pipelines. These projects are supported by significant Federal Office of Pipeline Safety co-funding monies and are tested at the state-of-art

pipeline integrity test facility at the NYSEG training/R&D center in Binghamton, New York.

- The NYSEARCH RMLD (Remote Methane Leak Detection) ("RMLD") revolutionized leak survey methods world-wide by allowing for the remote detection of methane. In addition to reducing operating costs and generating significant royalties, the RMLD significantly improves public safety. The RMLD served a particularly valuable public safety function during the recent flood disaster assessment and recovery operations in the Southern Tier of New York.

Since 2002, RG&E gas R&D has deployed 26 new technologies into the workplace.

## ELECTRIC AND GAS METER OPERATIONS

Q. Can you please describe the organization and function of the RG&E meter services work group?

A. The Meter Services Department at RG&E is headed by a manager, who oversees several groups involved with measurement of gas and electricity and rubber goods (personal protective equipment) testing facilities. There is an electric and gas meter test and repair lab in Rochester, an electric meter test and repair lab in Binghamton and a gas meter and regulator test and repair lab in Geneva. All labs contain calibration and test equipment approved for use in New York State. The department has a standards lab for the calibration of the electric and gas equipment used in the field such as hot sticks, gas sensing equipment, pressure

calibrating equipment, volt meters, power quality equipment and similar equipment. RG&E tests high voltage and current equipment in this lab including current transformers and voltage transformers for electric metering. Meter Services also includes a meter reading services group that is responsible for the collection and data analysis for the MV90 meter reading system and supports the day-to-day running of the Radix Handheld Meter Reading System at RG&E. Electric Operations at RG&E has the responsibility of Electric Field Measurement positions. Meter Services has one Meter Engineer who is responsible for making sure the Electric Meter Technicians are supported in their field work and that they complete mandated programs, can troubleshoot, and perform new large meter installation work.

Q. What is the staffing and organization of the RG&E Meter Lab?

A. RG&E's Meter Lab currently consists of a Supervisor, two Meter Technicians, and a Senior Meter Technician that work inside the lab. There is also a Senior Meter Technician that works in the field on Gas Field Measurement activities.

Q. What types of activities do the employees in the RG&E Meter Lab perform?

A. The Meter Technicians in the lab test the meters RG&E removes from service requiring tests. These include any meters removed for PSC test programs (approximately 1,500 gas meters and 1,500 electric meters), meters that are removed for special testing (high bill complaints, special projects), and meters removed for other reason that are intended for re-use. In addition, lab employees are responsible for testing samples of new meters from manufacturers to make

sure they perform within RG&E and New York State's specifications before being placed into service. This group repairs and adjusts meters that are intended to be re-used in the field and restocks those meters. They are also responsible for retiring and recycling meters that are no longer serviceable.

The Senior Meter Technician in gas field measurement is responsible for the measurement integrity at all of our largest gas customers, primarily focusing on the equipment such as the gas volume correctors and Metretek (telemetering), and large gas meters. This work includes annual synchronization of 900 Metretek (telemetered) readings, the annual calibration of 240 gas volume correctors, semi-annual reading verifications on these same 240 gas volume correctors, the installation, maintenance, and troubleshooting of all of these facilities, as well as general maintenance and troubleshooting on all large gas meters in the field (turbines, rotaries, and diaphragms typically larger than 1,000 cfh capacity).

Q. Is the Panel proposing additional staff positions for the RG&E Meter Lab?

A. RG&E is proposing to add two (2) additional gas field measurement full time equivalent positions. The current resource of one field person is not able to maintain all of the mandated work and keep up with the new meter installations, troubleshooting, and still be able to proactively verify the measurement integrity at all of the largest gas customers. The additional positions would complete all mandated work and provide backup and contingency. RG&E has identified projects to evaluate the integrity of the gas measurement equipment and make sure RG&E incorporates state-of-the-art metering into long-term plans. An

additional task of the field personnel is to continue to validate meter readings at all of the Volume Corrector sites on a monthly basis to make sure the equipment is operating properly on the 230 largest customers.

In addition, RG&E is proposing to add an analyst position. This position would report to the Supervisor of the Meter Lab and support all of the Meter Services Departments at RG&E as well as the Meter Engineer. This position would be responsible for analyzing data, preparing reports and record keeping. This data will help us better determine whether any metering or measurement issues exist on a global scale and to identify and react to those problems much sooner.

Q. Are you proposing to add additional field positions for Electric Metering?

A. There are approximately seven (7) Electric Meter Technicians at RG&E. Six of these seven Technicians perform trouble maintenance work routinely in addition to electric metering work. RG&E is proposing to add three (3) additional full time equivalent positions to support electric metering at RG&E.

Q. Is the Panel proposing to add positions in any other department within Meter Services?

A. No. The existing staffing levels in the remaining departments are adequate and should be maintained at the current levels.

Q. What is the estimated incremental cost of these positions?

A. The incremental costs are shown in Exhibit __ (RGECROGAS-5) (Incremental Positions).

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

A. Yes.