STATE OF NEW YORK

PUBLIC SERVICE COMMISSION

Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Niagara Mohawk Power Corporation for electric service

Case 10-E-0050

EVIDENTIARY HEARING

Thursday, September 9 2010
10:00 a.m.
Public Service Commission
3 Empire Plaza, 3rd Floor
Albany, New York

BEFORE: WILLIAM BOUTEILLER, ALJ

APPEARANCES:

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ALSO PRESENT
CHRISTOPHER SMITH, ESQ.
SARAH MILLER

ALJ BOUTEILLER: Let my call this case. This is case number 10-E-0050. This is the Commission's proceeding on its own motion concerning National Grid and the rates being proposed for the Niagara Mohawk Power Company, its electric rates.

We had appearances last week. We don't need to make any new appearances for people who have previously provided their appearance, but if you were not in attendance during the hearing last week we can note your appearance now. Mr. Koda.

MR. KODA: Richard J. Koda of Koda Consulting, Inc., on behalf of the IBEW Local 97.

ALJ BOUTEILLER: Thank you, Mr. Koda. Is there anyone else who needs to make an appearance in this case?

MS. NESSER: Your Honor, for the company, Carlos Gavilondo.

ALJ BOUTEILLER: Thank you for your additional appearance.

Before we turn to our first witness today, let's take care of any housekeeping and preliminary matters that we need to address. Let's turn first to Mr. Koda. While off the record you indicated there is no cross-examination for your witness. You've polled the parties, and they've told you that.

MR. KODA: That's my understanding, Your Honor.

ALJ BOUTEILLER: Okay. With that understanding and with the parties present in the room, I'm prepared to receive your witness by affidavit, so -- and I know you've provided the testimony and there's been no changes to your testimony since the time it was pre-filed?

MR. KODA: That's correct.

ALJ BOUTEILLER: Okay. I know you provided a digital copy of your testimony to the reporter. I have your pre-filed testimony, so that will suffice for me as well. I understand that you have an affidavit executed?

MR. KODA: I do.

ALJ BOUTEILLER: Okay. Can you provide me one for the record up here? If there's any party in attendance who wants a copy -- I know you have some limited copies available.

MR. KODA: This is the original, Your Honor.

ALJ BOUTEILLER: Can you afford a copy?

MR. KODA: And a copy.

ALJ BOUTEILLER: Okay, thank you.

MR. KODA: You're welcome.

ALJ BOUTEILLER: Can you distribute those to anyone in the room who cares to have for their records a copy of your affidavit? So to begin with we will mark for identification as Exhibit Number 325 -- did I get that correct?

MR. O'BRIEN: That's correct.

ALJ BOUTEILLER: -- as Exhibit 325, the affidavit offered by Mr. Koda for his witness whose name I'll spell, S-k-e-r-p-o-n.

(Exhibit No. 325 was marked for identification.)

ALJ BOUTEILLER: Absent any objection from the parties present in the room, I will instruct the reporter to copy his testimony into the record as if it were given orally today.

(The referenced testimony is inserted into the record as follows.)

STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

PROCEEDING ON MOTION OF THE COMMISSION AS TO THE RATES, CHARGES, RULES AND REGULATIONS OF NIAGARA MOHAWK POWER CORPORATION FOR ELECTRIC SERVICE	:	CASE NO. 10-E-0050

DIRECT TESTIMONY OF

THEODORE SKERPON

ON BEHALF OF

INTERNATIONAL BROTHERHOOD OF ELECTRICAL WORKERS, LOCAL 97

JULY 14, 2010

I. STATEMENT OF QUALIFICATIONS

Q. WHAT IS YOUR NAME AND ADDRESS?

A. My name is Theodore Skerpon and my business address is 713 Erie Boulevard West, Syracuse, New York 13204.

Q. BY WHOM ARE YOU EMPLOYED?

A. I am the President and Business Manager of International Brotherhood of Electrical Workers ("IBEW"), Local 97, AFL-CIO ("Local 97" or "Union"). I had been employed by Niagara Mohawk Power Corporation, Inc. ("Niagara Mohawk") for over twenty-four years. Since 1986, my job classification had reflected my work within various departments; my most recent classification was Customer Service Representative. I have held positions within the Union since 1992 -- first as Steward and then as Chief Steward from 1995 to 1997. In 1997, I was appointed to Local 97's Executive Board. In 2004, I was appointed to the position of Treasurer of Local 97. On July 13, 2010, I was sworn in as President/Business Manager of IBEW, Local 97.

Q. WHAT IS THE NATURE OF YOUR WORK IN YOUR CURRENT POSITION WITH LOCAL 97?

A. As Business Manager of Local 97, I have primary responsibility for directing and coordinating Union affairs throughout National Grid's entire area of what was Niagara Mohawk's operations. Local 97, with offices in Syracuse, Buffalo, Albany and Oswego, represents approximately 3,200 men and women who are directly involved in operating the electric and gas, transmission and distribution system of National Grid in the New York jurisdiction. Local 97 also represents over 1,500 workers presently employed in the nuclear, fossil, hydro, gas, highway and clerical units of other utility and non-utility companies in New York. Without the dedicated efforts of Local 97 members, the quality electric and gas service experienced today by customers throughout Upstate New York would not be as high as it is.

With regard to the electric service rate filing made by Niagara Mohawk Power Corporation, d/b/a National Grid ("Niagara Mohawk" or "Company"), while the interests of ratepayers, commercial, shareholder and others are represented by a variety of parties, no party other than Local 97 represents the interests of the rank and file workers employed by Niagara Mohawk.

II. SCOPE AND PURPOSE OF TESTIMONY

Q. WHAT IS THE PURPOSE OF THIS TESTIMONY?

A. The purpose of this testimony is to present to the Commission the reasons why Local 97 believes that the full request of the Company for its revenue requirement in this proceeding should be approved by the Commission.

Q. WHAT DOCUMENTS DID YOU REVIEW AND EVALUATE IN PREPARING YOUR PREFILED DIRECT TESTIMONY?

A. In preparing this testimony, I reviewed certain direct testimony and exhibits filed by the Company and its responses to various interrogatories of the parties in this proceeding, specifically those involving employees and their ability to perform their work to provide safe and adequate electric service to Niagara Mohawk customers, as well as a variety of other documents related to the reliability of the Company's operations and provision of electric service.

Q. WAS THIS TESTIMONY PREPARED BY YOU OR UNDER YOUR DIRECT SUPERVISION?

A. Yes, it was.

III. CONCLUSIONS AND RECOMMENDATIONS

Q. WHAT CONCLUSIONS AND RECOMMENDATIONS HAVE YOU REACHED REGARDING AMOUNTS FILED BY THE COMPANY IN THIS PROCEEDING PERTAINING TO CAPITAL EXPENDITURES, AS WELL AS OPERATIONS AND MAINTENANCE PROPOSALS?

A. Based on my review of the Company's filing, I conclude that the amounts the Company has requested in its filing for construction and operations expenditures are appropriate to maintain and continue to improve the operation and reliability of the Company. I recommend that the Commission adopt the requested revenue requirement proposal of the Company, especially in both areas of construction and operations and maintenance expenditures.

IV. BASIS FOR CONCLUSION AND RECOMMENDATION

Q. WHAT IS THE BASIS FOR YOUR CONCLUSION THAT THE LEVEL OF EXPENDITURES REQUESTED BY THE COMPANY IN THIS PROCEEDING SHOULD BE ADOPTED BY THE COMMISSION IN THEIR ENTIRETY?

A. Given that the Company serves approximately 1.59 million customers across upstate New York in territories including metropolitan areas, such as the cities of Albany, Buffalo and Syracuse as well as many rural areas in northern New York and the Adirondacks, it is important that the electric service provided to customers in these areas be adequate, safe and reliable.

In the period 2005 through 2007, the Company's reliability performance was not up to what the Commission required and what customers in the Company's territories have come to expect. The Company missed both its reliability performance mechanism targets for System Average Interruption Frequency Index ("SAIFI") and Customer Average Interruption Duration Index ("CAIDI") in 2005 and also missed the SAIFI target in both 2006 and 2007. This unfortunate performance began to turn around dramatically in 2008 and 2009 when the Company made both its SAIFI and CAIDI targets due in part to increased capital investment, operational spending and improved performance.

In my opinion, a factor that contributed to the improved performance was an agreement that was entered into in late May 2007 between Local 97 and the Company regarding transmission line and substation construction services. As a result of this agreement, two new and separate work groups were established entitled Transmission Line Services and Substation Construction Services. These work groups were initially comprised of represented workers who applied for at least ten posted Line Mechanic positions per Division (Central, Eastern and Western) for transmission line work, and at least ten Electrician positions per division for substation construction work. In addition, it was agreed that Fleet Technician positions may be posted to perform vehicle and equipment maintenance. These positions have divisional responsibilities and can be assigned to work anywhere within the Division. In addition, crews may also be assigned to work outside their Division or in other Divisions by mutual agreement. The new structure and added employees improved electric service.

As noted in the Company's Petition for Authorization to Defer Electric Transmission and Distribution Investment Costs, recent expenditures by the Company have exceeded what was originally thought to be adequate in the context of the Company's Merger Petition back in 2001:

> National Grid's spending both on T&D capital investments and on T&D O&M expenses during 2009 substantially exceeds the annual levels projected in the forecast underlying the Merger Rate Plan rates. The Merger Rate Plan projected T&D capital expenditures during 2009 of $144.5 million and T&D-related O&M expenses during 2009 of $193 million.[1] In contrast, National Grid invested a total of $313.1 million in

[1] National Grid USA and Niagara Mohawk Merger Petition and Joint Proposal, Financial Forecast and Supporting Workpapers, Volume II, January 17, 2001, pp.377-378 updated by IR-RAV 27 that includes

T&D capital projects during 2009 and spent $306.2 million on T&D-related O&M.[2]

Also, as noted in the Company's 2010 Electric Service Reliability Report to the Commission, the Company's internal field and construction workforce levels increased from 2007 to 2008, and were relatively stable from 2008 to 2009.[3]

The Company has also recently undertaken a comprehensive Transformation Initiative ("TI").[4] The purpose of the TI is to improve customer service, while promoting increased safety, network reliability and performance, and efficiency. As a result of the TI, the Company has identified opportunities to increase existing field force productivity. The Company, together with IBEW Local 97, has established an internal Distribution Line Construction ("DLC") workforce pilot to undertake construction of Distribution Line projects on a dedicated basis in order to make most effective use of the capacity created by TI productivity improvements.

The DLC pilot is discussed in testimony submitted by the Company in this rate case.[5] It was undertaken to create a framework for in-house crews to perform distribution construction line work typically performed by contractors in the past. Pilot development began in October 2009, with pilot implementation targeted for April 1, 2010 through April 1, 2011. The pilot actually started on April 5, 2010. This initiative provides new construction capabilities that enable an internal workforce,

AFUDC and O&M expenditures per Exhibit 1 based on the MJP.

[2] Case 07-E-1533, Petition of Niagara Mohawk Power Corporation for Authorization to Defer Electric Transmission and Distribution Investment Costs, May 28, 2010 at Executive Summary I-5.

[3] 2010 National Grid, Niagara Mohawk Electric Service Reliability Report, at B-7 - B-9.

[4] Case 10-E-0050, Proceeding on the Motion of the Commission as to the Rates, Charges, Rules and Regulations of Niagara Mohawk Power Corporation d/b/a National Grid for Electric Service, *Testimony of the Infrastructure and Operations Panel*, Book 26, at 43-49.

[5] ibid. at 150-151.

dedicated to capital construction, to perform a larger portion of the infrastructure investment program while providing for greater visibility of and comparison to the value of work delivered by the external third party vendors. This also enables benchmarking opportunities to develop further value.

It is my understanding and belief that these appropriate spending increases and initiatives have gone a long way to improving customer service and reliability. It is also important to note that through its provision of safe, adequate and reliable service, Niagara Mohawk supports a significant portion of the overall economy in upstate New York. The dollars expended on management and non-management payrolls, as well as the Company's expenditures for capital construction and operations and maintenance projects which enable electric services to be maintained and improved, contribute to the overall well-being of the upstate economy.

Q. PLEASE SUMMARIZE YOUR CONCLUSIONS AND RECOMMENDATIONS.

A. Based on my review of the Company's filing and my experience in the field operations of Niagara Mohawk, I conclude that the amount of capital and operations and maintenance expenditures the Company has requested in its filing will continue to support and improve the Company's provision of safe, adequate and reliable electric service for its New York customers by funding adequate levels of internal and external labor elements that would perform the necessary activities to keep the electric system in proper, and increasingly improving, working order.

Q. DOES THIS CONCLUDE YOUR PREFILED TESTIMONY?

A. Yes, it does.

ALJ BOUTEILLER: So we now have your affidavit in the record. We also have in the record your pre-filed testimony. Is there anything further, Mr. Koda, that we need to accomplish with your witness?

MR. KODA: No, Your Honor.

ALJ BOUTEILLER: Okay. What other preliminaries or initial matters can we take care of at this point?

MS. NESSER: Your Honor, yesterday the company filed a motion for a Protective Order asking that certain information be redacted from the public record in both the Staff Accounting Panel Number 5 and Mr. Sloey's AFS-1S. Your Honor hasn't had an opportunity to rule on that motion, but I see that staff counsel can speak for herself. I understand that she will not oppose it. And we have taken the liberty of redacting the information from the exhibits that we've provided to Your Honor.

ALJ BOUTEILLER: Okay. Let's go off the record.

(Discussion off the record.)

ALJ BOUTEILLER: Can I hear from staff since you've been referred to?

MS. CICERANI: Yes, Your Honor. Ms. Nesser is correct that staff has no objection. In fact, we support the motion.

ALJ BOUTEILLER: Thank you very much. I note that they are proposing a reduction from a staff-provided exhibit in the case, so that's why it's necessary to hear from you. Does any other party care to address the motion or my taking it up at this time? Okay.

I will rule from the Bench. I have been previously contacted by counsel for the company and notified in advance of the submission of the motion which came in late yesterday afternoon. In anticipation of the motion I was asked to consider whether or not we could modify in the document management system that we have here the pre-filings that were provided by the company and by staff. So to set the stage for this motion I did, in fact, contact our keepers of the DMM system, and yesterday we did accomplish including in the DMM system the redacted versions of the documents that you've provided. I did that based upon a conversation I had with company counsel where I got my first understanding of what the motion is about.

The motion deals with the given names for certain employee children who are minors. It also deals with the specific identification of the schools, educational institutions that they are attending. And in one instance it deals with certain medical information of a current employee which was contained in information provided in response to discovery both in Massachusetts and here in New York.

Is my characterization of the information correct, Counsel?

MS. NESSER: It is, Your Honor.

ALJ BOUTEILLER: Okay. Unless some party can convince me otherwise that the public interest and the consideration of these issues in the case would require that level of detail, I'm prepared to rule that this information is, in fact, of a personal nature, probably of no relevance or material import for purposes of the proceeding, and it would be important from my perspective to maintain the privacy of minor children in their educational institutions and an individual who cares not to make public his or her medical condition. So I'm prepared to rule at this time from the Bench that that information is protected. Our record doesn't require or need that information at that level of detail. If at some time in this proceeding somebody were to suggest that we need on the record specific identification of minor children or specific identification of some educational institution, we can take that matter up at the time that some party seeks to elicit that information in the record, but at this point I'm ruling as a general matter that that information is private and will not be included in the record.

MS. NESSER: Thank you, Your Honor.

ALJ BOUTEILLER: Is there anything further with respect to your motion I need to accomplish?

MS. NESSER: No, there isn't.

ALJ BOUTEILLER: Any further preliminaries before we take up the first witness for today? Very good start. In ten minutes we've accomplished two major things.

Now let me turn to the company counsel and ask you to call your first witness for today.

MS. SWEET ZAVAGLIA: Thank you, Your Honor. Company calls Andrew Sloey.

ALJ BOUTEILLER: Mr. Sloey, please rise.

A N D R E W F. S L O E Y,

having been first duly sworn by the notary public,

was examined and testified as follows:

ALJ BOUTEILLER: Please be seated. For our official purposes I need to have you state both your name and your business address for our record.

THE WITNESS: My name is Andrew Sloey. My business is One Metrotech Center, Brooklyn, New York.

ALJ BOUTEILLER: Thank you very much. At this point we turn to your counsel who will assist us in getting your pre-filed documents into the record.

MS. SWEET ZAVAGLIA: Thank you, Your Honor.

DIRECT EXAMINATION

BY MS. SWEET ZAVAGLIA:

Q Mr. Sloey, do you have before you a document entitled "The Direct Testimony of Andrew Sloey" dated January 29, 2010, consisting of a cover sheet and 26 pages?

A I do.

Q Do you also have before you a document entitled "The Supplemental Testimony of Andrew Sloey" dated May 3, 2010, consisting of a cover sheet and six pages?

A I think I do.

Q Do you have further before you a copy of a document entitled "The Rebuttal Testimony of Andrew Sloey" dated August 6, 2010, consisting of a cover sheet and 68 pages?

A I do.

Q Do you have any corrections to that testimony?

A Yes, we have two corrections.

Q What would those corrections be?

A On page 4, line 20, we need to change the title of the exhibit to Rate Year/Historic Year Comparison.

ALJ BOUTEILLER: Okay.

MS. CICERANI: Which testimony?

THE WITNESS: Apologies. The rebuttal filing dated August 6, page 4, row 20. And we would just change the title of that exhibit from "Rate Year" to "Rate Year To Historic Year Comparison."

ALJ BOUTEILLER: Let's go off the record.

(Discussion off the record.)

ALJ BOUTEILLER: Off the record I just was able to follow you precisely to the exact location, and now I understand the nature of your change. Can you tell us what your next change is?

THE WITNESS: Certainly. Same testimony, rebuttal testimony, page 45 of 68. It's row 10. And the percentage that's sort of like a third of the way along the line, currently it says "24.52." That should say "23.52."

BY MS. SWEET ZAVAGLIA:

Q Mr. Sloey, do you finally have before you a document entitled "The Supplemental Testimony of Andrew Sloey" dated August 30, 2010, consisting of a cover sheet and four pages?

A Yes, I do.

Q If I were to ask you the questions contained in the documents before you today, would your answers be the

same?
A Correct.
Q Do you adopt those documents as your testimony in the proceeding?
A Yes, I do.
Q Do you also sponsor exhibits pre-marked for identification Number 54 through 80?
A Yes.
Q Were those exhibits prepared by you or under your direction and supervision?
A They were.

MS. SWEET ZAVAGLIA: Your Honor, the company offers Mr. Sloey for cross.

ALJ BOUTEILLER: And you've provided the reporter the pre-filed testimony of this witness in digital form?

MS. SWEET ZAVAGLIA: Either have been or will be on PDF.

ALJ BOUTEILLER: Off the record.

(Discussion off the record.)

ALJ BOUTEILLER: The pre-filed information in this case is being provided to the reporter in digital form. She has previously received the bulk of the pre-filing here, but, however, you've just made two corrections on the record, and those corrections have not been provided to the reporter in her digital form. So with knowing that, I will instruct the reporter to copy into the record as if given orally today the pre-filed testimony of this witness with the corrections that you've just identified for our record.

(The referenced testimony is inserted into the record as follows.)

Before the Public Service Commission

NIAGARA MOHAWK POWER CORPORATION d/b/a NATIONAL GRID

Direct Testimony

of

Andrew F. Sloey

Chief Financial Officer, US Financial Services

Dated: January 29, 2010

Testimony of Andrew F. Sloey

Q. Please state your name and business address.

A. My name is Andrew F. Sloey. My business address is One MetroTech Center, Brooklyn, NY 11201.

Q. By whom are you employed and in what capacity?

A. I am employed by National Grid USA Service Company ("National Grid Service Company") as Chief Financial Officer, US Financial Services.

Q. Please briefly describe your educational background.

A. I hold a Bachelor of Business degree from Kuringai College (now the University of Technology, Sydney) and I am a fellow of CPA Australia.

Q. What is your professional background?

A. I am presently CFO of the US Financial Services group for National Grid plc ("National Grid") businesses in the United States. I relocated to the US in 2007 to integrate the accounting, financial reporting and planning functions of National Grid's existing US business (consisting of utility companies in Upstate New York, Massachusetts, Rhode Island and New Hampshire) with its recently acquired subsidiary, KeySpan Corporation (serving customers in Brooklyn, Long Island, Massachusetts and New Hampshire). Prior to this, I was based in the United Kingdom where I was responsible for consolidating the accounting, financial reporting and planning operation within a Shared Services Organization established to support the UK operations. I joined National Grid in August 2004 when National Grid acquired the UK subsidiary of Crown Castle International, an owner/operator of infrastructure for the cellular network and television/radio broadcast operators in the UK. At the time that Crown Castle UK was acquired, I was Finance Director of that business, having relocated from Crown Castle's Australian subsidiary in 2002 where I served as the General Manager of Finance & Administration for Crown Castle's business in Australia. Prior to Crown Castle, I spent just under 20 years with the multi-national consumer goods company, Reckitt & Colman, where I served in a number of senior finance and planning roles.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to describe the Service Company structure used by National Grid in the US, to explain the charges that have been assessed to and incurred by Niagara Mohawk Power Corporation d/b/a National Grid ("Niagara Mohawk") during the Historical Test Year ending September 30, 2009 ("Historical Test Year" or "Test Year"), and the bases upon which those charges have been assessed and incurred. I also discuss the Transaction Delivery Center and the transition of services to Syracuse.

Testimony of Andrew F. Sloey

Q. How is your testimony organized?

A. In the first section I discuss the structure of the Service Companies and their contracts with Niagara Mohawk. In the second section I discuss Service Company accounting and include a description of the types of charges assessed by the Service Companies, as well as a summary of the Historical Test Year charges in total and the specific charges assessed to Niagara Mohawk's electric operations. In the third section I describe the Transaction Delivery Center and the transition of services to Syracuse.

Q. Do you sponsor any exhibits as part of your testimony?

A. Yes. I sponsor the following 17 exhibits, which were prepared or compiled by me or under my supervision and direction:

(i) Exhibit __ (AFS-1): Service Company and Affiliate Company structure;

(ii) Exhibit __ (AFS-2): National Grid USA Service Company Inc. Agreement with Niagara Mohawk;

(iii) Exhibit __ (AFS-3): National Grid Corporate Services LLC Agreement with Niagara Mohawk including 2009 and 2010 Service Requests;

(iv) Exhibit __ (AFS-4): National Grid Engineering & Survey, Inc. Agreement with Niagara Mohawk including 2009 and 2010 Service Requests;

(v) Exhibit __ (AFS-5): National Grid Utilities Services LLC Agreement with Niagara Mohawk including 2009 and 2010 Service Requests;

(vi) Exhibit __ (AFS-6): Cost Allocation Policies & Procedures Manual for legacy National Grid;

(vii) Exhibit __ (AFS-7): Cost Allocation Policies & Procedures Manual for legacy KeySpan Corporation;

(viii) Exhibit __ (AFS-8): National Grid USA Cost Allocation Training Presentation Deck;

(ix) Exhibit __ (AFS-9): Example of Service Company Cost Allocation Methodology;

(x) Exhibit __ (AFS-10): National Grid USA Service Company, Inc. Expenditures by Expense Type/Total Charges for the Year Ended September 30, 2009;

(xi) Exhibit __ (AFS-11): National Grid USA Service Company, Inc. Expenditures by Charged Entity/Total Charges for the Year Ended September 30, 2009;

Testimony of Andrew F. Sloey

(xii) Exhibit __ (AFS-12): KeySpan Service Companies Expenditures Allocated to Niagara Mohawk for the Year Ended September 30, 2009;

(xiii) Exhibit __ (AFS-13): Cost Allocations Driver Summary - Legacy National Grid and KeySpan Service Companies;

(xiv) Exhibit __ (AFS-14): FERC Form 60 National Grid USA Service Company Inc.;

(xv) Exhibit __ (AFS-15): FERC Form 60 KeySpan Corporate Services LLC;

(xvi) Exhibit __ (AFS-16): FERC Form 60 KeySpan Engineering & Survey, Inc.; and

(xvii) Exhibit __ (AFS-17): FERC Form 60 KeySpan Utilities Services LLC.

Q. How are the Service Companies' costs reflected in Niagara Mohawk's rate filing in this proceeding?

A. The Service Company data I sponsor for the Historical Test Year is used as the starting point for projecting Niagara Mohawk's Service Company costs in the Rate Years ending December 31, 2011, December 31, 2012 and December 31, 2013 (collectively, the "Rate Years"). The projection

Testimony of Andrew F. Sloey

of these costs from the Historical Test Year through the end of the Rate Years is supported by the Revenue Requirements Panel.

Service Company Structure

Q. Please provide a brief description of National Grid's Service Company structure.

A. In the United States, National Grid is a multi-state utility holding company, with state-jurisdictional operating affiliates in New York, Massachusetts, New Hampshire and Rhode Island. National Grid uses mutual service companies ("Service Companies") in order to enable the state operating affiliates, including Niagara Mohawk, to deliver high quality and efficient service to customers. As shown in Exhibit __ (AFS-1), as of September 30, 2009, there are four Service Companies in operation at National Grid. The Service Companies provide services to the National Grid regulated utilities as shown in Exhibit __ (AFS-1) and the unregulated companies (collectively, "Affiliate Companies"). National Grid Service Company is the only legacy National Grid service company and provides a full range of support services including corporate functions such as accounting, auditing, employee, tax, treasury and information services as well as construction, engineering and power supply services and has approximately 2,800 employees. National Grid

Testimony of Andrew F. Sloey

Service Company provides services to all the regulated utilities as well as the unregulated companies owned by National Grid USA, Inc. (“National Grid USA”). In contrast, the three legacy KeySpan Corporation Service Companies have been organized to provide separate areas of service that are, in the aggregate, comparable to the full range of services provided by National Grid Service Company. The three legacy KeySpan Corporation Service Companies are: (i) National Grid Corporate Services LLC, with approximately 3,400 employees, (ii) National Grid Engineering & Survey, Inc., with approximately 650 employees and (iii) National Grid Utilities Services LLC, with approximately 150 employees (collectively the “KeySpan Service Companies” and, collectively with National Grid Service Company, the “Service Companies”). National Grid Corporate Services provides traditional corporate and administrative services, National Grid Engineering & Survey provides engineering and surveying services and National Grid Utility Services provides gas and electric transmission and distribution systems planning, marketing and gas supply planning and procurement services. Prior to the repeal of the Public Utility Holding Company Act of 1935 (“PUHCA”), National Grid USA and KeySpan Corporation were subject to the jurisdiction of the Securities Exchange Commission (“SEC”) under PUHCA. As part of the regulatory provisions of PUHCA, the SEC regulated various transactions among

Testimony of Andrew F. Sloey

affiliates within a holding company structure. Allocation methodologies approved by the SEC continue to be used to allocate Service Company costs to affiliates.

Q. What agreements for services does Niagara Mohawk have with the Service Companies?

A. Niagara Mohawk contracts with National Grid USA Service Company, Inc. for services. Attached as Exhibit __ (AFS-2) is the Service Company Agreement between Niagara Mohawk and National Grid USA Service Company, Inc. Niagara Mohawk also contracts with the KeySpan Service Companies for services. Attached as Exhibit __ (AFS-3), Exhibit __ (AFS-4) and Exhibit __ (AFS-5) are the Service Company Agreements between Niagara Mohawk and the KeySpan Service Companies.

Q. What types of services are provided by the Service Companies?

A. The Service Company Agreements included as Exhibit __ (AFS-2), Exhibit __ (AFS-3), Exhibit __ (AFS-4) and Exhibit __ (AFS-5) provide a description of the services provided. Further description of the services provided is also included in Appendix B of the legacy National Grid Cost Allocation Policies & Procedures Manual provided in Exhibit __ (AFS-6) and Appendix A of the legacy KeySpan Cost Allocation Policies &

Testimony of Andrew F. Sloey

Procedures Manual provided in Exhibit __ (AFS-7). In general, the services provided are those typically required to operate a gas distribution or electric transmission or distribution utility and include, for example, accounting, construction, engineering, information systems, rates and regulatory support and treasury services. The costs of these services include payroll, outside vendors, materials, personnel expenses and computer expenses, to name a few.

Q. Do the Service Company Agreements with Niagara Mohawk discussed above establish performance thresholds and levels of services?

A. No. The Service Company Agreements form a contract between the Service Companies and Niagara Mohawk as to what type of services will be performed and the basis upon which the cost of delivering these services is to be charged.

Q. Is National Grid developing agreements to define the level of services provided by the Service Companies to the Affiliate Companies?

A. Yes. Consistent with the recommendations set forth in the Niagara Mohawk Management Audit, National Grid is developing Service Level Agreements between the US Electric Transmission, Electric Distribution and Gas lines of business ("Lines of Business") and organizational groups and departments that provide shared services to these Lines of Business ("Organizations").

Q. What is the purpose of the Service Level Agreements?

A. The Service Level Agreements are separate from the Service Company contracts and are intended to focus on the efficiency and quality aspects of the services being provided to the Affiliate Companies and to establish clear performance measures.

Q. Please explain the process for developing the Service Level Agreements.

A. National Grid has created a two-tier approach for developing the Service Level Agreements. The first tier incorporates the Master Service Level Agreements ("MSLA") that generally describe each Organization's annual objectives, services provided, key dependencies, costs, performance reporting and commitments to continuous improvement. The second tier incorporates the Functional Service Level Agreements. These agreements are more detailed and establish the key performance measures that will measure efficiency and quality.

Testimony of Andrew F. Sloey

Q. When does National Grid anticipate that the Master Service Level Agreements and Functional Service Level Agreements will be executed?

A. National Grid is in the process of developing Service Level Agreements that cover the functions that deliver services across the Lines of Business. The review and completion of these Service Level Agreements may take up to a year. As explained in Niagara Mohawk's response to the Management Audit Report, the Company will file the final agreements with the Commission. Further detail on the Company's implementation efforts relative to Service Level Agreements is set forth in the Company's implementation plan being submitted in Case 08-E-0827. A copy of that plan is also included with Mr. Zschokke's testimony in this rate case.

Q. Does National Grid's Service Company structure benefit customers of Niagara Mohawk?

A. Yes. The Service Company framework creates efficiencies of scale for Niagara Mohawk and all other Affiliate Companies. By establishing a centralized entity to provide service to designated affiliates, National Grid is able to implement common corporate policies, streamlined business processes and integrated information services, all of which enhance the cost effectiveness of the services provided. National Grid is able to obtain advantages in purchasing certain goods and services from third parties because of the volume of purchases made by the Service Companies. The Service Company framework provides for the consolidation and integration of common systems and the assignment of costs to the Affiliate Companies that are supported by each Service Company.

Q. Do the Historical Test Year Service Company costs reflect the impact of the completed acquisition of KeySpan Corporation by National Grid?

A. The acquisition of KeySpan Corporation by National Grid was completed in August 2007. Since that time there has been a progressive consolidation of several Service Company functions across legacy National Grid and KeySpan Corporation. One of the key strategies associated with the KeySpan Corporation acquisition was the realization of synergy savings for the benefit of customers and shareholders. Significant progress and synergies have been achieved to date through the consolidation of Service Company departments and locations. However, integration to a single set of processes through implementation of a common platform is required to fully realize the synergy savings contemplated at the time of the KeySpan merger.

Testimony of Andrew F. Sloey

Q. Does National Grid intend to combine or reorganize the existing Service Companies?

A. Yes. As explained in Appendix 4 of the National Grid/KeySpan Merger and Gas Revenue Joint Proposal, National Grid USA intends to combine or reorganize the existing Service Companies.[1] To date, none of the Service Companies have been restructured; however, National Grid USA remains committed to consolidating three of its four Service Companies (excluding National Grid Engineering and Survey, Inc.) once any necessary regulatory approvals are obtained and the Companies can be unified on a common financial systems platform with common allocation methodologies. The Service Companies will propose a new consistent allocation methodology. To the extent that costs increase or decrease to Niagara Mohawk as a result of this change, Niagara Mohawk will reflect the credit or debit to customers in a deferral account as identified in the testimony of the Revenue Requirement Panel.

[1] Case No. 06-M-0878 et,al, *Joint Petition of National Grid PLC and KeySpan Corporation for Approval of Stock Acquisition and other Regulatory Authorizations, Merger and Gas Revenue Requirement Joint Proposal* dated July 6, 2007. Also see*, Order Authorizing Acquisition Subject to Conditions and Making Some Revenue Requirement Determinations for KeySpan Energy Delivery New York and KeySpan Energy Delivery Long Island* (Issued and Effective September 17, 2007). The recently released management audit report in Case 08-E-0827acknowledges the initiative to consolidate the Service Companies and recommends continuation of that effort.

Testimony of Andrew F. Sloey

Q. Is the Company proposing any changes to the current allocation methodologies in this proceeding?

A. No. At this time, the platforms and systems needed to facilitate the consolidation have not been implemented. Until the Service Companies are consolidated, we propose to maintain the current cost allocation methodologies.

Q. Will the scope of services provided by the Service Company to Niagara Mohawk change between now and the end of the Rate Years?

A. National Grid plans to continue to provide Niagara Mohawk the same Service Company services that were provided in the Historical Test Year through the end of the Rate Years.

Service Company Charges

Q. Please describe how National Grid Service Company charges for its services.

A. National Grid Service Company charges are either directly charged to individual Affiliate Companies (where a service is performed for the benefit of a single Affiliate Company) or, when the service performed is for the benefit of multiple Affiliate Companies, charges are aggregated into Service Company "bill pools" and allocated to each Affiliate

Company that benefits from the service using approved allocation methodologies. As shown in Exhibit __ (AFS-13), the cost allocation methodologies are determined by cost drivers (for example the number of employees in each company or the number of customers) to ensure that each Affiliate Company receives its appropriate share of the cost. Bill pools have been established to accommodate different types of expense that are incurred by the Service Companies (for example, employee time, travel expenses and third party invoice costs). Where it is not possible to use a specific cost driver as an allocator, a general allocator is used to distribute the cost based on the proportion of operation and maintenance costs of each Affiliate Company using the service. To support compliance with the Service Company Agreements, validation rules have been established within legacy National Grid's PeopleSoft general ledger that restrict service providing departments to only the appropriate ranges of bill pools. To further explain the National Grid Service Company accounting, a presentation is included as Exhibit __ (AFS-8), the National Grid USA Cost Allocation Training Presentation Deck.

Q. Please explain how the cost drivers for National Grid Service Company bill pools are determined.

Testimony of Andrew F. Sloey

A. We look for cost causation. For example, the cost driver for the bill pool used to allocate Data Center costs is CPU usage by company. Another example is the cost driver for the bill pool used for allocating Human Resource costs is the number of employees at each company. Bill pools are established at the beginning of the fiscal year and reflect the prior year's actual data or budget data for the upcoming year. Bill pools may be updated during the year if there is a significant structural change to the organization such as a merger or sale of a business unit.

Q. Please describe how the KeySpan Service Companies charge for their services.

A. All costs incurred by the KeySpan Service Companies are recorded on their books before being allocated. The process of allocating Service Company costs to Affiliate Companies is accomplished using functionality contained in Oracle General Ledger ("Oracle"), which supports an automated, rules-driven process known as "Mass Allocations." Mass Allocations is a recurring routine, run as a part of the monthly closing cycle that: (i) aggregates KeySpan Service Companies costs into "cost pools" (ii) calculates the amounts allocable to each Affiliate Company and (iii) generates and posts all required journal entries.

Testimony of Andrew F. Sloey

Q. Please explain the allocation rule designed to aggregate KeySpan Service Company costs into "cost pools".

A. A KeySpan Service Company cost pool is the aggregation of costs with a common set of attributes. These attributes are reflected in the appropriate Oracle account code segments to define the cost of the underlying services or activities that are then distributed to the Affiliate Companies utilizing the service using an appropriate allocation code.

Q. Please explain the allocation rule designed to calculate the amounts allocable to each Affiliate Company.

A. Each KeySpan Service Company cost pool is assigned a specific "allocation code" that defines the basis used to distribute costs from the pool to the various Affiliate Companies. Cost pools and allocation codes are constructed based on cost causation principles and are designed to maximize usage of "direct" allocation codes. Direct allocation codes are used when charges have been incurred to the direct benefit of a single Affiliate Company. In these instances, all of the cost pool is charged to that Affiliate Company. Where it is not possible to use a "direct" allocation code, an "indirect" allocation code is assigned based on the most appropriate causation/driver method (for example, the number of employees or the number of meters in use). Where it is not possible to

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make an allocation based on either a direct or indirect allocation code, then a general allocator is used to distribute charges to Affiliate Companies that use a particular service. For the KeySpan Service Companies, the approved general allocator is the "3 Point Formula." To further explain the KeySpan Service Companies' accounting, a presentation is included in Exhibit __ (AFS-7).

Q. What is the 3 Point Formula?

A. The formula consists of three factors that achieve an appropriate allocation of costs to Affiliate Companies when direct charging or cost causal relationships can not be established. It is a calculated ratio that compares each of the formula factors for the Affiliate Company to the total of the same factors for all recipient Affiliate Companies. The factors are an equal weighting of Revenue, Assets, and Expenses. These ratios are calculated annually based on actual reported in the books and records of the Affiliate Companies.

Q. Please describe the accounting for shared assets owned or leased by the Service Companies.

A. In order to provide support to the Affiliate Companies, the Service Companies own and lease a number of shared assets that are used either by Service Company employees to provide services to the Affiliate Companies or used by the Affiliate Companies themselves on a shared basis. These are principally shared office facilities and information technology ("IT") equipment and software.

Where assets are leased, the lease rentals are charged to Affiliate Companies at cost, consistent with the allocation methodologies explained above. Where the Service Companies finance and own shared assets, the Service Companies charge Affiliate Companies an incurred return on the asset, booked depreciation expense, incurred operating and maintenance expense and any applicable taxes. National Grid Service Company's charges to affiliate companies include an operating charge determined in accordance with these principles and a financing charge that reflects a return on the debt and equity used by National Grid Service Company to finance the shared assets.

KeySpan Corporate Services also assesses a charge for shared assets on the same basis.

The financing charge assessed by the Service Companies is derived from their actual capitalization. National Grid Service Company has a modest

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equity component that is charged out at a 10.5 percent return and a much larger debt component that is derived from external loans obtained by KeySpan Corporation at an interest rate of 5.803 percent.[2] The 10.5 percent equity component is reflected in Exhibit __ (RRP-2). KeySpan Corporate Services' similarly assesses interest charges on the minimal costs that flow to Niagara Mohawk as rent expense.

Q. Please describe the accounting for shared assets owned or leased by Niagara Mohawk.

A. In addition to shared assets owned by the Service Companies, there are a number of shared assets owned by Niagara Mohawk that are used to provide service to other Affiliate Companies. An example is the Investment Recovery Center. Where assets are leased, the lease rentals are charged to Affiliate Companies at cost, consistent with the allocation methodologies explained above.

Where Niagara Mohawk finances and owns shared assets, Affiliate Companies also receive a charge that recovers Niagara Mohawk's incurred return on the asset, booked depreciation expense, incurred

[2] National Grid Service Company was authorized by the Securities and Exchange Commission on January 5, 2001 to earn a rate of return equal to 10.50% of contributed common equity. See, 74 S.E.C. Docket 183, 2000, National Grid USA Service Company, Inc. 70-9673 (Issued January 5, 2001).

operating and maintenance expense and applicable taxes. An example of how the charges are calculated is included as Exhibit __ (AFS-9).

Q. Does National Grid have a process to ensure that Service Company costs are being accurately captured and allocated among its various business units?

A. Yes. There are numerous controls in place aimed at ensuring the accuracy of charges from the Service Companies to the Affiliate Companies. National Grid utilizes a cost allocation integrity compliance framework to provide assurance that Service Company costs are being accurately captured and allocated among its various business units. The pillars of this framework are fully documented cost allocation policies and procedures for all Service Companies (Exhibits __ (AFS-6, 7), a training and awareness program including roles and responsibilities (Exhibits __ (AFS-8 and 13), a cost allocation compliance testing program, a Cost Allocation Review Committee and oversight provided by a Regulatory Cost Structure committee. Other controls include the annual calculation, updating and approval of billing pool and allocation code percentages including year to year variance analysis, development and monthly review of clearing accounts, development and review of Service Company operating expenses and equity, monthly allocations run controls, monthly review of suspense charges associated with intercompany billing and A/R to A/P monthly reconciliation. In addition to that process, general budget reviews performed by Line of Business Finance departments identify and address any cost allocation issues that arise. Please also refer to Exhibit __ (AFS-6), the Cost Allocation Policies & Procedures Manual for legacy National Grid and Exhibit __ (AFS-7), the Cost Allocation Policies & Procedures Manual for legacy KeySpan Corporation.

Q. What actions is the Company taking in response to the Commission's Order in Case No. 09-E- 0953?

A. On December 23, 2009 the Commission issued an Order in the above referenced proceeding regarding the accounting treatment of the Texaco Tank Farm. The Commission directed the Company to address in its next electric rate case filing how it has accounted for all operation and maintenance expenses, property taxes, SIR costs and capitalized costs relating to properties that are classified or should be classified as Non-Utility Property in the Historical Test Year and Rate Years. Accordingly, the Company has commenced a review of all plant including Non-Utility Plant. The review is on-going and expected to be complete by May 1, 2010. As explained in the testimony of the Revenue Requirement Panel,

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any adjustments based on this review will be provided in Corrections and Updates submitted in this proceeding.

Q. Have you summarized the charges from the Service Companies to Niagara Mohawk in the Historical Test Year?

A. Yes. Please see Exhibits __ (AFS-10, 11 and 12) for a summary of all Service Company charges for the Historical Test Year ended September 30, 2009.

Q. Please describe Exhibits __ (AFS-10, 11 & 12).

A. Exhibits __ (AFS-10 and 11) present National Grid Service Company charges in several ways. First, the charges are sorted by charged company and segment in total and by bill pool. Second, the charges are sorted by expense type in total and by bill pool. Exhibit __ (AFS-12) presents the KeySpan Service Companies charges as allocated to Niagara Mohawk for the year ended September 30, 2009.

Q. For calendar year 2008, was National Grid required to make any regulatory filings setting forth its Service Company charges and their allocation among various business units?

A. Yes. FERC Form 60, attached as Exhibits __ (AFS- 14, 15, 16 and 17), reflects these charges for the twelve months ended December 31, 2008.

Q. How does the summary on Exhibits ___ (AFS-10 and 11) compare to Exhibit __ (AFS-14)?

A. The costs reflected on Exhibits __ (AFS-10 and 11) are higher than those reflected in the FERC Form 60 for National Grid Service Company because Exhibits __ (AFS-10 and 11) amounts include "convenience" payments while the FERC Form 60 does not. Convenience payments are invoices paid by the Service Company on behalf of the Affiliate Companies where this is the only service the Service Company is providing. An example of this is payroll taxes. Rather than send many checks to the IRS, the Service Company remits one check from the Service Company to the IRS, but directly allocates the appropriate expense amount to the Affiliate Companies in the general ledger. Because National Grid Service Company creates the payment and directly allocates the costs, the originating company in the system is the Service Company.

Transaction Delivery Center

Q. Please explain the transition of services to Syracuse.

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A. Following National Grid's acquisition of KeySpan Corporation there are numerous employees in various locations providing substantially similar support services of a transactional nature to the Affiliate Companies. National Grid is in the process of consolidating these support functions to the Syracuse Office Complex ("SOC"). Functions being consolidated in the SOC include , Payroll, Accounts Payable, Employees Services and Transactional Procurement

Q. What is the Transaction Delivery Center?

A. The ability to attract talented and skilled workforce in our upstate New York region and the favorable operating economics make Syracuse an attractive location within National Grid's US footprint. As functions are transitioned to or consolidated in the SOC they are brought into National Grid's newly created Transactions Delivery Center ("TDC") located in Syracuse. The TDC is designed to:

- facilitate better standards of service, greater efficiency and cost savings;
- centralize and streamline transactional activities;
- deliver high-quality services at the right cost; and
- design a TDC that is scalable and can accommodate future growth

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The TDC enables the consolidation of facilities in Melville, Waltham and MetroTech to Syracuse. In addition, process improvements are continually being implemented as the transition occurs. The TDC enables the Company to achieve synergy savings identified in the KeySpan merger proceeding.

Q. Has the Company included the capital costs associated with the Transaction Delivery Center in the Rate Years?

A. Yes. The Company has included capital investment costs associated with the TDC in the Rate Years as supported by the Infrastructure and Operations Panel and Revenue Requirement Panel.

Q. Does that conclude your testimony?

A. Yes it does.

Before the Public Service Commission

NIAGARA MOHAWK POWER CORPORATION d/b/a NATIONAL GRID

PSC Case No. 10-E-0050

Supplemental Testimony of

Andrew F. Sloey

Dated: May 3, 2010

Testimony of Andrew F. Sloey

Q. Please state your name.

A. My name is Andrew F. Sloey.

Q. Are you the same Andrew F. Sloey that previously provided testimony in this proceeding?

A. Yes. I provided direct testimony as part of the Company's January 29, 2010 filing.

Q. What is the purpose of your supplemental testimony?

A. The purpose of my testimony is to provide an update on the Company's review of Non-Utility Property as required by the Commission's Order in Case 09-E-0593.

Q. Please explain the review that the Company was required to conduct.

A. As discussed in my direct testimony, on December 23, 2009, the Commission issued an Order in the above referenced proceeding regarding the accounting treatment of the Texaco Tank Farm. The Commission directed the Company to address in its next electric rate case filing how it has accounted for all operation and maintenance expenses, property taxes, SIR costs and capitalized costs relating to properties that are classified or should be classified as Non-Utility Property in the Historical Test Year and Rate Years.

Q. What actions did the Company take in response to the Commission's Order?

A. The Company commenced two reviews of plant. Those reviews were not complete at the time of the Company's January 29, 2010 filing in this proceeding. Accordingly, the Company provided that any adjustments resulting from these reviews would be submitted in its Corrections and Updates filing.

Q. Please explain the Company's reviews of plant.

A. The first review involved a review of land parcels in rate base. The purpose of this review was to identify parcels that should be retired from rate base because of a sale or divestiture or transferred from rate base to Non-Utility Property because the particular parcel was not used or useful. The second review involved research into the status of property currently classified as Non-Utility Property to specifically identify those parcels that were either transferred from rate base and are subject to Site Investigation and Remediation ("SIR") program remediation or were purchased directly to Non- Utility Property to provide benefits to customers by reducing the

Testimony of Andrew F. Sloey

overall cost of SIR. As explained in the Company's response to Information Request Number NM-200, AAE-14 and discussed in the supplemental testimony of the Revenue Requirement Panel, in some instances it is more cost effective to purchase contaminated property and undertake remediation as the site owner than it is to remediate the property to unrestricted use status.

Q. Please explain the results of the first review.

A. The first review analyzed rate base land parcels by plant location to identify those parcels that did not also contain rate base plant equipment or other non-land assets. This analysis produced a list of approximately 180 parcels of land that required further research to determine whether they were used and useful to utility operations. This review indicated that many of these parcels were still used and useful for functions such as inventory storage yards and other utility operations.

The review also identified parcels that required retirement as follows: 59 parcels of land in FERC Account 350, Transmission Substation Land, associated with previously owned hydro station assets that were sold as a part of generation divestiture, required retirement. The Company confirmed that these transmission substation land parcels were sold as a

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part of divestiture of the hydro stations, that they were removed from the real estate tax assessment basis at the time of sale and that no real estate taxes have been paid on these parcels since that time. However, these parcels were not retired from Plant in Service at the time of the sale. The entries to retire these 59 parcels from Plant in Service were processed in March 2010. In addition, there were four parcels of land that were associated with distribution substations and one parcel of land associated with a former Gas Regulator Station site that upon investigation should have been retired. The entries to retire these five parcels from Plant in Service were also processed in March 2010. The original cost of all 64 parcels retired was $143,152. This first review further identified 9 parcels of land determined to be no longer used and useful to utility operations and they were transferred to Non-Utility Property, also in March 2010. These 9 parcels had an original cost basis of $18,011.

To comply with the prescribed accounting under the Financial Recovery Agreement ("FRA") approved by the Commission in Case No. 29327, a fair market value appraisal of the parcels transferred has been ordered. The FRA provides that in lieu of sharing net gains or losses from the sale of utility property, the entire net amount (calculated as being the delta between the appraised market value and the historical cost base) is to be set aside for rate making effective July 1, 1990 utilizing a deferral mechanism used to offset remediation costs associated with other properties in the Non-Utility portfolio that are subject to the SIR program. The market appraisal needed to determine this net amount (either a gain or loss) of the parcels transferred from rate base to Non-Utility Property has been commissioned. Journal entries to complete the transfer and recognize any gain or loss will be processed once these have been received.

Q. Please explain the results of the second review.

A review of existing Non-Utility Property was conducted to specifically identify within the Company's fixed asset system those land assets subject to the SIR program, whether transferred from rate base or acquired directly into Non-Utility Property in order to mitigate what would otherwise be higher SIR costs. Eleven locations encompassing 12 parcels of land were identified with an original cost of $2,247,643. These 12 parcels have been uniquely tagged within the Company's fixed asset systems so that costs can be effectively tracked. This same tagging system will be used to account for any future additions to the Non-Utility portfolio that are also subject to the SIR Program.

Testimony of Andrew F. Sloey

Q How does the Company propose to account for adjustments resulting from the reviews of plant?

A. The Revenue Requirements Panel provides an explanation of the accounting adjustments resulting from the reviews of plant.

Q. Does this conclude your direct testimony?

A. Yes it does.

<u>Before the Public Service Commission</u>

<u>NIAGARA MOHAWK POWER CORPORATION d/b/a NATIONAL GRID</u>

<u>Rebuttal Testimony</u>

<u>of</u>

<u>Andrew F. Sloey</u>

<u>Dated: August 6, 2010</u>

Q. Please state your name.

A. My name is Andrew F. Sloey.

Q. Have you previously provided testimony in this proceeding?

A. Yes. I provided direct testimony as part of Niagara Mohawk Power Corporation d/b/a National Grid's ("Niagara Mohawk" or the "Company") January 29, 2010 filing and supplemental testimony as part of the Company's Corrections and Updates filing submitted on May 3, 2010.

I. <u>Introduction</u>

Q. What is the purpose of your testimony?

A. The Staff Policy and Accounting Panels raise certain concerns and issues relating to Service Company charges to Niagara Mohawk. National Grid plc ("National Grid") has four mutual Service Companies and I refer to them generally as "Service Company" or "Service Companies" throughout my testimony. The purpose of my testimony is to respond to the concerns of the Staff Policy and Accounting Panels. Specifically, I address 1) the structure and purpose of the Service Companies, including budget development, review and challenges, 2) the escalation in costs charged from the Service Company to Niagara Mohawk, 3) allocation issues such as cross-subsidization of Affiliate Companies, and 4) internal controls and review of Service Company charges. My testimony also addresses certain adjustments and issues presented by Staff with respect to construction work order closing delays.

Q The Staff Accounting Panel proposes an approximately $26 million macro adjustment to Service Company charges to Niagara Mohawk. Does the Company agree with Staff's macro adjustment?

A. No. Staff's macro adjustment to the Company's Rate Year forecast of Service Company charges is arbitrary and wholly unsupported. As I will cover later in my testimony, the largest component of Niagara Mohawk's costs are direct charged. For the Legacy National Grid Companies, direct charges are those costs that are either incurred directly within Niagara Mohawk, or originate from the National Grid USA Service Company, Inc., or another Affiliate Company and are directly charged to Niagara Mohawk without the need to use an allocation process (either a cost causal bill pool or a general allocator bill pool). As the Legacy KeySpan companies do not have the ability to direct charge to Niagara Mohawk (or in fact any Affiliate Company in the NGUSA group) an allocation code has been established within the KeySpan Service Companies to allow costs to be directly allocated to Niagara Mohawk where this appropriate. Any costs not direct charged or directly allocated as described above are considered to be "allocated" costs. Of those costs that are allocated, the Company has demonstrated clearly that, with a few minor exceptions, the charges and allocation methodologies are appropriately applied. Staff argues that certain adjustments are required to correct specific allocation errors. Even if they were warranted, however, these adjustments total only approximately $6 million. Staff offers no support for the additional $20 million adjustment. Staff's macro adjustment in no way relates to the services received by Niagara Mohawk in the Historic Test Year or forecast in the Rate Year. Accordingly, Staff's macro adjustment is without merit and should be denied.

Q. Does the Company agree with Staff's recommendation that the Commission institute a separate proceeding to evaluate all aspects of the Service Company?

A. No. Staff offers no basis for such a proceeding. Contrary to Staff's characterizations, the Company takes cost control and monitoring very seriously. The Company has implemented a number of measures to review and test the accuracy of Service Company charges to affiliate companies. These measures are discussed in detail below. The Company has devoted significant time and resources to the review of its cost allocation methodologies and has sought input and assistance from external resources. For example, as discussed later in my testimony, the Company engaged PricewaterhouseCoopers ("PwC") to assist the Company in its evaluation and testing of its cost allocation process. Furthermore, a Comprehensive Management Audit of Niagara Mohawk Power Corporation was completed in December 2009. The audit did not raise control or Service Company independence concerns nor did it identify the need to implement substantial changes to the budget process. Moreover, Staff has submitted hundreds of questions relating to Service Company charges. The Company has in all instances worked with Staff to provide timely and meaningful responses. The Company agreed to an extension of the suspension period to allow Staff time to conduct its review and does not understand why a review of Service Company charges was not possible within the schedule adopted in this proceeding. Staff's recommendation that a separate proceeding be instituted to evaluate Service Company charges is unnecessary, as Staff may, at any time, conduct an audit of Niagara Mohawk's costs, including Service Company charges. A separate proceeding is therefore unwarranted.

Q. Does you Sponsor any exhibits?

A. Yes. I am sponsoring the following exhibits prepared under our direction and supervision:

Exhibit __ (AFS-1R)	Niagara Mohawk's Cost on a Per Customer Basis
Exhibit __ (AFS-2R)	Illustrative Overview of the Service Company Department/Function Budget Process
Exhibit __ (AFS-3R)	Rate Year to Historic Year Comparison
Exhibit __ (AFS-4R)	Mapping of Service Contract Functions to Current Organization
Exhibit __ (AFS-5R)	PeopleSoft Allocation
Exhibit __ (AFS-6R)	Reservoir Woods Square Footage Comparison

Exhibit __ (AFS-7R)	Reservoir Woods Bill Pool Comparison
Exhibit __ (AFS-8R)	Consultant Invoice Adjustments and Detailed Support
Exhibit __ (AFS-9R)	Copies of IRs

II. Structure of the Service Companies

Q. Please explain National Grid's organizational structure as it relates to its Service Companies and Lines of Business.

A. National Grid USA is comprised of over 100 regulated and non-regulated legal entities. There are approximately 20 primary entities that consist of the regulated utilities and contain the electric distribution, gas distribution, electric transmission and generation activities that are the core of National Grid's business in the US. As is shown in Exhibit __ (AFS-1), accompanying my direct testimony, National Grid organizes itself along five Lines of Business ("LOB"): (1) Electric Distribution and Generation; (2) Gas Distribution; (3) Transmission; (4) Non Regulated; and (5) Other, with focused (LOB) management teams overseeing the relevant activities of the entities within their purview. As demonstrated in Exhibit __ (AFS-1), a single legal entity may span more than a single Line of Business. For example, Niagara Mohawk comprises the Gas Distribution, Electric Distribution & Generation, and Transmission Lines of Business. The four Service Companies in operation at National Grid, *i.e.*, National Grid Corporate

Services LLC, National Grid Utility Services LLC, National Grid Engineering & Survey, Inc., and National Grid USA Service Company Inc., provide common support for Affiliate Companies and for each of the LOBs.

Q. What role do the Service Companies play in the organization?

A. As noted in the National Grid USA Service Company contract, Exhibit __ (AFS-2), with Niagara Mohawk Power Corporation, the Service Companies are "engaged primarily in the rendering of services to companies in the National Grid USA holding company system." Services include, among others, executive and administration, human resources, information technology, legal, and regulatory. The service contracts between the four Service Companies and Niagara Mohawk (as well as with all other affiliates), define the range of services that may be provided and require that these services be provided at cost. Within the National Grid USA structure and systems, it is only the Service Companies that contain the mechanisms (bill pools and allocation codes) that allow the sharing of services to a number of affiliated companies within and across various Lines of Business. Therefore, a service company should be viewed as simply a mechanism to share a cost between two or more affiliated companies.

Q. What are the benefits of a service company structure?

National Grid USA has established a service company structure to facilitate the efficient, centralized charging of costs for employees who provide services across multiple regulated (and unregulated) entities. This operating model allows for economies of scale and provides consistency of service delivery, accounting and financial/regulatory reporting that would not be possible if the individual affiliates secured the services on their own. It should be noted that the final report in the Comprehensive Management Audit of Niagara Mohawk included a Finding/Conclusion that the use of service companies to accumulate and allocate costs associated with the services provided to multiple LOBs is appropriate. In Order 667 relating to the "Repeal of the Public Utility Holding Company Act of 1935 and Enactment of the Public Utility Holding Company Act of 2005," the Federal Energy Regulatory Commission ("FERC") agreed with commentators that "centralized provision of accounting, human resources, legal, tax and other such services benefits ratepayers through increased efficiency and economies of scale" (p. 110). FERC further "recognize[d] that it is frequently difficult to define the market value of the specialized services provided by centralized service companies" (p. 110). In setting rates for Massachusetts Electric Company, the Department of Public Utilities (DPU) in Massachusetts recognized that "such services as legal, accounting, regulatory, human resources, and engineering . . . [provided by service companies] . . . are the types of services that the Company requires on a continuing basis and provide a benefit to the Company for the proper operation of its business and the delivery of electric service to its customers." The DPU went on to state:

> It is common for a public utility holding company structure to have centralized accounting, financial, and regulatory functions… because these types of services require a close familiarity with both the operating company and its holding company, it is unclear whether an RFP would result in the type of response that would achieve the objective to minimize costs (D.P.U. 09-39, p. 259-60).

In the Pennsylvania Public Utility Commission v. Peoples Natural Gas Company (Oct. 26, 1978) decision, the Pennsylvania Public Utility Commission noted that their "approval of the service company charges [wa]s based upon a recognition that respondent [Peoples Natural Gas Company] shares the advantages of lower costs occasioned by economies of scale--that costs to respondent for the services performed by the service corporation would be considerably higher if these services were incurred on an individual basis by respondent"(p. 205-206). Also, the Virginia State Corporation Commission in Case No. PUE-2006-00023 has found that "[m]embers of a public utility holding company that consolidate and centralize corporate services can normally achieve significant economies of scale and other business efficiencies through elimination of duplicative personnel and facilities across the holding company's system."

Q. Does the Company evaluate whether services can be provided at a lower cost than are provided by the Service Company?

A. The Company generally relies on Service Companies to provide day- to-day core services such as accounting, human resources and legal to all of the affiliated companies in the National Grid USA holding system. This results in a more efficient, consistent and lower cost delivery than if each affiliate company sourced these services independently. National Grid does not put services such as these out to bid because they require a close familiarity with the operating company, holding company, and National Grid's reporting, systems and controls processes. The Company does not believe that a bidding process would achieve the Company's objective of minimizing costs without introducing an unacceptable level of complexity associated with having multiple external vendors provide these core services. Institutional knowledge is a key component to the provision of core services, particularly in a regulated environment. If, however, the Company has a special project, significant event, or need for supplemental resources that the Service Company is unable to support, the Company uses its competitive bidding process or other standard practice to obtain another provider.

Q. Please continue.

A. Labor costs are a significant percentage of costs charged from the Service Companies to Niagara Mohawk. National Grid analyzes its compensation packages (union and non-union) to determine whether those labor costs are competitive with the market. As shown in Exhibit__(AFS-1R), the Company's total costs on a per customer basis are lower than the costs of all but one utility in the State. The Company's analysis includes both direct and allocated charges as well as, as discussed later, all of the FERC 900 Accounts except Accounts 908 and 928.

Q. Do you agree, as Staff suggests, that it is problematic that most of Niagara Mohawk's management are Service Company employees?

A. No. Where departments and individuals share time across more than one entity, as under our management organizational structure, as a practical matter, those departments and individuals should be employed by a Service Company. This is the only arrangement where costs can be distributed in a consistent manner to a number of affiliated companies. The much less efficient alternative would be to replicate management and support activities in each utility rather than sharing across utilities. Further, as explained above, the primary purpose of the Service Company is to render services to Affiliate Companies. There is no incentive for management to bias their actions in favor of the Service Company. Moreover, Staff's claim unfairly assumes bad faith or a lack of integrity on the part of Niagara Mohawk's management.

Being an employee of a service company does not in any way alter individual and management responsibility and accountability to act in the best interests of each utility that the employee serves. For example, Tom King is President of National Grid USA and Executive Director of the Electric Distribution business. The fact that he is a Service Company employee in no way diminishes his accountability for each affiliated utility or the Electric Distribution & Generation LOB and does not affect the conduct of his duties in any way. Staff's narrative that the Service Company is indifferent, if not hostile, to the interests of Niagara Mohawk is simply not true.

Q. How are costs distributed by the Service Companies to the various Affiliate Companies they support?

A. As explained in my direct testimony, services provided to Affiliate Companies are charged to each company at cost based upon the guidelines set forth in the Service Agreements with the Affiliate Companies. In particular, costs are (1) directly charged; (2) allocated using a reasonable and equitable allocation ratio (a pre-defined bill pool for National Grid USA Service Company or a pre-defined allocation code for KeySpan Service Companies) based upon a cost-causal relationship between the costs and the entity receiving the costs; or (3) allocated using approved general allocation methodologies if the former two approaches are not feasible.

Q. Staff suggests that the Company cannot effectively control costs without maintaining overall Service Company budgets. Does the Company agree?

A. No. Staff's testimony assumes that because we do not construct budgets on a Service Company basis that costs are not reviewed/controlled. National Grid, however, has an established process in place to develop, review, and control budgets and actual expenses. Budgets are constructed for each Service Company department/function such as Legal, Financial Services, and Human Resources. Each of the Service Company departments form part of the operating expense that will, as described later in my testimony, ultimately be accounted for within one or a number of Service Companies and then allocated to Affiliate Companies as appropriate. By aggregating the budgets for all Service Company departments/functions, an overall service company budget can be derived. However, as I discuss in more detail below, management of costs occurs at the Service Company department/function level (as opposed to a total service company basis). The process of developing, reviewing, and controlling budgets and actual expenses is closely tied to our Line of Business organizational structure, and processes are in place to ensure that budgets and actual costs are actively challenged so that costs are effectively controlled.

Q. Did the Comprehensive Management Audit of Niagara Mohawk address the Company's budget process?

A. The audit did not raise a concern about the overall department/functional budget design. The report noted that the organizational responsibilities for planning priorities and budgeting allocations for the US Transmission and Electric Distribution & Generation ("ED&G") business are appropriate, and that there is a sufficient degree of bottom-up input in the business planning process.

Q. Please describe National Grid's process for developing and reviewing budgets.

A. The annual Business Planning process is a National Grid Group-wide (concerning National Grid's US and UK businesses) initiative focused on developing a five-year financial and operating profile for the organization. The first year of the Business Plan forms the budget for the next financial year, with each department/function (including Service Company departments/functions) constructing a full "bottom up" cost profile.

Q. What is the process for building the budgets for the Service Company departments/functions?

A. Every Service Company department/function undertakes a detailed budget-build analysis, including a consideration of costs for labor, services, and supplies/materials, to determine what each department/function will need to spend in the next financial year. Budgets based on this "pre-allocated" cost profile are allocated to the Affiliate Companies that will receive services and then aggregated to the corresponding Lines of Business. Budgets are constructed in close coordination with the LOBs receiving services.

Q. How are budgets that are initially created within the departments/functions performing Service Company functions assigned to the Lines of Business?

Exhibit__(AFS-2R) provides an overview of the budget assignment process for a hypothetical Service Company department/function. As explained above, budgets are first allocated to the Affiliate Companies that will receive services and then aggregated to the corresponding Lines of Business. Budgets are allocated to Affiliate Companies following the same methodology used to allocate actual expenses to Affiliate Companies. In particular, pre-allocated budgets are recorded at the appropriate Service Company as the Originating Company and either directly charged to a specific Affiliate Company or allocated to each Affiliate Company using the appropriate allocation codes and billing pools (based on approved SEC methodologies). At this point, the Service Company department/function budgets become "post-allocated." Post-allocation, the Affiliate Company charges aggregate to a budget at the Line of Business level.

Each of the Service Company departments/functions then reviews the post-allocated budget with each of the Lines of Business receiving department's/function's services. As explained above, affiliate company budgets are in effect, inherently in the LOB budget. At the review meetings, the Service Company departments/functions and Lines of Business agree upon the actions that need to be taken to improve financial and operating performance.

Q. What controls exist to ensure that budgets are appropriately assigned from the Service Company departments/functions to the LOBs after being allocated to the Affiliate Companies?

A. As explained above, in setting the budgets initially, the Service Company departments/functions review the assigned budgets with the Lines of Business. At the Service Company function/department level, a Vice President or Director is accountable to manage his/her budget within the guidelines established during the Business Planning process. He/she is responsible for reviewing planned activities and services provided, the costs to deliver that service in aggregate at the department/function level, and the Lines of Business to be charged.

Finance Decision Support teams have been placed in each LOB. One of their roles is to review and challenge service company department/function budgets assigned to the LOB as well as to prepare, review, and analyze variance reports on actual to budget costs.

Q. What role does the budgeting process have in the control of the actual expenses allocated to affiliate companies and thereby assigned to the Lines of Business?

A. The budgeting process serves as a major control on the allocation and assignment of expenses for services provided by the Service Company departments/functions to the affiliate companies and the Lines of Business respectively. In effect, a comparison of the actual expenses assigned to the Lines of Business to the budgeted costs arrived at during the budgeting process provides a control on the accuracy of the assigned costs to the Lines of Business.

Q. How are actual expenses for services provided by the Service Company departments/functions allocated to affiliate companies and assigned to the Lines of Business?

A. Exhibit__(AFS-2R) provides an overview of the process of allocating costs to the Affiliated Companies and assigning them to the Lines of Business. The summation of expenses within a Service Company department creates a "pre-allocated" expense pool. Pre-allocated expenses are recorded at the appropriate Service Company as the Originating Company and either directly charged to a specific Affiliate Company or allocated to each Affiliate

Company using the appropriate allocation codes and billing pools. The allocation codes and bill pools effectively allow for one line of accounting to be used to charge multiple Affiliate Companies. The actual expenses allocated to the Affiliate Companies are aggregated within the appropriate Lines of Business to determine the total actual expense (post-allocated charge) assigned to the LOBs.

Q. What controls exist to ensure that each Affiliate Company and Line of Business is being accurately charged for actual expenses?

A. A number of controls exist to ensure appropriate charging to Affiliate Companies and LOBs receiving services from Service Company departments. Service Companies' allocation codes and billing pools, which are used to charge Affiliate Companies, are based on predetermined allocation methodologies approved by the SEC. The allocations and bill pools include an inherent control framework.

As discussed later, periodic reviews of allocation codes and billing pools are conducted to ensure that they are maintained in accordance with the established allocation methodology.

Furthermore, as discussed above, the budgets generated through the Business Planning process provide a control that allows LOB management to compare the actual expenses charged with the budgeted amounts.

In addition, monthly meetings are held with the LOB management and Service Company department personnel. These meetings provide the opportunity for LOB personnel to discuss and challenge costs that have been allocated and assigned to their respective businesses.

Finally, Quarterly Performance Reports ("QPRs") are presented to both executive and LOB management. Sessions reviewing these reports focus on the expense that has been assigned to each LOB after being allocated to the affiliate companies. While QPR's are generally focused on the financial and operating results at the LOB level, sessions also include a review of the Service Company department/function costs being charged to Affiliate Companies. For example, regulated returns and company-specific issues are discussed at the meetings. Detailed reviews in preparation of the reports support the higher level LOB discussions. LOB management and Finance Decision Support teams focus on individual companies' performance and issues as part of the preparation for these meetings. LOB management review company-specific financial results and interact with Service Company management and Decision Support teams to understand results and costs that are being allocated to each Affiliate Company and assigned to the LOB.

Q. Is there anything else you would like to note about the Business Planning process and its relation to the allocation of Service Company costs to the Lines of Business/Affiliate Companies?

A. Yes. In sum, while budgets are not constructed at the overall Service Company level, budgets are constructed, managed, reviewed, and challenged by Service Company departments/functions and LOB management responsible for the Affiliate Companies receiving the services. While budgets are not constructed at the overall Service Company level, overall Service Company budgets can be derived by aggregating the department/function budgets flowing through the Service Companies. However, the derivation of overall Service Company budgets would not improve Niagara Mohawk's ability to review, control or monitor its charges from the Service Company. Given all of the controls in the budget development and expense allocation process, there is no reason to question the integrity of the process simply because budgets are not constructed at the overall Service Company level. The current process is better tailored to National Grid's organization because Service Company departments/functions may span more than one Service Company.

III. <u>Cost Escalation</u>

Q. Please address Staff's claim that Service Company charges to Niagara Mohawk in the Historic Test Year have increased 32.58 percent compared to 2008.

A. The Staff Accounting Panel argues that Niagara Mohawk's Service Company charges increased 32.58 percent from the 12 months ended September 30, 2008 to the Historic Test Year.

Q. How did Staff derive the 32.58 percent?

A. Staff derived the 32.58 percent increase using the Service Company bill amounts (from all Service Companies to Niagara Mohawk) provided in IR DPS-18 (RAV-13) for the Historic Test Year and the prior year and excluded cost to achieve ("CTA") spending from both years. The bill amounts include Service Company charges to Niagara Mohawk's electric and gas businesses excluding charges relating to capital work or balance sheet charges (for example the payment of a previously accrued expense) from Service Company. However, Staff used the CTA figure from IR DPS-14 (RAV-10), which does not reflect CTA originating at the Service Company exclusively, so the calculation needs to be refined. In addition, I need to correctly present the calendar year CTA figures into fiscal year figures for comparability. CTA amounts originating from the Service Companies in the Historic Test Year and the prior year were $24.4 million and $14.8 million, respectively, compared to the $18.8 million and $19.7 million used in Staff's calculation.

Q. Does the Company agree that Service Company charges increased in the Historic Test Year from 2008?

A. Yes, using Staff's methodology and updating the CTA adjustment, the Service Company charges to Niagara Mohawk increased by $68.2 million or 27.7 percent from the 12 months ended September 30, 2008 to the Historic Test Year, not the 32.58 percent calculated by Staff.

Q. Can you explain this increase?

A. Yes. There are a number of reasons for this increase, some of which were outlined in the Company's response to IR DPS-300 (RAV-96) so Staff should be aware of many of the underlying drivers. However, drawing a direct comparison between the data provided in IR DPS-300 (RAV-96) and this analysis is difficult because IR DPS-300 (RAV-96) included all charges originating from the Service Companies and thus capital and balance sheet charges were included. IR DPS-300 (RAV-96) is therefore a different view from the one that Staff used to calculate the percentage increase quoted above. Here, I address only increases relating to those percentages Staff quoted above. The explanations that follow also address the increase in Service Company charges to Niagara Mohawk as compared to the increase in charges to other Affiliate Companies.

Q. Please continue.

A. The explanations for the change in Service Company charges to Niagara Mohawk are summarized in two groups. Group 1 lists the incremental costs that were driven by additional activity undertaken by the Service Company directly on behalf of Niagara Mohawk and Group 2 lists the increased costs and activities that affected Affiliates Companies. The table below (Table AFS-1) summarizes the reasons for the increased charges in these groups.

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Table AFS-1

Summarized explanations for the increase in Service Company charges to Niagara Mohawk (Historic Test Year vs. Prior year)

	$M	%
Service Company charges to NMPC 12m ended Sep 2008	246.6	
Increased charges which are NIMO specific - Group 1		
Storms - pre any deferrals	15.7	
Employee migration to Svc Co	4.4	
SIR expense - pre any deferrals	3.3	
Bad debt mitigation	4.1	
Gas rate case support	0.6	
Gas corrosion work	0.4	
NMPC debt issuance costs	0.3	
subtotal	28.8	11.68%
Other increases in levels of Service - Group 2		
Pension/PBOP/Healthcare - pre any deferrals	13.6	
Variable pay	3.7	
Costs incurred for future productivity	4.3	
Information system projects	1.3	
Smart metering	0.7	
Increased time not worked	1.3	
Increased Service Co equity	1.1	
Items excluded from Cost of Svc	5.0	
Inflation at 1.5%	3.7	
Other	4.6	
subtotal	39.4	15.984%
Total Increase in charges	68.2	27.64%
Service Company charges to NMPC 12m ended Sep 2009	314.8	

As shown in the table above, there are four primary drivers of the increase in Service Company charges to Niagara Mohawk in Group 1 (charges for activity specific to Niagara Mohawk). These are the storm costs, primarily the

December 2008 ice storm, Site Investigation and Remediation ("SIR") costs, employee transfers from Niagara Mohawk to the Service Company, and expanded efforts to mitigate bad debt expense.

Q. Please provide further detail on these additional Service Company charges to Niagara Mohawk that are listed in Group 1 in the above table.

A. The single largest variance is storm charges, primarily relating to the December 2008 ice storm which caused (before deferrals) $15.7 million to be charged from the Service Company to Niagara Mohawk. This was primarily contractor costs. Also, compared to the prior 12 month period, Niagara Mohawk incurred an additional $3.3 million of SIR costs (before deferrals) from the Service Company for work done in Niagara Mohawk service territory in the Historic Test Year. In addition, National Grid has been centralizing certain functions within its Service Companies both to align management structures within the Line of Business/Service Company model and to become more efficient. During the Historic Test Year, employees moved from Niagara Mohawk to the Service Company in the Customer Service, Regulation and Pricing, and Operations groups. This change in origination of the service (formerly originating on Niagara Mohawk's books and now originating on the Service Company's books) accounts for $4.4 million of the increase in Service Company charges but is not an overall increase in Niagara Mohawk expense. The final area where activity undertaken on behalf of Niagara Mohawk has resulted in an increase in Service Company charges is in support of the Company's expanded efforts to mitigate bad debt expense following the deteriorating economic conditions that were experienced across Niagara Mohawk's service areas in 2009. While bad debt expense has increased, these efforts contained what would be a much higher growth in that expense. In support of the Company's bad debt mitigation effort, additional Service Company costs were incurred including an increase in inbound calls. This has driven higher expense of $4.1 million or 1.7 percent. Finally, there are several smaller items including rate case support, costs for raising Niagara Mohawk debt, and gas corrosion work totaling $1.3 million. Each of these cost drivers is clearly identifiable as supporting Niagara Mohawk. Removing these items brings the underlying increase in Service Company charges to Niagara Mohawk down to 15.98 percent. As will be shown later in this testimony, this increase is broadly in line with the increases experienced by other affiliates.

Q. Are there other factors driving the increase?

A. Yes. As shown in the table above there are a number of areas where activity and cost increases have affected all affiliates, including Niagara Mohawk. These Group 2 increase in charges from Service Company are pension, other post employment benefits (both before any deferrals) and healthcare costs, which increased $13.6 million (5.5 percent), collectively. These cost increases in the Historic Test Year were due to actuarial estimates, in the case of pension and post-employment benefits, and to actual claims experience, in the case of healthcare. Second, Niagara Mohawk incurred a $3.7 million increase related to variable pay for Service Company employees in the Historic Test Year. Third, the Company has incurred charges necessary to drive future savings, primarily in support of the Electric Distribution Operations Transformation effort of $4.3 million. Fourth, $5.0 million is made up of items that have been excluded from the cost of service.

Q. What are the remaining drivers of the increase?

A. Other reasons include smart metering $0.70 million, IS projects $1.4 million, an increase in time not worked of $1.3m (these labor charges would have been normalized in the cost of service) and an increase of Service Company equity charges of $1.2 million. It should be noted that Service Company Equity is a credit to Niagara Mohawk (see attachment 2 to IR DPS-12 (RAV-8)). Using an inflation rate of 1.5 percent as cited by Staff, I derive an inflationary increase of $3.7 million. The remaining increase of approximately $4.6 million is largely due to additional support required by Niagara Mohawk.

Q. What percentage of Niagara Mohawk's charges from the Service Company are directly charged to the Company?

A. Direct charges represent 44 percent of the O&M charges originating from the Service Company to Niagara Mohawk and 57 percent of total charges.

Q. Do you agree with Staff that normalizing adjustments should have been made to the percentage of Historic Test Year costs charged to Niagara Mohawk to align the increase more equally with all other affiliate companies?

A. No. Staff's methodology to determine the normalizing adjustment is to use the 32.58 percent increase to Niagara Mohawk, which I have shown is incorrect, and compare it to Staff's calculated increase to all affiliates, 20.38 percent and to apply this difference to the Rate Year forecast of Service Company charges. Like the 32.58 percent figure, Staff's 20.38 percent figure also must be adjusted for CTA and to make normalizing adjustments for two KeySpan entities where year over year movements are materially affecting the results. The two entities that require normalization are the Ravenswood generating station and the KeySpan money pool affiliate. The latter entity is solely used to provide for short-term cash and working capital requirements to the affiliates participating in the legacy KeySpan money pool. Charges to the money pool entity are dissimilar from other types of Service Company charges, as they are not allocated shared costs, and thus this entity should be normalized out of the comparative analysis. Making these adjustments reduces the increase to all affiliates to 18.29 percent. As described above, exclusive of specific items charged to Niagara Mohawk in the Historic Test Year, Niagara Mohawk's increase would be 15.98 percent. Therefore, applying Staff's methodology to the relevant figures, the comparison is between Niagara Mohawk's increase of 16.98 percent and an overall increase of 18.29 percent. Niagara Mohawk is clearly in line and an adjustment is unwarranted. The following table (Table AFS-2) shows Staff's figures and the Company's figures.

Table AFS-2

Staff view cited in testimony	HTY $(000s)	PY $(000s)	difference $(000s)	%
Service Company charges to NMPC ex CTA	320,193	241,511	78,682	32.58%
Service Company charges to other affiliates ex CTA	1,020,811	872,509	148,302	17.00%
Total Service Company charges to affiliates ex CTA	1,341,004	1,114,020	226,984	20.38%

National Grid view updated to correct for Svc Co originating CTA and to exclude Ravenswood and KSE Money Pool	HTY $(000s)	PY $(000s)	difference $(000s)	
Service Company charges to NMPC ex CTA	314,655	246,472	68,183	27.66%
Service Company charges to other affiliates ex CTA	1,037,177	896,386	140,790	15.71%
Total Service Company charges to affiliates ex CTA	1,351,832	1,142,859	208,973	18.29%

Further, as discussed in my direct testimony, costs are either directly charged to Niagara Mohawk or allocated using SEC approved cost allocation methodologies. The costs charged to Niagara Mohawk represent Niagara Mohawk's fair and reasonable share of costs for services it received in support of its utility operations. To shift any additional costs to Affiliate Companies would inappropriately and unreasonably allocate Niagara Mohawk's share of costs to other companies thereby undermining the entire process.

Q. Do you believe that reviewing only Service Company charges is the best way to view Niagara Mohawk's costs? Please explain.

A. No. What is important for Niagara Mohawk customers is the total level of costs incurred by the Company and that those costs were incurred in a prudent and efficient manner. The origin of those costs is not as important as the total level of costs. Indeed, charges can originate from either Niagara Mohawk itself or one of the Service Companies or, in limited instances, from another affiliate. To cite a specific example, employees in certain functions, such as Accounts Payable, are employed by either Niagara Mohawk or Service Company, as explained in the Company's response to IR DPS-524 (MM-182). What is important for Niagara Mohawk is that Accounts Payable charges are incurred in an efficient, and prudent manner, not what percentage of those costs originates from the Service Company or from Niagara Mohawk. And the Company can show that it is incurring administrative and general (A&G) costs in an efficient and prudent manner. Exhibit__(AFS-1R) shows that, since the merger of National Grid and Niagara Mohawk, Niagara Mohawk's electric A&G costs, excluding Customer Assistance Expenses (FERC 908 as the companies being compared have different programs) and Regulatory Commission Expenses (FERC 928 due to the impact of 18-A assessments), have decreased on a nominal basis from $433.8 million in 2001 to $383.6 million in 2009, an 11.6 percent decrease and on a per customer basis from $272.94 per customer in 2001 to $236.04 per customer in 2009, or a decrease of 13.5 percent. The Company acknowledges that while A&G costs are higher than they were in 2007, they are still the second lowest among New York utilities. Furthermore, as shown on Exhibit __ (AFS-3R), absent Pension and OPEB, SIR and storm costs, Niagara Mohawk's A&G costs in the Rate Year are lower than calendar year 2009.

Q. The Staff Accounting Panel says that Service Company charges are "skewed" to Niagara Mohawk. Do you agree?

A. No. As discussed above, the costs charged to Niagara Mohawk reflect direct charges for services provided or Niagara Mohawk's allocable share of costs determined using SEC-approved allocation methodologies. The Staff Accounting Panel argues that its proposed macro adjustment of approximately $26 million to the Historic Test Year is necessary to correct the "significant skew identified." I explained above that the HTY increase in Niagara Mohawk's charges from the Service Company, both independently and relative to other affiliates, was caused by an increase in Service Company services properly charged to Niagara Mohawk. Moreover, I believe Staff has misinterpreted the Company's response to IR DPS-293 (RAV-89) relating to synergy savings and unreasonably concluded that costs are "skewed" to Niagara Mohawk.

Q. Please explain.

A. The Company's lack of clarity in its response to IR DPS-293 (RAV-89) has led Staff to claim that the Company acknowledges that costs may be skewed to a particular affiliate. The Company never intended to acknowledge this because it is simply not true. Neither the direct charge nor the allocation of service company costs is skewed. Each company pays the costs directly charged for services provided or its allocable share based on cost causation or approved allocation methodologies. In response to a question regarding synergy savings, the Company was merely attempting to explain why it chose to use a bill pool analysis to determine the synergy savings allocation percentage to Niagara Mohawk as opposed to using the percentage of actual costs charged to Niagara Mohawk. The Company's point was simply that in any year an operating company may have a higher or lower percentage of total costs charged to it based on the level of services being provided. The most fair and reasonable method for allocating savings was therefore to use the bill pool analysis that I explain below.

Q. Please explain IR DPS-293 (**RAV-89).**

A. Staff asked the Company to explain how it derived the percentage of the total KeySpan merger savings attributable to Niagara Mohawk. The Company responded by explaining that it had estimated that 24.93 percent of total synergy savings would be attributable to Niagara Mohawk based on a bill pool analysis. As explained in the rebuttal testimony of the Revenue Requirements Panel, KeySpan merger synergy savings were tracked and identified by initiative. To determine the appropriate share of savings attributable to each

Affiliate Company, we assigned an individual bill pool to each initiative. Savings per initiative would therefore be attributed on the same basis as the costs that would otherwise have been incurred.

Q. Why did the Company use a bill pool methodology to determine the percentage of synergy savings attributable to each Affiliate Companies?

A. The Company believes this methodology provides the most accurate estimate of savings attributable to each Affiliate Company because it uses the same methodology as is used for shared expenses, and it avoids the anomalies that arise from including costs directly charged to individual affiliates in any year. In response to IR DPS-293 (RAV-89), the Company attempted to explain that this methodology would avoid highs and lows in direct charges to Affiliate Companies that can occur because of differing circumstances and activity levels. In its response, the Company used the example of Group Audit and said that "in any one year Group Audit's actual costs may be skewed to a particular operating company." A better way of explaining this would have been to say that in any one year Group Audit's costs may be more heavily weighted to a particular Affiliate Company because more services were provided to that affiliate and therefore more costs were charged to it. For example, an audit performed by Group Audit relative to Massachusetts Electric Company's ("Mass Electric") service connection procedures would result in more costs charged to Mass Electric than if Group Audit were providing a service that benefited all Affiliate Companies and the costs were shared accordingly. The reverse is also true. In any year, Group Audit's actual costs may be less heavily weighted to a particular Affiliate Company because fewer services were provided to it. Neither of these circumstances should affect the attribution of synergy savings to affiliates. Applying a bill pool to each synergy savings initiative also takes into account that total charges from the Service Companies are driven by many services for which there are no synergy savings initiatives. For example, Mass Electric receives electric transmission support services. If there are no synergy savings associated with these services, it would be inappropriate to include those costs in determining the percentage of synergy savings allocable to Mass Electric and other affiliates.

Q. Is Staff correct in saying that the Company does not monitor costs by the service headings listed in the Service Company Agreements?

A. Yes. As Staff points out, the Company does not track costs by the list of services provided in the Service Company Agreements. However, Staff's reasoning that because of this the Company can neither specifically identify the costs of those services nor explain and justify any increases in those costs is not correct.

Q. Please explain.

A. As the National Grid organization has changed over the years, certain services identified in and provided under the Service Company Agreements have moved to different areas of the Service Company organizations. For example, payroll (a service listed under Accounting in the Service Company Agreements) is now part of the Transaction Delivery Center. Another example is Customer Service. That service is now located within the Customer Energy Services and Customer Service Operations functions. As shown in Exhibit__(AFS-4R), there are a number of these situations. The Company's operating departments budget and monitor their costs on a functional basis, with reference to the services provided, not by the headings in the Service Company Agreements. This does not in any way lessen National Grid's ability to track or monitor costs, nor does it invalidate the list of services set out in the Service Company Agreements that have been in place in largely their current form for some years.

Q. Did Staff submit Information Requests on this issue?

A. Yes. Staff first submitted IR DPS-299 (RAV-95), which requested all charges to Niagara Mohawk from the National Grid Service Company broken down by the services listed in the agreements for the calendar years 2006 through 2008 and for the Historic Test Year. The Company provided this information to Staff in the format requested. Then, in IR DPS-300 (RAV-96), Staff asked the Company to explain every increase greater than inflation for those services by listing in the agreements. The Company discussed the question with Staff and explained that, for the reason identified above, it does not monitor increases in costs by the headings in the Service Company Agreements. The Company explained that significant work would be required to reclassify data from the Company's current reporting and tracking system to the Service Company Agreement headings. The Company provided the information in the format available (by department code/function). The Company also prepared a reconciliation of the Historic Test Year costs to the prior year that included 41 line items with specific explanations and justifications for increased charges from the National Grid USA Service Company to Niagara Mohawk and additional information explaining charges from the KeySpan Service Companies to Niagara Mohawk. As identified in that response, the most significant drivers of the increase were storm and pension costs. The fact that the Company does not track Service Company costs in the format sought by Staff does not mean that the Company can not or does not effectively control and monitor Service Company costs.

Q. What are convenience payments?

A. As explained in IR DPS-340 (RAV-118), convenience payments are amounts paid by a Service Company on behalf of an Affiliate Company that has incurred the cost directly. Examples of the types of charges that are paid by a Service Company on behalf of Niagara Mohawk include employee benefits (such as health insurance) and income taxes. For example, the Service Company will send one check to the insurer on behalf of one or more affiliates, and charge back the amount owed. No interest or premium is charged by the Service Company for this service.

Q. Please address Staff's claim that Niagara Mohawk's failure to monitor convenience payments independently means that the Company does not have the information necessary to monitor Service Company costs. (Staff Accounting Panel at 94).

A. This is a *non sequitur*. While the Company has not been able to track convenience payments (where the service company merely makes the payment for a cost that has been directly incurred within an affiliate) separately, this information would do nothing to improve its ability to monitor its Service Company charges for services rendered to affiliates. More importantly, Niagara Mohawk tracks all of its costs by the relevant cost component/ expense types. The fact that the costs were paid by the Service Company and charged back to Niagara Mohawk as convenience payments instead of being paid directly has no impact on Niagara Mohawk's overall costs. In Staff's example of a convenience payment relating to payroll taxes, Staff correctly explains that the Service Company writes one check to the Internal Revenue Service for payroll taxes in lieu of multiple checks from affiliates, and charges back to each affiliate the amount it owes. In its January

29, 2010 filing, the Company included a comprehensive calculation of payroll taxes, which had been paid by Service Company and charged back to Niagara Mohawk as convenience payments.

Q. Has the Company evaluated Staff's concern that Service Company charges to unregulated affiliate companies appears to have declined 17.5 percent and that Niagara Mohawk and its regulated affiliates may be subsidizing this decrease (Staff Accounting Panel at 77)?

A. Yes, and we do not agree. As Staff point out, this figure should be normalized for the sale of Ravenswood generating station, which reduces the amount to a 6.2 percent decline. In addition, as I discuss above, charges associated with the KeySpan money pool entity should also be normalized. Making this adjustment reduces the decrease in Service Company charges to unregulated affiliates to 2.5 percent. However, even if the decrease in costs charged to unregulated affiliates were significant, it would provide no foundation for Staff's statements that this "means more is being charged to the regulated affiliates, all else equal" or that this "could mean the regulated affiliates are subsidizing the costs of the unregulated affiliates." Staff ignores the fact that Service Company charges are not static from year to year. Rather, annual direct and allocated charges from the Service Companies are based on the nature and magnitude of work required by the Affiliate Companies in that year. No sound conclusion or fair allegation about subsidization can be based on the fact that Service Company charges to unregulated affiliates declined in the Historic Test year.

Q. Staff provides two examples where they believe Niagara Mohawk may be subsidizing unregulated Affiliate Companies (Staff Accounting Panel at 75). Did the Company review these allocations?

A. Yes. Specifically, Staff questions allocations relating to software license permit costs and PeopleSoft ERP costs. The Company reviewed these invoices and determined that an adjustment needs to be made to the software license permit costs, but that the PeopleSoft ERP allocation is correct.

Q. Please explain.

A. First, Staff questions a purchase order relating to a software license agreement. The purchase order was provided in response to IR DPS-282 (DAG-27) and says: "this purchase order funds a multi-site license term … for use by National Grid companies for the cost of $127,500 per year for a three year commitment. This license permits National Grid to use the software for the benefit of LIPA." Staff concludes that LIPA is being subsidized by regulated National Grid affiliates because LIPA was not allocated a share of the costs.

Q. Is it appropriate that the regulated Affiliate Companies receive charges for this software?

A. The software at issue is a GE Maps product that is used by the Transmission Planning functions in the Legacy National Grid and LIPA. Prior to the KeySpan merger, separate contracts existed for the Legacy National Grid and KeySpan (on behalf of LIPA). The contracts were consolidated after the merger and the purchase requisition language clearly provides that the costs are to be allocated 33.4 percent to National Grid and 66.6 percent to LIPA (through the MSA with LIPA) to accurately reflect use of the software. It is therefore appropriate to charge the regulated affiliate companies their appropriate share of these costs. In reviewing the charges, however, the Company discovered that the costs were charged to the legacy National Grid companies as if the contract consolidation had not occurred. An adjustment is therefore required to reflect LIPA's 66.6 percent of the costs and this change will be reflected going forward.

Q. Staff says that Niagara Mohawk's allocated share of the legacy National Grid license software costs (33.4 percent of the total) is overstated at 56.43 percent. Do you agree?

A. No. Niagara Mohawk's share of the costs is not overstated. The SEC approved bill pool allocator uses a simple mathematical calculation to determine the fair and reasonable costs to be borne by each company based on their respective use of the software. That mathematical calculation is the transmission operation and maintenance costs of each affiliate company over total transmission operation and maintenance costs. This calculation fairly and reasonably identifies the appropriate cost drivers and allocates costs accordingly.

Q. Please explain the Company's review of PeopleSoft ERP costs.

A. As identified in response to IR DPS-36 (RAV-22), PeopleSoft ERP costs are allocated through bill pool 00380 to all legacy National Grid Companies based on Operation and Maintenance Expenses. This is an SEC approved allocation methodology. All of the legacy National Grid companies use the PeopleSoft system as their financial ledger. Accordingly, it is appropriate that all of these companies should bear their fair share of the costs. Niagara Mohawk pays the greatest percentage of PeopleSoft costs because Niagara Mohawk has the highest percentage of the total Operation and Maintenance expenses. The other companies are smaller and their total Operation and Maintenance expenses represent a smaller percentage of the total. Their allocated share of PeopleSoft costs is less than Niagara Mohawk but proportionately the same. The Company has reviewed the allocation methodology and bill pool and determined that the PeopleSoft costs are being fairly and appropriately allocated to the legacy National Grid companies. Exhibit__(AFS-5R) shows how bill pool 00380 allocates costs to the various operating companies. As can be seen, the Operation and Maintenance costs for the two unregulated affiliates mentioned by Staff for comparative purposes

(Wayfinder Group Inc. and Valley Appliance and Merchandise ("VAMCO")) are extremely small, both representing less than 1 tenth of 1 percent of total O&M expense, respectively. These unregulated affiliates are effectively dormant, which accounts for the fact that they have *de minimis* O&M and therefore received *de minimis* charges.

Exhibit__(AFS-5R) also shows that Niagara Mohawk, the largest of the legacy National Grid companies, is allocated 52.9 percent of the total PeopleSoft ERP because Niagara Mohawk has 52.9 percent of the total Operation and Maintenance costs. Niagara Mohawk is not subsidizing unregulated Affiliate Companies, but rather is paying its fair and reasonable share of costs based on an approved cost allocation methodology.

Q. **Based on your analysis, do you agree with the Staff Accounting Panel conclusion that unregulated affiliates are being undercharged or cross subsidized?**

A. No. As stated above, the examples offered by Staff do not indicate that there is any systematic undercharging or subsidies to unregulated affiliates or that Niagara Mohawk is being systematically overcharged. The allocation review done at the end of FY2009 found that two percent of invoices over $100,000 utilized an inappropriate allocation methodology. The GE Maps software invoice referenced above would fall into this category. The allocation of the PeopleSoft ERP costs is correct.

IV. Cost Allocation – Rent Expense

Q. Please explain the Staff Accounting Panel's adjustment to the Reservoir Woods facility.

A. The Staff Accounting Panel proposes a $1.925 million adjustment to rent expense for the Reservoir Woods facility. Staff claims the cost of Reservoir Woods and the Westborough facility are allocated to affiliates based on the time charged to the Service Company departments at these facilities. According to Staff, because Reservoir Woods is allocated among 30 companies or segments, whereas Westborough was allocated among 14 companies or segments, Niagara Mohawk's 32 percent allocation of Reservoir Woods should be lower than its 24.6 percent share of Westborough. Staff claims the Company's allocation methodology is inconsistent and proposes to fix this inconsistency by creating a new methodology based on the percentage of total service costs allocated to Niagara Mohawk from both the National Grid USA and KeySpan Service Companies in 2009. This would result in an allocation of 21.15 percent of the costs of Reservoir Woods to Niagara Mohawk.

Q. Does the Company agree with the rationale for Staff's adjustment?

A. No. We disagree with Staff's arguments in support of the adjustment for the following four reasons. First, Staff misstates the allocation methodology. Second, Staff fails to recognize the fundamental difference between the services Niagara Mohawk receives from Reservoir Woods and the services it previously received from the Westborough facility. Third, the Company's allocation methodology is not inconsistent; it has been filed with the SEC and is the same methodology used by the Company in its recent gas rate case, Case 08-G-0609. Fourth, Staff's proposed allocation of 21.15 percent is arbitrary and without evidentiary support.

Q. Please explain your first issue with Staff's adjustment.

A. The allocation methodology for the Reservoir Woods and Westborough facilities is not based solely on time charged, as Staff indicates. Rather, as explained in the Company's response to IR DPS-182 (AAE-20) cited by Staff, the allocation is based on "the time charged to the National Grid system companies by Service Company departments that use the National Grid facilities . . . *weighted by the amount of square footage occupied by each such department at each respective facility*." (emphasis added). Therefore, facility costs allocated to affiliates can and will vary depending on (a) the number of departments that occupy a particular facility, (b) the floor area that each department occupies as a proportion of the total floor area, and (c) the time that each occupying department charges to each affiliate for services rendered. As the Westborough and Reservoir Woods facilities had very different occupancy and service delivery profiles the affiliate locations will also vary. As discussed below, it is the amount of square footage of the departments combined with the increased level of services being provided by them to Niagara Mohawk that explains the difference in the percentage of expenses allocated between Reservoir Woods and Westborough to Niagara Mohawk. Staff's failure to identify the proper allocation methodology and the difference in occupancy patterns calls into question the basis for the adjustment.

Q. Please discuss your second issue with Staff's adjustment and explain how the Reservoir Woods facility provides an increased level of service to Niagara Mohawk compared to the Westborough facility.

A. Staff's assumes that the Reservoir Woods facility provides the same level of services to Niagara Mohawk as the Westborough facility once did. This is not the case, however. As the Company explained in its response to IR DPS-182 (AAE-20), Reservoir Woods and Westborough are two entirely different facilities that provide different levels of service to Niagara Mohawk. Specifically, the departments that formerly occupied the Westborough facility provided a greater proportion of services to National Grid's New England affiliates than to Niagara Mohawk. The New England Control Center, for example, occupied 14 percent of Westborough, and provided services directly to the New England affiliates. The Legal, Load Research, and Regulatory departments at Westborough also provided services primarily dedicated to the New England affiliates. Niagara Mohawk's former allocation of 24.6 percent of the costs of the Westborough facility reflected the level of services and floor space dedicated to the Company.

Q. How does Reservoir Woods compare to Westborough in terms of services and floor space dedicated to Niagara Mohawk?

A. In contrast to the Westborough facility, the departments at the Reservoir Woods facility occupy a larger percentage of floor space and provide a greater percentage of services to Niagara Mohawk. Reservoir Woods represented a reorganization of National Grid. The construction of Reservoir Woods allowed National Grid to move departments that were previously located in facilities other than Westborough to a single, centralized location. The Electric Delivery Operations organization is a prime example. Departments within this organization include Distribution Asset Management and Project Management & Construction, to name two. These departments all provide a large percentage of services to Niagara Mohawk and occupy a significant amount of floor space, whereas in the past, they served Niagara Mohawk from facilities other than Westborough, such as the Northborough facility.

Q. Staff claims the Company did not provide any calculations to explain why Niagara Mohawk's share of Reservoir Woods is more than its share of Westborough. Is that a correct statement?

A. No, it is not. Attachment 1 to IR DPS-182 (AAE-20) is a table comparing the Reservoir Woods and Westborough facilities. It clearly shows why Niagara

Mohawk is allocated a greater percentage of the costs of Reservoir Woods than it was from Westborough. Specifically, the table shows the departments at Reservoir Woods and Westborough, the percentage of total square feet each occupied by each and the percentage of costs each department charged to Niagara Mohawk. As Attachment 1 shows, the total square footage of the departments providing services to Niagara Mohawk in Reservoir Woods totals 195,506 square feet with a total allocation rate of 32.02 percent. By comparison, the total square footage of the departments in Westborough that provided service to Niagara Mohawk totaled only 178,900 square feet with a total allocation rate of 23.54 percent. Staff fails to address Attachment 1 in their testimony.

Q. Does the Company have any additional calculations to further demonstrate that the costs of Reservoir Woods and Westborough are being properly allocated?

A. Yes. Exhibit ___ (AFS-6R) is a table that provides a square footage comparison by functional area of Reservoir Woods and Westborough. The exhibit shows that 68.7 percent of Reservoir Woods is dedicated to operational functions, with 43.8 percent of the facility dedicated specifically to electric distribution. This is significant considering that Niagara Mohawk accounts for almost 50 percent of National Grid's US electric distribution business. In contrast, Westborough was almost the complete opposite, as 67.6 percent of the building was dedicated to shared services functions.

Q. What is the significance of these figures?

A. Staff's analysis assumes that Reservoir Woods is a shared services facility building - one that allocates a greater percentage of its time across all of the National Grid companies - similar to Westborough; therefore, following Staff's logic, the costs to Niagara Mohawk should be the same. As Exhibit __ (AFS-6R) shows, however, this is not the case. Staff fails to recognize the fundamental shift in services now being provided to Niagara Mohawk from Reservoir Woods. Reservoir Woods is more of an operational building, with 43.8 percent of the facility dedicated specifically to electric distribution. This means Reservoir Woods contains a greater concentration of departments that provide direct services to Niagara Mohawk. In addition to the direct services being provided from these operational departments, Niagara Mohawk is also receiving its allocated percentage of shared services costs from Reservoir Woods. Simply put, the departments in the Reservoir Woods facility occupy a larger percentage of floor space and provide a greater percentage of services to Niagara Mohawk.

Q. Please discuss your third issue with Staff's adjustment.

A. Staff's argument that the Company's allocation methodology is inconsistent is false. The Company's methodology for the allocation of costs between

Reservoir Woods and Westborough has been filed with the SEC. It is also the same methodology that the Company used to allocate the costs of the Westborough facility in the Company's recent gas rate case, Case 08-G-0609.

Q. Please discuss your fourth issue that Staff's proposed allocation of 21.15 percent for the Reservoir Woods facility is arbitrary and without evidentiary support.

A. Staff's proposed allocation of 21.15 percent is based on the percentage of total costs allocated to Niagara Mohawk from *both* the National Grid USA and KeySpan Service Companies in 2009. There is no evidence to support such an allocation. Indeed, Staff's 21.15 percent allocation is lower than the 24.6 percent that was previously allocated to Niagara Mohawk from the Westborough facility, which, as demonstrated above, houses far fewer services and devotes much less floor space to Niagara Mohawk than the Reservoir Woods facility. Further, the KeySpan Service Companies provide significant amounts of service to the gas companies. As discussed above, Reservoir Woods is primarily dedicated to the electric business. In the response to IR DPS-18 (RAV-13), the Company indicated that the KeySpan Service Companies charged Niagara Mohawk only 4.6 percent in 2009. Thus, Staff's inclusion of the KeySpan Service Companies in this equation fails to take into account cost causation factors, and serves only to drive down the allocation factor. Staff's position has no merit.

Given that approximately 86 percent of employees occupying Reservoir Woods are employed by National Grid USA Service Company, a more accurate comparison would be to compare the percentage of costs charged to Niagara Mohawk by National Grid USA Service Company in 2009. Utilizing the data supplied by the Company in its response to IR DPS-18 (RAV-13), the following percentage of National Grid USA Service Company charges were allocated to Niagara Mohawk electric:

- 2006 = 34.5 percent (Dist 28.5%, Trans 6.0%)
- 2007 = 36.1 percent (Dist 29.1%, Trans 7.0%)
- 2008 = 34.3 percent (Dist 27.4%, Trans 6.9%)
- 2009 = 34.4 percent (Dist 27.8%, Trans 6.6%)
- **AVERAGE = 34.9 percent (Dist 28.2%, Trans 6.7%)**

This data indicates that, on average over the last four years, 34.9 percent of the costs of the National Grid USA Service Company have been allocated to Niagara Mohawk electric. If the Company were to allocate the costs of the Reservoir Woods property on the same basis, an overall rate of 32 percent of costs being allocated to Niagara Mohawk would be in line with the allocations of the overall National Grid USA Service Company costs.

Q. Please explain the Staff Accounting Panel's adjustment to the SOC facility.

A. The Staff Accounting Panel proposes four adjustments related to the SOC. The first three of these adjustments reduce facilities expense, depreciation expense, and plant in service by $0.082 million, $0.092 million, and $1.605 million, respectively. The final adjustment increases SOC accumulated deferred income taxes by $0.118 million. In support of the adjustments, Staff merely states that the Niagara Mohawk allocation rate for Reservoir Woods and Syracuse are different and that to fix this alleged inconsistency, Staff proposes a 21.15 percent allocation to SOC in line with the allocation they proposed for Reservoir Woods above.

Q. Does the Company agree with Staff's adjustment?

A. No. Similar to the Reservoir Woods adjustment, the SOC adjustment is arbitrary and made without factual support. Historically, the Company has allocated affiliate owned facilities and Service Company owned or leased facilities differently. Niagara Mohawk owned facilities, like SOC, have been allocated based on O&M expense, whereas Service Company owned or leased facilities, like Reservoir Woods, have been allocated based on time charged, weighted by floor space occupancy, as discussed above. The Company allocated the costs of SOC in the same way in the Company's last gas rate case.

Q. Do you have any further comments on Staff's adjustments to facility costs?

A. Yes. At page 130, lines 8 to 14, of the Staff Accounting Panel's testimony, they state that, "[i]f the Commission does not agree that the allocations should be reduced to 21.15 percent, then the allocation for Reservoir Woods should at least be reduced to the 25.6 percent allocation factor used by National Grid on the SOC for consistency." We note that if the Company were to allocate Reservoir Woods based on the SOC bill pool, the costs of the facility would shift to customers of the legacy KeySpan utilities in Downstate New York, which currently receive only a small percentage of services from Reservoir Woods, consistent with the services they receive Exhibit __ (AFS-7R) is a comparison showing the current bill pool for Reservoir Woods and using the 25.6 percent allocation factor proposed by Staff. It demonstrates that the costs allocated to Downstate New York customers would increase from $4.324 million to $5.843 million in the Rate Year, an increase of $1.519 million. The costs allocated to Upstate New York customers would decrease from $6.378 million to $5.390 million, a decrease of $0.988 million, and therefore a net increase to total New York State of $0.531 million. Thus, Staff's method would inappropriately shift costs from Niagara Mohawk to the KeySpan utilities without regard to cost causation.

Q. Please continue.

A. The Company also notes that if the Commission were to adopt Staff's theory that any facility that houses shared service functions should be allocated based on the percentage of total service company charges to the affiliates, the Company would need to increase the allocations to Niagara Mohawk from facilities such as MetroTech in Brooklyn. MetroTech's rent expense in the Historic Test Year was $11 million, of which only two percent was charged to Niagara Mohawk. If we were to increase the allocation to 21.15 percent, in accordance with Staff's rationale, this would require an increase of approximately $2 million in Niagara Mohawk's rent expense in this case.

V. <u>Cost Allocation - Consultant Expense</u>

Q. Please summarize the issues Staff raises relating to cost allocation of Consultant Expense.

A. Staff primarily raises three issues. First, Staff asserts that certain costs have been "misallocated" due to the use of an inappropriate bill pool. Second, Staff asserts that certain costs have been "mismapped" between legacy accounting systems. Third, Staff proposes a number of normalizing adjustments to the Historic Test Year. Staff cites a number of specific invoices to support its position and proposes a normalizing adjustment of $3.2 million to remove certain charges originating from and charged to Niagara Mohawk in the Historic Test Year. Staff submits that the remaining $6 million of adjustments relating to specific invoices supports its request for a $26 million macro adjustment. However, although the Company agrees that certain isolated adjustments are appropriate, the vast majority of Staff's adjustments are inappropriate and unsupported. Exhibit __ (AFS-8R) provides detailed supporting information relating to each of the invoices discussed below including a comparison of the Company's and Staff's adjustments.

1) Allocation Issues

Q. Please summarize Staff's adjustments relating to alleged allocation issues.

A. First, Staff argues that the Historic Test Year costs for Morgan Lewis's work on four matters should be normalized out, either in whole, or in part, because they were either an inappropriate allocation to Niagara Mohawk or a non-recurring cost. Next, Staff proposes adjustments to remove costs associated with International Computer Marketing Corporation ("ICM") and Vitec Solutions ("Vitec") on the basis of allegedly improper allocations to Niagara Mohawk. The Company disagrees with Staff's position for three reasons. First, Staff points to a sample of invoices to make a wholesale disallowance of legitimately incurred costs. This is inappropriate and arbitrary, as Staff is performing a selective look at only limited invoices. Second, it is incorrect for Staff to allocate charges based on the geographical locations referenced in the invoices. Third, it is also incorrect for Staff to conclude that, because various invoices have different allocation rates to Niagara Mohawk, the entire costs should be disallowed. As shown on Exhibit __ (AFS-8R), the

Company is making certain adjustments to more accurately allocate charges to Niagara Mohawk. The Company is also reviewing how Morgan Lewis bills the Company to make sure cost allocation is correct.

2) <u>Mapping Between Service Company Accounting Systems</u>

Q. Staff says that double counts and errors could have occurred when transitioning costs between legacy National Grid and KeySpan Service Company accounting systems (Staff Accounting Panel at 303). Does the Company agree with this statement?

A. No. It is not possible. During the planning phase of the 2007 merger of KeySpan and National Grid, it was determined that it would not be possible to fully assimilate KeySpan companies onto the legacy National Grid financial system (PeopleSoft) in time to allow for uninterrupted financial and management reporting. Therefore an interim solution was designed to pass data between KeySpan's ledger system (Oracle) to PeopleSoft and vice versa. This two-way integration includes a mapping of the Oracle to PeopleSoft account codes and incorporates internal control and correction procedures for any transactions that have no mapping. This design is referred to within National Grid as "The Bridge."

In summary, transactions are processed by a Service Company and then passed between systems and converted to the receiving system's charts of accounts. If no mapping can be derived, transactions are mapped to a suspense account to ensure they are represented in the financial balances of the receiving system. Through a reconciliation, suspense balances are eliminated as account codes are subsequently reviewed and mapped, or the subject transaction is reversed in the sending system if upon review the transaction is determined to be erroneous. Controls exist within both the Accounting group and the Financial Solutions group to monitor and manage suspense balances.

Q. Can transactions be double counted as they pass between systems?

A. No. It is not possible for transactions to be double-counted or duplicated as they are passed from one system to the other, nor can they be mapped to multiple accounting strings. The Bridge was designed to not include any cross charging of the Service Companies' Income Statements for the express purpose of avoiding double allocations. National Grid bill pools do not include any KeySpan Service Companies to prevent charges entering the KeySpan system and subsequently being returned to any National Grid operating company that may have already been charged. As a further enhancement to the system, validation rules are now in place to prohibit any expenses being charged to a Service Company Billing Entity that would be passed over the Bridge. There are also reconciliation reviews to ensure that each transferred file between KeySpan and National Grid is received only once and that the two systems are always in sync. Variance reports are used to determine that all transactions are received in total and that ledger balances tie between the two systems.

Q. Please summarize the Staff Accounting Panel's normalizing adjustments to contractor expense.

A. Staff proposes an adjustment to remove certain NESCO contractor credit and collections and call center costs on the basis that they are not recurring and that the Company's labor forecast reflects the transfer of employee recruiting services to be performed internally by the Company. Staff proposes second adjustment to contractor costs on the basis that certain Mercer Human Resources costs have not been sufficiently supported and are not recurring in the Rate Year. Finally, Staff proposes a third adjustment to remove KeySpan Corporate Services LLC consulting costs due to a lack of supporting invoice documentation.

Q. Please summarize the Company's response to these adjustments.

A. First, the Company agrees that in certain limited instances adjustments are appropriate. The Company has, however, in all cases provided sufficient documentation and support for the Historic Test Year costs. Second, in addition to the information provided in Direct Testimony and discovery, I have included Exhibit __ (AFS-8R) to support certain vendor costs. Finally, an inadvertent production error resulted in supporting documentation inadvertently being omitted from a discovery response to Staff. The information has been produced and the costs fully supported.

VI. Cost Allocation Review

Q. Does the Company agree with Staff's position that the Service Company cost review process is ineffective?

A. No. Staff argues that the process is ineffective for the reasons explained previously relating to lack of independence. Following the merger with KeySpan, National Grid underwent significant organizational change. National Grid assumed responsibility for operating four service companies under two separate and distinct accounting systems with very different processes. The accuracy and integrity of cost allocations was of paramount importance. In the first few months after the KeySpan merger, National Grid reiterated its commitment to ensuring that cost allocations are appropriate and management commissioned a Cost Allocation Integrity Project team. National Grid committed some of its most experienced resources to work on the project team, including two former Internal Audit Directors and a former Internal Audit Manager, whose combined experience includes several decades of service working for National Grid and predecessor companies, including Niagara Mohawk. The Project Team was governed by a Cost Allocation Integrity Steering Group, as documented in the Company's response to IR

DPS-338 (RAV-116). The Project Team performed a comprehensive review of Service Company employee labor allocations and non-labor transactions for the period April 2008 through January 2009. The project review population consisted of 3,538 invoices with a total value in excess of $3.2 billion and a review of the labor allocations of over 7,200 Service Company employees. The results of the review were that 98 percent of the invoices reviewed were found to have correctly applied an approved allocation. Also, 92 percent of the labor allocations were found to have correctly applied an approved allocation methodology. It was noted that some of the exceptions were due to the gradual transition, integration and consolidation of services that occurred in the first year after the KeySpan merger.

In addition to the work performed by the Company around cost allocation integrity, the Company engaged PricewaterhouseCoopers ("PwC") to assist the Company in its evaluation and testing of the cost allocation process. PwC provided advisory services and issued a report dated May 15, 2009. In its overall observations, PwC states that while some exceptions were noted through the testing conducted, there were no pervasive trends or large errors noted.

National Grid continuously strives for better procedures and greater accuracy. While the Company acknowledges that in limited and isolated situations the cost allocation process is subject to coding errors that result in over or under allocations, the Company maintains a culture of compliance and commitment to constant improvement that includes comprehensive review and testing procedures to minimize any such errors. The Company believes that with well designed controls and effective review, the overall impact of errors is not material.

While isolated errors have been identified, based on the review work performed by the Company and PwC, these errors are not indicative of any larger, systemic issues.

Q. What did the team do with the results of the review?

A. The Project Team took actions including making invoice corrections that resulted in a net allocation shift of $0.3 million from legacy KeySpan affiliates to legacy National Grid affiliates. All Service Company employee labor allocations that were noted as being in need of an update were made on a prospective basis as discovered. The Project Team conducted a cost allocation training campaign to foster a culture of cost allocation awareness across the newly restructured organization. The Cost Allocation Integrity Project Team also updated the Cost Allocation Policies and Procedures and other cost allocation tools that were then posted on the Company's Infonet website for employees to reference.

Q. Has the Cost Allocation Integrity Steering Committee made any recommendations?

A. Yes. One recommendation is that a permanent Cost Allocation Review Committee take over responsibility for the on-going review of Service Company allocations after the Project Team is disbanded. As described in the Company's response to IR DPS-336 (RAV-114), the Cost Allocation Review Committee is comprised of representatives of each of the National Grid Lines of Business who are accountable for the financial results of each business segment so that a meaningful review and challenge of Service Company allocations can be conducted. In addition, there is also representation from the National Grid's Legal and Regulation & Pricing Departments. The Committee has met on a regular basis since the disbanding of the Cost Allocation Integrity Project team and the results of their reviews and meeting minutes were provided to Staff in response to IR DPS-336 (RAV-114). And while Review Committee members are employees of one of the Service Companies, they are charged with ensuring allocations are correct across all of National Grid's entities.

VII. <u>Construction Work Order Closings</u>

Q. What adjustments does the Staff Accounting Panel propose with respect to plant accounting for CWIP work orders closings?

A. Staff recommends that the Company expense $6.827 million as depreciation within 30 days of the Order in this case and make a corresponding reduction of $6.827 to rate year net plant.

Q. What is the basis for Staff's adjustment?

A. The basis for staff's adjustment is an assertion that there have been unusual delays in the processing time to close construction work orders to plant in service and that this has resulted in an understatement of depreciation expense. Staff then performed the calculations summarized below to produce an estimate of the depreciation expense that would have been charged had work order closure been completed within 1 month of the advised plant in service date.

Q. Please describe staff's calculation

A. First, in response to IR DPS-3 (AAE-3), the Company provided an estimate of \$3.526 million representing depreciation expense for the period between January 1, 2005 through December 31, 2009 for projects that have greater than a six month period between the in-service date and the closing date, allowing for a one month closing lag. Second, Staff calculated an additional \$1.35 million of depreciation for the same period January 1, 2005 through December 31, 2009 for projects closed less than six months from the in-service date, allowing for a one month closing lag to increase calculated depreciation expense for that period by \$4.876. Third, to account for 2003 and 2004, for which information was not available, Staff then calculated an average annual depreciation expense of \$.975 million and applied that average to the entire seven year period to arrive at their proposed adjustment of $6.827 million. (Staff Accounting Panel at 368-375).

Q. Please summarize Staff's position with respect to its proposed write-off of $6.827 million of depreciation and the corresponding reduction in rate year net plant.

A. Staff states that delayed closings of construction work orders to plant in service results in avoided depreciation expense during the period of delay. Staff cites the Uniform System of Accounts (USOA) by stating that "Work orders shall be cleared from [Construction Work in Progress] as soon as practicable after completion of the job." Staff interprets "as soon as practicable" to be within one month of the plant being placed in service. Staff further states that when it is not possible to achieve the 1 month work order processing time that the Company should true up depreciation expense as if closure had occurred in 1 month. As I will discuss later in my testimony, this true up process would have to be executed manually and would apply to the majority of work orders closed in any year. Staff further argues that the virtue of its recommended adjustment is to ensure that the shareholders would bear the cost of closure processing time that is greater 1 month. Staff have not provided any support for the 1 month work order closure processing time and as I will show later in this testimony, this is an unreasonably short processing time that is out of step with industry practice and would be very costly to rectify using manual procedures with minimal impact on either the depreciation expense charged in the period or rate base. Staff's proposed adjustment for prior periods is therefore inequitable and unreasonable and should be rejected.

Q. Please summarize the Company's response to this adjustment.

A. The Company does not agree with Staff's proposed adjustment for two principal reasons. First, Staff's adjustment is inequitable and unreasonable as it requires the Company to incur retroactive depreciation expense without any corresponding adjustment to remove any excess depreciation incurred on assets replaced by a new construction work order and that would have retired effective from the same work order closure date. There will also be other retirements processed in the same period that also have processing times greater than 1 month. In addition, Staff does not propose to compensate the Company for its foregone return for those assets retroactively assumed to be in service but never included in rate base. Second, Staff's proposal that all closings occur within one month of in service dates is not reflective of the specific work performed or practical implementation constraints. Further, Staff's proposal does not consider the cost of the significant manual work that will be required to true up these offsetting impacts in depreciation, and the resulting change to rate base relative to the minimal improvement in accuracy that will be achieved.

Q. Please explain in more detail why Staff’s proposal is inequitable and unreasonable?

A. Staff’s proposal requires that the Company incur the depreciation expense retroactively to 2003 thereby increasing the depreciation reserve and reducing the Company’s rate base. Under Staff’s proposal, the Company must retroactively incur the depreciation expense for newly constructed assets that have not been depreciated from the in-service date to the closing into FERC 106 – Completed Construction Not Classified (“CCNC”). Staff fails, however, to recommend a corresponding adjustment to reverse the excess depreciation incurred on assets that would have been retired for that same period assuming the one-month closing rule. For the duration of the delay in closing the new project work order, the assets to be retired continued to depreciate until they were finally closed to FERC 108 ("Accumulated Reserve for Depreciation"). This one-sided proposal is inequitable to the Company and unreasonable because it would afford customers a benefit they are not owed.

Staff's adjustment is also inequitable because it seeks to reduce rate base for the benefit of customers without compensating the Company for the corresponding foregone return. Based on Staff’s assumption of consistent closing delays, the Company’s rate base would have been understated in 2001 when rates were last established and remain understated today. Customers have therefore already been receiving the benefit of lower rate base in the current rate plan. Staff nevertheless proposes that this understated rate base be reduced further by $6.827. At the same time, Staff does not propose that the Company be compensated for its foregone return for in-service assets where the work order was delayed past when rate base was established.

In any case, Staff's interpretation that closing work orders "as soon as practicable" means closing within one month of in service dates is not reasonable and is not achievable.

Q. Why does the Company believe that a one month construction work order close processing time is not reasonable or achievable?

A. The issue of construction work order close processing times is industry-wide and not specific to National Grid. The nature, scope and scale of construction projects varies widely and inevitably some work orders will have shorter processing times to close to plant in service while others will take longer. There are two main reasons driving work order close processing times. First, processing times will be extended when work orders do not include all of the necessary accounting requirements required by the company's fixed asset accounting system, PowerPlant. In complex projects where this information is more difficult to source an estimate is required in PowerPlant for transferring costs to FERC 106, CCNC. Second, close processing times will be extended when multiple work orders are generated to plan, schedule and execute the various stages in what is a single construction project. In these situations the work orders for the various stages/components of the project will remain open until the project in total is complete. The in service dates for each stage/complexity of the project will then be retrospectively set.

Q. Please explain how completing the accounting estimates required by PowerPlant in order to close construction work orders drives processing time.

A. The functions that experience the longest work order close processing times are transmission work over 115kV, distribution and transmission sub-stations and facility projects. These projects tend to be larger and more complex, so making the required information more difficult to produce. Also, there is not an automated interface between the various estimating systems and PowerPlant, these complex project estimates (that are generally prepared outside of PowerPlant) must be manually entered into the Company's PowerPlant accounting system, which is a significant effort. All other capital projects have standardized compatible units that automatically generate estimates in PowerPlant, which will shorten work order closure processing times.

Q. Why are in-service dates backdated?

A. Because of the information required to close construction work orders it is not possible to simultaneously record a plant in service date and close the related work order. All in service dates will therefore be backdated to some extent. However, as I have covered in previous testimony, there are a number of factors that drive the processing time between the reporting of a plant in service date and work order closure. More simple, smaller projects will tend to have shorter close processing times while the larger and more complex projects that often contain multiple work orders reflecting each stage in the project will have longer close processing times and therefore a longer back dated in service date. Processing times will also be extended where a project is waiting for a customer interruption to allow newly constructed assets to be energized. This process can take considerable time, even though the project may have been completed months previously.

Q. Has the Company taken any action to improve its closing process?

A. Yes. National Grid has been proactively striving to improve closing work orders to plant in-service by undertaking a comprehensive plan. As noted above, extended work order close processing times are driven by the underlying nature of the construction work, are not specific to National Grid and have historically impacted all utilities. Prior to system automation, all work orders were closed manually from maps and paperwork handed off to accounting from the field. With the development of work management systems, Niagara Mohawk, like other utilities, began automating this process by building interfaces between work management and the fixed assets system.

However, as noted above, not all of Niagara Mohawk's work can currently be managed automatically in work management systems and as a result, manual work is still required. Solutions for this manual work, which include transmission, sub-stations, and facility projects are not available in PowerPlant and are still to be developed.

Prior to the implementation of the Enterprise Resource Planning System in 2004, the Company closed many more "blanket" work orders automatically. The Company now has greater detail to support individual work order closings, but also increased close-out volume. In addition, Plant Accounting has implemented internal controls to ensure the proper and timely closing of CWIP dollars. As part of the CWIP analysis process, system and process training for individuals involved in the work order process has been reinforced. Reports have been generated to address inactive work orders to improve on the timely reporting of in-service dates. Project engineers are alerted when a project is estimated at over one hundred thousand dollars and actual dollars have reached seventy five percent of budgeted dollars. The engineers are required to reply regarding the status of the project and Plant Accounting responds accordingly. A quarterly review process has been implemented to review all work orders with total costs exceeding one million dollars and monthly aging reports are available to project engineers to be reviewed for project status.

Q. Does the Company agree with Staff's recommendation to automatically true up depreciation when the one month closing period can not be achieved?

A. No. Aside from the practical reasons stated above for closings exceeding one month, Company does not have the functionality to true up depreciation expense (on either newly constructed assets or retirements) back to a retrospective in service date. Any true up would therefore be a complex manual calculation that would have to be applied to [many/the majority} of work orders. This would impose a significant additional cost.

Q. What other recommendations does the Staff Accounting Panel propose with respect to plant accounting for CWIP work order close processing times?

A. Staff recommends that the Commission in its order require the Company to include a comprehensive analysis of avoided depreciation in the Company's next gas and electric rate cases.

Q. Does the Company agree with these recommendations?

A No. As stated above, the Company does not believe that Staff's depreciation adjustment is necessary or appropriate. Therefore, it also does not believe that the recommended analysis is necessary.

Q. Does this conclude your testimony?

A. Yes.

Before the Public Service Commission

NIAGARA MOHAWK POWER CORPORATION d/b/a NATIONAL GRID

Supplemental Testimony

of

Andrew F. Sloey

Dated: August 30, 2010

Q. Please state your name.

A. My name is Andrew F. Sloey.

Q. Have you previously provided testimony in this proceeding?

A. Yes. I provided direct testimony as part of Niagara Mohawk Power Corporation's d/b/a National Grid ("Niagara Mohawk" or the "Company") January 29, 2010 filing, Corrections and Updates testimony submitted on May 3, 2010, and Rebuttal Testimony filed on August 6, 2010.

Q. What is the purpose of your testimony?

A. We are responding to the Supplemental Testimony of the Staff Accounting Panel dated August 6, 2010. Specifically, we address Staff's comments on certain employee expenses.

Q. Do you sponsor any exhibits?

A. Yes. I sponsor the following exhibit:

Exhibit____ (AFS-1S): Expatriate and Other Employee Expenses Reviewed for the Historic Test Year

Q. Please explain the Staff Accounting Panel's comments on employee expenses.

A. The Staff Accounting Panel questions the appropriateness of certain employee expenses identified by the Massachusetts Attorney General's office in Docket No. 10-55. Staff does not propose any specific adjustments relating to these expenses but offers them in support of its $26 million macro adjustment to Service Company charges.

Q. Did the Company review the specific employee expenses questioned by Staff?

A. Yes. The Company found that these specific expenses fall into two general categories.

Certain costs relate to expatriate employee expenses that the Company is removing from the cost of service and the other costs have been identified as officer and director employee expenses.

Q. Is the Company proposing an adjustment to its revenue requirement?

A. Yes. As shown on Exhibit__(AFS-1S), Summary Sheet, the Company is removing $4.266 million from its cost of service. This adjustment consists of $3.378 million of expatriate expenses, approximately $784,000 of officer and director employee expenses and inflation.

Q. Please explain the Company's review of expatriate expenses.

A. As explained in a letter dated August 12, 2010 to the Administrative Law Judges in this proceeding, the Company noted that expatriate employee expenses would be removed from the revenue requirement as those expenses should properly be borne by shareholders. At this time, the Company is removing expatriate employee payroll and benefit costs from Niagara Mohawk's cost of service. We are also removing living and relocation costs that have been identified as expatriate expenses. Exhibit__(AFS-1S), Summary Sheet and Sheets 1 through 6 include Niagara Mohawk's allocated share of the total expatriate expenses, which is being removed from the revenue requirement. In total, the Company is removing approximately $3.4 million of expatriate expenses. Sheets 1 through 6 reflect the total expatriate expenses billed from United Kingdom affiliate companies or paid through the Company's Expense Report System or Accounts Payable in the Historic Test Year. The sum of these expenses is reflected on the Summary Sheet of Exhibit__(AFS-1S).

Q. Why is the Company removing expatriate expenses from Niagara Mohawk's cost of service?

A. Although National Grid believes the expatriate program provides value to all of its operating companies, it has become apparent from our review that some expatriate costs were misallocated or should have been charged to shareholders. In order to prevent future errors, National Grid intends to retain an outside, independent firm to conduct a comprehensive review of Company policies and practices to distinguish between the expatriate costs that are appropriate for inclusion in a cost of service and those that are not and to ensure the proper allocation of those costs. The Company looks forward to continuing its relationship of transparency by sharing the lessons learned in that review with the Commission at the appropriate time. For purposes of this case and in the interests of expediency, however, we are simply removing expatriate costs as described above.

Q. Did the Company review the other specific expenses questioned by Staff?

A. Yes. In addition to expatriate expenses, Staff questioned other employee expense items determined to have been incurred by officers and directors of the Service Companies or the Massachusetts Gas Companies and charged to Niagara

Mohawk. The Summary Sheet of Exhibit__(AFS-1S) reflects expenses that the Company agrees should be removed from the Company's revenue requirement totaling $784,028. The costs we are excluding comprise the employee expenses for officers and directors of Niagara Mohawk in addition to the employee expenses for officers and directors of the aforementioned companies. The word "directors" is used here to refer to those employees who serve on the Board of Directors of the respective companies. Although the majority of these costs are properly included in the costs of service, our review has revealed that some employee expenses were misallocated or should have been charged to shareholders. Similar to the approach that we plan to take with respect to expatriate costs, National Grid intends to retain an outside, independent firm to conduct a comprehensive review of Company policies and practices to distinguish between officer and director employee expenses that are appropriate for inclusion in a cost of service and those that are not and to ensure the proper allocation of those costs. The Company will also share the lessons learned in that review with the Commission at the appropriate time. For purposes of this case and in the interests of expediency, however, we are simply removing the employee expenses for the officers and directors of the companies listed above.

Q. Does this conclude your testimony?

A. Yes.

ALJ BOUTEILLER: We have identified all of your exhibits with a preliminary numbering from 54 to 80.

And I believe you said that the witness is available for cross-examination. Let's turn first to staff for cross-examination of this witness.

MS. CICERANI: Thank you, Your Honor.

CROSS-EXAMINATION

BY MS. CICERANI:

Q Good morning, Mr. Sloey.

A Good morning.

MS. CICERANI: Your Honor, first I had sent an e-mail to the parties and to Your Honors concerning a large exhibit that contains IR responses that staff would be using to try to move this along a little bit, and it has IR responses not only that we used with Mr. Sloey but other IR responses, and I'd like to mark that for identification. It is an exhibit of the Department of Public Service staff concerning certain Information Requests, and it is 312 pages long.

ALJ BOUTEILLER: Okay. Let's go off the record while you distribute that around, and while we're off the record I'll find out if this is supposed to be 326.

MR. O'BRIEN: 326.

(Discussion off the record.)

ALJ BOUTEILLER: While off the record we had copies distributed to everyone in attendance, and we can mark this for identification as Exhibit Number 326.

(Exhibit No. 326 was marked for identification.)

MS. CICERANI: Thank you, Your Honor.

BY MS. CICERANI:

Q Mr. Sloey, if you could turn to page 17, lines 11 to 13 of your rebuttal testimony, there you state that one of the controls to ensure proper charges to affiliates is that service companies allocation codes and billing pools, which are used to charge affiliate companies, are based on predetermined allocation methodologies approved by the SEC, is that correct?

A That's correct.

Q And then on page 7 of your direct testimony, if I could refer you there --

A I'm there.

Q -- at about line 3 you state that "before the repeal of the Public Utility Holding Company Act of 1935 the SEC had jurisdiction over the regulated -- over and regulated such service company transactions and that the allocation methods approved by the SEC continued to be used by the company that allocates service company costs," is that correct? I'm sorry. Page 7, line 17?

A Oh, thank you. That's correct.

Q Do you agree that the SEC jurisdiction over these transactions was repealed by the Energy Act of 2005 and the passage of the Public Utility Holding Company Act of 2005?

A I believe that's the case.

Q And FERC assumed jurisdiction over these types of transactions in 2005 with the enactment of the Public Utility Holding Company Act of 2005, is that correct?

A I believe that also to be the case.

Q Does FERC require that National Grid service company contracts and their underlying cost allocation methods be approved or authorized by FERC?

A I believe they're required to be approved by FERC, correct.

Q Do you know under what section they would require that?

A I don't.

MS. CICERANI: Your Honor, we'd like to make a record request that Mr. Sloey identify under which section the company is using to indicate that FERC actually requires that these contracts be approved or authorized.

ALJ BOUTEILLER: You have no objection to him conferring with his own counsel to provide you a response they'll provide?

MS. CICERANI: I do not.

ALJ BOUTEILLER: Okay.

BY MS. CICERANI:

Q Do you know whether FERC requires that the National Grid service company contracts and their underlying cost allocation methods have to be filed with FERC, just filed?

A I don't believe that they have to be filed with FERC. And when you say "contracts," we're actually talking about the allocation methodology, so there are service company agreements and contracts between the service company affiliates for the allocation methodologies that are contained therein.

Q We're actually referring to both.

A I don't believe -- I don't believe either are required to be filed. I just believe -- my understanding is that the allocation methodology needs to be approved.

Q By FERC?

A By FERC.

Q And you will provide the information as to where -- underlying that belief?

A We will.

ALJ BOUTEILLER: Let me just be clear. The first request that you made was what kind of provision of federal law required that they provide submission of their items for approval. Now you're asking a factual question, I believe, and the question, I think, that might follow up from there is to your knowledge, has the company submitted its allocation methodologies to FERC and had them approved?

THE WITNESS: To my knowledge, we have. All of the methodologies we're using across the Legacy service companies have been approved by FERC, and we can provide the date and reference of that approval.

ALJ BOUTEILLER: Okay. By reference to the approval, the actual documentation you received from FERC approving your proposal?

THE WITNESS: I would have to confer to find out what sits below the approval, but we maintain as part of our records and our compliance the date we got approval for a particular methodology. These methodologies have been very stable and have been in place for quite some time on both the Legacy Grid side and the Legacy KeySpan side. In fact, I'm actually struggling to recall when we actually had a new methodology approved. They tend to be very stable.

ALJ BOUTEILLER: Okay. But the nature of regulation of your company has gone through major modifications within the last decade, I would suggest, and I guess what we'd like to understand in the first instance is if you have a required allocation method which is binding and imposed by the federal government, that being FERC, can you give us the transaction that led to the process that you're employing now? And I think that's the call of the inquiry, to find out exactly what's mandated or required by FERC.

THE WITNESS: Correct.

ALJ BOUTEILLER: Thank you.

MS. CICERANI: Thank you, Your Honor.

BY MS. CICERANI:

Q Mr. Sloey, at page 17, lines 13 and 14 of your rebuttal, you indicate that the company's allocations and bill pools include an inherent control framework, is that correct?

A Correct.

Q Considering that the SEC no longer has jurisdiction over these, can you explain how the allocations and the bill pools include an inherent control framework?

A Yes, because the approval defines how -- defines how the allocation methodology will be applied. And then within our accounting systems, we use those bill pools and we record accounting strings, so people only have to record an activity that points to the way the allocation of the bill pool will work. So we take that decision-making away, and it's actually executed through the system.

Q Okay. We're operating now under the assumption that you received an approval from the FERC who now regulates these issues?

A Correct.

Q So I guess we'll wait to see what the response is to determine that. Thank you.

At page 46 of your rebuttal, line 21 --

A Rebuttal, did you say?

Q Yes.

A Yes.

Q You state that the company's methodology for the allocation of costs between Reservoir Woods and Westborough has been filed with the SEC. On what date did the company file its allocation methodology with the SEC, do you know?

A I don't know, Counsel. I'd have to make an inquiry.

Q Could you please provide the date that the company filed its allocation methodology for Reservoir Woods with

the SEC to us?
A We will.
ALJ BOUTEILLER: Yes. And for purposes of the record, unless counsel objects to any information request, we will assume that your silence means that you're accepting the information request and will respond to it as quickly as you can reasonably do?
MS. SWEET ZAVAGLIA: Yes, Your Honor.
ALJ BOUTEILLER: Okay. We'll turn back again to staff counsel.
MS. CICERANI: Thank you.
BY MS. CICERANI:
Q Do you know whether the reservation woods allocation methodology was approved?
A I believe it was, correct -- Reservoir Woods, Counselor.
Q Okay. Could you provide that approval, also?
A We will.
Q Thank you. If you could turn to page 9, line 17 of your direct testimony --
MS. NESSER: What page, Jane?
MS. CICERANI: Page 9, line 17, of direct testimony.
MS. NESSER: Thank you.
A Line 17?

Q   Yes. It starts on line 17. There you discuss the service level agreements being developed by National Grid, and I'd just like to ask you a few questions about these agreements. If you could look to your response to DPS 295, it's actually page 88 of Exhibit, what I believe is 326, the exhibit that was just marked, the new one. Yes, that's the one.
A   I'm sorry, Counsel. Would you just repeat the page number? 326?
Q   No. It is page 88 of that exhibit.
A   I have it.
Q   Is it correct that the service level agreements will not be legally binding contracts between Niagara Mohawk and the National Grid service companies?
A   That's correct.
Q   And is it your understanding that these service level agreements will not be inter-affiliate agreements between Niagara Mohawk and the National Grid service companies so that they would not be filed under Section 110(3) of the Public Service Law?
A   That is my understanding.
Q   Is it correct that the service level agreements will not be the basis of the service company cost allocations and charges to Niagara Mohawk from the National Grid service companies?

A I think it's not going to be the basis, but I think you have to -- if I could just qualify, you have to look, I think, at the way the purpose of the service level agreement is to set out and improve the operating performance of the service company and improve the cost profile, so it will affect the cost that will ultimately be charged to Niagara Mohawk, but it won't be the basis of their determination.
Q Thank you.
A It's how -- if I could -- it's how, sort of, the operational management and the vice presidents responsible for service company activity jointly agree to improvement of programs and priority and execution.
Q Is it -- but it's not the basis, so is it the service company contracts that are filed with the PSC under PSL Section 110(3) that will continue to be the basis for the allocation of those costs?
A Correct. They will set out the scope of the service and the allocation basis.
Q Is it also correct that FERC will not audit the operation of the service level agreements but will instead examine the cost allocation transactions under the service company agreements?
A I don't know how FERC would conduct and progress on the next order, but certainly, when they were conducting

the affiliate transactions, they were very interested in how we were approaching this and what we were doing, so it was certainly a matter of discussion with FERC. I don't know whether it will be a formal part of their subject matter when they produce their audit report.

Q Thank you. In Exhibit AFS-8R, you go through various allocations of invoices and make some adjustments to your direct testimony to explain adjustments that you've made from your direct case, is that correct?

A Yes, it is correct. I have it.

Q I'm actually going to have you look back at the exhibit you probably just put down.

A That's okay.

Q That is page 219 of Exhibit 326. This is the company's response to IR DAG-58 and Attachment 1. Do you have that?

A I have it.

Q If you could look to Attachment 1, you can see that there are three different billing pools that are used -- being used to allocate the Alston Bird invoices shown on that sheet; do you see that? It's 233, 236 and 238.

A Correct.

Q Would you accept, subject to check, that bill pool 236 is used to allocate the Alston Bird work done on the FERC standards of conduct?

A I couldn't tell from here, so it will have to be subject to check. I have no idea what the subject matter is of the Alston and Bird invoice.
Q You would have to check that invoice?
A Subject to check.
Q Then looking at that attachment, that Niagara Mohawk's share of this type of work for bill pool 236 is 44.55 percent, is that correct?
A That's correct, out of bill pool 236.
Q Thank you. Would you accept, subject to check, that bill pool 238 is used to allocate all the Alston Bird work done on FERC monitoring?
A Again, subject to check.
Q Thank you. And that Niagara Mohawk's electric share of this type of work is 54.33 percent?
A Correct.
Q Thank you. Do you know whether the Alston Bird description of FERC monitoring applies to a particular case, or is it of a more general descriptive category?
A Counsel, I have to check. It feels more general descriptive, but I'd have to check.
Q Okay. Do you know whether that category, the more general category of FERC monitoring, applies to just electric, or is it electric and gas operations? Does it cover both?

A I'd have to check. I believe we have FERC -- I believe we have gas utilities that are also FERC-reported, so it would be both.
Q Do the FERC standards of conduct apply only to the electric portion of the industry or to both electric and gas?
A I don't believe it distinguishes. It would apply to both. But again, I have to check, but I believe it's universal.
Q And bill pool 238, which concerns the --
A The FERC monitoring.
Q -- the FERC monitoring, that also would possibly contain both electric and gas?
A It depends. I guess it would depend on the nature of FERC monitoring. I mean, was it related to specific issues related to just the electricity business, or was it more general related to electric and gas. And until I understood the nature, I couldn't comment.
MS. CICERANI: Your Honor, we'd like to mark for identification a three-page document -- well, it is from Attachment 6 to DAG-3-SAP, and it is the redacted version.
ALJ BOUTEILLER: For identification we'll mark this as Exhibit Number 327.
MS. CICERANI: Thank you.

(Exhibit No. 327 was marked for identification.)

BY MS. CICERANI:

Q   Mr. Sloey, if you could just take a minute, you might want to review some of the descriptions and, in the final column on Exhibit 327, to see the type of work. I know it's a little difficult to see.

A   It might take me more than a minute. I've scanned a few. I don't know.

Q   Okay. I'm actually looking, for example, 1, 2, 3, 4, 5 up from the bottom where the description is "looking for items of interest to Grid." Do you see that?

A   Yes, I see that.

Q   And then the next one right below that, "monitor industry and regulatory issues that may be of interest to National Grid." Do you see that, also?

A   I see that.

Q   Having reviewed this, would you suggest that this FERC monitoring matter number probably covers more generic type cases than something specific?

A   I'd agree, Counselor, it feels generic, but I just don't have any knowledge of the matter.

Q   If you could look up at the very first one, there it indicates that there was a review of an e-mail regarding a gas topic to report. Do you see that?

A   Regarding -- from somebody walker regarding gas topics, correct.
Q   Is it likely that bill pool 238 has allocations to gas companies, also?
A   The invoice should have allocations to gas company. I'd have to check the 238 bill pool.
Q   Okay. We can do that. You can look at AFS-8R. I believe it's page -- well, I'm not sure which page, but I will look. Somewhere around page 103.
A   I don't know if it goes to 103.
Q   I'm sorry. It's in SAP-2.
A   That explains it. Which is SAP-2, Counsel?
Q   Do you not have a copy of SAP-2 up there? We can show it to you. This was pre-filed --
MS. CICERANI: This was a pre-filed exhibit of the Staff Accounting Panel, Your Honor.
ALJ BOUTEILLER: At this point you just want to have the witness have a copy of the Staff Accounting Panel's exhibit in front of him for cross-examination?
MS. CICERANI: Yes, sir.
A   Thank you.
Q   You're welcome.
ALJ BOUTEILLER: Which page are we working on on this?

MS. CICERANI: Page 43.
A I'm on it.
Q You're on it, okay. If you look there, you can see the bill pool category 238?
A Yes, ma'am.
Q You see it includes Nantucket Electric, Massachusetts Electric, New England Power, United State, Niagara Mohawk and Narragansett Electric?
A I can see.
Q So are there any gas companies listed there?
A No, Counselor, there aren't.
Q Thank you. The matter number -- the matter name "FERC standards of conduct," do you know whether that applies only to the electric portion of the industry or to both electric and gas?
A Counselor, I believe it applies to both.
Q Why is -- you had already indicated that -- the percentages that Niagara Mohawk Electric's share was?
A In 238 bill pool, yes, off the previous exhibit.
Q Right. And also on 236?
A Sorry?
Q And also on 236? Both bill pools?
A Both bill pools, correct.
Q Thank you. Why is Niagara Mohawk Electric charged a higher percentage for the FERC monitoring than it is for

the FERC standards of conduct, 54.33 percent versus the 44.55 percent?
A I'd have to look at the underlying transaction. I don't know. It doesn't appear logical. But I'd have to look at the underlying detail.
Q Could you provide us that information, please, the underlying detail and the information?
A The basis for that discussion?
Q Yes. Thank you. Is it correct that National Grid's unregulated affiliate, KeySpan Electric Services, LLC, provides O&M and construction management services to the Long Island Power Authority for its transmission and distribution facilities?
A That's correct.
Q If you could look at SAP-2, pages 41 through 49?
A This one?
Q Yes.
A The section starting "Counsel listed bill pools"?
Q Yes. Is it correct that none of the Alston Bird legal costs for FERC monitoring, as we've described as being encompassed in bill pool 238 -- is it correct that -- I lost my own place there.
A It's on page 43.
Q Thank you.
A You're welcome.

Q Is it correct that none of the -- those Alston Bird legal costs for FERC monitoring are shown allocated to KeySpan Electric Services, LLC?
A That's correct.
Q And none of Alston Bird's legal costs for the FERC standards of conduct are allocated to KeySpan Electric Services, LLC, is that correct?
A That's correct. Can I just sort of clarify one point? National Grid's business, transmission and distribution business on Long Island isn't FERC-regulated. It's only its generation business. And by far the largest piece of business on Long Island is the transmission and distribution business. Under the electric services we are effectively LIPAs. We're effectively LIPAs. LIPAs provide the services that would be LIPA that would be subject to that regulation. The generation business is regulated by FERC -- or contractually.
Q So it's your understanding that the LIPA system is subject to FERC regulation?
A I couldn't comment on exactly how. All I can comment on is National Grid's contractual relationship for T&D services on Long Island, and there National Grid is the provider of the services to LIPA. LIPA actually is the utility on Long Island. The situation is slightly different for the generation activities on Long Island.

Still, National Grid is the provider, but those arrangements, those contractual arrangements between LIPA and National Grid are FERC-regulated.

So I guess the point I'm flagging, Counselor, is I have to sort of dig into it a little bit, but I'm actually not surprised for FERC monitoring that there isn't T&D -- an allocation to a T&D company on Long Island. I am surprised there isn't KeySpan generation services on their invoices. I offer that comment.

Q But you did offer to provide some digging in of additional information?

A Yeah. But I think the two points are what's National Grid's status in relation to the provision of T&D services on Long Island, which is not the utility that's LIPA. And separately, the status of FERC regulation or oversight of the generation activities on Long Island.

Q But KeySpan Electric Services does perform a management function for LIPA, correct?

A Correct, but it's directly to LIPA. We are not the utility. We are LIPA's provider of services on Long Island. LIPA is the utility.

Q Well, since you do assist in some fashion --

A I'm sorry?

Q Whatever we call it, is it possible that the legal knowledge that was obtained by the law firms, Alston Bird and the others, for National Grid in those more generic reviews, that those -- that that information is shared with the KeySpan Electric Services and that that would be valuable to LIPA?

A I couldn't tell you. I'd have to comment that I'd have to go and check, because I think that depends on the nature of the relationship, which is actually being regulated by FERC. I can tell you with respect to generation that would be the case. I would have to check in relation to -- by far the largest part of the business is the transmission and distribution services on Long Island.

ALJ BOUTEILLER: Can you in your inquiry find out whether or not, did LIPA make any use of the information that was gained and costs which were allocated to Niagara Mohawk?

THE WITNESS: I will.

ALJ BOUTEILLER: Thank you.

A Sorry. It's a confusing contractual arrangement.

Q That's okay. Is it correct that billing code 233 was used to allocate general transmission work for Alston Bird performed for National Grid? Or maybe I should say would you take it subject to check?

A Can we do that, yeah, because it will be another five documents.

Q That's correct. Niagara Mohawk Electric's share of the billing code 233 is 56.43 percent. Would you accept that, subject to check?
A It would probably be on the schedule here.
Q It might be.
A And wouldn't it be 54?
Q I'm sorry?
A Wouldn't it be 54? Page 43, so, Counsel, page 43.
Q Well, I have -- if you look above that, 233 at the top, it's got 56.43 several times. And then also it looks like there's two numbers, either 56.43 percent and then also the 54.
A Then, Counsel, I must be on the wrong page. I'm on page 43.
ALJ BOUTEILLER: Let's go off the record.
(Discussion off the record.)
BY MS. CICERANI:
Q The question was whether it was correct that Niagara Mohawk Electric's share of billing code 233 is 56.43 percent?
A That is correct on the schedule.
Q All else equal, if some of these general transmission work legal invoices were allocated to KeySpan Electric Services, LLC, for the general transmission work it performs for LIPA, is it correct that Niagara Mohawk

Electric's share of these costs would be less than the 56.43 percent it was allocated, all else equal?

A All else equal, Counsel, I think that would be the case, but I would want to check because of the contractual relationship between T&D, I'm not sure that the FERC oversight in relation to T&D business is appropriate, and that's the point I think we said we would go and check.

Q Okay, thank you. In AFS-8R, I believe it's sheet 5 of 72, it's around page 95.

A Rebuttal, yeah.

Q Yes. The AFS-8R to the rebuttal?

A Could you repeat the page number, Counsel?

Q Page 95.

A My 8R only goes up to 72.

Q I'm sorry. It's sheet 5 of 72. 95 is the number at the bottom. I apologize.

A Sheet 5 of 72.

Q And there you -- you take the position that 27 percent of the cost for the FERC financial audit to be allocated to Niagara Mohawk Electric, is that correct?

A Correct.

Q And for that you'd be using, it looks like, bill pool 239, is that correct?

A Where do you see that? Oh, at the bottom of the paragraph. Correct.

Q Thank you. Do you know whether bill pool 239 also allocates a portion of its cost to any of National Grid's other unregulated affiliates?
A I don't. I'd have to check. Couldn't we check off the other exhibit, SAP-2 that we just looked at?
Q You can look at SAP-2, page 43. I'm sorry. Page 239. I have no idea why I said 243. I know why. I'm sorry. It's page 43. I'm a little confused, and I apologize. SAP-2, page 43.
A Okay, I have it.

ALJ BOUTEILLER: The question is whether or not any of these are National Grid unregulated --

MS. CICERANI: Unregulated affiliates, that's correct, Your Honor.

ALJ BOUTEILLER: Affiliates.

A I think subject to the question around KeySpan Electric Services and KeySpan Generation Services, because those are contractual relationships sometimes with regulatory oversight, they're not directly regulated.
Q Thank you. The reason you allocate some portion of these other -- you allocate some portion to these other unregulated affiliates is that some of the billing pool allocations looked at in the FERC audit also include allocations to these affiliates, is that correct?
A Part of the scope of the audit, yes, was compliance

with FERC cross-subsidization provisions.
Q What Niagara Mohawk employee checks to see if Niagara Mohawk is getting the proper share of legal invoices billed through the service company?
A What employee of Niagara Mohawk?
Q Correct.
A It wouldn't be an employee of Niagara Mohawk. It would be an employee of the service company who has responsibility for the activities of Niagara Mohawk.
Q So is there any Niagara Mohawk employee who would check to see if Niagara Mohawk is getting the proper share of any invoices billed through the service company?
A Possibly, because if there are employees of Niagara Mohawk relating to fuel activities, and there are invoices like storm costs flowing through the service company, they'd be checked within -- by employees of Niagara Mohawk. If you're talking about certain corporate services activities, they would be by employees of service companies who are responsible for the activities.
Q If someone from Niagara Mohawk would be checking, what actually would be their process? Would they then have to report that to a service company employee or through the service company?
A If they're checking the invoice, based on the delegations they record their approval of that invoice

through the system. It's online.

Q   So Niagara Mohawk employees have the ability to make the -- make their own allocation?

A   That's correct. Where the activity is within the scope of their authority, correct.

Q   Can you give me examples of what types of activities those might be?

A   It would be more fuel-related. The employees of Niagara Mohawk are largely connected with field activities in the Niagara Mohawk service territories, so it would be activities in relation to those activities.

Q   Who would be responsible for checking to see which affiliate should be charged the costs for things such as rewards paid out to employees who put out the fire at the unregulated generating plant in Port Jefferson? Did anyone from the service company check this out?

A   I'm not familiar with the particular transaction. I'm not actually familiar with the fire at the plant that you refer to.

Q   What about AMX gift cards that were given to employees, does that sound familiar to you?

A   Only from the newspaper. I'm not familiar with the particular transaction.

Q   Okay. But you did read that in the newspaper?

A   I did.

Q And did not at that point follow to determine whether or not that was accurate?
A I didn't.
Q So do we know who from the service company would actually check that out?
A Well, it would be the vice president responsible for the activity, so we'd have to understand, you know, who organized that transaction, what the basis of that transaction was, and then how that vice president made the decision.

ALJ BOUTEILLER: Let me just interject and you can inform me and help me understand and appreciate how the intercorporate transactions might go. But I think the thrust of the questions you just heard are asking the question, within the entity known as Niagara Mohawk, is there any check or balance on your allocation process which would occur within that entity in isolation from the service company or from a parent company or anyone else? Is that a possibility, or is that feasible? Is that the way you operate?

THE WITNESS: Your Honor, to properly answer the question at two levels, at a transactional level, if a Niagara Mohawk employee engages -- creates a transaction within the scope of their authority, that transaction will be approved within Niagara Mohawk by the employee -- the entity, Niagara Mohawk.

ALJ BOUTEILLER: Let's just stick with that. So if I'm a lineman at Niagara Mohawk --

THE WITNESS: Or a supervisor.

ALJ BOUTEILLER: Let's just make me a lineman, okay? My time has to be allocated to somebody, and in the first instance I would indicate who I think the allocation should be to, me or my supervisor?

THE WITNESS: That's right, and your supervisor would approve the times, and there would be that check that happens within the system.

ALJ BOUTEILLER: I'm thinking of something different. I'm thinking in terms of at some point somebody produces a report, and that report says "this is the totality of allocations to this entity known as Niagara Mohawk and, in particular, its electric operations." Is there anybody within the organization known as Niagara Mohawk Electric who would then either do a check or a balance or review of that for the accuracy of the information contained in that invoice indicating the total amount, or would that all be done within the service company proper?

THE WITNESS: I'm getting just -- just to give a little explanation, I'll try to help the understanding. National Grid uses a line of business model, so we have management teams that are set at a line of business level, and those lines of business management teams have responsibility for the utilities within their purview. All of the monitoring in aggregate of Niagara Mohawk's utility activities is conducted by those lines of business management.

At the line of business management level those people are employees of the service company. But they're not acting -- when they're doing that approval process, they're not acting on behalf of the service company; they're acting on behalf of the utilities which they have responsibility for, because they actually have responsibility for a number of utilities. If you take our electric distribution and generation line of business, they're responsible for the activity of multiple utilities, so they conduct those monitoring activities across the range.

ALJ BOUTEILLER: They're doing it for both entities simultaneously, and the accuracy of that transaction is important to both entities at the same time?

THE WITNESS: Correct. And they're doing

it -- you know, management reporting structure, the activities then roll up to a line of business level, so they're doing it at the line of business level as well.

ALJ BOUTEILLER: So you're indicating the line of business management is the controlling operative function here and really has no corresponding element or similar process that gets done at the Niagara Mohawk Electric level?

THE WITNESS: No, because they're doing it -- they're doing it for the line of business, which includes the entities, including Niagara Mohawk, they're responsible for.

ALJ BOUTEILLER: Yes, I understand. Please proceed.

THE WITNESS: Sorry.

BY MS. CICERANI:

Q Could you turn to AAE-55? It is page 190 in Exhibit 326.

A 326, Counsel, is SAP-2?

Q No, I'm sorry. It's the larger exhibit.

A Right. So this is 326.

MR. MAGER: What page?

MS. CICERANI: 190.

BY MS. CICERANI:

Q Is it correct that the company agreed that some of Niagara Mohawk's security department costs at the Syracuse office complex should have been allocated to other affiliates because the Syracuse office complex has its own service department?
A I'd have to read the exhibit, Counsel. This 8055?
Q This is A-8055, if you look at response number 2.
A That's correct.
Q Thank you. Is it correct that for all the years the Syracuse office complex has housed the National Grid Service Company departments that none of the Niagara Mohawk's security department costs have been allocated to other National Grid affiliates?
A I'd have to take it subject to check about all years but -- I'd have to check.
Q So by not allocating any of the Syracuse office complex security department costs to the other National Grid affiliates that use the complex, Niagara Mohawk was essentially subsidizing a portion of the other affiliates' operations, isn't that correct?
A Correct.
Q Is it correct that staff brought this misallocation issue to the company's attention, likely in this IR?
A Probably. I don't know, but probably.
Q I think we've done some of this, but let me ask

again, anyway. Is someone from Niagara Mohawk responsible for making sure that Niagara Mohawk's costs for things like the security department costs are being properly allocated to the affiliates, just as other affiliates' costs are being allocated to Niagara Mohawk?
A I think we have. We have people who are responsible, line of business management that are responsible for all of the utilities in their area of responsibility.
Q For an employee that's responsible for a line of business, what sort of check or process is there for that employee to ensure that it is Niagara Mohawk that should be charged for one thing or being properly charged for it versus another affiliate?
A The process -- the process is the people that are commissioning, so whether it's security or whatever, the people that are responsible for the provision of those services, their job is to understand, you know, who is the beneficiary of the service and to get the right accounting string and, therefore, to get to the right bill pool or allocation code, depending on whether you're Legacy Grid or Legacy KeySpan activity, and then the line of business finance teams and management teams are responsible for the, you know, overall review of the financial performance and therefore the appropriateness of the allocations. So they're sort of like controls at both the transaction

level and then we have the review controls that are executed by the lines of business.

ALJ BOUTEILLER: Let me ask you a question of a general nature, because I guess what we're trying to probe here is to find out how these people go about doing their business.

THE WITNESS: Right.

ALJ BOUTEILLER: If I go to the bank and I ask them to put money in my account, I'm pretty well assured that the bank is going to do that and not put the money in somebody else's account. Here with the whole notion of allocations would you say that your people doing their allocations and the like are working with the same degree of accuracy that a banker might be working?

THE WITNESS: A-55, demonstrably not the level of accuracy of a bank.

ALJ BOUTEILLER: Should we insist they operate the way a banker might operate with dealing with the funds or responsibilities of different clients?

THE WITNESS: I don't think any error is acceptable. And where we find an error like this, whether it's brought to our attention by staff or we find it through our own review processes, we're going to take a real strong look at why it happened, what was the cause of that error, and go ahead and fix that error. So I guess it's a little bit different to a bank where we have -- you know, we have a large, complex organization. The organization, as staff has observed, has been undergoing substantial change over the last two years following the merger, so we have many people that are changing roles, changing functions, so it's been a very -- you know, it's been a very volatile three years.

ALJ BOUTEILLER: Yes.

THE WITNESS: So can you get this a hundred percent perfect? We strive for that. We want it to be as close as we can, but there will be errors. When we have 10,000 or 12,000 people, you know, recording accounting strings and allocating, you know, that's a large volume of transactions that's occurring.

ALJ BOUTEILLER: So is my ideal not achievable that we have your allocators operating with the same degree of accuracy that we would expect a public banker to have in the accuracy of their transactions? Is that not attainable by your people?

THE WITNESS: I think it's attainable, but it would require a set of banking systems and controls, and bank examiners have an entirely different framework to -- you know, the way, you know, sort of accounting, reporting and control frameworks are operating in a utility. So I think it's an attainable ideal, but it's a very hard -- it's a very high standard -- perfection is a very high standard to get 100 percent correct.

I guess the question is would any of those issues that have been identified, would any of them have a significant impact on the Niagara Mohawk rate case? I think that's sort of the second question. So could something, you know, that's hugely significant lead through is the second question I'd ask.

ALJ BOUTEILLER: Do we have any standards or measures by which we can ascertain what those items might be, the degree to which your allocations need to be accurate? Is there any barometers I can look at to understand?

THE WITNESS: There isn't a barometer. I mean, there's a barometer for financial reporting, which is a different set of standards. And in the accounting literature, you know, those materiality standards are very clearly defined.

For U.S. rate-making and the proper

recording of allocations, our objective is to get them absolutely correct. The point that I want to make, without minimizing the impact of any error that we've made, is actually it's quite difficult to get it a hundred percent correct all the time because of the complexity, people changing, the sheer volume of bill pools.

When you go -- to use your analogy, Your Honor, when you go to the bank, one of the first questions you're asked is please put in your account code. And I don't know how many bank accounts you have, but it's probably, you know, one of five. As you saw from the exhibit that we just discussed with counsel, SAP-2, we have 300 bill pool methodologies on the Legacy Grid side and 200 on the Legacy KeySpan side, because we're still merging the companies, so the array of choice is just much greater in order to ensure the proper accounting of the transaction. So the transaction itself is much more complex than a deposit that you might make at a bank.

The compliance checking that would happen in a bank -- I mean, a bank has both -- they have teams of bank examiners, so they're examining transactions both systematically and sort of manually. We just don't have that. We require -- you know, we rely on the control frameworks that we build into the systems and the accounting systems and the accounting strings. We rely on analytical reviews.

We rely also heavily on training. You know, this is a very complex area. Imagine yourself back as a lineman. You get an invoice and tell me which of 300 bill pools I have to select. So we try to make it as easy as possible through programmatic coding within the system, and also training and education, because a lot of this is about training and education.

ALJ BOUTEILLER: Okay, thank you. I appreciate your willingness to engage in colloquy with me, so I appreciate that.

THE WITNESS: No problem.

ALJ BOUTEILLER: Let's go back to staff. Counsel?

MS. CICERANI: Thank you.

BY MS. CICERANI:

Q If you could turn to page 12 of your rebuttal, you discuss the process for reviewing and developing service company department/function budgets. Is that correct?

A We're ready.

Q Starting at page 12, as I said, you're discussing the process you use for budgets, correct?

A Um-hum.
Q At page 16, line 3, you state that "the budgeting process provides a major control on the allocation of expenses for services provided by the service companies to its affiliates, including Niagara Mohawk, through the comparison of actual expenses budgeted amounts at the line of business level."
A Um-hum.
Q Is that correct? Now, on page 14 of your rebuttal at lines 13 to 20, is it correct that for each service company department function --
A I'm sorry, Counsel. I'm a little behind you. I was reading the last extract.
Q Page 14.
A Which one, now?
Q Page 14, lines 13 to 20. Is it correct that for each service company department function, such as legal, financial services, human resources, et cetera, its budgeted amount is allocated to affiliates receiving service to show each affiliate would have a budgeted service company amount for services provided by the department function?
A That's correct.
Q All right. So I just want to talk a little bit about the monitoring process during the year where the budgeted

amounts are compared to the actual expenses. If you look to page 17, line 18, you discuss the controls provided where line of business management periodically compares the actual expenses to the budgeted amounts during the year, is that correct?
A That's correct.
Q And you state that part of this control -- or part of these controls are sessions which also include a review of the service company department function costs being charged to affiliate companies, correct?
A Correct.
Q Okay. If you could look at question 4 and 5 of RAV 126 SAP, that is located at page 125 of Exhibit 326.
A Page 125, RAV 126?
Q Correct.
A I'm there.
Q Okay. In this IR we ask for all the reports monitoring and comparing service company budget and actual costs and Niagara Mohawk's response. Is it correct that the monitoring reports of service company charges were provided at the line of business level and that no operating affiliate level reports were provided that compared the budgeted service company charges allocated to Niagara Mohawk to the actual allocated costs?
A Subject to checking, yes.

Q Is it correct that no Niagara Mohawk employee produces monthly variance reports that quantify and describe all the variances in actual versus budgeted service company charges?
A No Niagara Mohawk employee?
Q Correct.
A I thought we discussed that previously. All of the monitoring occurs through line of business finance teams. Those line of business finance teams and their management teams are employees of the service company charged with the responsibility for a specific set of utilities.
Q Is there a service company employee who produces the variance report that quantifies and describes all the variances in the actual versus the budgeted service company charges of Niagara Mohawk?
A Those reporting processes are still being formed, but inside the electricity distribution and generation line of business monthly financial report, we do include entity statements for Niagara Mohawk and their key utilities. I don't know why they weren't provided in here, but we do -- that information does go to the management team, to Tom King's EDG management team.
Q Can you provide us those monthly -- those reports?
A Sure.
Q Thank you. Is it generally correct that labor costs

should be accounted for in a manner consistent with the accounting for travel expenses for a particular activity?

A Generally -- I was just repeating the question. Sorry. Would it be correct to assume that labor and travel would be allocated in the same way using the same bill pools and allocation codes allocated consistently. I would expect so, but I'm not sure it's uniform. I have to think about it.

Q Could you -- as a record request could you confirm whether or not you believe that that is a general method, that that would be generally correct, that it should be treated consistently, labor and travel expenses?

A Yeah.

Q Thank you. In Staff Accounting Panel's supplemental testimony we point out that some of National Grid's employee travel expenses related to attending a hearing in Rhode Island, and some of those costs were allocated to Niagara Mohawk Electric. Do you agree that some of the National Grid employees' travel expenses related to attending the Rhode Island hearing were allocated to Niagara Mohawk Electric?

A Subject to check, yes.

Q Would you check?

A Yeah, absolutely.

Q Do you know whether any of that employee -- the

employees' labor costs related to preparing for the hearings, traveling to the hearings or taking part in the hearings were also allocated to Niagara Mohawk Electric?
A I don't know whether they were.
Q Is that something you could provide for us, please?
A We could provide and check.
Q Thank you.
A Could I --
MS. SWEET ZAVAGLIA: I'm sorry. I apologize. I was just going to ask, can you be clear what the record request on that one was?
MS. CICERANI: Certainly. We wanted to get the employee labor costs related to preparing the hearings, traveling to the hearings or taking part at the hearings, what portion of those were allocated, or if any were allocated to Niagara Mohawk Electric.
BY MS. CICERANI:
Q Do you know if any -- if either in-house counsel or outside counsel helped prepare that employee for those hearings?
A Counsel would have absolutely helped prepare -- just to clarify, helped prepare for the Rhode Island hearings. Yes, they would.
Q Then I guess we'd ask the same record request for that counsel's time, how counsel's costs were accounted

for and allocated and how they were allocated.
A   Right.
Q   Mr. Sloey, while on assignment in the U.S. do you maintain any U.K. responsibilities?
A   No.
Q   So who is doing your work back in the U.K.?
A   A lady called Helen Barrett.
Q   Okay, thank you.
A   She used to work for me. She's very good.
Q   Well, that's good. Can you explain how you account for your time and your related labor costs? For example, do you use certain billing pools for all your labor costs?
A   Yes, I use an all-company billing pool, so it wouldn't -- my costs -- my costs here in the U.S. would hit all the companies in the U.S. holding company group.
Q   For everything that you do?
A   You said just labor.
Q   Okay.
A   So my compensation.
Q   If at the time you were working on -- you're working on something that's 100 percent directly related to a particular affiliate, you still then apply your more general billing pool --
A   Correct.
Q   -- allocator?

A Correct.
Q Okay.
A Could I offer an explanation as a comment?
Q Certainly.
A Where -- you know, where we have sort of, you know, people that are quite senior in the organization that work on many, many different issues and affiliate matters on sort of like a daily basis, what we don't do is we don't charge -- you know, we don't sort of keep time sheets and say "for this hour I worked on the Niagara Mohawk rate case," or in this case week -- month. We don't --
MR. VISALLI: Year.
THE WITNESS: Exactly. Sometimes 24 hours a day.
A So we don't record those time sheets. What we do is we look at time served and how time is distributed on sort of a much larger time period, and those costs get allocated using an all-company billing pool because over time that would be a reasonable allocation of the costs and a much more effective use of my time than sort of trying to do time sheets on sort of an hour-by-hour basis, and that would be the case for quite a number of senior executives across the U.S. group.
ALJ BOUTEILLER: What determines that allocation factor? What measure determines that

allocation factor?

THE WITNESS: Okay. So I am -- I'd have to check, Your Honor, but I'll tell you what my assumption -- I think I'm sort of a Legacy Grid person, in which case the all-company bill pool would be based on all the affiliates O&M, O&M of a particular affiliate as a percentage of total O&M incurred across the U.S. group.

ALJ BOUTEILLER: That's the operative assumption for purposes of allocating your time?

THE WITNESS: That's right.

ALJ BOUTEILLER: And rather than try to figure out on a day-to-day, hour-by-hour basis, that's used generically over the entire time period?

THE WITNESS: Yes, on a reasonable assumption that over a year that would be a good reflection of how I spend my time.

ALJ BOUTEILLER: Your allocation then would only change when the company recalculates the relative amounts of O&M invested or calculated for each particular entity?

THE WITNESS: Correct. It would be part of our annual bill pool reset process.

ALJ BOUTEILLER: Okay. Thank you.

BY MS. CICERANI:

Q With that larger bill pool -- so you said all the companies. Does that include the non-regulated companies, also?
A I'd have to check.
Q Okay.
A I'd have to check, but I believe so. It's an all-company bill pool, so it would be -- yes, it would be all companies.
Q But you'll confirm that?
A I will confirm, yes.
Q Thank you.
ALJ BOUTEILLER: Let's go off the record.
(Discussion off the record.)
ALJ BOUTEILLER: Is there a question, Counsel?
BY MS. CICERANI:
Q When you provide the information that we just discussed concerning your labor costs, could you just also provide the bill pool for us, what the bill pool number is?
A Yeah, absolutely.
Q When you travel, are your travel expenses accounted for in the same way as your labor costs?
A They should be.
Q So you use the same billing pool?

A It should be the all-company bill pool. However, I do have to recognize that I did use the wrong one for a period of time.
Q And who brought that to your attention?
A One of my colleagues.
Q Okay. Through a formal process?
A Through a frank exchange of views that I should be more careful.
Q How long have you been working in the U.S., Mr. Sloey?
A Since August 2007, so three years. Three years, one month.
Q During your stay in the U.S. have you ever traveled back to the U.K. for business purposes?
A Yes.
Q How many times have you traveled back and forth?
A Maybe six, seven. Actually, that probably understates it. Probably, maybe, let's say ten, but not more than ten.
Q How much of these travel expenses to and from the U.K. were charged to U.K. operations in the historic test year?
A None. None, I wouldn't think, but I'd have to check, but I would expect none.
Q Could you please confirm that for us?

A Yeah, because the bill pool that I would use wouldn't charge to U.K., wouldn't charge to a U.K. entity.
Q Does National Grid's U.S. Finance/Tax and Treasury Department perform work for K-E-D-N-Y, KEDNY?
A Yes.
Q And for K-E-D-L-I, KEDLI?
A Yes.
Q For any of National Grid's unregulated subsidiaries?
A I mean, yes, they would but much less. They're very, very small.
Q Okay. I'd like to refer you to DAG 60. This is starting at page 261 of Exhibit 236.
A 326 or 236?
Q Did I say it wrong?
A Yeah.
Q 326.
A Sorry, Counsel. Page number?
Q 261.
A It's a long discovery request, Counsel, so where are we going to look?
Q We're looking down at page 285 at the very bottom. Can you see there a charge for $4,003.48 for year-end celebration, U.S. Finance/Tax and Treasury, at Lucciano's Restaurant in Brooklyn? Do you see that?
A Lucciano's, yes, last line.

Q And you'll notice at the bottom of 285, the bill pool that was used is 236. Do you see that?
A Correct.
Q Okay. You can either look or we can --
A You can tell me.
Q Okay.
A It will be quicker.
Q Okay. None of the costs were charged to KEDNY, KEDLI or National Grid's unregulated subsidiaries, is that correct?
A That's the error I was talking about in my account. That was my incorrect bill pool.
Q This has been corrected?
A Corrected prospectively, so I don't use for my expenses an all-company bill pool. I used the incorrect bill pool on my expenses, and that was an expense that was processed through my expenses.
Q Was there a correction made for this?
A Not for that item, no. Sorry, correction. I'm not familiar with this. This is a Revenue Panel RAV, so I'm not familiar with this one.
Q But you believe --
A Was this included -- was this an expense included in the historic test year?
Q Yes.

A That was excluded as part of the supplemental testimony adjustment, so there has been an adjustment made. I was referring to the original process of the transaction.
Q Thank you. I'd like to ask a record request that you provide the total historic test year cost by cost component of National Grid's U.S. Finance/Tax and Treasury Department along with how much is charged for each regulated and unregulated affiliate of National Grid.
A Okay.
Q Thank you. The Staff Accounting Panel points out in its supplemental testimony that 23.55 percent of certain costs associated with the Ravenswood closing were allocated to Niagara Mohawk Electric. Do you agree that these costs associated with the Ravenswood closing were allocated to Niagara Mohawk Electric, subject to check?
A Subject to check.
Q Yes. And Ravenswood was an unregulated generating station owned by National Grid that was to be divested as a condition of the KeySpan merger approval, correct?
A That's correct.
MS. CICERANI: Your Honor, I'd like to mark as an exhibit a three-page document containing a record request of AG -- record request AG 75. The cover page is an August 5th letter to Mark Marini. I

think it's 328.
ALJ BOUTEILLER: We'll mark it for identification as 328.
(Exhibit No. 328 was marked for identification.)
BY MS. CICERANI:
Q Look at the company's response, Mr. Sloey. In that response the company stated that some Ravenswood closing costs were allocated to the regulated affiliates because funds derived from the sale were used across the organization to fund utility operations. Is that correct? Look down at the --
A Last two lines, yes, I've got it.
Q That's correct. Do you see that there?
A I see that, correct.
Q Were any of these funds from the sale used to fund any unregulated operations?
A I'd have to go back and see how the funds were deployed. It was $1.8 billion divestiture, so it was a fair amount of funds that were flowing through the organization.
Q Could we ask that you provide all the accounting and documentation as to how the company tracks where the proceeds from the sale of Ravenswood go -- or went?
A Yes.

Q Thank you. Do you know whether any of the unregulated affiliates got a share of the specific Ravenswood closing costs?
A I don't. As I said, this is a Revenue Requirements RAV. I'd have to check and see how they were allocated.
Q The closing resulted in a gain in the sale on Ravenswood, is that correct?
A Large profit on sale, large cash inflow.
Q Did National Grid allocate any of the gain on the sale from this closing to the regulated affiliates, as it did the cost?
A The gain on the sale is an accounting -- is an accounting calculation which stays within the entity, so it can't allocate that. It's like -- it's the difference between the proceeds that you get and the net book value of the business that you're disposing of, so it actually is not sort of a cash number that you can allocate. You get the proceeds in, and then there's some closing costs that you wouldn't -- actually, you couldn't divest out the gain on the sale, which is an accounting entry.
Q How would you provide for -- or what benefit was provided to National Grid from the sale in terms of --
A The merger was consummated. As a result of the merger being consummated, customers across all of National Grid's utilities benefitted through the realization of

synergies, alignment of best practice, stronger funding because we've got the cash inflow.
Q I assume synergy savings, perhaps?
A Yes, synergy savings, which benefitted all utilities.
Q Thank you.
MS. CICERANI: Your Honor, could we go off the record for a moment?
ALJ BOUTEILLER: Off the record.
(Discussion off the record.)
ALJ BOUTEILLER: We'll resume with the cross-examination of the witness.
BY MS. CICERANI:
Q Mr. Sloey, why would the company send an employee to work in the U.K. from the U.S.?
A National Grid believes strongly in consistent practices and processes, the value that we can get by leveraging those across the two organizations. We have substantially similar businesses, so when we send people in either direction, it's both good for the individual, develops management capability and leadership, and also moves best practices, moves consistency of process, all of which National Grid believes derives a benefit which benefits all.
Q While in the U.K. does the employee typically work on U.K. matters?

A It depends. Sometimes they would have what we would call global responsibilities, so they're responsible both for things in the U.K. and the U.S. And sometimes they're responsible for just U.K. responsibilities. So we have cross -- sort of cross-country responsibilities based in both countries.

Q I'd like to direct your attention to IR RAV-151, page 193 of Exhibit 326.

A I'm there.

Q Okay. This IR asks about National Grid USA employees that were sent to work overseas, sort of the reverse of the expatriates, correct?

A It's still expatriates, just the other direction.

Q The other direction, okay. Just the ones from the U.K. -- coming from the U.K. The response states that 100 percent of all expenses other than labor incurred by these employees while in the U.K. are charged to the U.K., is that correct?

A Just point me, Counsel, if you would, please? Again, sorry. I apologize. It's a Revenue Panel RAV, so I'm not familiar with it.

Q If you look at response B, it says employee expenses that are incurred locally while on assignment are charged to the U.K. entity and remain in the U.K., so the expenses other than labor that are incurred while in the U.K. are

charged to the U.K., correct?
A   That's what this says, so I would assume it would be correct.
Q   But some of the employees' labor costs could be charged to the U.S., depending on if the employee maintained U.S. responsibilities while -- or performed global roles subsequent to the move, is that correct?
A   That would be my assumption, yes. It's hard to tell with the names redacted, but yeah.
Q   When these employees perform a global role, does National Grid use billing pools to allocate the employees' labor expense?
A   Actually, it's difficult to tell because -- without the names, so we have a couple of different methodologies. So if it's IS, we have what we call -- we have a recharging matrix which distributes costs in aggregate into three buckets, and then the U.S. buckets end up going through the allocation methodologies here in the U.S. I don't know who the people are.
Q   So, yes, but there are several methodologies to do it?
A   Two.
Q   Two?
A   Yeah.
Q   Okay, thank you. You described one of them?

A Yeah. And the other one is just a direct charge, so the cost might be incurred in the U.K. and it's a direct cost charge; it's an intercompany transaction through to the U.S.

Q Direct charge to who?

A To a National Grid company. A National Grid U.S. company. Sorry.

Q A National Grid U.S. company. A direct charge, and when would that occur? When would that type of allocation be?

A It's a cost that's incurred -- if there's a cost that's incurred in the U.K., so use the example of me, so my costs, I get paid in the U.K., so my costs are then direct charged through to a National Grid company, National Grid U.S. company and then on through the bill pool methodologies. And then we have people who are in the IS with both IS cross-charging matrix with global responsibilities, and the matrix determines the charge, and then it comes through the bill pool, so I guess the outcome is the same; the route is different.

Q When you say "direct charge," direct charge could mean direct charge to National Grid USA?

A And then it would be distributed via the bill pool.

ALJ BOUTEILLER: All such charges go through a bill pool?

THE WITNESS: Correct.
ALJ BOUTEILLER: Thank you. Please proceed.
BY MS. CICERANI:
Q If you could -- the billing pools allocate costs to all National Grid regulated and unregulated affiliates in the U.S.?
A It depends on the bill pool.
Q But for the employees that were sent to -- that are in the U.K., is it one or the other, or it still depends on the bill pool?
A It depends on who the employee is, what their responsibility is and therefore the bill pool that's attached to that responsibility, and there's just not enough information from this RAV to comment.
Q Could you provide us with the billing pools that you use when employees perform global roles as you described them as global roles? Could you please provide us with the bill pools you use?
A Okay. If I just phrase the question I think I'm going to answer, we're going to describe how the costs for a U.S. employee based in the U.K. with global responsibilities, how the U.S. element of those costs end up back to affiliates here in the U.S.
Q Right, and what billing pools.
A Yes, we can do that.

Q Thanks. If you could turn to the chart on page 195, and you look, there's columns towards the right. There's a grand total column and a salary column. Do you see those?
A I see.
Q If we look at the first employee on the chart, it shows that -- roughly $250,000 in total expenses and roughly $133,000 in salary, is that correct?
A Correct.
Q Does that mean 117,000 are non-salary costs?
A I assume so, yes.
Q And 100 percent of the 117,000, that was charged to the National Grid U.K. operations, is that correct?
A Again, based on our earlier -- the company's earlier response, I assume so, but I'd have to check.
Q Okay. And that 117 would cover things like lodging, auto, international allowance, tuition, whatever costs were incurred, is that correct?
A I wouldn't characterize it as whatever costs they incurred. It would be the costs they're entitled to under our expat policy.
Q But it would include things like lodging, auto, international allowance?
A When you say "auto," what do you mean?
Q The use of an automobile.

A It depends on the terms and conditions of the employee.

Q It may or may not?

A Yeah.

Q If the employee remains in the U.S. instead of going to the U.K., would all of this 117,000 have been incurred by the company?

A Which company?

Q National Grid.

A The costs would have been incurred here in the U.S., and if that person had stayed in the U.S. but still had global responsibilities, then wouldn't the charge go back the other way?

Q Well, would there have been a lodging charge if the employee stayed in the U.S.?

A Not if they weren't an expat. The essence of our expat policy is as expats you're responsible for your accommodation costs in your home country and accommodation is provided for you in the host country.

Q So minus the expat, if you had an a U.S. employee and they were doing their job, these types of costs, things like lodging, tuition for an employee's child or whatever, these things would not be incurred by the company, correct?

A Correct, because the person is not an expatriate.

Q Okay. If you could look down at the fourth employee listed on that chart, on that one it shows roughly $187,000 in grand total expenses and $140,000 in salary, is that correct?
A Correct.
Q And then that 47 is non-salary cost, correct?
A Presumably.
Q And 100 percent of the 47,000 was charged to the U.K. operation, is that correct?
A No.
Q Excuse me?
A I'm sorry. The 47,000 -- I'm sorry. Repeat the question.
Q 100 percent of the 47,000?
A Based on the company's earlier response to the RAV, I assume that would be the case.
Q Now, if we look at that employees's $147,000 salary, none of that was charged to the U.K. operations, correct?
A Correct.
Q It was all charged to U.S. operations?
A Correct.
Q So when National Grid spent the 47,000 relocation type costs to the U.K. for this employee, 100 percent was allocated back to the U.S. operations, correct, 100 percent of the salary was allocated back to the U.S.

operations?
A   100 percent, so I assume this is a U.S. employee going to the U.K. So, again, the cost was incurred initially in the U.S., so 100 percent of the costs, the salary cost, remained in the U.S. It wouldn't have had to have been allocated back. It was already here. If that's not too confusing.
Q   Much of this is confusing.
A   So, yes, we had a U.S. employee paid in the U.S., and it looks like 100 percent of their cost was retained in the U.S., their salary costs.
Q   They are working on U.S. -- 100 percent on U.S. matters?
A   I can't tell without the information. I apologize. Without the employee and the detail I just don't know.
Q   I guess then I would ask, at least for this chart, perhaps we could -- you could provide the background information so we could at least understand --
A   The basis of the charge.
Q   The basis for this charge.
A   Sure.
Q   Thank you. If you could go to page 10 of your rebuttal testimony, there you state that Niagara Mohawk's total costs per customer basis are lower than the cost of all but one utility in New York State, is that correct?

A Yeah. I think that's -- you're referring to 1R, so that would be A&G costs.
Q That's correct. Can we look at that exhibit, please? That is AFS-1R. In the middle of the exhibit you see the total expenses by each use. Do you see that?
A Correct.
Q And in 2006 and 2007 Niagara Mohawk's electric A&G was in the 322 million to 328 million range, correct?
A Correct.
Q And in August 2007 National Grid acquired KeySpan Corporation, is that correct?
A Correct.
Q And were there expected synergy savings associated with the merger?
A There were.
Q And those synergy savings were to, among other things, reduce the costs of National Grid U.S. affiliates including Niagara Mohawk, correct?
A Correct.
Q Do you agree that most of the KeySpan synergy savings were supposed to be achieved in the A&G areas?
A I'd have to check that. A significant part was in sort of corporate support functions, consolidation systems and processes, but I don't know what that is as a percentage of the total 200 million.

Q But a significant portion?
A It would be a significant portion.
Q Can we look at Niagara Mohawk's costs in 2008 and 2009, post KeySpan acquisition, the cost of increase from 320 to the -- the 320 range to the 383 range, correct?
A Correct.
Q And Niagara Mohawk's costs in both 2008 and 2009 are then up by approximately 19 percent over the 2006 and '7 costs, is that correct?
A Yeah, that would be correct.

MS. CICERANI: Your Honor, off the record?

ALJ BOUTEILLER: Off the record.

(Discussion off the record.)

ALJ BOUTEILLER: Let's declare our lunch recess time. We'll resume the hearing at 1:00. We'll stand in recess.

(Lunch recess.)

ALJ BOUTEILLER: Let's begin the afternoon session. Staff counsel is cross-examining the witness, and that's where we will continue.

BY MS. CICERANI:
Q Good afternoon, Mr. Sloey.
A Good afternoon.
Q If you could turn to -- well, on page 22 of your rebuttal you provide a summary of why the service company

costs increased by $68.2 million or 27.64 percent in the historic test year versus the prior year, is that correct?

A That's correct.

Q What comprises the $5 million increase in items excluded from the cost of service?

A I think there was -- I'd have to check, but I think there was a write-off of some global systems costs, and that was, I think, the largest item. I'd have to check what the other items are. I just can't remember off the top of my head.

Q You'll provide that for us?

A I'll be happy to provide it.

Q Okay. What does increased service company equity mean, and why did it cost an extra $1.1 million in the historic test year?

A The service company equity comprises two elements. The first is the return, because the service company owns assets, there's a modest return -- I want to say 10-1/2 percent, but I can't remember what the actual number is -- return on the equity. And in the previous year there was a tax credit relating to the timing difference of depreciation that didn't exist in the historical test year, so it was actually movement placed on that, so it was a benefit in the previous year. It didn't happen in the current year.

Q   If we could continue on to page 25, lines 16 to 17, you indicate that the remaining increase for service company charges is largely due to additional support required by Niagara Mohawk, is that correct?
A   Service company charges -- 17 -- correct.
Q   What additional support are you referring to?
A   Just I mean, the numbers are quite large, so when you're talking about reconciling changes, you know, between 250 million and 350 million, you can sort of get down to an explanation for a certain level of granularity, and then there's all other. I think what we're saying is there's a series of smaller items, and they number in the 20s and 30s, that sit behind the 4.6.
Q   Could you provide us the documentation?
A   We can give you the analysis as best we can do it, but it's not something that you can reconcile so precisely. You've just got to really understand the numbers are so large and so many.
Q   Can you provide --
A   We can do what we can do.
Q   Okay, thank you. And can you tell us -- this may be similar -- what comprises the 4.6 -- Mr. Sloey, do you agree that the 4.6 million of other that we just talked about is really the net of some level of expense decrease due to synergy savings and some level of service company

expenses increase?
A   Yes, I'd agree that it's the net net of all other things that you couldn't explain separately.
Q   Thank you. If you could turn to your rebuttal, page 29 to 30 --
A   Um-hum.
Q   -- you state there that in IR response DPS 293 the company didn't mean that the service company costs were skewed, is that correct?
A   Correct.
Q   And could you please look at the fourth paragraph of that DPS exhibit? It is page 1021 in SPP-1.
A   Okay.
Q   In the fourth paragraph it says, "For example, for an expense such as group audit in any one year a group audit's actual cost may be skewed to a particular operating company." Do you see that?
A   I see that word, yes.
Q   Okay.
A   Could I clarify the word?
Q   Well, I believe you did that in your testimony but sure.
A   Okay. Just to reiterate the point, I mean "skewed" was a poor choice of word. It's basically activity driven. In the case of this particular specific item, the

cost flow, according to the Agreed Order program. In some cases the program might be focused on some entities, and in the next year will be focused on other entities, so you'll see that variation in the charges. It was just an unfortunate choice of word.

Q On page 30, line 9, of your rebuttal, you state that "In any given year the operating company would have a higher or lower percentage of cost charged to it based on the level of service provided," correct?

A Correct.

Q If you based a forecast on an unadjusted historic test year in which an operating company had a higher percentage of costs charged to it based on the level of service provided in the historic test year, would you agree that the forecast would be higher in that year than it would have been if you'd used an average over a longer period of time?

A Yes, in principle I'd agree with that.

Q In the historic test year did Niagara Mohawk receive a higher or lower percentage of cost charged to it based on the level of service provided compared to other affiliates?

A I'll have to go back and look at the data for the other affiliates, but as we set out, I think, on sort of rebuttal, there was a number of cost increases that affected uniquely Niagara Mohawk, and then there was a group of cost increases that affected all affiliates in the U.S. group, so I think we probably answered it in that table.

Q You could you review that table, and if it's not answered in there -- or at least indicate to us whether you believe it is, once you review it, and then also provide the information if we didn't get it there? I'm a little confused as to where you think this information is.

A Okay. Maybe you could just ask the question again. Let's be clear, the question I'm trying to answer. If I haven't answered properly, I apologize.

Q Okay. In the historic test year did Niagara Mohawk receive a higher or a lower percentage of costs charged to it based on the level of service provided compared to other affiliates?

A I'm not sure I could answer. Just thinking about the question, I mean, in the test year they received the services that they received reflective of the costs, so you have to sort of do that comparison against each of the other affiliates within the group. That's quite a large -- that's quite a large analysis.

ALJ BOUTEILLER: So far I'm taking the response as an indication that the witness is not willing to provide the information you requested.

MS. CICERANI: I understand that, Your Honor. Thank you.

ALJ BOUTEILLER: Okay.

BY MS. CICERANI:

Q If you have variance reports, do you think that you would have been able -- at the company level do you think you'd be able to determine this information that we're talking about?

A I'm just not quite sure of the information, Counselor, that you're trying to get at. I think the point that we were trying to make in your testimony is that service company charges are not static year to year. The levels of services delivered would change, and so would the allocation. So I just feel you've asked a kind of open-ended question, would the cost be higher or lower? Yes.

Q Or no -- okay, that's fair. That's fair. Hypothetically, if Niagara Mohawk was charged for historic test year service company costs that should not have been allocated to Niagara Mohawk at all, would the historic test year costs for Niagara Mohawk be higher than they would otherwise have been?

A Correct. In the rate year -- the forecast in the rate year -- if we hadn't -- if we omitted something from the historic test year that hadn't been normalized that should have been, then that would have resulted in a higher rate year forecast.

Q On page 36 of your rebuttal you discuss why service company charges to unregulated affiliates have decreased compared to the significant increase in service company costs to regulated affiliates, is that correct?

A That's correct.

Q And you state that staff's analysis ignores the -- that service company charge -- actually, what you just said -- that service company charges are not static, correct?

A Correct. I think what the paragraph tries to speak to is there are a couple of adjustments that you needed to make to the analysis that staff had done to get a like-to-like comparison, and then the overall consideration that service company charges will vary based on the level of activity year to year.

Q So are you saying that the historic test year was simply an unusual year in which less service company work was performed for the unregulated affiliates than would be the norm?

A It's probably going to be quite hard to define the term "unusual." When you put two huge companies together, you divest businesses, you make business changes, lots of changes happen. You have to remember this was 18 months after a major merger, and so there will be some volatility in the underlying numbers as you implement business changes. So I'd have to go back and look at it to see what particularly drove that decrease to the unregulated subsidiaries. The point we're just trying to make is that it wasn't the 17 percent reduction that was originally posed in staff's rebuttal.

Q How many historic test year invoices of costs were there covered in this rate filing?

A Pass.

Q An order of magnitude, perhaps?

A If you'd let me, I can confer with a colleague and we can probably give you a pretty accurate estimate.

Q Hundreds? Thousands? Hundreds of thousands?

A Hundreds of thousands, I'd guess. May I confer?

ALJ BOUTEILLER: Yes, you can confer if you'd like to, if he is in the room, or she.

THE WITNESS: He is. Danny.

ALJ BOUTEILLER: Let's go off the record for your conference, and we'll go back on the record when you have an answer.

(Discussion off the record.)

ALJ BOUTEILLER: You're prepared to provide an answer to the question at this time?

THE WITNESS: I guess.

A   It would be hundreds of thousands, probably not more than half a million, but we could actually count just by counting transactions if the information was important.
BY MS. CICERANI:
Q   Your rebuttal at page 52, starting on line 14, you state that "staff took a sample of invoices to make a wholesale disallowance of legitimately incurred costs and that this was inappropriate and arbitrary," is that correct?
A   Correct.
Q   Did anyone in the company review every historic test year invoice to determine that they were legitimately incurred?
A   We didn't review every invoice, but we did review a substantial number of the test year, so we talked elsewhere in the testimony about a significant review process that we undertook. Four months of that review process was actually felt in the test year, so a substantial amount of the testing that was done validated the test year numbers, so we did test a substantial number, but we certainly didn't test all.
Q   Did anyone in the company review every invoice in the historic test year to determine if they were recurring in nature?
A   Again, "every invoice" is a very high standard.

There's hundreds and hundreds of thousands of transactions.

MS. CICERANI: Your Honor, if we could go off the record for a moment?

ALJ BOUTEILLER: Sure.

(Discussion off the record.)

BY MS. CICERANI:

Q Mr. Sloey, the Staff Accounting Panel in its testimony -- I don't know if you have a copy of that up there?

A The policy of accounting?

Q The Accounting Panel. Just roughly at page 287 -- and I'll summarize, essentially the company -- the question was whether or not the company -- what the company did to determine the normalizing adjustments, that normalizing adjustments needed to be made, and that staff list out several IRs, all of which we ask to explain the specific types of costs and how this was done and how the adjustment was made, if there was an adjustment made. And if you look on the top of page 288 of the Staff Accounting Panel testimony, we indicate -- to most if not all of these IR questions the company responded with the exact same answer. "The company's approach to the review of historical year data was organized principally by expense type." Do you see that?

A I do.
Q For each expense type -- it was general data. Do you see that line of testimony?
A I do.
Q Okay. It seems somewhat inconsistent with what you're saying now in terms of the analysis that you performed, so I'm wondering if you could now provide us with the analysis that you were just describing as to what you do with these hundreds of thousands if not half a million invoices?
A Okay. I mean, my responsibility on the preparation was sort of the preparation of the historical test year costs. The normalization adjustments was done as part of Revenue Panel, so I'm not sure I'm best qualified to answer that.
Q Is that something, though, that you believe the company could provide for us now?
A For clarity, I'd just like to be clear on the question you're asking.
Q I'm asking you for the analysis that was done as it related to every invoice in the historic test year to determine whether or not the costs were, one, legitimately incurred, two, recurring in nature, or three, out-of-period costs?
A Okay. I think I'd have to defer that to the Revenue

Panel, and just -- I guess my only editorial comment would be a review of every invoice isn't just an incredibly high standard but an incredibly expensive task to undertake.

Q At page 57, lines 13 to 18 of your rebuttal testimony --

A Line?

Q 13, starting at line 13.

A Um-hum.

Q You state that "Price Waterhouse Coopers assisted the company in its evaluation and testing of the cost allocations process and that Price Waterhouse" -- I'm going to call it PWC -- "observed that while some expectation -- exceptions were noted through the testing conducted, there were no pervasive trends or large errors noted," is that correct?

A That's correct.

Q Can I refer you to Exhibit 326, page 93? This is the Price Waterhouse engagement letter. Actually, if you turn to the cover page of the report, which is at page 100 of the exhibit.

A Yeah, I have it.

Q It states that "these services did not constitute" -- do you see -- "these services do not constitute an audit conducted in conformance with generally accepted auditing standards, an examination of any type, an accounting opinion or other attestation or review services in accordance with the standards established by the AICPA, by the Public Company Accounting Oversight Board or any other professional governing body. Accordingly, PWC provides no opinion or any other form of assurance with respect to the services or the information upon which our work was based." Do you see that?

A I do.

Q And also at page 2 of the engagement letter under "Our Responsibilities," PWC states that in performing its work in this engagement, "we will not verify or audit any information provided to us." Do you see that?

A I actually don't. Which paragraph, please?

Q This was on page 2.

A Page 2, yeah.

Q Under "Our Responsibilities."

ALJ BOUTEILLER: I don't see that section.

MS. CICERANI: Okay.

BY MS. CICERANI:

Q If I could direct your attention, it's actually on page 119. It's the second page of the engagement letter, which actually starts on page 118. There is the section that -- you see where it says "Our Responsibilities"?

A Yeah, I've got it.

Q Okay.

A Yeah, I understand. So the first letter was the engagement letter to start the process. The first letter you referred to was the cover note at the end of the process.
Q That's correct. Thank you.
A You're welcome.
Q Based on the information that we just talked about, would you agree that the observations made by PWC were not based on an audit performed by them and that they didn't verify or audit the information the company provided them as part of the cost allocations review process they participated in?
A I probably -- they didn't audit it within the terms of public accounting practices, which is very specific, which governs how an audit should be -- or financial statement audit should be conducted, but what PWC did do is they provided us advisory services. And if I could just probably go back a little bit in time, when National Grid started this piece of work, we were concerned, coming out of the merger, there being so much change, that we were concerned the allocations were being performed appropriately, because we have people performing allocations on two different systems, making sort of dual pooling allocation choices. Responsibilities are changing. And so what we purposely did, we actually set

huge sample sizes. And I think we even referred to it in the testimony. We wanted a much more comprehensive look, because often some of the problems that you find in allocations doesn't emerge from statistical sample. We wanted a much more comprehensive check. Had we had PWC do it, that would have been a hugely expensive exercise. You know, we have certain capabilities and we were able to devote the resources to do it quickly, but what we did want PWC to provide us is the challenge and review in terms of process and efficacy of checking how to get more assurance. And they did selectively do testing, but they did their work as an advisory piece of work, not as a financial statement piece of work. I'm not sure it devalues the work entirely is the point I'd like to make.

ALJ BOUTEILLER: And, Staff Counsel, you're not trying to represent that the statement that appears on page 57 of 68 in the rebuttal testimony is inaccurate in and of itself?

MS. CICERANI: Is inaccurate, Your Honor?

ALJ BOUTEILLER: Is not inaccurate in and of itself. You're not representing that that statement was not made by Price Waterhouse, are you?

MS. CICERANI: No, Your Honor.

ALJ BOUTEILLER: Okay. Thank you. Please proceed.

BY MS. CICERANI:
Q On page 1, lines 4 and 5 of your rebuttal testimony -- you really don't need to flip to it if you don't want to -- you state that Niagara Mohawk Power Corporation was referred to as Niagara Mohawk or the company throughout your testimony, is that correct? You can look if you want.
A I believe you.
Q On page 57, lines 12 through 14, you state that --
A Should I look?
Q Sure. It's entirely up to you.
A I'm there.
Q You state -- this is page 57. You state that "the company performed this cost allocation integrity work and engaged PWC to assist the company in performing this evaluation and testing," is that correct?
A That's correct.
Q So when you refer to "the company" on page 57, you do not mean Niagara Mohawk?
A No, I mean broadly the National Grid USA holding company.
Q And it was not Niagara Mohawk that engaged PWC, is that correct?
A Correct.
Q Niagara Mohawk didn't perform the evaluation and

testing of the National Grid cost allocations that you describe on pages 56 and 57 of your rebuttal, is that correct?
A That's correct. The study looked at allocations for all activities in the companies in the U.S. group, not just Niagara Mohawk.
Q On page 56, line 20, to page 57, line 1, of your rebuttal you state that "the Cost Allocation Integrity Steering Group governed and provided the oversight to this National Grid review, correct?
A Correct.
Q If I could refer you to DPS-338, which is on page 1103 of Exhibit SPP-1 -- 1113.
A Okay, I have it, Counselor.
Q Is it correct that according to that, all the members of the Cost Allocation Integrity Steering Group were employees of either National Grid service companies, National Grid USA Service Company or National Grid Corporate Services?
A That's correct.
Q Is it correct that Niagara Mohawk receives accounting services under its service contract with National Grid USA Service Company per Schedule 1 of that contract? And I believe you'll find this in AFS-2.
A Correct.

Q If you could look to -- this is page 96 of Exhibit 326, the National Grid response to FERC data request 1, question 401.
A This is --
Q I'm sorry, 326. Exhibit 326 is -- it's a white covered one. Page 96, in that response, it states that "The franchised public utilities don't have their own finance and accounting departments. Finance and accounting services, including the recording and reporting of the costs billed from the service companies are provided exclusively by the service companies on behalf of the FPUs." Is that the case for Niagara Mohawk?
A Correct. The accounting is done by -- the accounting is done by the employees of the service company.
Q So the costs for the accounting and the financing functions performed by the service company for Niagara Mohawk then are included in the service company cost allocations and bills that the service company employees record and report for Niagara Mohawk, correct?
A Correct.
MS. CICERANI: Your Honor, I'd like to mark for identification a multi-page document with a cover letter dated April 2, 2010. I believe it's Exhibit Number 328.
MR. O'BRIEN: 329.

ALJ BOUTEILLER: Let's go off the record.

(Discussion off the record.)

ALJ BOUTEILLER: The document you distributed has a National Grid identification on the front page. The letter is dated April 2, 2010 and, as you said, it has numerous pages. We for identification will mark this as 329.

(Exhibit No. 329 was marked for identification.)

BY MS. CICERANI:

Q If you look one, two, three, about four pages in, there's the signature lines for the service contract. Do you see that the individual signing for Niagara Mohawk under this contract is Lorraine Lynch?

A I do.

MS. CICERANI: Your Honor, we'd like to mark as an exhibit a single-page document that is dated 12-31-2009 for Niagara Mohawk Power Corporation, and this is actually a page -- pages 104 and 105 of the Niagara Mohawk Annual Report.

ALJ BOUTEILLER: For identification it will be marked as 330.

(Exhibit No. 330 was marked for identification.)

BY MS. CICERANI:

Q To your knowledge, Mr. Sloey, is the same Lorraine Lynch who is listed at page 104 of the Annual Report the -- I'm sorry -- the same Lorraine Lynch who signed the service contract?
A Employee line number 8, yes, that would be the same Lorraine.
Q Thank you. If you follow that line across to the footnote reference, is it correct that Ms. Lynch is paid by National Grid USA Service Company?
A She wouldn't be. She'd be paid by KeySpan Corporate Services, and -- I think the question is who is Lorraine Lynch employed by and paid by, and it wouldn't be National Grid USA Service Company; it would be the KeySpan Corporate Services company.
Q Are you generally familiar with the company's rebuttal revenue requirement that's in RRP-1R?
A Somewhat familiar.
MS. CICERANI: Your Honor, may I approach? I have a copy of it just to show Mr. Sloey.
ALJ BOUTEILLER: You can approach the witness. Company counsel can approach the witness as well.
(Discussion off the record.)
BY MS. CICERANI:
Q Mr. Sloey, I just showed you and identified a line on

RRP-1R. This is sheet 9 of 18. Adjustments -- down at the bottom, adjustment 5 was an adjustment to write off depreciation associated with delayed work on the closings, and I just showed you that, correct?

A Correct.

Q And on that exhibit it shows that staff had made an adjustment, and then the company essentially reversed staff's adjustment, so as far as the company was concerned, there's been no adjustment to the write-off or depreciation associated with delayed work closings, correct?

A Correct. That's my understanding.

Q So based on this, is it the company's position that there are no financial implications to the company of these extended delays in closing the construction work orders to plants and service?

A I think we would say there's none. I think what we're saying is the adjustment is not substantial. I think staff's adjustment or proposed adjustment was based around an assumption that work orders could be closed within one month. And what we tried to -- the issue we tried to address in rebuttal testimony is that is just an unachievable standard as part of the management order. The process we have for reviewing our work order cycle close-out and process is trying to achieve a 90-day close

cycle.
Q You said that they were not -- there were some, but you just don't believe they were significant?
A Correct. I think staff's adjustment for multiple years based around a one-month closing was around $6 million.
Q Yes.
A Something less than a million a year. So moving to a 90-day closing will actually be significantly less than that. I don't know what the annual depreciation charge is in Niagara Mohawk, but it's in the -- it would be well over a hundred million.
Q Your adjustment amount negates staff's adjustment completely, correct?
A Correct.
Q So at least from that respect you're suggesting there be no adjustment, for there to be no write-off -- financial implications -- excuse me, I'm -- that there would be no financial implications to the delayed work order?
A My understanding is we made no adjustment in the cost of service for that.
Q Page 63, lines 19 to 21.
A Rebuttal?
Q Yes, of your rebuttal.

A I apologize.
Q That's okay, because I need to go back to what we were just talking about. I looked down and lost my place. Page 66 of your rebuttal testimony, this is consistent with what I believe you were saying, that the company is undertaking an effort to reduce the amount of time, correct?
A Yes.
Q So if there's no financial implications to the company for these extended delays in the construction work order to plant and service, why are you undertaking the effort to reduce the amount of time it takes to close the work orders?
A I think efficiency. I think the way the adjustment was calculated, it didn't take into account all impacts of the calculations. So the adjustment -- there are some off-setting impacts that were taken into account, so we challenged the adjustment on that basis.
Secondly, just about efficiency, becoming more efficient and continuing to improve. You know, the company has sort of a wide portfolio of complex projects. Some can be closed in a very short amount of time. Others take much longer to close. We're just trying to improve the efficiency in the process.
Q Now, at page 63, lines 19 through 21 of your rebuttal

testimony, you state, "Based on staff's assumption of consistent closing delays, the company's rate base would have been understated in 2001 when the rates were established," is that correct?

A That's correct.

Q Did staff testify that these closing delays were a problem prior to the 2001 merger?

A I don't believe -- I don't recall -- I don't believe they did.

Q Is this a closing -- is this closing delay problem something that happened after National Grid took over Niagara Mohawk?

A No. I think closing delays -- one of the big challenges, when you're doing large construction portfolios, is getting these projects closed expeditiously. They're very complex, so it's a systemic -- it has been a systemic problem across our industry, in fact, so it's just something that we see is something that we can improve.

Q But you don't know for a fact whether or not there were any of these problems at Niagara Mohawk prior to when National Grid merged with the company, correct?

A I think we could see evidence of the problems because you have very high CWIP balances, so you could see evidence of that problem existing.

Q And you are now undertaking an effort to look at this issue eight years later?
A No, I wouldn't characterize it that way. There's been two or three efforts to reduce CWIP balances and improve the process. I think in the past the efforts have been very much focused around the symptoms, just getting the balances down. So you do a blitz. You figure out the programs, what do you have to do to get them closed. I would characterize this effort as being very much different. To be honest, it came out of the work that North Star did as part of the management order. And we're going to address, you know, what's the underlying cause, what are the changes that you have to implement in the process, not just to improve it one time but to make sure the improvements are systematic.
Q Mr. Sloey, has National Grid reorganized Niagara Mohawk's property records department since it acquired the company?
A When you say "property records," fixed asset accounting?
Q Yes.
A Has it reorganized it since National Grid acquired Niagara Mohawk?
Q Yes.
A So it would have been reorganized, because it was

initially conducted out of Syracuse. The function was then transferred through to Westborough, New England. And it was then consolidated when National Grid acquired Rhode Island. And the function was then reorganized when it was moved to Long Island following the KeySpan mergers. I guess, yes.
Q Is there still -- does that department still exist at Niagara Mohawk in any fashion?
A Again, it's a service company group and proficiency. We don't -- we don't structure our organization so -- just to one particular entity. And they're structured so they provided a consistent range of services, so we have one plant accounting department or property records. But inside that department we have people who specialize in different type of construction activities, but we don't arrange the teams by entity.
Q Has National Grid, to your knowledge, reduced the number of employees in that department in total across all affiliates since it acquired Niagara Mohawk?
A I couldn't tell you.
Q Sorry?
A I couldn't tell you. My assumption is yes, considering it was acquired in 2001. I'm trying to remember. I mean, I wasn't here, but I'm trying to remember the iterations from manual records to different

systems through Walker, so appreciably there were some efficiencies on the way through. We haven't -- but since the KeySpan merger we haven't significantly -- in fact, I don't think at all. We have probably increased the staff on the plant accounting side since the merger because we're still operating two systems, so we're still operating Legacy PeopleSoft and Oracle. Power Plant is the property accounting system in both, but they operate fundamentally differently, so you have a parallel universe that you manage.

Q You would have increased the size in total?

A I suspect so, yes.

Q But do you assume or do you know whether or not that is the sum of the departments from both of those organizations you're referring to?

A No, I have to go and check. Not off the top of my head.

Q Would you assume that there would be something fewer than two total departments?

A I don't -- I don't -- at this point my answer is no because we haven't integrated the systems. We can only make that efficiency when we bring them onto a common platform and a single instance of Power Plant. Otherwise, they just continue to do the same level of work. So my expectation would be no.

Q Okay.

MS. CICERANI: I'm sorry, Your Honor. We need a moment.

ALJ BOUTEILLER: Take your time.

BY MS. CICERANI:

Q Mr. Sloey, if we could go back to your testimony at page 19.

MR. MAGER: Rebuttal?

MS. CICERANI: Yeah.

Q There you state that "Based on staff's assumption of consistent closing delays, the company's rate base would have been understated in 2001 when the rates were last established, correct?

A Correct.

Q You just indicated that you had some sort of analysis that you performed?

A In relation to what?

Q To the closing costs -- not closing costs -- the closing delays in the construction work department?

A That's right. We're undertaking a process to understand the cause and therefore improve that process. Is that the analysis you're referring to?

Q Well, you just mentioned that you believe this was a systemic problem and that you looked at it and there were at least three periods of time?

A There were two or three blitzes of trying to get the balance down, so I know it was a preexisting problem, correct.
Q I guess, then, could you provide us with the analysis that you performed those two or three times?
A We can provide you with a trend -- be able to provide you with a trend in CWIP balances, which is a good leading indicator, and we'll provide you with whatever other information we can get in terms of closing delays going back to that time. But you just need to understand that we're going back beyond PeopleSoft into Walker. We don't have those systems online, so just understand it's not an easy question to answer.
Q I understand.

ALJ BOUTEILLER: To be clear on the record, you are going to make some effort to respond?

THE WITNESS: Yes, we will.

ALJ BOUTEILLER: These are your choices, and you need to be clear on the record to what degree you're going to perform, and I think you have been, but we're taking this as a probative instance of your follow-through.

THE WITNESS: We will make an attempt to give a response, so I'm just managing expectations, if I'm allowed to do that. It's not an easy question to answer, and the answer won't be complete.

ALJ BOUTEILLER: Okay.

BY MS. CICERANI:

Q Would you accept, subject to check, that staff's adjustment does not include any work orders prior to 2003, subject to check?

A Prior to 2003, correct.

Q In your rebuttal testimony on page 63 starting at line 8, you state that "Staff failed to make an off-setting adjustment to reverse excess depreciation incurred on assets that would have been retired for the same period assuming a one-month closing rule," right?

A Correct.

Q Do all new assets replace retiring assets?

A Not all of them, no. Many.

Q Have you done any analysis showing how many of these work orders with delayed closing replaced retiring assets?

A I don't think -- analysis wouldn't be the right characterization. We've taken some estimates, yes.

Q Where would we find those estimates? What would we look to?

A It's not something -- it's just our own internal workings. We haven't provided it as part of our record or discovery requests. I mean, projects can have both. They can be genuinely new construction, which doesn't have retirements. Many of it is replacements that will have retirements, or they can be retirement-only projects. So you need to look at all three. You just can't look at one.

Q On average how old were the assets that were replaced by the 2003 through 2009 construction work orders?

A I have no idea.

Q 30 years? 40 years?

A I would -- certainly less than 40, in the 20 to 30 range, but it would be a wild guess. If you want to know the answer, I'd rather provide the answer.

Q That's okay. You don't need to.

A Okay.

Q Do you think that the original cost of the 30- to 50-year-old assets, assuming that there are some, being replaced is more or less than the cost of the 2003 to 2009 replacement?

A It would be less and -- yes, it would be less. I think we're saying that the retirement value would be higher than the depreciation on the construction, on delayed closing construction. I'm saying it isn't a significant element to the calculation and adjustment that's missing.

Q Do you know what construction inflation has been over the past 30 to 50 years?

A No.

Q Why didn't the company undertake an analysis to estimate how much extra depreciation it reported on these old assets that should have been retired? Was it that the amount was too immaterial to try and estimate that extra depreciation?

A To be honest, we didn't think about it until after staff proposed the adjustment in their accounting testimony. So then we looked at it and said it was a very small number, anyway. There is this offset. We know we have the delay problem from 2001, so it's an element of rate base that wasn't there. It just didn't seem a very large issue, honestly.

Q Do you generally agree that the larger the company, the more opportunities there are for economies of scale within the company relative to a smaller company?

A I mean, larger in absolute sense, but as a percentage of the cost basis relevant to that company, I imagine they'd be broadly the same when you normalize for size.

Q Well, when you normal -- I'm not normalizing for size. Let me just give you an example. If a company had 100 employees, they might need, for example, two human resource employees to serve those hundred, but the company with 600 employees might need only about eight to serve them, so you're kind of looking at a ratio of human

resource employees, you know, one to fifty in the smaller, one to seventy-five in the larger. Does that generally make sense to you?
A Intuitively, yes, but you have to look at the company. One was non-union and one was heavily unionized with 23 different unions and you'd expect a different ratio. But intuitively, yes, hypothetically.
Q In National Grid's billing pool allocators is it correct that the company does not include in the development of those allocators the relative levels of any economies of scale that each affiliate could achieve on a stand-alone basis? Is that correct?
A Counsel, I just don't understand the question.
Q Okay. Is there in the development of the allocators, the billing pool allocators, is there a consideration for economies of scale in terms of the size of a company?
A No. I mean, Counsel, bill pool is a very simple mathematical device. It creates a denominator, identifies a numerator, and you apply that to a cost pool. The impact of scale, and I guess the point you're driving at, Counsel, is synergy is actually in the cost pool on which the bill pool operates, not the bill pool itself. The bill pool is just math.
Q Is Niagara Mohawk the largest of the National Grid U.S. affiliates in terms of customer numbers?

A Yes, it would be.
Q And in terms of employees is it the largest, in terms of number of employees?
A I imagine so, but I've never actually looked at it on that basis. It would be very easy to test. I imagine so.
Q In terms of revenues?
A Yes.
Q Essentially, in terms of all the determinants the company uses to develop its billing pool allocations, Niagara Mohawk is the largest of the National Grid U.S. affiliates?
A Well, it's not all because, I mean, we have like 200 different bill pools. You've referred to any sort of, you know, people-driven ones and revenue-driven ones, whether it's floor area, space, rubber gloves. There's huge types of bill pools. Number of computers.

MS. CICERANI: Your Honor, I'd like to mark as an exhibit, this is just a hypothetical billing pool allocation of human resources for department labor costs. It's a single-sheet exhibit.

ALJ BOUTEILLER: For identification we'll mark it as Number 331.

(Exhibit No. 331 was marked for identification.)

BY MS. CICERANI:

Q Mr. Sloey, I'm going to walk you through this, but I don't know if you want to admit it. This is a document that we created to just sort of try to talk through this aspect that we've been exploring a little bit further. I don't know if you need a minute or you --
A Why don't you walk me through it, and if I need a minute to think, I can take it there.
Q All right. If we look at scenario one -- and I guess I'd like to discuss your rebuttal testimony at page 32, lines 5 through 12. There you state that "in developing the KeySpan synergy savings amount in the Niagara Mohawk revenue requirement, the appropriate bill pool was applied to each synergy savings initiative to derive Niagara Mohawk's share of savings." Is it correct that you did not use the overall service company cost allocation percentages to allocate synergy savings to Niagara Mohawk since the total charges from the service companies were driven by many services for which there were no synergy savings?
A That's right. We thought the bill pool methodology would give the fairest -- would give the fairest representation. Bear in mind, when you're trying to attribute synergies, you're trying to attribute a cost that you haven't actually incurred, so it becomes a very hypothetical calculation.

Q If you could look to scenario one, there are existing pre-merger economies of scale in the HR department of the larger affiliate with each HR employee being able to serve 300 employees. Do you see that in column C?
A 300?
Q I'm sorry, 600 employees in column C, compared to the affiliate's HR employees being able to serve only 500. Column C is sort of a little offset there. Well, the column isn't, but the numbers are.
A Is that a ratio? So we're saying 9,000 divided by 15 is 600?
Q That's correct.
A Okay.
Q In this scenario there are no merger savings that occur -- hang on a second. If you look at column B and column F, you'll see that there's no pre-merger savings or post-merger savings. There's no synergy savings, essentially. They're the same, 17 and 17 employees in both cases, correct? Do you see that?
A I do.
Q Okay. In scenario one, pre-merger, do you agree that the -- that company A's pre-merger HR costs are 1,500,000, which would be column E?
A Yes.
Q And pre-merger there would not be any billing pool

allocations for HR since company A is a separate entity and incurs 100 percent of its own cost, correct?
A Okay.
Q The post-merger company A becomes affiliate A.
A Is that in scenario two?
Q No, in the same -- if you're looking -- still in scenario one?
A Right.
Q Okay. You see affiliate A. And company B becomes affiliate B. If post-merger you base the HR billing pool allocators on the number of employees within affiliates A and B, which is column A again, without giving any consideration to preexisting economies of scale, that affiliate A will actually incur a higher HR cost post-merger than pre-merger, if you look at column H versus column E. Do you see that?
A Okay. So, Counsel, just so I understand, we're saying that the costs that would be charged, so affiliate A incurred 1.5 million costs under their own steam pre-merger, and they incurred 1.53 post-merger because the working assumption here is that affiliate B, I guess, is so much less efficient? I'm not quite sure how it works.
Q I'm not sure that that would be the working assumption. So under the billing pool methodology affiliate A is now assigned one thousand -- 530,000, and

affiliate B, 170,000, correct?
A   Yeah, one third.
Q   Okay. All right. I'm just trying -- so, therefore, in that scenario, affiliate A, the larger affiliate, actually has negative savings, is that correct?
A   That's what it says.
Q   Okay. We'll leave the hypothetical, and I now have just a very few more questions for you.
     If I could refer you RRP-1R, sheet 3 of 18.
          MS. CICERANI: Does anybody have that?
          MS. SWEET ZAVAGLIA: What was that?
          MS. CICERANI: RRP-1R, sheet 3 of 18.
A   Is it in one of these things?
Q   No, it's in the company's filings.
          MS. SWEET ZAVAGLIA: It's a revenue panel exhibit. It's a revenue requirement.
BY MS. CICERANI:
Q   Near the top of that exhibit -- you have it now, correct?
A   Correct.
Q   Near the top of that exhibit, for the company's federal income tax calculation, the fourth addition down, it's taxable income, business meals, 50 percent disallowance. Do you see that? Is that correct?
A   I see the fourth one down is employee expenses.

Q One, two, three, four -- do you have sheet 3 of 18?
A Sorry. Okay. Sorry. Counsel, point to me again business meals, 50 percent disallowance. I've got it.
Q That's in addition to federal tax income, correct?
A That's right. So book expense would have been 100 percent. It's being added back because 50 percent would be disallowed.
Q How much of this addition to taxable income for business meals is related to the cost you're removing from the revenue requirement?
A Counsel, I would have no idea.
Q Could you perhaps provide the details showing how much of the addition to taxable income for business meals is related to the cost being removed?
A So what we removed from the revenue requirement in supplemental testimony was all the expenses for expatriates and officers of the nominated company, so we'd have to go back and do that analysis.
Q Is that something you can provide?
A Is this $330? 330,000.
Q 330,000.
A Okay, we'll do it.
MS. CICERANI: Your Honor, just one moment, if we could?
(Discussion off the record.)

BY MS. CICERANI:
Q   Mr. Sloey, are there any expatriate costs in the January 2004 through January 2009 Niagara Mohawk capital costs -- capitalized costs? I'm sorry. Capitalized costs?
A   I wouldn't think so. I would have to think about the question, but I wouldn't think so. You mean capitalized into planned? I wouldn't think so, no. They're expenses within the year unless you had particular expats engaged in construction activities and therefore it flowed through as part of the salary, but I'd have to check to see which expats were in town during that time period.
Q   Is that something you could check for us?
A   Yes, we could.
Q   Thank you.
A   It would be just small -- I can only think of potentially one guy.
Q   Are there any expatriate costs in the January 2004 through January 2006 Niagara Mohawk -- 2009 -- I'm sorry -- deferral account, Niagara Mohawk deferral account? Or many accounts?
A   That's a big question.
Q   Is that something you could --
A   Again, to the extent that the deferral contained activities that were costs based on labor and burden and

expat, possibly.
Q So when you removed the expatriate costs that you did from here, you did not do this analysis to determine if there were any in the deferral account, correct?
A I have to defer to the Revenue Panel.
Q Okay.
A Because they did the analysis.
Q Okay.
MS. CICERANI: I have no further questions, Your Honor.
ALJ BOUTEILLER: Okay. Let's go off the record.
(Discussion off the record.)
ALJ BOUTEILLER: We will resume with the cross-examination, and I guess Mr. Mager wants to go next.
CROSS-EXAMINATION
BY MR. MAGER:
Q Good afternoon, Mr. Sloey.
A Good afternoon.
Q Just a couple of general questions. You're the chief financial officer of National Grid USA?
A No. I'm the chief financial officer of the U.S. Financial Services Group.
Q Okay. Are you an employee of Niagara Mohawk?

A I'm an employee of the National Grid USA -- actually, I'm an employee of the U.K. company, but my accounting follows the National Grid USA accounting, Legacy National Grid Service Company. I apologize. It's a little confusing. That's the way it is.
Q So can I assume the answer to my question is no, you're not an employee of Niagara Mohawk Power Corporation?
A Correct.
Q And you're -- is it fair to say one of your responsibilities is -- covers the allocation of service company costs to the various affiliate companies, including Niagara Mohawk?
A That's correct. I run the service company accounting function, or people in my group.
Q Okay. I'd like to follow up on a line of cross that staff counsel asked you regarding the compilation of the historic test year expense and how that was used to get to the proposed rate year expense. Do you recall those line of questions?
A I do.
Q Okay. Now, would you agree that certain costs incurred during the test year are non-recurring and therefore should be the subject of a normalizing adjustment?

A Yes. There will always be those costs in any year.
Q Okay. Those could be various service company allocations including a direct charge? For instance, there could have been some scope of work that was done solely for Niagara Mohawk that was direct charged to Niagara Mohawk but was non-reoccurring; is that fair?
A It's possible.
Q And it also could be on a task or a scope of work that was allocated by a bill pool, right, that it was not something that happened during the historic test year that was not expected to recur during the rate year; that would also be subject to a normalizing adjustment?
A Also possible.
Q Okay. And in compiling the test year service company expenses, what role did you play in determining what expenses were non-reoccurring?
A People on my team supported the rate and regulation team, and they compiled the cost of service. But, actually, the compilation of the cost of service -- the normalizing adjustments were done as part of rate and regulation and the responsibility of the Revenue Panel.
Q Okay. And do you know what -- I think you testified in response to staff that there were literally hundreds of thousands of invoices that comprised the test year service company expenses. Do you recall that?

A I do, correct.
Q Okay. And what was the process by which those hundreds of thousands of invoices were reviewed to determine which ones were non-recurring and unlikely to, you know, occur in the rate year and therefore should be subject to a normalizing adjustment?
A Counsel, as I said, the normalizing process was actually performed by the rates team and will be spoken to by the Revenue Panel.
Q So you didn't -- you have no knowledge of that? You weren't part of that process?
A I have some knowledge of what happened, and I have some knowledge of the costs that were normalized, but it's very limited. The process was actually run by the rates team.
ALJ BOUTEILLER: Which means they made the determination of what to normalize and what not to normalize?
THE WITNESS: Correct.
ALJ BOUTEILLER: You did not make those determinations?
THE WITNESS: I did not.
MR. MAGER: Thank you.
BY MR. MAGER:
Q And there were some questions that staff counsel

asked in terms of the relationship between the service companies and Niagara Mohawk, and I just want to follow up on that -- on them. With respect to the contracts that exist between the various service companies and Niagara Mohawk, am I correct that it's the service company that decides the contract should be entered into by both parties?
A   No. It's a contract. It's mutual. So the affiliate requests the services and the service company and the affiliate agree to a contract and execute it.
Q   So it's Niagara Mohawk's independent decision whether it's going to use a service company to perform a certain service?
A   The service contracts provide generically a list of a range of services, and so that range of service is included in the service delivery.
Q   Right. I understand. There's contracts between Niagara Mohawk and a bunch of service companies, all of which you oversee, correct?
A   Correct.
Q   And each one of those contracts includes a range of services that the service company provides to Niagara Mohawk?
A   Correct.
Q   Okay. Does -- is it a decision of Niagara Mohawk

whether to enter into that contract with the service company and also to decide what services it's going to contract out to the service company, or is that decision made by the service company?

A It's made broadly as sort of part of the U.S. group, so the group believes in the sort of delivery of common services across all of the affiliates, and those cost services are delivered out of the service company, so all of the affiliates enter agreements with the service companies to take those services.

Q So it's a decision of National Grid USA that Niagara Mohawk should enter into these contracts?

A I don't know whether I'd characterize it exactly that way. It's a decision of the U.S. group. They believe in the philosophy of the service company, that that's in the interest of ratepayers because you can deliver a consistent set of services effectively, and then those cost services are deployed all across the utilities in the U.S. group.

ALJ BOUTEILLER: If I'm understanding the way you operate, would it be fair to say that the line of business decides to enter into the contract with the service company?

THE WITNESS: That's true, because the line of business is responsible for each utility under its purview. I guess I'm speaking to a more broader concept that in the U.S. we believe in the concept of service company, so it's much more a formality to agree to -- to take those services because we have the structure built to deliver them.

ALJ BOUTEILLER: So it's a formality, the action taken between the service company and the lines of business? Would you call that just a formality?

THE WITNESS: It's a significant formality.

ALJ BOUTEILLER: It's an official and formal and philosophical agreement on both sides?

THE WITNESS: That's right.

ALJ BOUTEILLER: So it's not a difficult negotiation?

THE WITNESS: Correct.

ALJ BOUTEILLER: But it is a responsibility that you feel that you need to enter into a formal document that you do so.

THE WITNESS: Correct.

ALJ BOUTEILLER: And it's usually done at the level of line of business with the service company?

THE WITNESS: So the line of business will agree, but then the officers of Niagara Mohawk will sign the agreement with the service company.

ALJ BOUTEILLER: Okay. Thank you for letting me understand that.

Please proceed.

BY MR. MAGER:

Q So the decision on the contract and whatever negotiation takes place is between the service company and the line of business?

A Correct.

Q And by "line of business," that's -- the lines of business are run by National Grid USA, the parent company?

A No, the lines of business are run by the management team of the lines of business.

Q Okay. Who does the management team of a line of business work for?

A Okay. So they work for -- they're employees of the service company. But they're employees of the service company purely because they share time across a range of utilities. They're responsible for the activities of the utilities in their responsibility.

Q So if I got this right, employees of the service company negotiate on behalf of the service company, and employees of the service company negotiate on behalf of the line of business?

A That's right, but they're -- I don't think that is right. I mean, they're technically --

Q It either is or isn't.

A They're technically employees of the service company. However, their responsibility -- they're employed by the service company purely to use the allocations, methodologies that exist in our system so they can share time across all of the utilities. They're not sort of acting in the interest of the service company. They are acting in the interest of the utilities they're serving.

ALJ BOUTEILLER: Okay. Another way of approaching this, to whom are they accountable? Who are their officers or who are their principals?

THE WITNESS: The line of business management, so it's Tom King who runs the electricity distribution and generation. He's also -- he has two roles. He's the head of the electricity distribution and generation line of business. He's also president of National Grid USA.

ALJ BOUTEILLER: He wears two hats.

THE WITNESS: He wears two hats. And all of his management team report to him. But in answer to counsel's question, those people are employees of the service company, but they're employees not because they represent the service company; it's because we need to have the mechanics to share their time across utilities. They're providing consistent services.

ALJ BOUTEILLER: At the line of business activity you're talking about here, we're talking about true corporate officers?

THE WITNESS: Yes.

ALJ BOUTEILLER: Thank you.

Please proceed.

MR. MAGER: Okay.

BY MR. MAGER:

Q Now, is it fair to say that the service company employees decide or have responsibility for the -- using the correct cost allocators with respect to a type of expense?

A That's correct.

Q Okay. And between Niagara Mohawk and National Grid who decides whether or how a particular cost allocator should be updated or changed?

A Well, we have a standard policy, so we determine the appropriate -- the appropriate allocation methodology for each event or type of event. We then have a standard review process which occurs on a monthly basis where we run analytics to check the outcome of our process, and then we update all bill pools and allocation codes annually.

Q Okay. And I understand the annual updates where you

take existing pools and you just simply update the numbers?
A   New denominators.
Q   Do you ever change policies in terms of applying a different pool to a similar type of expense or change policies in terms of how costs should be allocated?
A   Not so much change policy, but you would change the implementation. So someone who used to have all company responsibilities and they suddenly change or they change their job or you reorganize that part of the business, it may result in a change in the allocations because you need the charges to be distributed in a different way, so we change the execution but not the policy.
Q   Let me go at my question this way. I think you said there's maybe 300 different choices on the National Grid service company and a similar amount on the KeySpan side. Do you recall that?
A   I do.
Q   Okay. And would it be fair to say that for certain types of services there may be multiple choices that may seem applicable to a person assigning time or costs?
A   No. To a large extent we try to take that decision away from the individual, so what we do is we ask the individual in the accounting string that they have to record, when they're recording a transaction, to record

only the company and the activity. And then behind the scenes those company and activity codes point to the right accounting. So someone doesn't have to go through all the 300. They have to think about what they're doing and who they're doing it for.

Q If it's not really difficult to choose, then you would expect a very high level of accuracy, wouldn't you?

A I didn't say it's not really difficult. I said we try to make it easier. It still is a little bit difficult. And often things change. So when someone changes their role or we reorganize the business, we have to then make sure they understand the correct change to the allocation methodology that they use.

Q Okay. I believe you indicated that there's no independent review or audit or investigation by Niagara Mohawk separate and apart from anything the service companies do in terms of making sure that the costs allocated to it are fair and equitable?

A Not by employees of Niagara Mohawk, no.

Q To your knowledge, has Niagara Mohawk ever analyzed whether it would be more cost-effective for it to perform a service instead of one of the service companies?

A The core services, so talking about core accounting, HR, legal, tax, treasury, the answer to that question would be no. We believe the services are best delivered efficiently centrally and allocated across the utilities. When it gets down to procurement services, some aspects of our heirs, there are external -- external outsourcing activities that are conducted.

Q Well, and I understand that the National Grid policy or approach or view that economies of scale make it cheaper to -- for service companies to perform certain services. I guess what I want to explore with you is in cases where Niagara Mohawk is consistently being allocated 45 or 50 percent of the costs, has it ever analyzed whether, given that it's responsible for such a high allocation, whether it could do certain services more cost effectively on its own?

A No.

Q Okay. Could you turn to page 9 of your direct testimony, please?

A I have it.

Q Okay. I'm looking at lines 9 to 15 of your direct testimony. And is it fair to say that the service company agreements do not provide any type of guaranty or level of performance?

A That's correct.

Q Okay. To your knowledge, has Niagara Mohawk ever undertaken an evaluation of the quality of services provided by the service companies?

A It's done as part of our ongoing management review process. It's just across the year through any of our reporting cycles forecasting annual plans, it's just open dialogue between the lines of business who are responsible for Niagara Mohawk's management and the departments who are providing services around cost efficiencies, strategies, you know, different ways to do the service. That happens just as a part of an ongoing management process.
Q So you're saying service company employees fulfilling different roles talk about this. And what I want to get at is has Niagara Mohawk, itself, independent from the service companies, ever evaluated, to your knowledge, the level of performance it gets from the service companies?
A Not as Niagara Mohawk alone.
Q Okay. Do you know roughly how much Niagara Mohawk pays to the service companies annually, just ballpark?
A I'm just trying to think of all of the numbers I've looked at. It would be significant, 300 -- just on O&M was over 300 million.
Q So it's hundreds of millions?
A Yes.
Q If not billions?
A Substantial. Substantial.
Q Okay. Do you know, does Niagara Mohawk pay any other

outside contractors comparable amounts without requiring any level -- any performance standards or guaranties in terms of level of services?
A No.
Q You talked about -- I believe staff counsel questioned you on this, too -- that you're starting to develop performance indicators or measurement criteria, is that correct?
A Yes.
Q And am I correct that the service company is the entity responsible for designing the performance criteria upon which they're going to be judged?
A No, that wouldn't be correct. It's agreed between the lines of business and the service company, the service departments providing the service.
Q So it's employees of the service company agreeing with employees of the service company how the service company is going to be evaluated?
A It's the same point again.
Q Okay. Is anyone from Niagara Mohawk, independent from the service companies, participating in that process?
A I'm sorry. An employee of Niagara Mohawk only?
Q Yes. Is any employee of Niagara Mohawk who is not -- only -- participating in the process of designing performance standards that Niagara Mohawk will be able to

expect from the service company?
A Counsel, I couldn't tell you exactly, but I would imagine, yes, because some of these are quite detailed operational metrics, so there may be operational employees of Niagara Mohawk participating in that process, but I couldn't tell you exactly.
Q You don't know sitting here today?
A Correct. But the metrics cover fleet, materials, inventory, so wouldn't Niagara Mohawk operational people be involved in that? Probably.
Q Okay. But there's no individual person responsible for representing the individual utilities?
A Correct.
Q Okay. And if we can skip forward a little bit, so the performance standards are put in place. What happens if a service company fails to achieve a performance standard? Does the utility have to pay less?
A There isn't a financial penalty, but there's just -- it's a management process. At the end of the day the objective here is to improve the process, reduce the cost, become more efficient or improve quality. It's not about punishing people. There isn't a standard which says, "well, if we don't hit the performance, I'm going to pay less," because that would leave a stranded cost in the service company that has to be dealt with.

Q Yes, but these are services that utility customers are funding. And if utility customers -- if the service company themselves are saying "we expect to at least achieve this minimal level of performance," and then they fail to do so, why should utility customers bear that expense?
A Because the objective here is to improve it, to set a benchmark and then improve the service. I just go back to the cost. If the cost of delivering the service is X and someone gets a discount, where does the other X go?
Q Well, it's not a discount, is it? I mean, wouldn't that provide a stronger financial incentive for the service companies to do well, than telling them that they're going to get a hundred percent recovery from utility customers no matter how poorly they do? Wouldn't the better incentive be to put some money on it?
A Possibly.

ALJ BOUTEILLER: Let me interject at this point. If we've established that there's no one at the NiMo entity level to be used or who could perform either a check on the process or the balance, please address, if you can, how is this process then transparent to third parties interested in the results in specific locations, be they regulators or entities who are capable of performing independent reviews? I mean, it's the transparency, I guess, of the activity within your service unit that needs to be observed and either verified or accepted or examined by others. How do you address that?

THE WITNESS: I mean, at the entity level it actually -- it is more difficult because the agreements, the SLA agreement is between the line of business -- it's an operating agreement between the line of business and the vice president and the groups that are providing the service, so it happens at that higher level, so that actually makes that transparency more difficult.

ALJ BOUTEILLER: Right.

THE WITNESS: But that was something that -- you know, that was something that we explored with North Star as part of the management order. We agreed when we provided our responses to the management order that -- you know, that we agreed that that was, within National Grid's operating model, an appropriate way to go forward.

ALJ BOUTEILLER: So would you agree that with the current structure in the way you operate, it's even all the more important that regulators serve in the capacity of examining your affiliated transactions and come to grips with them or

appreciate them or come to accept them?
THE WITNESS: I'd agree with that.
ALJ BOUTEILLER: Thank you.
Please proceed.
MR. MAGER: Thank you.
BY MR. MAGER:
Q Please turn to page 13 of your direct testimony. Are you there?
A I'm there.
Q Okay. You indicate on page 13 that the company plans to consolidate three out of its four service companies. National Grid plans to consolidate three out of its four service companies. Do you see that?
A Correct. Yes, I see it.
Q And when is that going to happen?
A It will be subject to regulatory approval, but it will probably happen concurrent with the system's implementation that allows to align the allocation methodologies across the National Grid U.S. group.
Q In terms of dates, what's the approximate time frame?
A Our system strategy will be late for 2011 system alignment. The regulatory timetable, in all probability, will be longer. So we'll probably initiate the as-is world in the new system and then, when we've completed regulatory approvals, move to a new methodology.

Q Now, the goal, I would assume, of consolidating three companies would be to produce synergy savings and efficiencies?
A Yes.
Q As such --
A As well, ease of use, you know, much more transparency across the U.S. group. It makes it very complex, running multiple systems.
Q Okay. So is it fair to say that the combined cost of the three consolidated companies should be less than those -- the cost of those three companies individually?
A On implementation of the system and alignment of the methodologies, yes.
Q Okay. Now, I see, I think, starting on line 12 you discuss that you expect to change allocation methodologies due to the consolidation?
A Um-hum.
Q Now, let me try to understand that. Let's say that -- pick any type of service cost. Why would the consolidation of three service companies impact how a cost should be allocated? I understand you might be updating the service company costs and there may be synergies, but why should the methodology itself change?
A Create a cost shift effectively.
Q Yes.

A   Probably just let me illustrate it by looking at the general allocator. So on the Legacy Grid world we use as the general allocator, when you can't use a cost causation bill pool, we use O&M of all the affiliates. So O&M is the numerator for the company over total O&M of all affiliates in the U.S. group.

On the KeySpan side we use the three-point formula. A three-point formula is a blended rate between assets, revenue and O&M. And so, just mathematically, you can't align those equations. They generate different answers. So when you move to a common methodology, there will be a cost shift. Hopefully, it will be small. And we've done some analysis which shows how small it potentially can be. But it will happen because an allocation methodology is an estimated calculation.

Q   You testified that as a result of that change in methodology, costs may actually increase to Niagara Mohawk.

A   Didn't we say either increase or decrease?

Q   Yes. So the result of this consolidation, which may produce synergy savings, still may produce a cost increase to Niagara Mohawk?

A   Correct. So if you separate the question into two, so in terms of -- for a given cost pool, might dollars move because you've changed the methodology, the answer to

that is yes.
Q Go ahead. I'm sorry.
A The question two, as a result of merging the methodologies, merging the service companies and aligning a common system, will the cost of executing service companies services fall? Absolutely.
Q Okay. So I guess that you still think it's a possibility that the cost shifting that occurs by changing methodologies may for at least some utilities outweigh any share of synergy savings related to their consolidation?
A We haven't completed the analysis. My expectation would be is the synergies would be greater --
Q Okay.
A -- in our utilities, but we have to complete the analysis. It's actually quite a complex calculation.
ALJ BOUTEILLER: Let me interject to make sure I am understanding what I first read and examined on your nice, beautiful picture about the service companies.
THE WITNESS: Thank you.
ALJ BOUTEILLER: It sounds to me like you're describing a two-step process. In the first instance is it your intent to consolidate all of the service companies that are serving KeySpan? Is that correct?
THE WITNESS: No. Actually, our intention,

Your Honor, is to consolidate all of the service companies across the National Grid USA group in one go.

ALJ BOUTEILLER: All in one go.

THE WITNESS: All in one go.

ALJ BOUTEILLER: So you're accomplishing two objectives simultaneously?

THE WITNESS: That's right.

ALJ BOUTEILLER: You're consolidating the three companies that serve KeySpan, and then you're integrating them with the same systems as shared by Niagara Mohawk and National Grid USA Service Companies.

THE WITNESS: Correct. So actually three things, Your Honor. Consolidating the service companies, aligning the systems, putting them all onto a common systems platform, and the third, then, is giving everybody a common -- so we have a common set of methodologies across the U.S. group, so effectively halving the number of allocation methodologies we have to use.

ALJ BOUTEILLER: And from all of this activity you've conceded on the record that the allocations as they occurred in Niagara Mohawk could be affected by all of this activity?

THE WITNESS: They could be affected, but as I've just tried to explain to counsel, in two ways. Firstly, for a given cost pool, just aligning the methodologies, because these are complex mathematical calculations, if you use a different set of calculations, you get a slightly different answer. There will be a cost shift for a given cost pool. However, the efficiencies that were gained by doing that, in my view -- and it is a view -- it will outweigh -- the synergies will outweigh the cost shift.

ALJ BOUTEILLER: So holding everything else constant, the next time we would take a look at this, we would expect that the synergies effect would outweigh the cost incurred effect and provide everyone a net benefit.

THE WITNESS: Okay. I think everyone a net benefit, but we'll have to do the calculations.

ALJ BOUTEILLER: And we'll cross our fingers.

Please proceed.

BY MR. MAGER:

Q How would you do that calculation?

A There's two calculations. The first one is what will happen if we align everybody onto a common methodology, so you have to sort of go back through all the transactions and then run a pro forma calculation and saying, "let's assume you didn't use this methodology but we used that one; what would the outcome be across all of the affiliates?"

The second calculation is how much of the synergy benefits would be realized, which is probably much easier. So if I look at my group and I look at service company accounting, I have two teams. I have a Legacy National Grid team, who run Legacy National Grid Service Company on Oracle -- I'm sorry -- PeopleSoft, and I have the Legacy KeySpan team who run on Oracle. I'll only need one team.

Q Okay. Is National Grid planning on doing that comparison so that information will be available in the future?

A Yes. I mean, as part of our sort of regulatory process, which we haven't yet defined, we will have to make submissions to all of our regulators around the alignment of allocations methodologies and the impact of that.

Q Okay. Now, you say that to the extent costs increase -- and they may decrease -- but to the extent costs increase as a result of this change, you're simply going to charge customers the difference to a deferral account; is that what you're saying on page 13, lines 12

through 15?
A Correct. The customers will get the benefit of the synergy.
Q And they'll bear the expense of any increased cost by the cost shift?
A If it is an increase to Niagara Mohawk. It might be a decrease.
Q Judging from your prior answers, I take it no one from Niagara Mohawk individually is going to be involved in the process where different allocation methodologies are combined?
A Counsel, we're going back to the same point. We have line of business management teams employed by service companies whose interest actually is the utility, not the service company. It sounds a little strange, but that's the way it is.
Q Well, when -- the line of businesses, they cover multiple utilities, right?
A Yeah. If we could maybe just refer you to the exhibit in my direct testimony.
Q It's just a very general question. They cover multiple utilities, correct?
A Correct.
Q And they also -- do the individual lines of businesses include regulated utilities and unregulated

companies within the same line of business?

A Probably no, with the possible exception of the discussion we had before lunch around LIPA and KeySpan Electric Services, which is sort of a unique contractual relationship as opposed to a regulated relationship.

Q Okay. And so there's --

A That would be the only one I could think of.

Q Okay.

A I think that we sort of drew that picture in sort of the exhibit, wherever it was.

ALJ BOUTEILLER: I think it's AFS-1 is the one I'm looking at, which shows five lines of businesses. It does show the existence of KeySpan units within the electricity, distribution, generation line of business, and you had been asked the distinction you could draw.

THE WITNESS: Correct. So all of those, if we look at the electricity, distribution, generation line of business, you can see all the Legacy utilities from the Legacy National Grid world, and on the KeySpan side, electric services is a contractual relationship. KeySpan Generation Services is very close to a regulated relationship by FERC, but it's still contractual, and I just can't remember the Glenwood energy company. I have to try.

BY MR. MAGER:
Q On page 14 you talk about -- of your direct -- how National Grid service companies charge for their services. There's direct charges and pools that -- we covered that. Generally speaking, do you agree with me that where a service is provided for a single affiliate company other than Niagara Mohawk, then neither Niagara Mohawk nor its customers should be allocated any of those costs?
A Correct.
Q Okay. And with respect to the use of bill pools, do you agree with me that where a service is provided for multiple affiliate companies not including Niagara Mohawk, that neither Niagara Mohawk nor its customers should be allocated any of those costs?
A Correct. So you'll see a bill pool in that circumstance which would exclude Niagara Mohawk.
Q Okay. So any expenses -- any expenses that were incurred for multiple entities other than Niagara Mohawk, none of those should be in the test year or rate year projections?
A Should not, correct.
Q Okay. On page 21 of your direct testimony you discuss the process by which there's verification and controls in place to ensure the accuracy of cost allocations?

A Correct.
Q Yet in this case in your supplemental testimony you've identified a slew of expenses that were inappropriately charged to Niagara Mohawk, is that correct?
A Correct.
Q Okay. I have a question about some of that.
MR. MAGER: And I'd like to mark as an exhibit a newspaper article regarding this.
ALJ BOUTEILLER: Let's see your newspaper article. In the first instance, before we mark anything with respect to newspaper articles, I'll allow you to engage in a line of inquiry. You can refer to it. These are public documents appearing in the outside world. Whether or not they warrant evidentiary value in our proceeding is something I'm not clear about, and that's my reason for being concerned about even marking them. You can show it to the witness. You can distribute it. You can engage in your line of inquiry. But before any newspaper articles become part of the probative evidentiary record in this proceeding, you will have to demonstrate through your cross-examination that the information is worthy of inclusion in the record.
MR. MAGER: Your Honor, in light of your

comments, I think I don't necessarily need the article in the record as an exhibit. I want to ask a few questions on it.

ALJ BOUTEILLER: You're not precluded along those lines.

MR. MAGER: Okay.

BY MR. MAGER:

Q Did I already give you a copy? Did I give you one?

A You did.

Q Okay.

A I did promise to tell the truth.

Q Okay. I have that in mind. This article talks about various expenses that at one time were allocated to Niagara Mohawk customers as part of this rate case, and my understanding is that they've subsequently been removed from the rate case?

A That's correct.

Q There's a part -- a part of the article indicates that a number of these expenses relate directly to you individually?

A Correct.

Q Is that accurate?

A It is correct.

Q Okay. And can you tell me what expenses that you previously allocated to Niagara Mohawk customers were removed from the rate case?

A So any of my compensation costs, any of my expatriate related expenses, any of my just, you know, travel and entertainment expenses relating to the operations of our business were also excluded from the rate case in relation to me, so there should be zero costs in relation to me now in the cost of service.

Q Okay. Things like fixing toilets and things like that, is that related to you?

A Yes, it was.

Q Okay. Can you take me through your thought process in why you thought fixing a broken toilet at your house was an expense that should be charged to Niagara Mohawk customers?

A I can. Actually, it's not my house. Correction, Counselor. It's actually a house that's owned by National Grid. So National Grid was simply repairing and maintaining an asset that they own. We repair thousands of toilets a year. So I actually live in that house that's owned by National Grid.

Q Go ahead.

A I'll let you ask your question.

Q Okay. So you now consider the allocation of those costs to customers to be inappropriate?

A National Grid considers it made a mistake in allowing those costs to go into the cost of service and have removed them, correct.

Q Okay. And I guess what I'm trying to understand was that if -- if you, as the person in charge of allocating these costs, thought that these type of expenses were properly allocable to Niagara Mohawk customers, then is that symbolic of the thinking among people who work under you?

A No, I don't think it is. I think it's sort of a broader policy question around National Grid, National Grid deciding what costs were properly incurred but should be appropriately retained as a shareholder expense versus expenses that should be passed to customers as part of a rate filing. And that was the decision-making process that resulted in this supplemental testimony and the adjustments in the Niagara Mohawk rate case.

Q Okay. And what is the distinction that -- what is the line of demarcation that National Grid now believes is appropriate in terms of types of expenses that should be allocated to shareholders versus customers?

A I think we probably set it out in our supplemental testimony with respect to this case, but I think National Grid has also undertaken to do an independent review to actually have independent advice in terms of what expenses should be appropriate. Because the way that National Grid calculated that adjustment, the cost of service for Niagara Mohawk now does not reflect all of the costs that are actually needed to run the Niagara Mohawk business, so it doesn't have a controller expense. There's no cost for me. There's no cost -- we all perform management functions on behalf of Niagara Mohawk, and those costs are not in the case, so it's an over-compensating adjustment.

Q You say that you're going to undertake further audits and investigations?

A Correct.

Q What are those -- what, exactly, is going to be done?

A So I think we probably refer to it in the supplemental testimony. What we're going to do is we're going to look at all of our policies and procedures that created the events which allowed these costs to not be properly classified as shareholder expenses and be passed down to the cost of service, and there National Grid admits and wants to correct quickly.

Q What happens if during that process you discover numerous other expenses that were improperly billed to customers?

A Then if we find that, then I would imagine that we would adjust them. But I think the point that I would make is that these expenses were in a very narrow range. They were a very unique type of expense. They're very self-contained in our company. They're very easy to identify, and they were adjusted out as soon as we realized and it was brought to our attention that we'd made this error.

Q It wasn't brought to your attention by any of your internal controls or processes, right?

A No. It was brought to our attention by regulators.

Q Okay. So it's possible that notwithstanding all the internal controls you have that regulation of these type of expenses could lead to corrections or improvements in the process?

A It's possible, but because of the unique nature of these expenses and the way that we calculated the adjustment, it would be very unlikely.

Q That's what you thought before these were discovered, too, right?

A These were properly incurred expenses but hadn't been properly accounted for and reviewed as part of the preparation for the cost of service.

Q And I guess that's what concerns me is what expenses were properly reviewed as to cost of services -- as part of the cost of service?

A I mean, all the other costs were reviewed in the normalizing adjustments as recommended by the Revenue Panel, basically, the ones that were eliminated as part of the initial cost of service. Then when this error was brought to our attention, we now over-compensated and removed all of these costs from the cost of this case.

Q Well, in setting up your test year you didn't -- you obviously didn't get to this level of review; otherwise, it would have been spotted earlier, right?

A Clearly.

Q So what level of review did you get to?

A I mean, the costs -- all of the costs were reviewed as part of our -- you know, that we talked about as part of testimony of the cost allocation review work, the amount of work that we did in checking all of the costs. But this decision around these expatriate and officer expenses was not about the appropriateness of the costs. It was whether they should be passed down into the cost of service. It wasn't that the cost was wrong. It was incurred either under our expatriate policy or our expense policy. The error that National Grid made is actually not making the judgment that it should be a shareholder cost and not be passed into the cost of service.

ALJ BOUTEILLER: In the old convention of parlance that I'm familiar with, we have this notion of below-the-line items.

THE WITNESS: Good.

ALJ BOUTEILLER: Okay. You're telling us

you put these above the line, and the admission you're making is that in most of these instances you now believe they belong below the line.

THE WITNESS: And, in fact, the $4 million adjustment that we've made to this case as part of supplemental testimony includes expenses that should be below the line but also includes, because we've over-compensated and we're very conservative in the correction, also included expenses that should be above the line. They are now excluded from the case.

ALJ BOUTEILLER: And until you have your independent review, none of those items will come above the line until you have the proper rationale.

THE WITNESS: That's correct. They're excluded from the case.

ALJ BOUTEILLER: Okay. I just want to understand your position so I can convey it accurately when it goes past my desk to other desks.

THE WITNESS: Okay. That's fine, Your Honor.

BY MR. MAGER:

Q I guess using above the line and below the line, if your further research and analyses show that there are other costs that really should be on the shareholder account, is it then too late to do anything about it for purposes of this rate case?

A Our intention is to complete this review very expeditiously. However, what I would say is the concept in U.S. rate-making of what should be below the line is just a narrow range of activities. Charitable contributions, political contributions, lobbying. And we've now added, effectively, a new class of exclusions, which are these expatriate and officer expenses. So because it was so self-contained in our company, it was a narrow range of activities and affected a narrow range of people, we believe we've identified and over-compensated in the adjustment. We don't expect the review to confirm that there are additional costs that should be to the account of shareholders, but we're very willing and prepared to undertake the review and do it quickly.

Q It's not just costs allocated between shareholders and customers, but also is the review going to get at the accuracy of how costs are allocated among affiliate companies as well?

A Yes, we intend to have that as part of the scope.

Q And to the extent that that investigation reveals that more costs were allocated to Niagara Mohawk than should have been, there's no plan to fix that for purposes of this rate case, is there?

A We haven't -- we haven't sort of determined the

process following the completion. We need to first appoint the independent party who will be helping us on this review. We'll then be able to agree to scope and then to time and then we'll be able to determine process at the end of that.
Q When is your understanding of the timing for this process, if you know now?
A We're in advanced stages of discussion with independent parties that will provide this review. We expect to have appointed the party probably in a very short number of days as opposed to weeks. We'll then proceed to agree to scope of that party, and then we'll know what the time frame is. But again, we expect it to be done in a relatively short number of months.
Q Okay. Can you please turn to page 57? Actually, I'm sorry. Can you first turn to page 40 of your rebuttal testimony? Are you there?
A Yeah, I'm here.
Q Okay. You talk about, on lines 17 through 19, an allocation review that was done at the end of 2009 that was limited to invoices over $100,000.
A Um-hum.
Q And then skipping ahead to page 56, you discuss the -- how the accuracy and integrity of cost allocations are of paramount importance?

A Um-hum.
Q Do you see that?
A I do.
Q And then on page 57 you again talk about a review process. Is the review process referred to on page 57 the same one referred to on page 40?
A It is.
Q Okay. Now, staying on page 57, you decided this review process was limited to invoices over a hundred thousand dollars?
A Um-hum.
Q Would it be fair to say that a hundred thousand plus dollar invoices are likely to get more attention during the allocation process than smaller invoices?
A Likely, yeah, I think that would be the case, but not -- I wouldn't like the characterization that anything below a hundred thousand dollars we wouldn't look at at all, so it would get -- they probably get more focus but as would a less than a hundred thousand dollars.
Q Basically, it's fair to say that more thought and attention would be given to the allocation process for a hundred thousand dollar expense compared to a hundred dollar expense?
A Maybe, correct.
Q You talk about and I think you had a colloquy with

the judge about, you know, the accuracy of a bank and a hundred percent being difficult to achieve, but to get -- I guess they found there were 2 percent inaccuracies on the invoices -- on certain invoices with a total value of 3.2 billion. Do you see that?
A Yes, I do.
Q Then there's also a follow-up sentence which indicates that on another subset there was 92 percent accuracy or 8 percent inaccuracy?
A Okay.
Q Can you distinguish those two figures?
A Yeah, of course. So, actually, with the two different data sources, so those costs that are pooled and allocated out of service companies, two pools, there's accounts payable invoices, an invoice that comes into the organization that needs to be coded, and then there's how people charge their time. They operate through different processes, so we tested both.
Q Okay. With respect to hundred thousand dollar plus expenses, there was a 2 percent error rate on invoiced expenses and an 8 percent error rate on labor expense?
A Except there was no flaw on the threshold of labor. We looked at all 7,500 employees.
Q Okay. You looked at all the employees and you looked at all of their charges on how they charged their time?

A On the bill pools that they used, the bill pools and allocation codes that they used to charge their time.
Q For every expense on every day?
A For every -- it wouldn't be every expense on every day, but it would be -- I'd have to confer and check just exactly how it was done.
Q Yeah. I'm not sure --
A It was actually we checked -- we checked the appropriateness of the allocations for all 7,000 people, so, you know, were they used incorrectly, had the all-company bill pool, or did they only support a group of companies and so they should use a narrowly defined bill pool, all those were checked for all 7,200 people.
Q Let's say a person spent one day working on one utility's stuff and another day for a different utility. Did you go back and check to see how they -- whether they accurately reflected their costs over time?
A I think we did, but I'd have to confer to the record and come back to you on an answer. I believe we did.
Q Do you believe that the 8 percent error rate on labor allocations is acceptable?
A No, we don't.
Q Do you believe it's problematic?
A I believe the impact on the Niagara Mohawk rate case is small relative to the overall case. I believe it is

problematic, and I believe that we should improve the processes, and that's exactly what we did following the review to reduce the error rate. But is it a significant error rate in terms of context of a NiMo rate case? No, it is not.

Q At least with respect to part of this review, the -- at least the invoice piece, just a hundred thousand dollar plus invoices totalled, I believe you said, over $3.2 billion. Is that what your testimony says on line 4?

A That's right. That was the total value of invoices tested in the population.

Q Right. And for a lot of the expenses and a lot of the pools, doesn't Niagara Mohawk comprise roughly 25 to 55 percent of the allocation pools?

A That's correct.

Q So just on these invoices alone, you're talking about a value that could be well in excess of a billion dollars?

A That's right. But we're also talking about a very high level of accuracy in that. And four of the months that was included in this review period are actually in the historical test year.

ALJ BOUTEILLER: Let me follow up there. With respect to the invoices for which you found 98 percent accuracy, you believe that that's a good result, a good performance. You're not suggesting that that needs -- requires any improvement or systematic efforts?

THE WITNESS: Actually, we did, as a result of that, so, you know -- yeah, absolutely. We undertook various training programs. We identified where were those errors occurring, why were they occurring. We trained the people. We put in some additional control procedures. I wouldn't want to give the impression that, you know, this -- as counsel suggested, that any error is acceptable. What I'm saying is, you know, was the impact of the error material and significant on Niagara Mohawk? Probably not.

ALJ BOUTEILLER: Is this the floor, then, for your forward-going behavior of your expectations?

THE WITNESS: It better not get worse.

ALJ BOUTEILLER: So the next time you do this calculation and this test, you would expect to see a result higher than this 98 percent figure that you have here?

THE WITNESS: I would, Your Honor. Yes. Put a lot of time and effort into it.

ALJ BOUTEILLER: Thank you.

Please proceed.

BY MR. MAGER:

Q Okay. Can you turn to your supplemental testimony? And we're almost done here. Actually -- I'm sorry, it's an exhibit to your August 30 supplemental testimony. I'd like to ask you a couple of questions on Exhibit AFS-1S.

A I have it.

Q Okay. Could you please turn to sheet number 4? Actually, let me take a step back first. Leave that page open. But for service company costs, basically, the utility is billed the service company's exact precise costs plus some return on equity?

A Correct. That's the only margin in the equation, on the actual transaction is the cost.

Q Okay. So the extent the charge to the utility is reasonable depends upon the reasonableness of the service company's costs, right?

A In concept, yes.

Q I had a couple questions --

ALJ BOUTEILLER: When you pose your questions, please identify which line you're going to be speaking to specifically.

MR. MAGER: Yeah.

BY MR. MAGER:

Q I guess -- a couple questions, let's just say, on car leases on this page. If you look at line 3, there's a car lease for the month of February 2009 of over $1800, and a little more than 52 percent is allocated to Niagara Mohawk. Do you see that?

A I see it.

Q Then another line, say 54, there's a car lease for the same month, February 2009. This one is for almost $1200, and there's a 56 percent -- a little over 56 percent allocation to Niagara Mohawk. Do you see that?

A I do.

Q Explain to me how the leasing of a car results in different allocation factors.

A I'd have to look at the transaction. I just can't talk from this schedule.

ALJ BOUTEILLER: As a follow-up to that, is your representation that these are the lease costs and the most cost effective leases that should be accomplished for these individuals that you're showing here?

THE WITNESS: It would be, but these are costs that are now excluded from the case.

ALJ BOUTEILLER: I understand that, but again, getting back to your basic rationale, your representation is these would be the least cost, most cost effective for rate-making purposes, were they still included?

THE WITNESS: Correct. Looking at the

heading of the schedule, this would be a vehicle. The expatriate was entitled to a vehicle under his terms of employment, and this would have been the most cost effective way of meeting that entitlement.

ALJ BOUTEILLER: And in the future these might surface again in a rate case and you might present it based upon the results of your outside independent review?

THE WITNESS: Correct.

ALJ BOUTEILLER: Please proceed.

BY MR. MAGER:

Q I wasn't going to ask that, but I guess what type of cars do you lease for $1800 a month?

A I'd have to go and check. I don't know. It might have been a short-term rental. Maybe it was part of the expatriate's relocation. I can see that there are two months. I don't know who D. O. Peterson is. I'd have to go check.

Q It looks like the $1800 is one month, and the one under is 1600, and the one under it is almost 1400, and the one under that is almost 1400. I guess I'm just trying to see if these are -- are these the normal prices that the company pays to lease a car for a month?

A It would depend. There's not enough information.

ALJ BOUTEILLER: Can you take that as a

from-the-Bench request? You provide us what would have been -- you've provided very useful information when you responded to the question that asked about the home that you occupy and what would be the basis for your incurring costs and allocating it for repair. You indicated that the title to those premises are in corporate hands.

THE WITNESS: Correct.

ALJ BOUTEILLER: Okay. If you have a similar answer for these leases, could you provide that for the benefit of the Bench?

THE WITNESS: Absolutely. Maybe it would help. Let's pick a few, pick three or four and we'll go look at three or four.

ALJ BOUTEILLER: Yes.

THE WITNESS: Okay.

ALJ BOUTEILLER: Thank you.

Please proceed.

BY MR. MAGER:

Q Okay. So for similar type expenses for, like, car leases as an example, you don't -- you don't know today why some leases -- why there may be three or four or five different allocation factors applied to Niagara Mohawk Electric?

A I couldn't tell from the schedule, no. I'd have to

investigate it.
Q   Okay. How would a car lease be allocated?
A   It should follow a car lease, which is a stable, routine charge, it should follow the charging of the expatriate or the individual's time. So if they're using an all-company bill pool, it should follow that. It's just part of their compensation. Counsel, I can't explain why it is. I just have to look at it.
Q   Okay. Do the -- does the company ever lease cars for employees other than expatriates?
A   It would. I'd have to sort of -- I have to defer to the HR panel and look at the company car policy. I'm part of a different policy, so I know what happens to me and I don't get a lease.
Q   You don't get any $1800-a-month leases?
A   Sorry.
Q   Okay.
A   It's my car.
Q   Okay.
MR. MAGER: I don't have anything further, Your Honor. Thank you.
ALJ BOUTEILLER: Mr. Walters, do you want to proceed?
MR. WALTERS: Am I all right here?
ALJ BOUTEILLER: You're fine if you use the

microphone and the reporter can actually see your face.

MR. WALTERS: I think I've satisfied both criteria.

ALJ BOUTEILLER: She'll let us know if you don't.

CROSS-EXAMINATION

BY MR. WALTERS:

Q Good afternoon, Mr. Sloey. My name is John Walters with the New York State Consumer Protection Board. I have some questions for you. And if I hit on some areas that you've testified to previously, I apologize, but I'll try to limit the questions to areas you haven't been examined on yet.

A That's fine.

Q Just a little follow-up. First, if you recall, back on staff's cross-examination you indicated that at one point you came to the realization that you had been using the wrong billing pool. Do you recall that?

A I do.

Q And from what period of time -- first of all, I guess, when were you made aware of that?

A Probably a few weeks ago as part of this inquiry.

Q And you said it was the result of, I think you used the term, a frank conversation that you had. Is it fair to say that you had been allocating costs to the wrong billing pool for the entire period that you've been an employee?

A In the U.S.

Q In the U.S. That goes back to 2007?

A When I arrived here, I was using a Legacy Grid bill pool, and -- Legacy Grid company, and I should have been using the all-company bill pool. It was my error.

Q During the line of questions from MI, you stated something to the effect that in the U.S. we, referring to National Grid USA, prefer the service company approach?

A Um-hum.

Q Is the same approach used for National Grid companies, say, in U.K.?

A In substance, yes, but not in form. So the concept of central delivery of service exists. We just don't use the service company structure because the regulation structure in the U.K., it works differently.

Q Okay. Then to follow up in the follow-up mode, you talked about the hundred thousand dollar invoices that were examined?

A Um-hum.

Q And I believe Mr. Mager questioned you as to whether or not invoices for amounts lower than that were given less consideration. Is that an accurate statement?

A I think counsel's question was in the processing of the invoice did we pay more attention to something higher than a hundred thousand than we did to lower. In the actual review we actually did tests, and I would have to -- it would have to be a request. We actually did examine some invoices under a hundred thousand. We actually did do a sampling of that, but it wasn't as exhaustive as above a hundred thousand.
Q That's for purposes of arriving at cost of service for the cost of service study?
A No, it was done well in advance of the NiMo rate case. It was done by us because we were interested in compliance, the correct operation and allocation at a time when our company was undergoing fundamental change.
Q You also mentioned labor invoices that were checked, and I'll try to tie this in, tie in two topics that are unrelated, and please correct me, but you mentioned in Mr. Mager's cross that all the labor invoices have been checked. I believe you quoted a number of 7200 employees?
A Correct. Can I just clarify? It wasn't a labor invoice. People record their time, actually go into the system and record how they spent their time. It wasn't a third-party invoice that came across our desk.
Q All right. Understood. Going back, keeping that thought in mind, going back to the staff's cross,

initially you had discussed the only instance in which a Niagara Mohawk Electric Company employee would be able to allocate a direct cost would be -- you cited different field workers and employees of that nature that are able to do that. Is that -- is that correct? A direct cost to Niagara Mohawk?
A Well, the service company employee can allocate the cost directly to Niagara Mohawk, so if you don't need to use a bill pool, then don't. If the cost that's being incurred is wholly to benefit Niagara Mohawk, we can record it directly without going through our allocation process.
Q So the 7200 employees, the labor invoices that you're referencing are service company?
A 7200 service company employees, correct.
Q Thank you.
A From both Grid and KeySpan service contracts.
Q Again, back to Mr. Mager's questions regarding the not-on-the-record newspaper article that you were questioned on, you indicated that certain of the expatriate costs -- excuse me -- certain of the expatriate costs had been brought to your -- when I say "your," the company's knowledge through "regulators"?
A Through the regulatory process, yes.
Q Right. Can you identify the various regulating

entities that brought these costs to your attention?
A The regulators, so go ahead.
Q Which regulators?
A Okay. So through the Massachusetts rate case. I think we referenced that in our supplemental testimony and this case, the PSC.
Q And as a result you indicate that there's going to be analysis done and certain lessons learned will be implied, I assume. Is that an across-the-company-wide analysis, or is that just concerning cost allocated to Niagara Mohawk?
A It must be company-wide, because it's a closed-loop system, so the costs come into the U.S. group. If the allocation to company A is wrong, then there must be a corresponding error somewhere else.
Q You've mentioned a process that the company was going through, and that shortly -- I don't mean to pin you down to a specific time period, but shortly a party would be appointed to conduct the independent review. Do you recall that?
A I do.
Q What type of process was initiated or did the company go through in order to bring this entity to this job or the anticipated job?
A There's probably a relatively small number of candidates with experience in U.S. rate-making experience

in this type of activity. Cost DataStation, you know, sort of large-scale related mining activities, there aren't too many candidates, so we're able to identify a short list relatively quickly, and we're in advanced discussions at this point.

ALJ BOUTEILLER: Let's go off the record.

(Discussion off the record.)

BY MR. WALTERS:

Q One more question back on the topic. I'm sorry I'm jumping around here a little bit. But on your specific circumstances, the allocation mistake, are you aware of or do you know of whether or not other -- I'll just use the term -- top executives report in the same manner, is it possible that they could be making the same mistake?

A I'm not aware of others that have made a mistake, but it is possible that they did. And part of the exclusion process means that that couldn't now have an impact on the Niagara Mohawk rate case. And the review that we're undertaking will strengthen that procedure and policies in the area.

Q If you look to page 6 of your rebuttal, I'm going to ask you questions on your rebuttal and then on your direct. I'll stick to your rebuttal and then we'll finish and we'll go to your direct, I think, so it's simpler. Page 6?

A Um-hum.
Q Line 20, you were asked the question, "What are the benefits of the service company structure?"
A Yes.
Q What would you say are the drawbacks?
A I haven't been asked that question. There's certainly a drawback in having four service companies when you only need one, so they're very complex to run. I'm just not sure that there is one. I mean, they can be relatively complex to run, but with clear procedures and policies, good training and, above all, good systems they can be very effective, and it allows you to deliver consistent services across a range of utilities cost effectively.
Q So from your perspective there's -- there are no drawbacks?
A It means -- going back to the discussion I had with Your Honor a little while ago, it means that sometimes the transparency is a little bit harder to achieve, seeing much more time and effort to the tools that you use for reporting, because you pool costs and then you allocate costs, and that's a less transparent process than if you have separate accounting groups and legal groups in each of the utilities, but that's a very expensive way of -- that's a very expensive solution.

Q If you look to page 9 again of your rebuttal testimony, I think you answered this question earlier under cross-examination with Mr. Mager, whether the company evaluates whether services could be more cost effectively procured, and I think your answer was that there haven't been any analysis of that type?
A Not with respect to those cost services accounting, we don't carve those up. We have the entire accounting group that's providing those consistent services. What we don't do is say "can I pass out journal entry" and then carve out of accounting one little slice and say "can I do that externally?"
Q On the same page you cite -- you reference the idea that the company generally relies on service companies for what you call core services?
A Um-hum.
Q One of those services you included are legal services, correct?
A Correct.
Q And one of the reasons that you cite, I guess for all the categories, is the familiarity and institutional knowledge that sort of aids in your efficiency with those types of services?
A That's correct. And the integration. You need one set of procedures, so, you know, we report as a single

group, and so you have one set of reporting processes, one timetable, one system. It would be very hard to manage if you had 23.
Q Does National Grid have an in-house counsel department?
A Yes, it does.
Q Would you say that it's fair -- would it be fair to say that the members of that department are familiar with and have institutional knowledge regarding National Grid USA?
A Yes, it would.
Q On lines -- same page, page 9, lines 13 through 15, you cite a need to avoid complexity as a reason for not bidding out an exchange for a minimization of costs?
A Um-hum.
Q Do you feel that the company's current shared services process is a complex one? I think earlier you stated that.
A Shared services process.
Q Yes, the process of allocating costs to different --
A I think it is, yes. Yeah, I do think it is because we've got two processes when you only need one.
Q Page 11 again, still on your rebuttal, on line 21 you use the term "feasible." I believe you state that -- hold on. I'm sorry. Let me try to get to the right page here.

I'll just read the full sentence. At number 3 you state, "allocated using approved general allocation methodologies as the former two approaches are not feasible."
A Um-hum.
Q The term "feasible" in that sentence, how do you define that?
A Okay. Maybe we just talk about the hierarchy of how we approach it. In all cases, when you receive a charge into the service company, the most preferable method of making that charge from the affiliate is on a direct basis. So if the service is delivered wholly to a single utility or a known subset of utilities, to actually do it on a direct basis, so that's item one. The second, if you can't do that, if that's not possible, the second preferable method is using a cost causal bill pool. So if you're occupying a portion of a building, you know, rubber gloves, number of people, to get that reflection of the costs. And if that doesn't work, just a more generic service, we would use what we call the general allocator. And as I've explained in previous questions, on the Legacy Grid side that general allocator is an O&M-based allocator. On the Legacy KeySpan side it's a three-point formula, assets, revenue and O&M.
Q Page 29, still on your rebuttal, specifically lines 6 through 9, you discuss -- wait a minute. I'm sorry. I

think I have the wrong page here. Hold on just a second. Page 24 -- I apologize -- on lines 6 through 9 you discuss the company's efforts in support of the company's bad debt mitigation effort. You state that additional service company costs were incurred, including increase in inbound calls.

A Um-hum.

Q What would -- how would you define the relationship between an increase in inbound calls and bad debt? In other words, is there a correlation that you're making between customers whose perhaps bills have been written off, or describe the process that you're describing.

A Okay. As part of managing a debt ledger, you have open items. The more proactive with different types of strategies that you use to collect overdue debts, typically, what happens is you generate more inbound calls into your call center as the people make customer account inquiry, requests for grant information because often they're low income inquiries. So you just generate a much higher volume of activity through your call centers. And so whenever we develop bad debt mitigation plans, we have to weigh up what benefit do you get in terms of a lower write-off of bad debt expense versus the cost being imposed on the organization in executing activity and a volume increase through call centers.

Q Further down, same page, lines 12 through 15, you talk about -- you're referencing back to the difference between the allocation to Niagara Mohawk and the other National Grid USA affiliates, and you cite to storm costs and bad debt, SIR cost increases, et cetera. Didn't the other affiliates in National Grid USA experience, for instance, the ice storm of 2008? Aren't those costs attributable to New Hampshire utility, I would think?
A A couple on a much, much, much smaller scale.
Q Would that be true across the board, Massachusetts, Rhode Island, there's still more cost?
A There were costs, but not to the scale of Niagara Mohawk.
Q So you're talking about a relative comparison?
A Yeah. And downstate, obviously, there wasn't.
Q I'm sorry for the blank periods here. I'm just trying to look through -- some of the questions have been asked.
If you could refer to your direct testimony, page 13 -- again, you discussed this, I believe, with Mr. Mager -- line 9, you talk about regulatory approvals that need to be attained by the company initially. What entities do you need to get regulatory approval from? In other words, are we talking about all the various affiliates and their jurisdictions, the PSCs?

A That's right. The state commissions in each of the four states that we operate.
Q And --
A And FERC.
Q And FERC?
A I believe FERC as well, but I believe that's related to a question we undertook to provide an answer earlier.
Q All right. If you could look to page 140?
A Of what?
Q I'm sorry, your direct. I'm sorry, not 140, 21. So many numbers. I think I heard you say that the cost -- lines 15 through 17, you discuss the Cost Allocation Review Committee and, additionally, oversight provided by a Regulatory Cost Structure Committee?
A Um-hum.
Q I heard you comment on who or which individuals would constitute the Allocation Review Committee, and you might have also mentioned the Regulatory Cost Structure Committee, but I didn't hear that.
A No, we didn't.
Q Who are the individuals that would be on the oversight committee of the oversight committee? I'm sorry. The oversight committee of the Revenue Allocation Review, the Cost Allocation Review Committee?
A The Cost Allocation, we discussed those individuals

this morning.
Q Right, but then --
A Then the Regulatory Cost Structures Group is a slightly different breed, so the Regulatory Cost Structures Group, again -- I mean, I guess to sort of jump to the question that I think is being asked, are these people service company employees? Yes, they are, but they're there in their capacity as members of the lines of business and regulation teams responsible for the activities of the utilities. They have no interest in the efficient operation of the service company.
Q Thank you, Mr. Sloey.
MR. WALTERS: That's all I have.
THE WITNESS: Thank you.
ALJ BOUTEILLER: Is there any other counsel in the room who has questions for the witness? If not, at this time our standard convention is that you're permitted to have a conversation with your counsel in private to determine whether or not there's any further questions that your counsel wants to ask of you after having heard all this cross-examination. So we'll give you time to do that. And when you come back, your counsel will tell us whether or not there is any further redirect for you, and that could open up another line of inquiry

from the other counsel, so that's the downside if you have any more questions. So you may want to convince your counsel one way or the other.

THE WITNESS: I have no plans for this evening now.

ALJ BOUTEILLER: While you're doing that, let's go off the record, and we'll come back on the record when we're ready to ask you whether or not there's any redirect. But given the hour here, I just want to raise a couple of things, and I'll let the parties tell me what their preference is. If we don't get to Mr. Niazi today, I understand we cannot get to Mr. Niazi tomorrow. So if we want to get to Mr. Niazi today, probably we need to take him next after this witness. But that's for the company and CPP to arrange or decide with input from other parties. I don't know if the plan was for the Infrastructure Panel to hold over, ride over, but you can consider all those dynamics. And you also have the knowledge, too, that I probably owe you a little bit of time from our first day of hearings, so if you want to make use of a little bit more time today, I will accommodate you, but I don't see me staying here past 7 :00, okay? So use that input, confer among yourselves, and then when we come back on the record you can tell me where we plan on going, and you'll also know -- you can estimate to what extent we'll have more time needed today with this witness. Wait until we get the process rolling of them considering redirect or not. I don't want to rush anything.

MS. NESSER: Can we have 20 minutes to discuss redirect with Mr. Sloey? And I wonder if staff can let us know how long cross-examination for the IR.

MR. LECAKES: I'm thinking 45 minutes to an hour at the most.

MS. NESSER: Okay.

MR. LECAKES: But they're refined. I went over them with a fine tooth comb.

MS. NESSER: I'm sure they're very surgical, Dakin.

MR. MALONEY: I probably have about 45 minutes to an hour for Mr. Niazi.

ALJ BOUTEILLER: You guys can all work this out. The reporter knows we're going to take at least 20 minutes so she can rest her hands and get her rest in. I'll come back to the Bench in about 20 minutes. And if you're ready before me, knock on the door and I'll come running out, okay? So we plan on going back on the record at about 4:00. Thank you.

MS. NESSER: Thank you.

(Discussion off the record.)

ALJ BOUTEILLER: Counsel, is there redirect for your witness?

MS. SWEET ZAVAGLIA: Yes, Your Honor, there is.

ALJ BOUTEILLER: Okay. Please proceed.

MS. SWEET ZAVAGLIA: Thank you.

REDIRECT EXAMINATION

BY MS. SWEET ZAVAGLIA:

Q Mr. Sloey, would you please explain how the line of business management model and the operating companies as independent legal entities work together?

A Sure. I mean, the responsibility of the line of business management teams, even though they are employees of the service company, their obligation is to manage the affairs of the utilities under their responsibilities to meet the regulatory obligations. That's their primary responsibility. So the fact that they're employed by a service company simply allows them to share time. It's a mechanical need. It doesn't change their underlying obligation.

Q Staff counsel asked you questions about certain American Express gift cards that were provided to employees who worked to extinguish the fire at Port

Jefferson. How were those costs treated in this case?
A They were very small costs. They were either treated -- they were either excluded because they were prior to the historic test year, or they were excluded as part of the adjustment we made in supplemental testimony.
Q Now I'd like to direct your testimony to what has been marked for identification as Exhibit Number 328. This is the response to the Mass AG. Do you have that?
A I have it.
Q Now, staff counsel asked you a question about the costs associated with the sale of Ravenswood. Would you please explain how those costs were treated in this case?
A Okay. Firstly, the document -- I don't remember the number, the document you just showed me -- they were an employee expense claim, and they have been excluded as part of the supplemental adjustment. We've already over-compensated and removed all these costs from the NiMo case. I think the other question that I was asked more broadly is where were the costs and -- where were the proceeds and costs from the Ravenswood sale allocated and confirmed that none of those were allocated to Niagara Mohawk.
Q Now I'd like to direct your attention next to AFS-1R.
A I have it.
Q Now, staff counsel pointed to an increase in Niagara

Mohawk's A&G costs from 2007 to 2008, and looking at the schedule it appears to be approximately $60 million?

A Correct.

Q Would you please explain the drivers of that increase?

A I mean, there's a few drivers, so probably the biggest single driver was an increase in the company's pension and OPEB costs. So over that time there was significant dislocation in the financial markets. Plan values reduced. You know, accounting expenses increased. That was about $17 million of the increase.

Over that same period we had, also -- I guess it's somewhat related to the deterioration of the economy -- we had an increase in bad debt expense. That was 17 million -- sorry -- $11 million.

We talked a little bit in the last discussion around bad debt mitigation costs. Those increased -- to actually manage to contain that bad debt expense was an additional 4 million. There's an increase in variable pay costs for Niagara Mohawk employees of 6 million. And then relative year-on-year, 12 million increase in cost to achieve synergies in transformation activities. And then there was a small number of about 5 million which, as we discussed earlier in testimony, there's sort of 20 to 30 things sort of behind that that sort of make up the increase.

Q Staff counsel asked you how many trips to the U.K. for business you have made while you were based here in the U.S. When traveling to the U.K., are you performing work for the U.K. companies?

A No. It's just a continuation of my U.S. responsibilities. I thought when I was asked the question before I have no U.K. responsibilities. Someone replaced me in the U.K. when I left.

Q Staff counsel asked you a series of questions about delay in work order closings. Did the company perform any additional analysis to determine what costs would be required to close work orders within one month as staff recommends?

A Okay. It was really a partial analysis, so we looked at it from my group or the accounting group or the property group. We think it would take probably another sort of four to five people to be able to close those work orders in a month, and then probably an additional cost of half a million dollars. But the real cost would actually be in the field to be able to sort of, you know, change processes, get things through sort of as-built drawings, estimations, final estimations. We weren't able to quantify that. But given the depreciation expense that was being proposed, the adjustment was only $1 million on an annual basis. We're probably going to be having more costs. You know, it would probably cost more to achieve the $1 million and, I guess, in sort of annual depreciation cost of 170 million, that's a pretty small number.

Q Counsel for MI asked you about the consolidation of the four National Grid service companies. Would you please explain which service companies will be consolidated?

A I did misspeak. One will not be consolidated. It will be KeySpan Engineering Services who provides engineering services largely to, I think, the Long Island generation activities. For particular licensing reasons we need to hold that company separate, but the other three service companies will be consolidated.

Q The Judge asked by what standard do you measure how accurate the company must be. Would you please elaborate on the company's position?

A Okay. It's come up a number of times, actually, today, and we do -- we do strive to make it perfect. We do strive to make it perfect, but we must always be prudent. And the point that I was trying to make in the discussion with the Judge is at some point you run into diminishing returns. It can be very expensive to achieve perfection, and then we start increasing costs. We strive to be always prudent, so we've got to sort of, you know, tread the fine line. But any issue we find, no matter how small, as I said, we seek to understand the cause. If it's a training problem, a procedural problem, we go and remediate it. We don't sort of try to grade the error. We're just careful and prudent about the amount of costs we spend improving it, particularly if it's such a smaller problem.

Q Thank you.

MS. SWEET ZAVAGLIA: Your Honor, if I can have a moment?

ALJ BOUTEILLER: Sure.

MS. SWEET ZAVAGLIA: Your Honor, the company has no further redirect.

ALJ BOUTEILLER: Okay. Let me turn to the parties now and go through them one by one and find out if there is any recross for this witness.

MS. CICERANI: No, Your Honor.

ALJ BOUTEILLER: None from staff. From Multiple Intervenors?

MR. MAGER: Just two quick ones.

ALJ BOUTEILLER: Please proceed.

RECROSS-EXAMINATION

BY MR. MAGER:

Q Referring to AFS-1R, the exhibit, you talked about on

redirect the large increase in expenses from 2007 and 2008 to Niagara Mohawk; do you recall that?
A I do.
Q I think you mentioned some of the primary reasons were pension and OPEB cost increases due to the financial markets and bad debt expense due to the economy. Do you recall that?
A Yes.
Q Do you know why, then, Niagara Mohawk's costs went up so much whereas Central Hudson's barely moved and NYSEG and RG&E went down from 2007 to 2008? Weren't they subject to the same factors?
A I don't.
Q Okay. And then you mentioned variable pay costs. Now, this is not Niagara Mohawk employees' variable pay costs; this is the service company employees' variable pay costs?
A This is actually total A&G, so it includes both Niagara Mohawk and the service company.
Q All right. Okay. And is there -- are there different approaches in terms of what's included in the test year or rate year in terms of variable pay? Like the Public Service Commission has certain policies with respect to whether variable pay is recovered for utility employees from customers. Is this ringing a bell at all?

A   I know that they would have policies, but that would be part of Revenue Panel, and that should be taken up with Revenue.
Q   Okay.
MR. MAGER: Thank you.
ALJ BOUTEILLER: Mr. Walters?
MR. WALTERS: No, Your Honor.
ALJ BOUTEILLER: Anything further, then, with this witness? If not, you are excused, and we appreciate your testimony today, and thank you very much for all your patience.
THE WITNESS: Thank you.
ALJ BOUTEILLER: Let's go off the record, and let's impanel our next group of witnesses. Let's make sure there are enough chairs for them and make sure they are in their place before we go on the record.
(Discussion off the record.)
ALJ BOUTEILLER: Let me turn to the company and ask you to call your next witness, please, or next panel?
MR. GAVILONDO: Thank you, Your Honor. Carlos Gavilondo on behalf of Niagara Mohawk Power Corporation. And presenting for the Infrastructure & Operations Panel today on behalf of the company are

Ms. Ellen Smith, Mr. Keith McAfee and Mr. Bruce Walker. And if I may proceed, Your Honor, at counsel table with me is Ms. Catherine Nesser. And if I may proceed?

ALJ BOUTEILLER: If you've called your witnesses -- have you called your witnesses?

MR. GAVILONDO: I'd like to call them to the witness table.

ALJ BOUTEILLER: Okay. They've been called, and now I can ask you to rise, if you can raise your right hands, each of you.

(The Panel, as previously identified, was sworn and testified as follows.)

ALJ BOUTEILLER: Thank you. Please be seated. Please identify yourselves for the record by stating your name and your business address.

MS. SMITH: Ellen Smith, 40 Sylvan Lane, Waltham, Massachusetts.

MR. McAFEE: Keith McAfee, 1125 Broadway, Albany, New York.

MR. WALKER: Bruce Walker, Waltham, Massachusetts.

ALJ BOUTEILLER: We now will return to your counsel who will assist us in getting your testimony and your exhibits into the record.

MR. GAVILONDO: Thank you, Your Honor.

DIRECT EXAMINATION

BY MR. GAVILONDO:

Q Ms. Smith, could you please for the record indicate your title and your employer?

A (Smith) Yes. My title is Chief Operating Officer, U.S. Electric Operations, National Grid Service Company. I'm also an EVP of Niagara Mohawk Power Corporation.

Q Mr. McAfee, if you could, please, for the record indicate your title and your employer.

A (McAfee) I am vice president of operations for New York Eastern Division, and I am a Niagara Mohawk employee.

Q Thank you. Mr. Walker?

A (Walker) I'm the vice president for asset policy and strategy, and I'm a U.S. service company employee.

Q Are the three of you here today appearing on behalf of the company as what's been identified as the Infrastructure & Operations Panel?

A (Smith) Yes, we are.

Q Did the Infrastructure & Operations Panel prepare pre-filed testimony for this proceeding?

A (Smith) Yes, we did.

Q And I direct your attention to a document and I --

MR. GAVILONDO: Your Honor, if I may approach?

ALJ BOUTEILLER: Approach.

Q I call your attention to a document that consists of a cover page, a table of contents and 266 pages of questions and answers and ask you if you could please identify that for the record?

A (Smith) This document is the pre-filed direct testimony of the Infrastructure & Operations Panel dated January 29, 2010.

Q And was this testimony prepared by you or under your direction?

A (Smith) Yes, it was.

Q Do you have any changes or corrections to the testimony that you just identified?

A (Smith) Changes or corrections to our direct testimony are addressed in our subsequent submitted corrections and updates testimony and the rebuttal testimony.

Q If I were to ask you here today the same questions that appear in that testimony, would your answers be the same as they appear in your pre-filed direct testimony?

A (Smith) Yes.

Q Do you adopt this as your sworn testimony in this proceeding?

A (Smith) Yes.

MR. GAVILONDO: I ask that the testimony be entered into the record.

ALJ BOUTEILLER: Absent objection of the parties present in the room at this time, if there is no objection I will instruct the reporter to copy into the record as if given orally today the direct testimony that was pre-filed by this panel.

MR. GAVILONDO: Thank you.

(The referenced testimony is inserted into the record as follows.)

Before the Public Service Commission

NIAGARA MOHAWK POWER CORPORATION d/b/a NATIONAL GRID

Direct Testimony

of

The Infrastructure and Operations Panel

Dated: January 29, 2010

Testimony of the Infrastructure and Operations Panel

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Testimony of the Infrastructure and Operations Panel

I. Introduction and Qualifications

Q. Please introduce the members of the Infrastructure and Operations Panel.

A. The Panel consists of Ellen Smith, Bruce Walker and Keith McAfee.

Q. Ms. Smith, please state your name and business address.

A. My name is Ellen Smith. My business address is 40 Sylvan Road, Waltham, MA 02451.

Q. By whom are you employed and in what capacity?

A. I am employed by National Grid USA Service Company, and serve as Executive Vice President and Chief Operating Officer ("COO") for Niagara Mohawk Power Corporation d/b/a National Grid (the "Company"),[1] as well for Massachusetts Electric Company and Nantucket Electric Company d/b/a National Grid, in Massachusetts, Granite State Electric Company d/b/a National Grid, in New Hampshire, The Narragansett Electric Company d/b/a National Grid, Rhode Island, and New England Power Company, which owns and operates transmission

[1] Throughout this testimony, the panel will refer to National Grid plc as "National Grid," National Grid USA Service Company as "Service Company," and Niagara Mohawk Power Corporation d/b/a National Grid as "Niagara Mohawk" or "the Company." Service Company provides services to all of National Grid's U.S. affiliates, including Niagara Mohawk.

assets in Massachusetts, New Hampshire, Rhode Island, and Vermont. I am also responsible for operating the transmission, distribution and generation system on Long Island, New York as part of a service agreement with the Long Island Power Authority. As Executive Vice President and COO of National Grid plc's U.S. Electric Distribution, Generation and Transmission organization, I oversee approximately 6,000 employees and $11.7 billion of infrastructure assets serving over 4.6 million customers in the Company's U.S. service areas. In that capacity, I am responsible for all aspects of the Company's electric delivery system serving customers in Upstate New York, including the asset management, engineering, design, construction, operations and maintenance of the Company's electric distribution and transmission facilities.

Q. Please describe your educational background and business experience.

A. I am a graduate Onteora Central High School in Boiceville, New York, and attended Union College in Schenectady, New York, where I earned a Bachelor of Science degree in Mechanical Engineering and a Master of Science degree in Power Systems Engineering. I am a licensed Professional Engineer in New York State. Prior to joining National Grid, I worked for the Hess Corporation for 5 years as the President of Hess

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Microgen, which was in the business of building and servicing co-generation and small distributed generation facilities, and most recently, as the Vice President of Refinery Optimization, significantly improving the power and utility operations at the Hess Joint Venture Oil Refinery (HOVENSA, LLC) on St. Croix. Prior to Hess Corporation, I was President of Pratt &Whitney Power Systems for 5 years. I also spent over 18 years at GE Energy in various commercial and technical roles serving utility and industrial customers, and prior to that was with New England Power Service Company for 1 year as an associate engineer.

Q. Mr. Walker, please state your name and business address.

A. My name is Bruce Walker. My business address is 40 Sylvan Road, Waltham, MA 02451.

Q. By whom are you employed and in what capacity?

A. I am employed by National Grid as the Vice-President of Asset Strategy and Policy. In this capacity, I am responsible for analyzing reliability information throughout National Grid**,** establishing appropriate data governance to ensure the integrity and usefulness of the reliability data, developing appropriate asset strategies and policies consistent with the information obtained from analyzing the system and sustaining a viable network, and initiating research, development and demonstration projects for the distribution and sub-transmission systems throughout National Grid's service territory in the United States.

Q. Please describe your educational background and business experience.

A. I am a distinguished graduate of the United States Air Force Academy Preparatory School and thereafter received a Bachelor of Electric Engineering degree from Manhattan College and a Juris Doctor in Law from Pace University where I was the technical editor on the Environmental Law Review and received an Environmental Law Certificate. I also completed the 18 month Power Technologies Inc. (now Siemens Inc.) Distribution System Engineering course. Prior to beginning with National Grid in 2008, I worked in the utility industry for nearly 18 years for Consolidated Edison of New York, Inc. and Orange and Rockland Utilities in various capacities, including; various positions in Electric Operations, Mergers and Acquisitions, Regulatory Services and Emergency Management. I was appointed by the U.S. Secretary of Energy to the Electricity Advisory Committee in 2008 representing investor owned utilities and I was recently elected to the Board of Directors for GridWise Alliance.

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Q. Mr. McAfee, please state your name and business address.

A. My name is Keith McAfee. My business address is 1125 Broadway, Albany, NY 12204.

Q. By whom are you employed and in what capacity?

A. I am employed by Niagara Mohawk Power Corporation d/b/a National Grid. I am Vice President of Operations for the Eastern Division of New York. In that capacity I am responsible for the supervision of professionals and field forces who operate, maintain and construct the Company's electric infrastructure in that area.

Q. Please describe your educational background and business experience.

A. I graduated from Clarkson University in 1985 with a Bachelor of Science in Electrical Engineering. I received a Masters of Business Administration from New Hampshire College in Manchester, New Hampshire in 1991. I am a licensed Professional Engineer in New York State. I also completed the 18-month Power Technologies Inc. (now Siemens Inc.) Distribution System Engineering course.

Testimony of the Infrastructure and Operations Panel

I joined National Grid in 1992 as an Account Manager in Buffalo, NY. In 1994, I was promoted to Technical Services Manager in Albany, NY. In 1999, I was promoted to Regional Manger for the Northeast Region in Glens Falls, NY. In 2002, I was promoted to Director of Customer Operations for the Eastern Division of New York and in 2007 I was promoted to my present position Vice President of Operations, Eastern Division of New York.

Prior to National Grid, I was employed by Central Hudson Gas and Electric from 1985 through 1987 as an Associate Engineer in Newburgh, NY. Between 1987 and 1991, I held various operations management and engineering positions for Public Service Company of New Hampshire in Manchester and Nashua NH.

II. <u>Purpose of Testimony</u>

Q. What is the purpose of the panel's testimony?

A. The purpose of our testimony is to describe the Company's electric infrastructure investment and operations plan necessary to manage its electric system for the period covered by this rate case. The testimony includes a comprehensive overview and detailed description of the infrastructure investment plan for the rate period and the incremental costs

Testimony of the Infrastructure and Operations Panel

included as part of the operations and maintenance cost of service for the same period. The testimony also describes the methodology by which the Company manages the entire system and thereby develops and prioritizes its annual work plan and budget. Furthermore, we describe how the Company executes the annual work plan and key initiatives it is engaged in to manage its responsibilities.

Niagara Mohawk's service territory encompasses approximately 25,000 square miles in more than 450 cities and towns, and serves approximately 1.6 million electric customers. The Company's physical assets include more than 6,002 miles of transmission lines (4,815 miles of 115 kV lines, 504 miles of 230 kV lines, and 683 miles of 345 kV lines as of December 2008), and 313 transmission substations. National Grid has more than 4,500 miles of sub-transmission lines (3,400 overhead, 1,100 underground) on 64,000 towers/poles. These transmission and sub-transmission facilities serve 441 distribution substations supplying a distribution system consisting of more than 800 power transformers, 4,000 breakers, 42,800 circuit miles (35,900 overhead, 6,900 underground) of primary on over 1,200,000 poles and 442,000 line transformers.

Testimony of the Infrastructure and Operations Panel

Q. Please describe the Company's overall objective with the infrastructure and operations plan presented here.

A. Primarily, the plan is developed to meet our regulatory obligations which include providing safe, reliable, efficient, and environmentally sound electric service for customers at reasonable costs. The plan includes capital and operations and maintenance ("O&M") spending needed to meet state and federal regulatory requirements applicable to the electric system, address load growth/migration, maintain reliable service, sustain asset viability through targeted investments driven primarily by condition assessment, and fund those investments necessary to accommodate new public policy initiatives and technological developments, including the integration of renewables that affect the electric system.

Q. What format does the panel use to present the Company's infrastructure investment plan?

A. Our testimony presents the infrastructure investment plan in relation to the Company's fiscal year budgets. The Company's fiscal year is defined as the 12 month period from April 1 of a year, through March 31 of the following year, with the fiscal year being the end year. Thus, fiscal year 2010 ("FY10") would be the period April 1, 2009 – March 31, 2010. Throughout our testimony, we refer to budgets for the period FY11 – FY

14 (April 1, 2010 – March 31, 2014). These budget periods span the period covered by this rate case filing (January 1, 2011 – December 31, 2013).

The Company manages its infrastructure investment plan and other business operations on a fiscal year basis, and has presented prior investment plan information to the Commission and Department of Public Service Staff on a fiscal year basis for the past several years. Presenting the infrastructure investment information in this case on a consistent fiscal year basis facilitates comparison of the Company's current plan with prior submissions and investment requirements established by the Commission in other cases.

Although the Company's investment plan is presented on a fiscal year basis, the revenue requirement in this case is developed on a calendar year basis, as presented in the testimony of the Revenue Requirements Panel. The effect of the Company's capital investments on revenue requirements is affected by the estimated in-service dates for such investments. Our testimony describes briefly how in-service dates were determined for the infrastructure investments presented in the plan, and a more detailed discussion is also presented in the testimony of the Revenue Requirements Panel.

Q. How much is the Company planning to invest through its infrastructure investment plan during the FY2011-FY2014 period?

A. Niagara Mohawk plans to invest $424 million to improve its electric delivery infrastructure in fiscal year 2011 ("FY11"), $536 million in FY12, $613 million in FY13 and $635 million in FY14. In FY 2010, it estimates it will spend $378 million. Exhibit __ (IOP-1) depicts forecast and planned capital investment for the period FY10-FY14, on the basis of investment category as well as network segment. This exhibit also includes electric infrastructure program and project detail information which is described and referenced later in our testimony. The investment categories used by the Company in development of its infrastructure investment plan are also described in detail, below.

Q. Do the investment levels you mention include all of the capital investment reflected in the Company's revenue requirements in this case?

A. No. The annual infrastructure investment amounts mentioned do not reflect costs associated with the payment of $35 million associated with

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the Tri-Lakes project, or $57 million associated with the Luther Forest Technology Campus, each of which is described in detail in our testimony. In addition, the Company plans to make facilities and properties related capital investments during the rate plan period, as well as investments in information systems and technology, fleet, inventory management and investment recovery functions. These investments are needed to enable the Company to continue to provide safe and reliable service to customers, and are key to the Company's infrastructure and operating plans going forward. The levels of planned capital investments in properties and facilities are set forth in Exhibit __ (RRP-6), Schedule 1, Sheet 4, of the Revenue Requirements Panel's testimony, and are approximately $36.4 million in FY11, $32.4 million in FY12, and $4.4 million in each of FY13 and FY14. Additionally, planned Information Systems capital investments equal $5.1 million in FY11, $4.2 million in FY12, and $4.1 million in FY13. Finally, our testimony supports capital investment of approximately $0.6 million annually related to fleet services, inventory management and investment recovery.

Q. Does the Company's filing in this case reflect the amount of capital investment anticipated in the period from the end of the historic test year until the start of FY 2011?

Testimony of the Infrastructure and Operations Panel

A. Yes. The historic test year ended September 2009, and the investment plan period described in this filing commences April 1, 2010. For the period October 1, 2009 – March 31, 2010, the Company anticipates capital spending of $229 million on electric infrastructure and general plant, $4.5 million on Information Systems, and $11.3 million on facilities. These amounts are reflected in Revenue Requirements Panel Exhibit __ (RRP-6), Schedule 1, Sheet 4, and the supporting workpapers.

Q. How does the Company's infrastructure plan presented in this case compare to previous plans the Company has developed?

A. Our testimony describes how the infrastructure plan was developed and how it is structured. In those regards, the plan presented here is similar to prior plans. However, the plan presented here is a substantial reduction from previously developed plans which the Commission and its Staff have seen. The current plan reflects the Company's attempt to minimize the level of investment needed during the rate plan period, consistent with its obligation to continue to provide safe and reliable service, in order to mitigate the rate impact on customers. The Commission and its Staff have sent clear messages on the need for the State's utilities to take steps to practice austerity and to manage rate impacts to address the needs of customers during the current economic downturn, and the Company's current infrastructure plan is a response to those messages.

The plan that we are filing does not represent what we believe to be an optimal level of infrastructure investment. In January 2009, the Company filed its five-year Capital Investment Plan reflecting planned electric infrastructure investment of $3.57 billion for the period FY10-FY14. Throughout 2009, the Company continued to evaluate and refine its investment plan as it developed or became aware of new information and circumstances. In December 2009, the Company met with Staff and presented an infrastructure investment plan that reflected a substantial reduction from the investment levels included in the Company's January 2009 Capital Investment Plan filing in Case 06-M-0878. The reductions reflected our effort to reduce investment costs to a minimum level consistent with maintaining near-term reliability and sustaining the system over the rate plan period. We took this action mindful of reducing rate impacts to customers. The December plan presented to Staff continues to represent what we believe to be a preferred level of capital spending even in these difficult economic times. Nonetheless, in response to Staff's feedback and the Commission's December austerity order, we are proposing in this case a plan that reduces our proposed level of capital investment further, resulting in a proposed level of investment of $2.3 billion (including the Luther Forest and Tri-Lakes projects) for the FY11-FY14 period. Exhibit __ (IOP-2) provides a comparison, by year, of the infrastructure investment plan reflected in this rate case and the Company's January 2009 Capital Investment Plan filing.

Q. Could you provide examples of changes reflected in the plan presented here compared to what the Company presented to Staff in December?

A. The Company carefully evaluated its investment plan to identify projects that could be deferred or re-phased without substantially reducing near-term reliability or risking non-compliance with mandatory requirements. Over the current Company's 5-year capital budget cycle (FY11-FY15), we identified deferrals of over $350 million of work from the December 2009 plan presented to Staff. Some of these deferred projects include: Ticonderoga Lines rebuild (moved out to FY14+); Priority 3 & 4 Oil Circuit Breakers (reduced and moved out to FY14+); Gardenville-Homer Hill 151/152 phase 2 (moved out to FY14+); Rotterdam Station rebuild (moved out to FY14+); and strategy to reinforce the transmission system in the Frontier and Southwest regions (N-1), (N-1-1) (re-phased).

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Although our proposed plan carries with it increased reliability risks, all else being equal it should enable us to meet the reliability targets that we are proposing for the period of this rate case. It should be noted, however, this plan reflects a minimum level of spending necessary to maintain reliability in the near term. Ultimately, the investments removed from this plan will need to be addressed to sustain reliability in the future as the reduced capital spending in this plan is largely the result of deferring work.

Q. What value will the Company's proposed capital investment plan provide to customers?

A. Our proposed capital investment plan reflects the minimum level of spending that is consistent with achieving our proposed reliability targets in the near-term and making small progress towards addressing some of the longer term reliability risks faced by our customers. The plan will permit us to meet statutory and regulatory requirements and to replace equipment that is damaged or that fails. It will also permit us to address a limited set of system capacity and performance issues and asset condition problems. An optimum level of investment would remediate more system capacity and performance issues and asset condition problems. The proposed plan thus strikes an uncomfortable but reasonable balance between reliability and austerity. It holds costs to customers to the minimum reasonable level consistent with near-term reliable service.

Q. What would be the consequences to customers of deferring by a year some of the projects included in your proposed plan?

A. This question is best answered by discussing the categories of investments that we would defer if the Commission were to approve a lower level of investment than we are proposing and the consequences of deferring those investments.

The Company's plan is developed on the basis of five primary investment drivers, or categories, and is presented in that manner in this testimony. These categories, which are described in detail later in our testimony, are: (1) Statutory or Regulatory Requirements; (2) Damage/Failure; (3) System Capacity and Performance; (4) Asset Condition and (5) Non-infrastructure. Investments in these categories range on a spectrum: work in the Statutory or Regulatory Requirements and Damage/Failure categories is considered mandatory, while work in the System Capacity and Performance and Asset Condition categories is more discretionary. Non-infrastructure work supports work in the other categories.

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As indicated in Exhibit __ (IOP-1) schedule 1, sheet 1 of 1, almost 45 percent ($983 million) of the planned infrastructure spending will be mandatory work in the statutory/regulatory requirements and damage/failure categories. Examples of investments in this investment category include work on Niagara Mohawk's Clay and Porter substations to bring them into compliance with Northeast Power Coordinating Council ("NPCC") design, protection and operation standards, or capital work done to repair a portion of a distribution feeder damaged in a storm event or extend service to new customers.

This work could not be deferred for a year without potentially violating mandatory reliability standards, degrading near-term service reliability to existing customers or delaying service to new customers.

The system capacity and performance category accounts for approximately 23 percent ($502 million) of the total spending, and includes such things as investments to ensure substations and feeders can reliably supply customer load within system design criteria. Examples of investments in this category include planned expansions and network upgrades to accommodate load growth associated with the new University of Buffalo Medical Complex, expansion of the Albany Medical Center and St. Peter's Hospital, and the medical complex in the Syracuse University area.

The asset condition portion of the plan represents nearly 32 percent ($690 million) of total planned spending for the FY11 to FY14 period. Programs in this category aim to mitigate future risks and consequences of potential failures caused by deteriorated assets. An example of a program in this category is the rebuilding of the Gardenville station, which is a 230/115kV complex south of the Buffalo area. This part of the network includes a substation that feeds regional load via eleven 115kV lines, and that has serious asset health issues including, but not limited to, control cable, breaker, disconnect and foundation problems. The station has had no major upgrades since it was built in the 1930s.

Deferring capital investment on projects in the system capacity and performance and asset condition categories would create greater reliability risk. The Company has more discretion with respect to the timing of when to proceed with investments on projects in these two categories than on projects that are in the statutory/regulatory requirements or damage/failure categories. If the Commission were to approve a lower level of capital investment than the Company is proposing, the additional work that we would defer would generally be those in these two categories. However, the proposed projects in the system capacity and performance and asset condition categories would still need to be done. Deferring them by a year or more would increase risk. There is not a direct correlation between levels of investment in a particular year and the corresponding reliability performance in that year. What we know, however, is that the system capacity and performance and asset condition projects included in our plan are only a subset of all the system capacity and performance and asset condition projects that have been identified by the Company. The ones included in the plan are included precisely because they are the ones that we have determined carry the greatest risk to reliability, safety or the environment. They are included in the plan because we have concluded that deferral is not an appropriate option even during this time of austerity.

A detailed discussion of the spending categories, as well as the underlying investments that make up these categories is included as part of the detailed infrastructure investment section of this testimony.

Q. Please summarize the panel's testimony regarding the costs of operating the electric system.

A. In addition to supporting the Company's infrastructure plan and other capital investments, we also address major expenses associated with operating the Company's electric delivery system, and in particular we describe incremental operations and maintenance ("O&M") expenses the Company expects to incur in connection with operating its electric system during the rate plan period as compared to corresponding O&M expenses in the historic test year period. Among the major O&M expense changes we describe in our testimony are:

- Increased costs from enhanced inspection and maintenance requirements;
- Tower painting and comprehensive aerial patrol, and footer inspection costs;
- Costs associated with enhanced vegetation management;
- Increased O&M and labor expense relating to the level of infrastructure investment;
- A proposal to implement a fully reconciling "storm fund" to reflect more accurately the historic expenses incurred in connection with extraordinary storm events; and
- Increased site investigation and remediation (environmental) costs.

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A detailed discussion of the major expenses is included as part of the Operations and Maintenance Expenses section of this testimony.

Q. Does the panel propose any tracking mechanisms related to capital or operating expenses presented in this plan?

Yes, the panel proposes a mechanism for tracking and reconciling certain deviations from capital investment budgets, including costs related to third-party activities outside the Company's control that affect the Company's operation of the electric system (e.g., third-party transmission-related costs). Details on the tracking mechanism and its operation are included in the testimony of the Revenue Requirements Panel.

Q. Does the panel address the recommendations presented in the recent Comprehensive Management Audit Report in Case 08-E-0827?

A. In accordance with the Order issued and effective on December 18, 2009 in Case 08-E-0827, the Company has developed an implementation plan addressing the recommendations presented in the management audit report. A copy of that plan is being filed in that case, and is also included as an exhibit to the testimony of Mr. Peter Zschokke in this case. As Mr. Zschokke's testimony describes, the Company has commenced implementation of several of the recommendations in the management audit report, including recommendations affecting the implementation of infrastructure investment plans and electric system operations. Although our testimony touches on some of the recommendations in the report and some of the things the Company is doing to address those recommendations, details of the Company's specific proposed implementation steps associated with individual audit recommendations are set forth in the implementation plan included with Mr. Zschokke's testimony.

Q. Does the Company discuss measures it is taking in response to the Commission's December 22, 2009 Order Approving Ratepayer Credits in Case 09-M-0435?

A. Yes. The Company continually seeks to improve efficiency in service, and our testimony describes some of the Company's cost-containment efforts needed to achieve its ambitious performance and productivity objectives. In addition, however, and in response to the Commission's directive, the infrastructure investment and operations plan in this case reflects further efforts by the Company to identify cost savings measures that would inure to the benefit of customers during the rate plan period, and we describe some of those efforts and considerations in our testimony.

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In some cases, the deferral of infrastructure investment will require interim mitigation operations and O&M spend.

Q. Are you sponsoring any exhibits as part of your testimony?

A. Yes. In connection with our testimony, we are sponsoring the following exhibits, which were prepared by one or more members of the panel or under their supervision and direction:

Exhibit __ (IOP-1): Forecast and planned T&D infrastructure investment levels by category, FY10-FY14;

Exhibit __ (IOP-2): Comparison of T&D Capital Expenditures FY10-to-FY14; NMPC Rate Case Filing vs. January 2009 CIP Filing;

Exhibit __ (IOP-3): Electric Reliability Performance 2005-2009;

Exhibit __ (IOP-4): Illustration of the project evolution process;

Exhibit __ (IOP-5): Facilities and properties capital expenditures;

Exhibit __ (IOP-6): Summary listing of information system projects;

Exhibit __ (IOP-7): January 15, 2010 Mobile Stray Voltage Testing Project report;

Exhibit __ (IOP-8): Inspection and maintenance incremental cost support;

Exhibit __ (IOP-9): Incremental cost support for tower painting; comprehensive aerial inspections; and footer inspections;

Testimony of the Infrastructure and Operations Panel

Exhibit __ (IOP-10): Incremental cost support for vegetation management activities;

Exhibit __ (IOP-11): Calculation of Storm Fund level;

Exhibit __ (IOP-12): Schedule of site remediation activities; and

Exhibit __ (IOP-13): Summaries of planned research, development and demonstration projects.

The Panel also includes workpapers in the form of the Company's Annual Transmission and Distribution Capital Investment Plan, filed in Case 06-M-0878, on January 29, 2010, the Report on the Condition of Physical Elements of Transmission and Distribution Systems, filed in Case 06-M-0878 on October 1, 2009 and supporting strategies, all of which are collected in Exhibit __ (IOP-14).

Q. How is the remainder of your testimony structured?

A. The remainder of our testimony includes:

- A summary of Niagara Mohawk's approach to managing the electric system;
- A description of the Company's infrastructure investment plan, including a description of major programs and projects driving the investment plan;

- A description of the Company's facilities and properties plan over the period covered by this case;
- A listing and description of the major information systems projects to be implemented during the rate plan period that are needed to implement Niagara Mohawk's infrastructure and operating plans;
- A description of the Company's O&M expenses, and particularly significant changes or initiatives driving known and measurable changes in costs in the period covered in this case as compared to the historic period;
- Descriptions of planned research, development and demonstration initiatives associated with the electric system;
- A brief description of efforts the Company undertakes in the areas of safety and environmental stewardship; and
- A request for modification of certain reporting requirements.

III. <u>The Company's Approach to Managing the Electric System</u>

Q. Describe the Company's philosophy and objectives underlying the development of its infrastructure investment and system operations plans.

A. As an energy delivery company, Niagara Mohawk's fundamental goal is to provide safe, reliable, environmentally sound and efficient electric service to customers at reasonable cost. In recent years, achieving this goal has become an increasing challenge for a variety of reasons. These include the deteriorated condition of many of our electric delivery system assets (consistent with their age profile), the obsolescence of various classes of assets, the need to accommodate changing and dynamic power flows, increasing power quality and reliability demands of our customers, volatility in the availability of and competition for commodities and equipment, and uncertainty in the economic, policy and technological climates influencing the electric utility industry. Looking forward, it is our sense that these challenges will only intensify, driven by public policy and legislative initiatives promoting new technologies, continued focus on energy efficiency, as well as a need to support societal efforts on climate change and environmental issues. It is within this challenging and dynamic framework that the Company develops and continually refines its infrastructure investment and operations plans.

Q. Describe the Company's approach to managing the electric system.

A. The Company's approach to managing the electric system has evolved over time. Over the past several years, the Company has shifted its operating focus from a reactive, repair-oriented approach to one driven by a well-defined asset management framework that embraces a portfolio of asset management techniques. In the past, the Company, like many other electric utilities, conducted much of its infrastructure maintenance and replacement activities based on the results of periodic engineering studies of asset performance or known operating deficiencies, rather than on the basis of data collected using a systematic process of inspection, data collection, and analysis.

The term “Asset Management” describes the systematic and coordinated activities and practices through which an organization optimally and sustainably manages its assets and asset systems, and their associated performance, risks and expenditures over their life cycles for the purpose of achieving its organizational strategic plan. Specific to the Company, this can be summarized as; the process used to manage the Transmission and Distribution system infrastructure and the electric system to ensure safe, reliable, efficient and cost effective service over the life cycle of the assets and asset systems. This includes work aimed at alleviating loading constraints and increasing capacity in specific areas to improve the reliability of service as well as asset condition projects aimed at rebuilding or upgrading system elements such as overhead lines, underground cables, substation equipment and network control systems. The Company adopted the asset management approach because it is best suited to manage a large number of physical assets and provides the best long-term value for customers.

The systematic approach associated with the asset management process targets specific assets for intervention based upon their condition. Candidates for intervention are selected based upon their current performance or condition and their forecast performance and condition based on known degradation mechanisms. Although age alone is not a reliable indicator of condition, it is an important factor when considering the volumes of assets that need to be managed to ensure long-term sustainability with acceptable reliability performance. Age is also an important attribute to assess assets that are beyond design life, at the end of useful life and/or obsolete, making maintenance cost-prohibitive or impossible.

The Company's Asset Management process includes developing "strategies." Strategies are documented standards or policies (Company or industry) against which assets and/or asset systems are assessed with respect to condition, performance, capacity and other factors. Strategies define "what" will be done, by setting forth systematic, coordinated activities and practices designed to result in the optimal management of

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assets and asset systems over their respective life cycle, to address either deficiencies in asset condition and performance, or non-compliance with internal and / or mandatory external planning standards. Strategies incorporate information obtained from system studies, industry knowledge, trend analyses and inspection, maintenance and replacement programs in order to achieve specific operating objectives for the respective asset class or asset system. Strategies result in implementation plans, in the form of programs or projects. These programs and projects describe 'how' the Company executes its Strategies and thus plans to manage and optimize asset performance and lifecycles. For example, the Overhead Line Refurbishment Strategy describes the efforts the Company will utilize to manage its overhead transmission line assets over the next 25 years based on an understanding of current conditions and forecast deterioration. Based on this strategy, a portfolio of approximately 30 projects has been defined to address what needs to be done for individual overhead lines to achieve the overall objective of the overhead line refurbishment strategy.

The Company's systematic approach to asset management uses a consistent scoring system that prioritizes all assets for replacement or upgrade based upon the likelihood and consequences of failure, and criticality to the system. Using this approach, the highest priority assets (i.e. those with the highest risk score and potential adverse impact to system safety, reliability, and the environment) are replaced first.

Q. What prompted the Company to move to a proactive, asset-management approach?

A. Infrastructure businesses throughout the world that manage large volumes of similar assets use asset management principles to manage asset life cycles in order to reduce the potential for unplanned failures, or having large populations of assets fail contemporaneously, requiring significant replacements over short periods of time. Such situations are highly undesirable since the lead time for major equipment (e.g., high voltage circuit breakers and power transformers) and work delivery (e.g., transmission line work) can easily be several years. Over the past ten years, the Company has seen increasing evidence of deteriorating conditions and performance on its system. Such deterioration is not out of the ordinary[2]; indeed, some deterioration is to be expected with greater service factor and age of an asset. Because of the long service lives of

[2] As noted in the Energy Infrastructure Issue Brief developed in connection with the State Energy Plan process, portions of the State's transmission and distribution system are in need of attention to ensure reliability in the future, as evidence by investor-owned utilities' plans to spend $13 billion over the five-year period between 2009 and 2013. See, http://www.nysenergyplan.com/final/Energy_Infrastructure_IB.pdf , p. 19.

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many of the Company's assets, and the fact that many assets were nearing the end of their service lives, the Company needed to adopt a systematic and proactive asset management approach or face the potential for a future "wall" of unplanned asset replacement due to failure.

Q. Can you provide an illustration of your statement regarding the deteriorating conditions of assets on the Company's system, and how a proactive asset management approach might serve to address the situation?

A. Replacing and renewing assets in a systematic manner is advantageous in at least two significant scenarios: one associated with low cost, large volume assets; and the other with high cost, lower volume assets. Regarding the low cost/large volume items, failure to replace these assets in a timely manner will result in a huge number of assets whose asset class becomes so aged that the volume of assets to be replaced at some point in the future will be insurmountable. Steel towers and power transformers will be discussed as examples of both these scenarios.

Niagara Mohawk's steel tower asset base is in excess of 20,000 towers. The average age of steel towers on the Company's system is 68 years, with more than 67 percent of 115 kV structures being over 70 years old.

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Again, although the age of a system component is not necessarily indicative of its condition or usefulness in serving customers, it is significant that a large segment of the component population is reaching the end of its useful life, anticipated to be in the range of 70-90 years. As the proportion of assets reaching the end of their anticipated service lives increases, proactive steps must be taken to reduce the compounding risk of unacceptable service consequences that could result from a high concentration of age-related equipment failure. The Company's steel tower strategy involves inspecting all towers on a 5-year cycle and rating each based on defined criteria, maintaining the towers through a painting and footer inspection/repair process, and replacing any towers rated in poor condition.

For high cost, lower volume assets, a systematic asset management approach will provide significant benefits since the challenges to replace these assets when they fail are complex and high cost. One example is the Company's power transformers at substations. Power transformers provide service to many thousands of customers and are the single largest capital investment in substations (which are the largest, most expensive and most complex portion of the distribution system in their own right) comprising almost 40 percent of the total investment. Power transformers deteriorate (degrade) with time and thermal operation because paper is a key component of insulation (which is a key component within the transformer) which suffers deterioration as a result of three key processes: oxidation, hydrolysis and thermal heating. The deterioration is cumulative and irreversible and thus cannot be addressed via maintenance. Nearly 50 percent of our approximately 807 substation transformers are greater than 50 years old. Thus, in twenty years, if the Company replaced 4 substation transformers per year in this age grouping (the average historical replace rate), it would still have 40 percent of transformers (or 323 units) greater than 70 years old and in total nearly 600 units (or almost 75 percent) would be greater than 50 years old. The Company's ability to efficiently and effectively replace the large number of complex assets would be compromised under such a trajectory, and system reliability and performance would be difficult to sustain. To address this situation, the Company has developed a transformer asset strategy to replace approximately 150 transformers over the next fifteen years (an average of ten transformers per year) to keep up with the aging population and to lessen the risk of unplanned failures.

Waiting to replace on failure is also not an acceptable method of managing large power transformers due to safety and environmental reasons. While

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the majority of power transformers fail internally, occasionally a unit may fail catastrophically, resulting in release of a large quantity of oil into the surrounding environment, or causing a fire that destroys much more than the transformer itself, such as happened at the Company's New Scotland station in 2004.

Q. Can you provide examples of what the Company has done to gain a better understanding of the condition of its transmission and distribution assets in order to implement the current proactive asset management approach?

A. Critical to any systematic and coordinated asset management process is a comprehensive understanding of the condition and performance of the physical assets over their life cycle. Good decision making requires adequate information about the assets and their associated strengths and weaknesses. In particular, it is important to understand the relationship between short-term asset management activities (maintenance, refurbishment, replacement, etc.) and their actual or potential effect upon long-term costs, risks and performance.

Historically, a substantial portion of infrastructure investment was driven by a run-to-fail and fix-on-fail methodology. Because of observed deteriorating reliability performance, and the need to provide customers with sustainable electric service, the Company implemented the proactive asset management approach based upon the principles of the Publicly Available Specification (PAS 55), "Specification for the optimized management of physical assets." PAS 55 was first published in 2004 in response to demand from industry for a standard for infrastructure asset management. PAS 55 specifically is intended to address the life cycle management of assets. Using the PAS 55 principles, the Company has implemented a process of collecting data and evaluating electric system assets through a number of inspection and monitoring programs, including:

- Dissolved Gas Analysis for all substation transformers and load tap changers;
- Aerial helicopter surveys of sub-transmission rights-of-way,
- Acoustic detection and partial discharge testing at metalclad substations;
- VLF (Very Low Frequency) testing of cables;
- Stabilized video surveys, enhanced infra-red surveys and aerial laser surveys of transmission lines;
- Substation condition assessments; and
- Asset health reviews.

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The collection of condition and performance data, and the interpretation of the data to generate useful and meaningful information to guide asset management decisions, are ongoing activities to enable improved risk management. Risk management is an important foundation for proactive asset management. This approach results in defined programs and projects that reduce overall risk.

In addition to several tools and systems the Company has introduced over the past several years to improve its understanding of system condition and performance, the Company has also introduced annual asset health reviews for all its transmission and distribution substation and overhead line equipment. This annual asset health review forms the basis of the annual "Report on the Condition of Physical Elements of Transmission and Distribution Systems" filed with the PSC (and which is included with our workpapers). The asset health review provides a methodology for identifying past or existing nonconformities with respect to defined strategies. The review also captures any asset-related deterioration, failures or incidents. The review provides leading performance indicators to provide warning of potential non-compliance with performance requirements and lagging performance indicators to provide data about incidents and failures. The asset health review provides both qualitative and quantitative measures and forms the basis of many of the Asset Condition driven infrastructure investments.

Q. What has been the result of the proactive asset management approach the Company adopted?

A. Following a period of declining reliability performance in the early 2000s, the Company has demonstrated steady reliability improvement from 2004 through 2008. Preliminary results for 2009 indicate that the Company again achieved its reliability performance targets. Exhibit __ (IOP-3) depicts the Company's reliability performance against established targets for the calendar years 2005 through 2009. The Company's reliability performance is in large part a result of its proactive asset management approach, as well as a number of other initiatives aimed at making the system more robust and resilient.

IV. Description of Niagara Mohawk's Infrastructure Investment Plan

Q. Describe the Company's infrastructure investment plan.

A. As described previously, the Company takes a comprehensive and integrated approach to managing its infrastructure investment. That effort results in, among other things, an infrastructure investment plan that categorizes planned investments on the basis of the primary drivers for those investments. The five primary investment drivers the Company has established for its infrastructure investment plan are: (1) Statutory or Regulatory Requirements; (2) Damage/Failure; (3) System Capacity and Performance; (4) Asset Condition; and (5) Non-infrastructure.

Q. Please describe what is included in the Statutory or Regulatory Requirements category of work.

A. Statutory or Regulatory requirements work includes capital expenditures required to respond to, or comply with statutory or regulatory mandates. These include those expenditures needed to ensure compliance with the requirements of the North American Electric Reliability Corporation ("NERC"), NPCC, New York State Reliability Council ("NYSRC"), the Occupational Safety and Health Administration ("OSHA"), and the New York Public Service Commission. It also includes expenditures that are part of the Company's regulatory, governmental or contractual obligations, such as responding to new customer service requests, transformer and meter purchases and installations, outdoor lighting requests and service, and facility relocations related to public works projects. For the most part, the scope and timing of this work is generally defined by others and is non-discretionary for the Company.

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Q. What capital expenditures are included in the Damage/Failure category?

A. Damage/Failure category projects are those capital expenditures required to replace failed or damaged equipment and to restore the electric system to its original configuration and capability following equipment damage or failure. Damage may be caused by storms, vehicle accidents, vandalism or unplanned/other deterioration, among other causes. The Company views the Damage/Failure category as a mandatory category of work that is non-discretionary in terms of scope and timing.

Q. Please describe the type of projects included in the System Capacity and Performance category.

A. System Capacity and Performance projects are required to ensure that the electric network has sufficient capacity to meet the growing and/or shifting demands of our customers. Projects in this category are intended to reduce degradation of equipment service lives due to thermal stress and to provide appropriate degrees of system configuration flexibility to limit adverse reliability impacts of large contingencies.

In addition to accommodating load growth, the expenditures in this category are used to install new equipment such as capacitor banks to maintain the requisite power quality required by customers and reclosers that limit the customer impact associated with a service event. It also includes spending to improve the performance of the network such as the reconfiguration of feeders and the installation of feeder ties.

Q. Please describe the type of projects that the Company would classify as being driven by Asset Condition.

A. Asset Condition expenditures are those investments required to reduce the risk and consequences of unplanned failures of transmission and distribution assets. As discussed above, the Company has adopted an asset management approach that relies on a holistic, longer-view assessment of assets and asset systems to inform capital-investment decisions. The Company conducts an annual asset health assessment which includes analysis of each major asset class and asset system. The assessments focus on identification of specific susceptibilities (failure modes) and the development of alternatives to avoid such failure modes.

Q. Please describe the type of projects that the Company would classify as "non-infrastructure ."

A. In addition to the direct spending on its electric network, the Company also invests a portion of its investment budget in systems, tools, and general plant that are required to operate the network. The "non-infrastructure" category of investment is for those capital expenditures that do not fit into one of the foregoing categories, but which are necessary to run the electric system. Examples of work in this category include spending for radio systems and test equipment, flood mitigation work at substations and capital repairs on substation buildings.

Q. Aside from the five investment drivers you have described, please discuss some of the Company's other considerations in the development of the infrastructure investment plan presented in this case.

A. All of the Company's recently developed investment plans reflect a disciplined and systematic approach to asset management in order to ensure the sustained safety, reliability and efficiency of the system. The plan presented in this case is similarly focused. However, in producing this current infrastructure investment plan, the Company was particularly mindful of the economic circumstances facing its customers. The Company thus challenged itself to include in the infrastructure investment plan only those programs and projects it determined to be essential or required during the period covered by the plan. Accordingly, the Company has identified opportunities to defer or reduce the scope of certain programs, such as the redesign of portions of the sub-transmission system to a looped system, and the distribution substation transformer replacement program, in order to mitigate the impact of potential rate increases on customers. As noted above, and in Exhibit __ (IOP-2), we have reduced our proposed level of capital investment in FY10-FY14 by $888 million from the level included in our January 2009 plan filed with the Commission, and substantially below our preferred level of spending presented to Staff in December 2009 after taking into account the difficult economic times. The near-term savings opportunities from such deferred investment, however, are not avoided costs. Work that is deferred from the work plan presented in this case will be required to be included in a future plan.

Failure to adequately invest in the system will also present increased risk leading to reduced reliability, and the condition of certain assets will continue to deteriorate. The Company is aware that it has the responsibility to manage these risks. This plan enables the Company to manage near-term reliability, safety and environmental risks while allowing limited progress in addressing the longer-term risks.

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Q. In addition to taking a hard look at the Company's plan, what other factors contributed to reduction in the overall investment plan compared to prior plan levels?

A. The current infrastructure investment plan reflects updated economic inflation assumptions. The updated inflation adjustment reflects the recent downturn in global economies from the high inflation levels experienced a couple of years ago, and has the effect of reducing the investment level somewhat.

However, aside from such external factors, the Company also aggressively pursues continuous improvement and efficiency efforts which help it contain costs and present this reduced level plan. Such factors include a new Procurement Transformation Program, aimed at leveraging the organization's large scale to improve materials sourcing and supplier relationship management. The cornerstone of the procurement transformation process is improved strategic sourcing to drive cost savings by leveraging our scale, standardizing materials and processes, and managing demand. The program also focuses on relationship management for our strategic suppliers, aimed at improving quality, customer service, cost and innovation, and on developing improved market intelligence to support our strategic sourcing process. Underpinning the procurement transformation program is the implementation of new technologies to support the improved processes.

Another initiative the Company is undertaking to reduce costs is the introduction of Distribution Alliance Contracts and Transmission Regional Delivery Ventures ("RDV"). The RDV and the Distribution Alliance contract models, which are described in detail later in our testimony, offer the Company additional tools to enable it to reduce the costs of delivering the infrastructure investment plan.

The Company is also transforming its electric operations to improve the level of service to customers, while promoting increased safety, network reliability and performance, and efficiency. As part of this effort, know as Transformation, the Company is addressing, among other things, work management, design, construction, asset management, network operation and customer management to optimize the efficiency and effectiveness of the organization.

Q. Could you please describe the Company's Transformation efforts in more detail?

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A. The central focus of Transformation is to promote a high performing organization that delivers value to customers at a high level of operational efficiency. The Transformation effort is currently focused in six core areas:

- *Asset Management*: Aimed at improving long-term planning efforts, which will enable the Company to enhance efficiencies in capital allocation and resource planning for system assets.
- *Customer Management*: Developing a Customer Order Fulfillment function to manage the customer relationship from initial inquiry to delivery of the first bill, which will streamline interactions with customers and increase customer satisfaction.
- *Contracting Strategies*: Establishing new performance-based construction contracts that encourage effective management and delivery of construction and maintenance services (e.g., the new RDV initiative mentioned above).
- *Work Delivery*: Establishing streamlined processes to ensure optimized work flow and resource utilization. Greater efficiency will be achieved in readying crews and equipment for deployment in the field and focus will be placed on crew productivity and safety.

- *Construction Design*: Creating design centers of excellence to standardize the design process and improve efficiency.
- *Network Operations*: Consolidating and standardizing network control centers and adding advanced distribution automation technologies to increase efficiency and improve service reliability.

Q. Could you provide examples of the ways in which operational efficiencies and long-term cost containment will be achieved through Transformation?

A. Specific examples of cost-containment efforts would include:

- *Centers of Excellence*: The Company's analysis shows that design personnel may spend up to 40 percent of their work day responding to customer queries for information. The Company is implementing a customer order fulfillment function to handle these customer inquiries, which will enable the design staff to focus most of their time on completing design activities. This change would not only reduce design costs (by increasing productivity of the current work force), but also improve the customer experience since the customer would have access to more resources specialized in customer interactions. The Company has created an Estimating Center of Excellence to focus on the process and delivery of high quality, timely, and more accurate project and program estimates. Improving the quality of estimates translates into a more accurate overall capital plan budget. The Company is centralizing administrative support services for field operations. This change is removing administrative work from field (now referred to as performance supervisors) supervisors in order to increase the amount of time supervisors spend in the field. This greater level of productivity will ensure improved work flow, safety assurance and productivity. Centralizing the transactional work will ensure adherence to standard processes resulting in improved accuracy, timeliness and completeness of information related to work performed, assets placed in service, and other company records.

- *Integrated Strategic Planning*: The Company is implementing new integrated planning processes to support both the long-term (up to 15 years) and short-term (0-18 months) project horizons. This change will have the effect of allowing for the more efficient planning and allocation of resources, improved procurement strategies and better contracting decisions. For example, with a longer term planning horizon, the Company will be in a position to secure longer term pricing arrangements, which are typically more cost-effective than short-term strategies.

- *Improved Work Processes*: The Company's evaluation of existing processes shows that field staff productivity can be improved through the completion of ancillary tasks such as stocking and preparing vehicles by employees other than those performing work in the field. The Company has identified new roles and responsibilities to address these opportunities, including: creation of a work readiness role that will prepare trucks and work assignments for daily crews; enabling performance supervisors to be in the field with the crews providing for visibility and coaching; and scheduling and preparing for a four week look ahead work plan.

Q. Will the Company incur costs in order to accomplish some of the changes that are necessary to achieve long-term cost reductions and productivity gains?

A. Yes it will. Although efficiency gains may be achieved through process changes and organizational tactics that do not involve significant costs, more significant efficiency gains require up-front investment in systems and equipment to automate work processes, improve worker productivity in the field, and achieve the Company's targeted level of productivity improvements.

Q. What are some of the key investments the Company is making as part of Transformation?

A. Costs associated with delivering the savings expected from Transformation include costs of new technology and systems, labor associated with implementing the new systems and processes, consultant and contracting costs, revised collective bargaining agreements, facility consolidation costs, and employee costs (for relocation, retention and severance). In return for these investments, the Company expects to achieve costs savings from the automation, standardization and integration of business processes and related information systems. Automation will require significant investment to purchase or modify the respective information-system technologies and resulting cost reductions benefit customers. In addition, the Company plans to continue to explore opportunities to leverage the scale of National Grid when making technology, organizational and process investments in similar shared services (e.g., procurement, fleet and IS).

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All these factors have been taken into account and are reflected the infrastructure investment plan submitted in this filing.

Q. Has the Company prepared an exhibit listing the electric system infrastructure investments it has planned for the period covered in this case?

A. Yes. Exhibit __ (IOP-1), Schedule 8 is a 26-page table listing all programs and projects included in the investment plan reflected in this rate case, segregated by investment category (i.e., (1) statutory or regulatory requirements; (2) damage/failure; (3) system capacity and performance; (4) asset condition; and (5) non-infrastructure (other)), and network segment (i.e., transmission, sub-transmission, or distribution) by year for the period FY11-FY14. In addition to the information set forth in Exhibit __ (IOP-1), Schedule 8, additional detail on all the infrastructure programs and projects that are reflected in this rate case are also included in the Company's 2010 Capital Investment Plan, which is being filed the same date as this rate case filing, and which is included as a work paper to our testimony.

Q. Please describe what the "Reserve" line included in several of the sheets in Exhibit __ (IOP-1), Schedule 8 represents.

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A. The Reserve line, generally a negative number, is used to balance the forecasted spend for the fiscal year to the budget for the fiscal year. For example, in Exhibit__ (IOP-1), Schedule 8, Sheet 15, the budget subtotal of Transmission projects in the System Capacity and Performance category in FY11 total $54.1 million. However, the total budget for projects in that spending category is $46.3 million. The difference is the Reserve of -$7.8 million, which balances the forecast to the budget.

The Reserve is a hedge that recognizes that historically there have always been unforeseeable delays in project expenditures, projects that are cancelled as further information becomes available, and projects completed for less than estimated spend due to efficiencies. The Reserve is also used to balance for future year unidentified projects, current year walked-in projects, and projects completed in excess of the estimated cost. The Reserve can be either positive or negative.

A. <u>Statutory/Regulatory Requirements</u>

Q. Please discuss the investments the Company plans to undertake in the Statutory or Regulatory Requirements category during the period covered by this rate case.

A. Exhibit __ (IOP-1), Schedule 3 shows the Company's current and planned spending for distribution, sub-transmission, and transmission projects included in the statutory/regulatory requirements category.

As shown in Exhibit __ (IOP-1), Schedule 3, Sheet 1 of 2, the Company will spend $850 million, almost 40 percent of its FY2011- FY2014 investment budget, on projects in this category. Exhibit __ (IOP-1), Schedule 3, Sheet 2 of 2 details the breakdown of spending for statutory/regulatory purposes for the distribution, sub-transmission and transmission portions of the network by budget classification.

About $553 million (65%) of the Statutory or Regulatory Requirements spend for the FY2011- FY2014 period will be directed to the distribution network About $200 million of this amount will be required to extend overhead or underground service to new residential and commercial customers, and $124 million will be needed to purchase the transformers needed to support new and existing customers. Another $93 million is budgeted to ameliorate issues identified on the distribution system by the

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Inspection and Maintenance program conducted pursuant to the PSC's 2008 Safety Order in Case 04-M-0159.[3]

The Company plans to invest $47 million (6%) of the statutory/regulatory requirements in the sub-transmission portion of the network. Nearly all of this spending will be to address issues identified through the inspection and maintenance program.

Spending to meet statutory/regulatory requirements on the transmission portion of the network is expected to increase considerably in the years ahead, when the Company will be required to spend $251 million (29%) between FY2011 and FY2014. Of this amount, $152 million is required for the Northeast Regional Reinforcement Program, needed to support the on-going Luther Forest Technology Campus project, and to solve thermal and voltage problems in the Saratoga/Glens Fall Area. An additional $53 million is directed to upgrade substations that have been newly classified at part of the bulk power system based on testing performed by the New York Independent System Operator ("NYISO"). These funds will be used to bring two substations, Clay and Porter into compliance with NPCC

[3] Order Adopting Changes to Electric Safety Standards, in Cases 04-M-0159 and 06-M-1467 ("2008 Safety Order"), issued December 15, 2008.

design, protection and operation standards for bulk power stations. The cost of these upgrades is $29 million for Clay and $24 million for Porter.

The Company will also spend over $46 million to implement its Conductor Clearance Strategy, with a program to ensure that transmission lines meet the clearance requirements established by the National Electric Safety Code ("NESC"). This work is needed to safeguard the public and Company employees as they work and travel under these over head lines, and was established in a 2005 review of the system using Aerial Laser Surveys ("ALS").

Q. Please describe some of the major projects and programs included in the Statutory or Regulatory Requirements category of the Company's infrastructure investment plan in more detail.

A. Below we provide more detailed descriptions of some of the major statutory/regulatory requirements programs and projects, segregated by portion of the electric system they address. Additional information on all of the programs and projects in this category are included in Exhibit __ (IOP-1), Schedule 8, Sheets 1-5.

Transmission

Northeast Region Reinforcement. This major program consists of reinforcements of the transmission system in the Saratoga and Glens Falls area and is necessary to respond to reliability needs caused by area load growth and the impact of the proposed Luther Forest Technology Campus ("LFTC"). The transmission reinforcement program will resolve thermal and voltage problems which will result from projected load growth in the Northeast Region. Currently, there are six major projects with forecasted spending levels over $2 million under this program including the construction of the new Turner Road substation and the associated taps, the re-conductoring of 44 miles of right-of-way miles of 115kV lines and the installation of a fourth transformer at the Rotterdam substation. Specific projects under this program are identified in Exhibit __ (IOP-1), Schedule 8, Sheet 5. Not doing this program would result in thermal and voltage problems under certain system conditions. This program will be funded for $7.3 million in FY11, $41.2 million in FY12, $65 million in FY13, $38.5 million in FY14, for a total of $151.9 million for the period. The estimated in-service dates for certain major plant additions under this program are reflected in the Revenue Requirements Panel Exhibit __ (RRP-6), Schedule 1, Sheet 4, lines 4, 9, and 16.[4]

115 kV Substation Bulk Power System (BPS) Upgrade. In April of 2007, NPCC adopted Document A-10, Classification of Bulk Power System Elements. In accordance with Document A-10, testing of the major substations across New York State was performed by the NYISO, and several Niagara Mohawk substations were classified as part of the BPS. All substations that were newly classified as BPS under the A-10 testing must be brought into compliance with specific NPCC design, protection and operation requirements. This major asset program will upgrade two of our 115kV substations (Clay and Porter substations) to bulk power reliability criteria. In addition to compliance with NPCC and NYSRC requirements, the benefits of completing these projects are reductions in system vulnerability to certain severe contingencies. These projects reduce the chances that system instability and voltage collapse would occur for these contingencies. Customers in central New York will benefit from the significantly reduced vulnerability of the transmission system to these highly disruptive contingencies. These projects are budgeted at $9.9 million in FY11, $20.0 million in FY12 and $23.0

[4] Later in this testimony the Company describes the convention it uses to reflect the in-service date of investments for purposes of the revenue requirement. The testimony of the Revenue Requirements panel contains a more detailed description.

million in FY13, for a total of $52.9 million for the period, as indicated in Exhibit __ (IOP-1), Schedule 8, Sheet 5. The estimated in-service dates for major plant additions under this program are reflected in the Revenue Requirements Panel Exhibit __ (RRP-6), Schedule 1, Sheet 4, lines 11 and 13.

Conductor Clearance Strategy. The need for greater clearances was identified as a result of a 2005 review of parts of the transmission system using an innovative technology called Aerial Laser Survey ("ALS"), in which aerial surveys measure clearances with an accuracy previously unavailable except by ground inspection. This program assures that Niagara Mohawk transmission lines meet the governing NESC by increasing ground to conductor clearances in substandard spans, and follows the PSC's 2005 Safety Order in Case 04-M-0159.[5] The primary driver for this work is to ensure the safety of the public and our employees and contractors as they work and travel under the overhead lines. There is one major project within this program: the Transmission Tower Clearance project. Completion of this project is necessary to comply with the 2005 Safety Order and adhere to the NESC. The budget for this program is $1.5 million in FY11, $15.0 million in each of FY12, FY13, and FY14, for a

[5] Order Instituting Safety Standards, Case 04-M-0159, issued and effective January 5, 2005 ("2005 Safety Order").

total of $46.5 million for the period, as indicated in Exhibit __ (IOP-1), Schedule 8, Sheet 3.

Remote Terminal Unit Strategy. A Remote Terminal Unit ("RTU") is a device used to transfer operational information from a substation to an Energy Management System ("EMS") in a control center. An RTU allows for remote operation and management of the system providing benefits in incident response and recovery and thus improving performance and reliability. Modern RTUs provide the system operators the capability to more quickly and more accurately diagnose faults. In addition, protection engineers and operations engineers have access to data for analysis. And asset managers have the ability to obtain field measurements from substation data systems related to protection, power factor monitoring, phase balancing, circuit reconfiguration and load balancing. The Company's obsolete RTUs are not capable of interfacing with modern energy management systems and do not comply with NERC Recommendation 28, released in response to the August 2003 blackout.

The Transmission Remote Terminal Unit ("RTU") Strategy involves replacing obsolete monitoring and control equipment with state of the art and fully supported equipment. In addition, much of the current test equipment is no longer serviceable and operates on computer hardware and software that is no longer supported by the manufacturer. Customers will benefit from the improved reliability of the transmission system as well as the more efficient management of the grid. In the event of a minor or major system disturbance, accurate data that is received in a timely manner is a necessity in the restoration process. Data received from the new RTUs will quickly identify key devices that have failed or have been affected by the event. The data will expedite isolation of the problem, reduce the duration of the outage and in some cases avoid the spread of an outage to other system components. The Company currently has three separate RTU programs within its Capital Investment Plans; these programs will address obsolete RTUs on the transmission system, and include installing over 150 new RTUs on the sub-transmission and distribution systems.

This program will be funded for $1.5 million in FY11, $2.0 million in FY12 and $1.4 million in FY13, for a total of $4.9 million for the period, as indicated in Exhibit __ (IOP-1), Schedule 8, Sheet 5.

Distribution and Sub-Transmission

Inspection and Maintenance Strategy and Program. The Inspection and Maintenance Strategy outlines the Company's strategy for the inspection of all electric line assets (Distribution Overhead, Underground, and Sub-Transmission line assets) to be once every five years, in conformance with the 2005 and 2008 Safety Orders. Any repair work identified as a result of the Inspection and Maintenance strategy will be prioritized based on the severity of the issues found and incorporated into the work plan as appropriate. Priority Codes are as follows:

- Level 1- Must be repaired/replaced within one week.
- Level 2- Must be repaired/replaced within one year.
- Level 3- Must be repaired/replaced within three years.
- Level 4- Information only, replace based on engineering judgment and budget availability (including project bundling/outage optimization considerations).

This strategy is designed to improve the reliability and sustainability of the electric distribution network based on condition assessment, safeguard the public and employees by identifying and addressing elevated voltages locations, improve service efficiency through optimized timing of maintenance activities, and meet the requirements of the PSC's 2005 and 2008 Safety Orders. The Distribution strategy is funded at $17.4 million in FY11, $29 million in FY12, $25.1 million in FY13, and $22.1 million in FY14, for a total of $93.6 million for the period, as indicated in Exhibit __ (IOP-1), Schedule 8, Sheet 1. Different project stages under the

Distribution portion of this program will be closing 3 months following the expenditure of the funds. The Sub–transmission strategy is funded at $9.6 million in FY11, $10 million in FY12, $11 million in FY13, and $11.5 million in FY14, for a total of $42.1 million for the period, as indicated in Exhibit __ (IOP-1), Schedule 8, Sheet 3.

B. Damage/Failure

Q. Please discuss the investments the Company plans to undertake in the Damage/Failure category during the period covered by this rate case.

A. Failed and damaged equipment caused about 40 percent of customer interruptions between 2006 and 2009.[6] With this in mind, the Company's investment plan includes $133 million over the period FY11 to FY14 to replace equipment that unexpectedly fails or becomes damaged. Exhibit __ (IOP-1), Schedule 4, shows the Company's current and planned spending to repair failed or damaged equipment on the distribution, transmission and sub-transmission portions of the network.

[6] Deteriorated equipment contributed to over 25 percent of customer interruptions during this period while lightning, motor vehicle accidents, and vandalism were responsible for another 16 percent.

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More than two thirds of this spending ($90 million) is required to address issues along the distribution portion of the network due to failed equipment or damage caused by severe weather.

The Company expects to spend an additional $27 million to replace equipment that based on experience may fail or becomes damaged along the transmission portion of the network. Almost half of these funds have been designated to replace rotting wood transmission poles that are deemed to be beyond restoration so as to ensure compliance with the National Electric Safety Code and in accordance with the Commission’s 2005 and 2008 Safety Orders.

The Company expects that required spending to replace failed or damaged equipment will be relatively flat over the rate plan period. The flatness of this budget is also dependent on implementing the investments identified in the System Capacity and Performance and Asset Condition categories (described later). Without the investments in those categories it is anticipated that the projected spending required to replace failed and damaged equipment would be higher.

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Q. Please describe some of the major projects and programs that are included in the Company's infrastructure investment plan in the Damage/Failure (D/F) category.

A. Below we provide a description of major projects and programs in this category, segregated by portion of the electric system they address. Detailed information on these programs and projects is included in Exhibit __ (IOP-1), Schedule 8, Sheets 6-7.

<u>Transmission</u>

Apart from a five-year budgetary reserve of $11.5 million added for remediation of unforeseeable failures based on historical spending levels, there are three major transmission programs associated with the Damage/Failure category. All three of these projects are driven by field inspection results. The Company follows a number of standard industry practices for the inspection of its overhead line assets. These include five year ground-level foot patrols, annual aerial infra-red (IR) inspections, ground level inspections for wood poles, footer inspections for steel structures and specific comprehensive inspections of lines with reliability issues. There are currently three programs employed to address the results of these inspections. First, the New York Inspection Projects which will address all the urgent condition issues that arise from the foot patrols, IR inspections, footer inspections and comprehensive inspections. Second, the Wood Pole Strategy will address all the issues on wood poles identified by the ground level inspections (Osmose Inspections). Finally, the Overhead Line Refurbishment Strategy will address all the long-term i.e. non-urgent condition issues identified through inspection. The current Steel Tower strategy will be phased-out during FY12 and be replaced by the long-term overhead line refurbishment strategy (described later in the Asset Condition section). Different project stages under this program will be closing 6 months following the expenditure of the funds.

NY Inspection Projects. This program assures that both steel tower and wood pole transmission lines meet the governing NESC standards by replacing hardware, wood poles, and structure components that no longer meet the governing code requirements. This follows standard industry practice and the Commission's 2005 Safety Order to adhere to the NESC. The goal of this program is to replace those damaged or failed components on the transmission overhead line system identified during field inspections (five year foot patrols, infrared inspections, etc.). This program will be funded for $0.5 million in FY11, $1 million in FY12 and FY13 and $3 million in FY14, for a total of $5.5 million for the period, as indicated in Exhibit __ (IOP-1), Schedule 8, Sheet 6. Different project stages under this program will be closing 6 months following the expenditure of the funds.

Wood Pole Strategy. Under this program, wood poles that are either priority rejects or reject poles (as classified following a ground line inspection), as well as those damaged by woodpecker activity, will be replaced. This program targets wood poles deemed to be beyond restoration by either re-treatment or placement of some form of additional pole support, usually at the ground line. Similarly, "reject equivalent," that is, deteriorated wood poles from such things as woodpecker damage, insect damage, or rotting are included. The maintenance of appropriate public safety level by assuring that transmission wood structures continue to meet the governing NESC standards is the driver for this program. Implementation of this program is necessary to conform to the Safety Orders and adhere to the NESC. The Wood Pole Strategy will be funded for $1.8 million in FY11, $1.5 million in FY12, $1.6 million in FY13, and $3.0 million in FY14, for a total of $7.9 million for the period, as indicated in Exhibit __ (IOP-1), Schedule 8, Sheet 7. The increasing amount in the later years reflects a forecast increase in the number of priority rejects that is expected in coming years. Different project stages under this program will be closing 6 months following the expenditure of the funds.

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Sub-Transmission and Distribution

Damage/Failure (D/F) programs and projects also cover sub-transmission and distribution substation, overhead and underground line construction and replacement resulting from vehicle accidents, weather (where a storm project is not required), vandalism, and asset failure. Projects are budgeted based on historical trends. This category also includes Level 1 Prioritized work identified through Inspection and Maintenance. The Company establishes a budget reserve for specific projects required to address failed equipment that arise during the year and cost more than $100,000. These reserves are based on historical calculations for specific projects within the category. The size and volume of damage/failures drives the spending within these projects. The infrastructure investment plan includes a D/F budget for the sub-transmission system of $3.6 million in FY11, $3.8 million in FY 12, $3.9 million FY13 and $4.0 million in FY14, for a total of $15.3 million for the period, as indicated in Exhibit __ (IOP-1), Schedule 8, Sheet 6. For the distribution system, funding for this D/F work is budgeted at $20.9 million in FY11, $22.1 million in FY 12, in $22.9 million FY13 and $23.7 million in FY14, for a total of $89.7 million for the period. , as indicated in Exhibit __ (IOP-1), Schedule 8, Sheet 6.

C. System Capacity and Performance

Q. Please discuss the investments the Company plans to undertake in the System Capacity and Performance category during the period covered by this rate case.

A. The Company plans to spend $502 million, 23 percent of the total FY2011- FY2014 investment budget, on System Capacity and Performance projects, as reflected in Exhibit __ (IOP-1), Schedule 5. It provides breakdowns of spending for System Capacity and Performance for the distribution, sub-transmission, and transmission portions of the network and by Program.

Approximately $228 million will be directed to the distribution portion of the network for projects required to address capacity constraints and correct impending reliability issues. Of this amount, $126 million will be required to ensure the distribution network can accommodate anticipated load growth without compromising reliability. This includes replacing line transformers in areas where capacity is or will soon be constrained and "Planning Criteria" projects to ensure other parts of the distribution network have sufficient capacity to meet the anticipated load. The analysis that developed the load forecast used in the capacity planning

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process incorporates the impacts of energy efficiency programs and distributed generation continuing at historic rates.

The Company's system planning group has also recently begun to review the list of prospective "load growth" projects to identify locations where the Company's targeted demand response or energy efficiency programs might either defer or obviate the need for an expansion project.

Approximately $95 million of funds in the System Capacity and Performance category for the distribution network will be used to up-grade or replace assets in the Company's distribution substations. These projects are key to the Company's plan to maintain and improve reliability because problems in substations can interrupt a large number of customers given the up-stream position of substations on the distribution network.

In order to better monitor the performance of distribution substations, the Company will spend approximately $21 million to replace obsolete Remote Terminal Units ("RTU") to transfer data to the energy management system in the control center

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In addition to specific projects; i.e., those $100,000 or greater, required to assure the network meets system planning criteria, the Company also budgets for work less than $100,000 under a Distribution Reliability Blanket Project established for each operating division. Some examples of the type of work that would come under the Distribution Reliability Blanket include installing sectionalizing switches, replacing conductor, correcting for low voltage, minor primary side tap rebuilds, and relocating facilities in response to repeated motor vehicle accidents. The Company projects that nearly $30 million will be required between FY11 and FY14 to fund this blanket.

An additional $11 million has been directed to perform the work identified in annual engineering reliability reviews ("ERRs") on specific feeders in response to reliability issues. The feeders targeted for review include many of those tagged as 'worst performing feeders' in the Company's annual reliability report.

The Company will also spend $27 million on distribution line reclosers that will help to isolate permanent faults on the overhead distribution system to minimize the impact of a fault on customers. Another $8 million will be used to address pockets of poor performance where customers

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have been subject to frequent interruptions due to recurring problems with on the network. The range of potential work on pockets of poor performance will depend on the problems that are identified through an engineering reliability review.

The Company will spend $49 million to address system capacity and performance issues on the sub-transmission system. More than half of this spending will be required to ensure that the sub-transmission network meets the Company’s planning criteria. Much of this spending will be directed toward re-conductoring portions of the sub-transmission system especially in the Kensington area and in the vicinity of the former Huntley Station in Tonawanda. The Company will also direct funds to support new large customers, including the Buffalo Niagara Medical Campus, and to automate portions of the sub-transmission system

The Company will spend $225 million from FY11-FY14 in the System Capacity and Performance category on the transmission system. Almost half of that amount is designated for nearly twenty projects to ensure that the non-Bulk portion of the transmission system complies with the Company’s N-1-1- Reliability Planning criteria.

Another $102 million of these funds will be required to fund projects in the Frontier, Genesee, and Southwest regions needed to mitigate risks to the bulk power system following the retirement of 355 MWs in 2007 at the Huntley Power Station in Tonawanda. Capacitor banks installed at Huntley will mitigate most immediate system concerns. The Company will need to construct a new substation in Tonawanda and relocate six circuits to the new station in order to mitigate the need for load shedding in the event of a severe fault.

Q. Please describe some of the major projects and programs that are included in the Company's infrastructure investment plan in the System Capacity and Performance category in more detail.

A. Below we provide a description of some major projects and programs in this category, segregated by portion of the electric system they address. Additional information on all of the programs and projects in this category are included in Exhibit __ (IOP-1), Schedule 8, Sheets 8-15. In addition, there are three additional projects included in the Company's investment plans that are not described in this section. These are described in greater detail in the section entitled Additional Projects, later in our testimony.

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Transmission

Frontier Region. The Frontier Region Program involves significant capital expenditures to construct a major set of upgrades and replacements to the 115kV system near the retired Huntley Generating Station in Western New York. These expenditures are driven by the closure of generation at Huntley and the present system conditions and minor load growth expectations are needed before the summer of 2012 in order to avoid severe thermal and voltage problems that would impact system security and reliability. Transmission system reliability improvements will develop through the implementation of the permanent solutions. Prior to 2012, the capacitor banks recently installed at Huntley will mitigate most post-contingency system concerns. However, should a severe fault occur during a heavy load period, load shedding would likely be required to maintain the security of the transmission system until the upgrades are completed. Currently, there are two projects directly included in the program: the construction of the Tonawanda station, and the relocation of the six circuits that will in the future terminate at the new station. In addition to the Tonawanda projects, the refurbishment of the Huntley 230kV Station is associated with this program. This program (excluding the Huntley station) will be funded for $29.3 million in FY11, $54.3 million in FY12, $12.3 million in FY13 and $5.7 million in FY14, for a total of $101.6 million for the period, as indicated in Exhibit __ (IOP-1), Schedule 8, Sheet 13. The estimated in-service date for the Tonawanda Station under this program is reflected in Exhibit __ (RRP-6), Schedule 1, Sheet 4, Line 7. Other project stages under this program will be closing from 6-12 months following the expenditure of the funds.

Reliability Criteria Compliance. This program involves significant capital expenditure over the next five years to construct major reinforcements of the 115kV and 230kV transmission systems in western New York, including the Frontier, Southwest and Genesee regions that extend from the NY/Canada border east to Mortimer Station and south to the Pennsylvania border. The reinforcements are needed to ensure adherence to reliability standards by strengthening the transmission network. Completion of this strategy will substantially reduce the exposure of customers to service interruptions. Generation that currently must be run at times for reliability purposes will no longer be required, avoiding future costs of dispatching the generation out of NYISO merit order. In addition some capability to accommodate new or expanding load will be added to the system. This program will be funded for $11.6 million in FY11, $29.8 million in FY12, $33.3 million in FY13 and $23.1 million in FY14, for a total of $97.8 million for the period, as indicated in Exhibit __ (IOP-1), Schedule 8, Sheet 15. The estimated in-service date for the

Construct Southwest Station project under this program is reflected in Exhibit __ (RRP-6), Schedule 1, Sheet 4, Line 12. Other project stages under this program will be closing from 6-12 months following the expenditure of the funds.

Other System Capacity and Performance. There are eleven separate projects with spend greater than $2 million each included in the "Other System Capacity and Performance" program, as indicated in Exhibit __ (IOP-1), Schedule 8, Sheet 14. These projects are required to ensure that the electric network has sufficient capacity to meet the growing and/or shifting demands of our customers. Projects in this category are intended to prevent the degradation of equipment service lives due to thermal stress and to provide appropriate degrees of system reconfiguration flexibility to limit adverse reliability impacts of large contingencies. The Syracuse area re-conductoring prospective project reinforces the transmission system in and around the Syracuse area. These reinforcements are necessary to respond to a system capacity and performance need caused by load growth in the area over the period of time between 2008 and 2018. This program will help avoid thermal overloads on the 115 kV system during contingency conditions. The program scope includes the following projects: Re-conductoring approximately 6.4 miles of the Yahnundasis–Porter 115kV circuit #3: Reconductoring two separate sections (one 6.8 miles, the other 6.1 miles) of the Clay–Teall 115kV circuit #10; and Re-conductoring 10.2 miles of Clay–Dewitt 115kV circuit #3. Planned investment for all the projects in the "Other System Capacity and Performance" program total $5.8 million in FY11, $7.3 million in FY12, $10 million in FY13 and $21 million in FY14, for a total of $44.1 million for the period, as indicated in Exhibit __ (IOP-1), Schedule 8, Sheet 14. Different project stages under this program will be closing from 6-12 months following the expenditure of the funds.

Sub-Transmission

23kV Upgrades Associated with Buffalo Niagara Medical Campus. The Buffalo Niagara Medical Campus is a collection of medical facilities in the downtown Buffalo, NY area that are planning major capacity increases. Combined, the Company has received requests for an additional 16.5MVA of new load in these areas. This additional load will overload the 23kV cable group supporting the area. To provide the necessary capacity to meet these customer requests, an additional cable group of four 23kV cables will be installed. To accommodate these additional circuits an underground conduit system is required as well as an additional bay of breakers at the Elm Street substation. The project is on a fast track to meet the customers' expansion plans. Project costs are budgeted at $7.3 million in FY11, as indicated in Exhibit __ (IOP-1), Schedule 8, Sheet 13. Different project stages under this program will be closing from 6-12 months following the expenditure of the funds.

23kV Cable Upgrades Huntley to Buffalo Station 24. This project will replace and upgrade four 23kV underground sub-transmission cables from Huntley substation supplying Buffalo Station 24. This group of cables is expected to be loaded beyond normal ratings during peak load periods as early as the summer of 2010. These improvements will also address potential contingency overloads on the same cables as post contingency loading could exceed emergency ratings by summer 2010. The project is in the conceptual engineering phase. Construction is expected to begin in late 2010 with an expected completion date of summer 2012. The project is budgeted at $0.2 million in FY11, $1.0 million in FY12, and $6.2 million in FY13, for a total of $7.4 million for the period, as indicated in Exhibit __ (IOP-1), Schedule 8, Sheet 13. Different project stages will close throughout the program life, with closing occurring 6 months following the expenditure of the funds

23kV Cable Upgrades Huntley to Buffalo Station 52. This project will replace and upgrade one 23kV underground sub-transmission cable from Huntley substation supplying Buffalo Station 52. This cable is expected to be loaded beyond normal ratings during peak load periods as early as the summer of 2010. These improvements will address potential contingency overload on the same cable as post contingency loading could exceed emergency ratings by summer 2010. The project is in the conceptual engineering phase. Construction is expected to begin in late 2010 with an expected completion date of summer 2012. The project is budgeted at $0.2 million in FY11, $1.0 million in FY12, and $1.2 million in FY13, for a total of $2.4 million for the period, as indicated in Exhibit __ (IOP-1), Schedule 8, Sheet 13. Different project stages will close throughout the program life, with closing occurring 6 months following the expenditure of the funds.

Upgrade Bethlehem – Avenue A #10 Line. This project will upgrade 1.8 miles of 34.5kV underground sub-transmission including new ducts and cable to provide load relief to the #10 line which is forecasted to reach its normal rating by the summer of 2011 and which could exceed its emergency ratings under contingency loading conditions. Upgrade of this cable will maintain existing reliability performance levels and provide additional area capacity for load growth. The project is in the conceptual engineering phase. Construction is expected to begin in late 2011 with an expected completion date of spring 2013. The project is budgeted at $0.3 million in FY12, and $2.0 million in FY12, for a total of $2.3 million for the period, as indicated in Exhibit __ (IOP-1), Schedule 8, Sheet 13.

Different project stages will close throughout the program life, with closing occurring 6 months following the expenditure of the funds.

Sub-Transmission Line Sectionalizing. A program is being developed to increase the sectionalizing capability of radial sub-transmission lines to better isolate faulted sections of lines thus facilitating the rapid restoration of customers on sections that are not adversely impacted.. The program is expected to extend over many years. Budgets have been forecasted based on conceptual expectations. This project is budgeted at $0.5 million in FY11, $1.0 million in FY12, $2.0 million in FY13, and $4.0 million in FY14, for a total of $7.5 million for the period, as indicated in Exhibit __ (IOP-1), Schedule 8, Sheet 13. Different project stages will close throughout the program life, with closing occurring 6 months following the expenditure of the funds.

Distribution

Pockets of Poor Performance Strategy. The intent of this strategy is to identify subsections of feeders (typically at the line fuse level) experiencing measurably more frequent customer interruptions than the remainder of the feeder. Typically, these identified areas are known as “pockets of poor performance.” The reliability levels targeted by Pockets of Poor Performance Strategy are:

- **Customer Level Reliability –** Reliability at the customer level is the main driver of this strategy. Identifying and correcting repeat device interruption locations will improve customer service.
- **Minimize reliability 'hot-spots' –** This strategy will help identify future reliability 'hot-spots' and support the timely correction of localized problems before they become larger issues.

Once these locations have been identified, a reliability review of the area will be conducted by Network Asset Planning to determine the source(s) of the problem. The range of potential work could be as simple as solving a coordination problem to performing preventive maintenance (e.g., tree trimming, repairing equipment, grounding and bonding) and/or line reconductoring. The Pockets of Poor Performance Strategy is level-funded at $2.1 million per year for FY11-FY14, for a total of $8.4 million for the period, as indicated in Exhibit __ (IOP-1), Schedule 8, Sheet 12.

Distribution Line Transformer Strategy. This is a "predictive approach" to mitigate unplanned outage/failure risks due to overloading and asset condition. There are approximately 442,000 transformers on Niagara Mohawk's distribution system. Transformer loading is reviewed annually using reports generated by the Company's GIS system. Transformers with calculated demands exceeding load limits specified in the applicable Construction Standard are investigated and overloaded installations are addressed by replacement with a larger unit or load is relieved via installation of a second transformer. The physical condition of distribution line transformers is evaluated on a five-year cycle as part of the Overhead and Underground Inspection and Maintenance Strategy. Poor condition units are replaced based on inspection results. The Strategy is in addition to replacements that are performed during customer-service upgrades, public requirements projects, and system-improvement projects. The main benefit of this strategy is the maximization of asset utilization, and sustained reliability performance. The Distribution Line Transformer strategy is funded at $4.5 million in FY11, $4.6 million in FY12, $7.6 million in FY13 and $9.6 million in FY14, for a total of $26.3 million for the period, as indicated in Exhibit __ (IOP-1), Schedule 8, Sheet 8. Different project stages will close throughout the program life, with closing occurring 3 months following the expenditure of the funds.

Feeder Hardening Strategy. The Feeder Hardening strategy and program identifies feeders with characteristics indicating the potential for significant reliability performance improvements related to overhead deteriorated equipment and/or lightning interruptions. This is a reliability-focused strategy designed to meet state regulatory targets. Feeders in this program undergo replacement of deteriorated equipment, installation of

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lightning arresters and animal guards and correction of non-standard grounding and bonding issues. FY11 is the year last feeder hardening will be utilized in NY. The Inspection and Maintenance Strategy incorporates the components of the Feeder Hardening Strategy after FY11. The Feeder Hardening strategy is funded at $3.0 million in FY11, as indicated in Exhibit __ (IOP-1), Schedule 8, Sheet 9. Different project stages will close throughout the program life, with closing occurring 3 months following the expenditure of the funds.

Distribution Line Recloser Strategy. The recloser application strategy is a reliability-focused strategy to install line reclosers on overhead distribution lines. Line reclosers are used to isolate permanent faults on the distribution system and minimize exposure of a fault to customers. Ideally reclosers are installed at locations which limit the size of the interruption to the fewest number of customers possible and/or reduce the mainline exposure on the feeder breaker. The benefits of this program are reduced outage duration and outage frequency. The Distribution Line Recloser Strategy is funded at $5 million in FY11, $6 million in FY12, $6 million in FY13, and $10 million in FY14, for a total of $27 million for the period, as indicated in Exhibit __ (IOP-1), Schedule 8, Sheet 12. Different project stages will close throughout the program life, with closing occurring 3 months following the expenditure of the funds.

Distribution Reliability Blanket. In addition to specific projects; i.e., those $100,000 or greater, the Company also budgets for work less than $100,000 under a Distribution Reliability Blanket Project established for each operating division. The amount of funding in each divisional blanket project is reviewed, and approved, each year based on the results of the previous annual reliability review, historical trends in the volume of work required as well as a forecasted impact of inflation on material and labor rates. The current year spending in each divisional project is monitored on a monthly basis. These projects are established to ensure that a mechanism is in place to initiate, monitor, and report on work under $100,000 in value. The blankets also provide local field engineering in each operating division with the control accounts to facilitate timely resolution of historical and new reliability issues that emerge. These blanket projects are budgeted at $6.6 million in FY11, $7.2 million in FY12, $7.8 million in FY13, and $8.3 million in FY14, for a total of $29.9 million for the period, as indicated in Exhibit __ (IOP-1), Schedule 8, Sheet 8. Different project stages will close throughout the program life, with closing occurring 3 months following the expenditure of the funds.

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Planning Criteria Projects. An annual capacity planning assessment is conducted to identify thermal capacity constraints, maintain adequate delivery voltage, and assess the capability of the network to respond to contingencies that might occur. The capacity planning process is summarized by the following tasks:

- Review of historic loading on each sub-transmission line, substation transformer, and distribution feeder.
- Weather adjustment of recent actual peak loads,
- Econometric forecast of future peak demand growth,
- Analysis of forecasted peak loads vis-à-vis equipment ratings,
- Consideration of system flexibility in response to various contingency scenarios, and
- Development of system enhancement project proposals.

Individual project proposals are identified to address planning criteria violations identified. At a conceptual level, these project proposals are prioritized and submitted for inclusion in future capital work plans. Projects in the load relief program are typically new or upgraded substations and distribution feeder mainline circuits. Other projects in this program are designed to improve the switching flexibility of the network, improve voltage profile, or to release capacity via improved reactive power support.

Some of the most significant planning criteria projects include:

Sycaway – Add 13.2kV Switchgear. The Sycaway substation is a 115-13.2kV substation in Brunswick serves approximately 4600 customers. The existing transformer and local feeders are forecasted loaded above their rating during summer peak periods. The substation is being expanded to add a second transformer, 13.2kV switchgear, substation capacitor banks and two additional 13.2kV feeders to serve area loads and provide improved operational flexibility to respond to various contingency with feeder switching. The project is currently in the final engineering stage. Construction is expected to complete in March 2011 with project closure in September 2011. This portion of the project is budgeted at $2.1 million in FY11, as indicated in Exhibit __ (IOP-1), Schedule 8, Sheet 10.

Swann Road TB2 Replacement. Swann Rd is a 115 -13.2kv two transformer substation in Lewiston. The existing transformer bank (TB) #2 is in poor condition and will be replaced with a new 25MVA unit. The project is expected to be completed in the spring of 2011 and it budgeted at $2.2 million in FY11, as indicated in Exhibit __ (IOP-1), Schedule 8, Sheet 10.

Inman Rd - Add 13.2kV Switchgear. Inman Rd is a 115-13.2kV substation in Niskayuna. There are loading and voltage concerns on nearby distribution feeders served from the Rosa and Watt Street substations. The addition of a second 33MVA transformer, 13.2kV switchgear, substation capacitor bank and two new 13.2kV feeders will provide additional area capacity to relieve area facilities and improve customer service. The project is currently in preliminary engineering. Construction is expected to begin in summer of 2011 and complete by March of 2012. The project is budgeted at $1.0 million in FY11 and $2.2 million in FY12, for a total of $3.2 million for the period, as indicated in Exhibit __ (IOP-1), Schedule 8, Sheet 10.

Frankhauser – Add 13.2kV Switchgear. This project proposes the installation of a new 115-13.2kV substation on Company owned land off Frankhauser Rd in Amherst. The primary driver of this project is to maintain reliability of the area and provide load relief for five area feeders that are expected to reach or exceed their summer ratings by 2012. In addition seven area substation transformers are at risk of exceeding their emergency ratings for a single contingency if load were not shed at peak periods. The plan to resolve these issues is to install this new substation with a 115-13.2kV 40MVA transformer, 13.2kV switchgear, substation capacitor bank, and four 13.2kV feeders. This project funds the 13.2kV substation additions associated with this plan. The project is currently in preliminary engineering. Construction is expected to begin in spring of

2011 and complete by March of 2012. The project is budgeted at $0.3 million in FY11 and $2.0 million in FY12, for a total of $2.3 million for the period, as indicated in Exhibit __ (IOP-1), Schedule 8, Sheet 10.

West Albion Transformer Addition. The West Albion substation is 34.5-13.2kV substation located in Albion. The existing transformer is forecasted to be overloaded and a second 5.3MVA transformer, regulators and additional 13.2kV feeder will be added to the substation to provide additional capacity to relieve the overloaded facilities. This project funds the associated substation additions. The project is currently in conceptual engineering phase. Construction is expected to begin in spring of 2011 and complete by March of 2012. The project is budgeted at $0.5 million in FY11 and $2.5 million in FY12, for a total of $3 million for the period, as indicated in Exhibit __ (IOP-1), Schedule 8, Sheet 11.

Starr Road Second Transformer. Starr Road is a 115-13.2kV substation in Cortland. It serves 22MVA of area load from a single 25MVA transformer. The limited field ties from other substations cannot carry all of the load of the station in the event of a transformer contingency. This may result in customer outages up to 24 hours in duration while a mobile substation is installed under emergency conditions. This project proposes to install a second 25MVA transformer at the substation as well as a 13.2kV tie switch inside the substation. The project is currently in the conceptual engineering phase. Construction is expected to begin in spring of 2012 and complete by March of 2013. The project is budgeted at $1.9 million in FY12 and $0.4 million in FY13, for a total of $2.3 million for the period, as indicated in Exhibit __ (IOP-1), Schedule 8, Sheet 11.

Ogden Brook – Installation of a 13.2kV Switchgear. The Ogden Brook substation is a 115-13.2kV serving approximately 3000 customers in the Glens Falls area via a single 22MVA transformer. The transformer is forecasted to be overloaded by the summer of 2013. This project proposes the addition of a second transformer, 13.2kV bus, substation capacitor and a new 13.2kV feeder to provide needed capacity to the area to reliably serve these customers. The project is currently in conceptual engineering phase. Construction is expected to begin in autumn 2010 and be complete by March of 2013. The project is budgeted at $0.25 million in FY11, $2.0 million in FY12 and $2.8 million in FY13, for a total of $5 million for the period, as indicated in Exhibit __ (IOP-1), Schedule 8, Sheet 11.

Ballston – Installation of a 13.2kV Switchgear. The Ballston substation is a 115-13.2kV substation in Ballston Spa. The single 22MVA transformer is heavily loaded and is currently being managed via load transfers among neighboring facilities. This project proposes to increase the capacity of the substation with the addition of a second transformer, switchgear and additional feeders. The project is early in the conceptual engineering phase. Construction is expected to begin until spring 2012 with a forecasted in service date around March 2014. The project is budgeted at $2.9 million in FY13 and $0.7 million in FY14, for a total of $3.6 million for the period, as indicated in Exhibit __ (IOP-1), Schedule 8, Sheet 12.

North Syracuse Capacity Increase. The North Syracuse study area encompasses the Towns of Clay, Cicero, Lysander and Salina. The area is loaded to 335MVA and serves approximately 67,000 customers. In 2008 two feeders were loaded beyond their summer normal rating and six substation transformers were at risk of contingency overload that would require load shedding at peak load periods. This project will add needed capacity to the area with the addition of a new 115-13.2kV substation with a 40MVA transformer, substation capacitor bank and switchgear supplying 5 new distribution feeders. Completion of this project will enhance customer reliability and will provide area capacity to support the continued load growth expected in the area. The project is in the preliminary engineering phase. Construction is expected to begin in autumn 2010 with a forecasted in service date around September 2012.

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The project is budgeted at $0.79 million in FY11, $2.3 million in FY12 and $0.1 million in FY13, for a total of $3.19 million for the period.

Distribution Load Relief Blanket. In addition to specific projects; i.e., those $100,000 or greater, required to realign the network with system planning criteria, the Company also budgets for work less than $100,000 under a Distribution Load Relief Blanket Project established for each operating division. These projects are established to ensure that a mechanism is in place to initiate, monitor, and report on work under $100,000 in value. The amount of funding in each divisional blanket project is reviewed, and approved, each year based on the results of the previous annual capacity planning review, historical trends in the volume of work required as well as a forecasted impact of inflation on material and labor rates. The current year spending in each divisional project is monitored on a monthly basis. The blankets also provide local field engineering in each operating division with the control accounts to facilitate timely resolution of system and equipment loading issues. These blanket projects are utilized to respond to issues such as overloaded sections of wire/cable or step-down transformers, the installation of feeder voltage regulators and capacitors, as well as minor work necessary to facilitate the reallocation of load on existing circuits. These blanket projects are budgeted at $1.1 million in FY11, $1.1 million in FY12, $1.2

million in FY13 and $1.2 million in FY14, for a total of $4.6 million for the period, as indicated in Exhibit __ (IOP-1), Schedule 8, Sheet 12.

Replacement RTU Program – Substations. This is one of the three RTU projects mentioned earlier in the testimony. This program will replace RTU's where existing RTU's have become obsolete and unsupported by the manufacturer. Replacement of these devices will ensure reliable operation of the electric system. The program is expected to extend over many years. Replacement candidates for the next 2 years are in the engineering phase and construction plans are prepared. Future year budgets have been forecasted based on conceptual expectations over the five year horizon. Construction is expected to begin summer of 2010. This project is budgeted at $1.8 million in FY11, $1.8 million in FY12, $1.8 million in FY13 and $2.0 million in FY14, for a total of $7.4 million for the period, as indicated in Exhibit __ (IOP-1), Schedule 8, Sheet 12. Different project stages will close throughout the program life, with closing occurring 9 months following the expenditure of the funds.

New Substation RTU Program. This also is one of the three RTU projects mentioned earlier in the testimony. Currently over 150 out of the 441 distribution and subtransmission substations require installation of RTU's. This strategy provides the means to leverage substation data that provides operational intelligence and significantly reduces response time to abnormal conditions through real time monitoring and control. Substations equipped with RTU's and subsequent communication to the EMS system can provide up to a 15 percent reduction in average customer outage duration (CAIDI) when compared with a similar feeder that is not equipped with and RTU to transfer information to the EMS capabilities. Based upon historical cost of similar projects, the strategy is funded at $2.5 million in FY11, $3.0 million in FY12, $3.0 million in FY13, and $4.0 million in FY14, for a total of $12.5 million for the period, as indicated in Exhibit __ (IOP-1), Schedule 8, Sheet 12. Different project stages will close throughout the program life, with closing occurring 9 months following the expenditure of the funds.

D. Asset Condition

Q. Please discuss the investments the Company plans to undertake in the Asset Condition category during the period covered by this rate case.

A. Exhibit __ (IOP-1), Schedule 6, Sheet 1 of 4 shows the Company's investment plan levels for projects required to address Asset Condition issues. Exhibit __ (IOP-1), Schedule 6, Sheet 4 of 4 details the breakdown of spending for Asset Condition for the transmission portions of the network. Exhibit_ (IOP-1), Schedule 6, Sheet 2 of 4 details the breakdown of spending for Asset Condition for the distribution portion of the network by strategy. Exhibit__ (IOP-1), Schedule 6, Sheet 3 of 4 details Asset Condition Spending for the sub-transmission potion of the network by strategy.

The Company expects to spend $690 million, nearly 32 percent of its FY11-FY14 investment budget, to improve the condition of deteriorated assets.

Over 60 percent of this spending ($430 million) is required to improve and sustain the condition of the transmission system. Approximately $198 million of this spending will be required to refurbish overhead lines. This spending will be the initial installment of a 25 year program to replace or refurbish steel towers, wood poles and re-conductor several transmission lines to assure the system remains in compliance with the 2005 Safety Order and the National Electric Safety Code. Another $139 million will be required to rebuild transmission substations in Gardenville, Dunkirk, Lockport, Lighthouse Hill and Rome. The planned replacement of these stations reduces the likelihood of an unplanned failure which could lead to long interruptions of the transmission system and the interruption of service to large numbers of customers. The Company also is also planning to direct $25 million to replace 39 transformers that have been designated as “high priority” based on their asset condition. An additional $23 million will be used to replace problematic circuit breakers in order to reduce the risk of in-service failure that could lead to a lengthy interruption on the transmission system and significant customer interruptions.

The Company’s investment plan will also direct $148 million to replace assets on the distribution portion of its network based on asset condition. As shown in Exhibit __ (IOP-1), Schedule 6, Sheet 2, two thirds of these funds will be used to replace equipment in substations. Close to $59 million will be used to replace or rebuild the Indoor 23-4kV Substations that were built in the 1930s and 1940s that now pose safety, capacity, and reliability issues. The Company will spend another $17 million to replace substation circuit breakers and to remove circuit breakers that are obsolete or do not operate properly and undermine reliability. Another $14 million will be used to replace the metalclad switchgear in several distribution substations: Altamont, Market Hill, North Troy and Oneida. This equipment is in poor condition, and when this class of switchgear fails, it generally impacts the entire bus and interrupts service to many customers. The Company plans to spend $16 million to replace underground cable and another $8 million to improve networks in urban areas to reduce reliability concerns.

As shown in Exhibit __ (IOP-1), Schedule 6, Sheet 3, the Company is also planning to spend $112 million to improve the condition of assets along the sub-transmission network. Most of this spending will be to replace towers, line, and underground cable. Over 20 percent of these funds will be used to replace equipment in substations.

Q. Please describe some of the major projects and programs that are included in the Company's infrastructure investment plan in the Asset Condition category.

A. Below we provide a description of major projects and programs in this category, segregated by portion of the electric system they address. Details of individual programs and projects is included in Exhibit __ (IOP-1), Schedule 8, Sheets 16-25.

<u>Transmission</u>

3A/3B Tower Strategy. In October 2003 Structure 347 on the Edic-New Scotland 14 line, a type 3A tower, failed. Two previous failures occurred on type 3B towers, Structure 3 in 1977 and Structure 66 in 1992 (adjacent towers 63, 64, 65, 67, and 68 were damaged by the collapsed tower). These failures occurred on the Edic-New Scotland 14 line. Phase I of this strategy addressed safety concerns on the Edic-New Scotland 14 line and has been completed. The selection of towers for replacement involved considerable analysis determining which towers presented the greatest public safety concern. The Company has four other 345 kV lines that use these same types of towers. They are the 345kV New Scotland–Leeds 93 and 94 lines, Athens-Pleasant Valley 91, and Leeds–Pleasant Valley 92 lines. The physical components of these lines include twin high strength steel static wires and a two conductor per phase arrangement of 795 kcm Aluminum Conductor Steel Reinforced ("ACSR") "Drake" supported by steel lattice towers. These lines were energized in 1962. Phase II will address these four remaining lines after Transmission Planning and the NYISO review the future load needs associated with them. The scope of this program is being developed with consideration of the overall risks to public safety as the primary driver with improved reliability a secondary benefit. The Company has limited the program to those towers which pose the greatest risk to public safety in order to reduce the costs of the programs. The two projects included within this program are: "Leads - Pleasant Valley 91/92 tower reinforcement" and "New Scotland – Leads 93/94 tower reinforcement." Implementing the program will reduce the risk of additional failures of the same type of towers in the future. This program will be funded for $0.05 million in FY12, $0.15 million in FY13, and $6.1 million in FY14, for a total of $6.3 million for the period, as indicated in Exhibit __ (IOP-1), Schedule 8, Sheet 22. Different project stages will close throughout the program life, with closing occurring 6 months following the expenditure of the funds.

Battery Strategy. Battery and charger systems are critical components that are needed to insure full substation operational capability during both normal and abnormal system conditions. A battery system that does not perform adequately could result in serious reliability consequences. There are three different projects within this program, the largest of which ("Battery Replacement Strategy Co36TxT") is funded for $1.2 million per year in FY11 and FY12, and $0.6 million per year in FY13 and FY14, for a total of $3.7 million for the period, as indicated in Exhibit __(IOP-1), Schedule 8, Sheet 22. Different project stages will close throughout the program life, with closing occurring 12 months following expenditure of the funds.

Circuit Breaker Replacement Strategy. The circuit breaker replacement strategy will address problematic circuit breakers on the Company's system. Circuit breakers play a key role in system performance, particularly for fault clearance, and the strategy is necessary to address problem circuit breakers and to prevent failures and unplanned outages. This strategy involves the purchase and installation of approximately 130 SF_6 (gas) circuit breakers over the next ten years (replacing high priority oil circuit breakers). Additionally, where cost effective and where their conditions warrant, the Company will replace disconnects, control cable and other equipment associated with these circuit breakers. The planned replacement of these circuit breakers reduces the likelihood of an unplanned failure which can lead to lengthy interruptions of the transmission system as well as significant customer outages. The program would also reduce the potential for catastrophic failures that pose safety risks, as well as the risk of damage to surrounding equipment. The program will be funded for $0.1 million in FY11, $1.1 million in FY12, $7.3 in FY13, and $14.5 million in FY014, for a total of $23 million for the period, as indicated in Exhibit __ (IOP-1), Schedule 8, Sheet 22. The estimated in-service date for the Circuit Breaker Replacement (priority 4) project under this program is reflected in Exhibit __ (RRP-6), Schedule 1, Sheet 4, Line 7. Other project stages will close throughout the program life, with closing occurring 12 months following expenditure of the funds.

Overhead Line Refurbishment Program. The Company has over 5,800 circuit miles of Transmission overhead lines in upstate New

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York and many of these overhead line assets are approaching, and some are beyond, the end of their anticipated lives. There are two main drivers for the proposed long-term overhead line refurbishment program. Firstly, the program will ensure that the Company's transmission lines meet the governing code as required by the Commission's 2005 Safety Order. Secondly the program will improve the reliability of the aging transmission system by rebuilding the worst performing lines before they become unacceptably unreliable.

The overhead line refurbishment program assures that the Company's transmission lines meet the governing NESC standards. This will be accomplished through the replacement of deteriorating structures (both wood and steel) and line components that no longer structurally or electrically adhere to the governing National Electric Safety Code. This will be done on a line-by-line basis and will follow an in-depth condition assessment and engineering evaluation of the lines. Refurbishment projects have been selected based upon six factors;

i) five-year average reliability statistics as published in the Transmission Network performance Report or any circuits that appear in the external SGS Statistical Services benchmarking list of worst performing 100 circuits

ii) condition as determined by field inspection, testing and analysis

iii) age distribution figures for overhead line assets show an aged population. A significant proportion of the Company's steel structure assets were installed between 1899 and 1939 (70 – 110 years old) and a large population of wood poles were installed between 1909 and 1985 (25 to 100 years old). A recent evaluation of the performance of 115kV lines against age demonstrated a strong correlation between age and decreasing reliability. Hence increasingly aged populations of overhead line assets present the Company with a reliability challenge

iv) whether the line consists of steel or wood structures

v) risk and criticality i.e. the Line Importance Factor which ranks lines based upon the consequences of failure and the part the circuit plays within the integrated transmission system

The final selection of lines will factor in additional considerations, such as outage availability, bundling to create economic packages of work, interaction with other strategies and projects, etc. In the early years the program emphasizes the worst performing circuits, typically 115kV circuits and aims to move transmission in New York to a longer-term (25+ years), systematic refurbishment approach for all overhead lines.

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The following table IOP-1 lists overhead line refurbishment projects that are either underway or have been initiated. Along with the list of circuits we have highlighted their current and previous rank in terms of least reliable. Seven out of the top ten circuits are included on the list and 16 out of the top 40.

Table IOP-1
Overhead Line refurbishments for the period FY10/11 – FY13/14

Circuit ID	Circuit Name	2009 Rank	2008 Rank
T1260	Gardenville-Dunkirk 141	2	7
T1270	Gardenville – Dunkirk 142	Double circuit efficiency	
T1530	Lockport - Mortimer 111	3	1
T1280	Gardenville – Homer Hill 152	4	3
T1950	Gardenville – Homer Hill 151	Double circuit efficiency	
T1540	Lockport - Mortimer 113	18	24
T1550	Lockport – Mortimer 114	1	7
T1510	Lockport – Batavia 112	6	5
T5770	Spier – West 9 (also a System Capacity project)	5	9
T3340	Taylorville – Mosier 7	7	8
T1160	Falconer – Homer Hill 153	34	20
T1170	Falconer – Homer Hill 154	16	17
T1340	Homer Hill – Bennett Road 157	11	29
T1660	Niagara – Gardenville 180	31	13
T1780	Niagara – Gardenville 182	32	42
T3320	Taylorville – Boonville 5	15	18
T3330	Taylorville – Boonville 6	Double circuit efficiency	
T1860	Pannell – Geneva 4 / 4A	14	39
T4210	Porter – Rotterdam 31 (bulk)	19	19

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Replacing deteriorated assets ahead of failure to maintain or improve reliability for customers is the objective for the overhead line refurbishment program. There are 15 projects over $2 million within this category including as discussed the refurbishment of many of the “worst performing lines” such as Lockport-Mortimer 111, 113 & 114, Lockport-Batavia 112, Taylorville-Mosier 7, Dunkirk-Falconer 161/162, Gardenville-Dunkirk 141/142 and Gardenville-Homer Hill 151/152 projects. This program will be funded for $20.2 million in FY11, $32.4 million in FY12, $53.4 million in FY13 and $92 million in FY14, for a total of approximately $198 million for the period, as indicated in Exhibit __ (IOP-1), Schedule 8, Sheet 23. Different project stages will close throughout the program life, with closing occurring 6 months following the expenditure of the funds.

Relay Replacement Strategy and Program. This strategy and program is driven by the need to ensure that reliable protective relay systems are in place to preserve the integrity of the transmission system during system faults. Niagara Mohawk’s transmission system is protected by approximately 8,000 relays. Approximately 6,500 in-service relays are electro-mechanical or solid state types. Many electro-mechanical and solid state relays are at or near their end-of-life. A replacement plan targeting the worst performing or obsolete relay families is planned to address this. Protective relays that are functioning properly are essential to a rapid isolation of faults on the system, protecting customers from outages and protecting equipment from damage. The new relays will yield additional operational data that has not been available previously, which will help identify the root causes of system failures and make it easier to prevent reoccurrences. This program will be funded for $50,000 in FY11, $1 million in FY12, $3.8 million in FY13, and $6.5 million, for a total of $11.35 million for the period, as indicated in Exhibit __ (IOP-1), Schedule 8, Sheet 24. Different project stages will close throughout the program life, with closing occurring 12 months following completion of the work.

RHE Breaker Replacement. This program includes the replacement of Federal Pacific oil circuit breakers (manufacturer's type code RHE). Due to their key function, the reliability of these circuit breakers is viewed as critical. The Federal Pacific type RHE circuit breakers are in poor condition, have a history of failure, lack adequate spare parts and have experienced mechanism, bushing, and interrupter problems. Equipment failures at high voltages (115kV and above) have the potential to be extremely dangerous, resulting in erratic voltage dissipation and flying debris. In many cases, adjacent equipment is damaged, further increasing the risk of injury and customer outages. The planned replacement of these circuit breakers reduces the likelihood of an in-service failure. The two projects within this program are "Lighthouse Hill" and "Oneida." This program will be funded for $0.1 million in FY11, $0.3 million in FY12 and $0.5 million in FY13, for a total of $0.93 million for the period, as indicated in Exhibit __ (IOP-1), Schedule 8, Sheet 24.

Shield Wire Strategy and Program. The shield wire is a critical element of a high voltage transmission line. During lightning strikes, the shield wire serves as a grounding element, shielding the lightning strikes away from energized conductors and conveying it to ground without permitting flashover to occur. A well grounded shield wire system significantly reduces the likelihood of an outage due to a lightning strike. In addition to lightning protection, the shield wire provides critical support against the imbalance of mechanical forces in the longitudinal direction. These forces, which can also compromise shield wire protection, can be caused by heavy wind, conductor drop or failure, splice failure, localized wind shear, ice loading (or unloading), structure tilt due to foundation failure or component failure, etc. An intact shield wire system will help minimize structural related outages. A dropped shield wire that goes unnoticed (no outage) creates a major safety concern to the public. The Shield Wire Strategy and Program involves replacement of a significant amount of shield wire on the overhead transmission system. In some instances OPGW ("optical fiber ground wire") will be used during shield wire or overhead line refurbishment projects. With the increasing need for communication bandwidth for SCADA, security and future SmartGrid applications, leveraging existing overhead line infrastructure to provide these communication routes is beneficial. The targeted assets are the shield wire on more than 400 miles of 115kV transmission lines or approximately seven percent of the total 115kV system. In addition to the safety issues, the program is targeting reliability improvements of the 115kV transmission system by reducing the total duration of sustained outages by over 2,000 minutes/year. The largest project in this program is the Gardenville-Homer 151/152 project. This program will be funded for \$8.2 million in FY11 and \$7.2 million in FY12, for a total of approximately \$15.4 million for the period, as indicated in Exhibit __ (IOP-1), Schedule 8, Sheet 24. Different project stages will close throughout the program life, with closing occurring 6 months following the expenditure of funds.

Substation Rebuild Projects. There are six stations under study for either upgrades or rebuilds to better meet current and future needs of the transmission system and its users: Gardenville (230/115kV), Dunkirk (230/115kV), Rome (115kV), Lockport (115/12kV), Lighthouse Hill (115/12kV) and Rotterdam (230kV, 115kV, 69kV, 34.5kV and 13.2kV).

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At this stage of planning, the six projects are anticipated to cost slightly more than $139 million in total. Details for these projects are included in Exhibit __ (IOP-1), Schedule 8, Sheet 24.

- **Gardenville:** The station is a 230/115kV complex south of Buffalo. It has two 115kV stations in close proximity that are referred to respectively as New Gardenville and Old Gardenville, and which both serve regional load. New Gardenville was built between 1959 and 1969 and has asset issues such as faulty control cables, deteriorated foundations and many disconnects have deteriorated beyond repair. Old Gardenville, built in the 1930s, feeds regional load via eleven 115kV lines. The station has serious asset health issues including, but not limited to, control cable, breaker, disconnect and foundation problems. The station has had no major updates since it was built. There have been a number of mis-operations that can be directly attributed to control cable issues in the past several years alone. Because of this, a project has been initiated that addresses these issues by completely rebuilding both 115kV portions of this station. The new 115 kV switchyard will be constructed in the western section of the site and there will be rerouting of approximately twenty 115 kV lines for the project. Project Sanction is expected in the fall of 2011. The

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estimated in-service date for this project is reflected in Exhibit __ (RRP-6), Schedule 1, Sheet 4, line 6.

- **Dunkirk:** The station is a 230/115kV station located south of Buffalo, and connected to 522MW of generation owned by NRG. The generation at Dunkirk was owned by Niagara Mohawk but sold to NRG. The Company retains ownership of most of the 230kV and 115kV switch yard; however, the controls are located in the generation control room owned by NRG. This station has recently experienced several 230kV mis-operations due to control cable issues. Complete replacement of control cables is not possible due to space constraints in shared areas.
- **Rome:** The station was constructed in the early 1920s. It has received several reconfigurations over the years with the current 115kV to 13.2kV dual bus being built in the early 1970s. The 115kV system at the station experiences periods of low voltage particularly if the tie-breaker is opened. Station property near the north bus section has been under environmental remediation the past several years due to a former coke plant at the site that produced natural gas which ultimately contaminated the site. There are multiple asset condition issues affecting the station including the 115kV disconnects being in poor condition and often failing while being operated. The 115kV

instrument transformers have weakened foundations, batteries and chargers have failed during bus outages, the control house has asbestos and deteriorated windows and doors and inadequate lighting, and the steel structure for the North bus is heavily corroded with degraded footings.

- **Lockport**: The station is a major 115kV transmission station with thirteen 115 kV transmission lines tying through the east and west bus sections. The overall condition of the station yard and control room is poor. This station was originally part of the 25 cycle system dating back to the 1910s. There is still some 25 cycle oil filled equipment which needs to be drained of oil and removed to avoid possible environmental problems or safety issues. The structures are severely rusted and in need of painting before steel is compromised. Support columns and breaker foundations are in a deteriorated condition and need to be repaired with several potentially needing full replacements. The original manhole and duct system for control cables is in a deteriorated condition and the station has experienced control wire shorts, battery grounds and unwanted circuit opening. The duct bank covers in the yard are bent and rusted and station personnel are hampered to perform repairs by the overall condition of the duct bank. Single control cables cannot be easily removed to replace without adversely affecting adjacent control cables in the same ducts. The 40 year old 115 kV oil filled breakers exhibit minor exterior rust and oil stains. Three of the 115 kV oil breakers have continued hydraulic mechanism leaks common to the BZO style breakers. Due to their age, failures of hydraulic system components have been notably increasing. Each of the oil breakers has aged bushing Potential Devices which have been another source of failure. Some of the 12 kV secondary breakers, are 1950 vintage and have historic mechanism problems. The control room building is in very poor condition needing painting and the flooring repaired. The existing peeling paint is likely lead contaminated. It is an oversized building with continued maintenance costs regarding the original roof and the intricate brickwork. Much of the old 25 cycle control circuitry is still connected to the DC battery and is a potential source of battery ground problems.

- **Lighthouse Hill:** This station is a significant switching station. It has two 115kV buses and seven transmission lines connecting to the station allowing power to flow from the Oswego generating complex to the Watertown area in the north and the Clay station in Syracuse. In addition, the station provides a direct source of off-site power and black start capability to the Fitzpatrick Nuclear Station. The disconnect switches are in a very poor and hazardous condition, with

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insulators failing frequently. Most of the oil circuit breakers ("OCBs") are in fair condition, but several are obsolete and would pose a challenge to repair. Seven OCBs are located 200 feet from the Salmon River, which is located below the yard elevation. The station is located approximately one mile up-stream of the New York State wildlife fish hatchery. Although the risk is low, any significant oil spill in the station would have a detrimental environmental impact.

- **Rotterdam:** This is a large station with 230kV, 115kV, 69kV, 34.5kV and 13.2kV sections spread out over multiple tiers on a hillside. The 230kV yard is the main supply for Schenectady. Rotterdam is supplied from the Porter Lines #30 and #31 and from Bear Swamp on the E205 line to Massachusetts. There have been three (R23, R24 and R84) catastrophic failures of Federal Pacific Electric RHE breakers at Rotterdam. In addition, two of the three 230kV auto transformers are candidates for replacement (#7 and #8 transformers).

Aggregate funding for these six substation projects will be $2.8 million in FY11, $8.9 million in FY12, $58.9 million in FY13, and $68.7 million in FY14, for a total of $139.3 million for the rate period, as indicated in Exhibit __ (IOP-1), Schedule 8, Sheet 24. These funding levels are based on conceptual engineering costs for the work at Gardenville and Rome stations and pre-conceptual cost estimates for the remaining stations.

Transformer Replacement Strategy and Program. The unplanned failure of a transformer can lead to customers being off-supply for long periods of time until the load can be re-switched, or in many instances, until a mobile substation can be delivered and installed. In addition, lead times to replace most power transformers are in the 18 to 24 month range. The scope of this major program includes the replacement of the 39 highest priority transformers based on their condition. Dissolved Gas Analysis ("DGA"), which is a standard and cost-effective condition assessment test, is used to detect anomalous behaviors within transformers which may indicate a developing fault. Transmission transformers are sampled at least annually, with suspected defective units on enhanced sample intervals. Power factor testing of the transformer and their associated bushings and an assessment of the line-tap-changer is performed during routine maintenance. Additional testing such as swept frequency response analysis (SFRA) and winding impedance tests may be recommended if a review of DGA results indicate further analysis is required. Based on the results of these tests a transformer condition score (1 to 4) is produced.

- Code 4 – under active review to identify the transformer has an internal problem or whether there is a benign reason for the behavior. Code 4 transformers are recommended for replacement within 5 years.
- Code 3 – units are suspected of having developing internal faults.
- Code 2 – indicates a transformer belongs to a suspected design group, however, there are no known issues.
- Code 1 – indicates a normal transformer with no known issues.

The condition codes define the requirement to replace or refurbish based solely on the condition of the asset while the replacement priority also includes criticality in terms of safety, environmental or reliability consequences of failure. This distinction recognizes that two assets, both with the same condition code can have different replacement codes because of the consequences of failure.

The scope includes the transformers (including radiators, fans and pumps), associated civil works, surge arresters and bus connections. This is a pro-active end of life management strategy to ensure the overall reliability of the transmission system. It is estimated that the failure of just one average 17MVA sized transformer could lead to a loss of power for approximately

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17,000 residential customers. The prolonged time needed for restoration (either through the installation of a spare or a mobile sub) would translate into millions of customer minutes interrupted. Examples of transformers to be replaced under this project include those at Altamont, Harper, Solvay, Teal and Swan Road. The program will be funded for $4 million in FY11, and $7 million each of FY12, FY13 and FY14, for a total of $25 million for the period, as indicated in Exhibit __ (IOP-1), Schedule 8, Sheet 24. The estimated in-service date for this project is reflected in Exhibit __ (RRP-6), Schedule 1, Sheet 4, line 5.

U Series Relay Strategy and Program. The Westinghouse U series line of relays was introduced in the early to mid 1970s, and production and support for these relays ceased in the mid 1980s. Westinghouse U series relays are at or near the end of their useful life and are installed on a number of important 345kV lines. Replacement parts and support for the Westinghouse U Series relays are no longer available, making continued maintenance of these devices very difficult. An un-repairable U Series relay could be out-of-service for an extended period of time before a replacement relay can be installed. This program will improve the overall dependability of the protection system. The more modern replacement relays will have the capability of providing fault and operational data which is currently not available. There are four different projects within this program. The work is necessary to avoid a negative effect on protection schemes, resulting in increased reliability risks to the Bulk Power System. This program will be funded for \$2.3 million in FY11 and \$0.7 million in FY12, for a total of \$3 million for the period, as indicated in Exhibit __ (IOP-1), Schedule 8, Sheets 24-25.

Steel Tower Strategy. Only one project remains in the steel tower strategy: South Oswego-Lighthouse Hill. Beyond this the overhead line refurbishment program will address longer-term steel tower replacement projects that were previously planned under the steel tower strategy. The remaining project will be funded for \$4.5 million in FY11 and \$0.4 million in FY12, for a total of \$4.9 million for the period, as indicated in Exhibit __ (IOP-1), Schedule 8, Sheet 24.

Other Asset Condition

Leeds Static VAR Compensator (SVC). This project is required to address the decreasing reliability of the SVC and obsolescence issues. Leeds SVC, installed in 1987, has shown declining reliability in the last six years. In February 2003, ABB, the manufacturer of the SVC notified the Company that technical support would be discontinued. Some replacement parts for these components are now completely unavailable. The proposed refurbishment work includes the replacement of all SVC

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components that are unreliable, have limited or no spare parts availability or are no longer supported by the manufacturer. An assessment of reactive power support requirements at Leeds Station was performed in 2005. The study found that loss of the SVC would de-rate the New York Central to East ("NYCE") boundary flows by 100 MW. The Company reviewed and reconfirmed the study in 2006. A 100 MW reduction of the NYCE capability has the potential to raise wholesale electricity prices for customers in the Company's eastern service territory, and other electric customers located east of the NYCE boundary. It would do so by increasing the number of hours of the year during which the interface becomes a binding constraint on power flows from lower cost generation located in Western and Central NY. Since 2000, there have been over 45 documented problems with the SVC, requiring moderate to major maintenance. These problems have occurred mainly in the protection, control, trigger pulse and thyristor systems. Many of these incidents have resulted in unplanned outages of the SVC, some for extended periods of time. These problems are likely to increase in frequency and severity going forward, thus resulting in an elevated risk of failure. This conclusion is also supported by the manufacturer. Doing this project will reduce the likelihood that the Central-East interface will be de-rated by

100MW. This program will be funded for $5.9 million in FY11, as indicated in Exhibit __ (IOP-1), Schedule 8, Sheet 22.

PIW Prospective Projects. In 2009/10 a budgetary reserve item for Problem Identification Worksheets ("PIWs") was introduced into the capital investment plan to recognize that a number of high priority, low cost, capital projects will inevitably arise during the year and that should be undertaken. PIWs are prioritized and engineering solutions for the highest priority are developed within year. Examples include the replacement at Geres Lock of fourteen 115kV manual disconnect switches and the replacement at Harper station of circuit switchers 2023 and 2024. This prospective program is based on historical levels of PIW activity and will be funded for $1.0 million in FY11, $1.5 million in both FY12 and FY13, and $3 million in FY14,, for a total of $7 million for the period, as indicated in Exhibit __ (IOP-1), Schedule 8, Sheet 23.

Transformer Replacement – Packard & Gardenville. In addition to the proposed transformer replacement strategy (discussed previously in the testimony), there are a number of General Electric 230/115kV transformers fitted with LR9 load tap-changers that are known to be in poor condition. Dunkirk transformer bank (TB) 31 failed in October 2007 and was replaced. Four similar transformers manufactured between 1957 and 1958 remain in-service at New Gardenville and Packard substations. The DGOA analysis on the Packard TB3 indicates an upward trend in combustible gases and the replacement of all four of these transformers is needed.

All four transformers have known condition issues, are categorized as condition 4, and are expected to fail within the next 5 years if stressed. If any one of these transformers failed, securing the Buffalo area network against the loss of a second transformer would require the Company to dispatch local generation. This program will be funded for $10.15 million in FY11, and $2.8 million in both FY13 and FY14, for a total of $15.75 million for the period, as indicated in Exhibit __ (IOP-1), Schedule 8, Sheet 23. The estimated in-service date for the New Gardenville TB3 and TB4 under this program is reflected in Exhibit __ (RRP-6), Schedule 1, Sheet 4, Line 15.

Surge Arresters. This program is driven by reliability, safety and the prevention of damage to other equipment during lightning or switching over-voltages. Tests conducted and reported by IEEE suggest that all silicon carbide arresters that have been in service for over 13 years be replaced due to moisture ingress (degradation was evident in 75% of arresters tested). There are approximately 700 surge arresters at 115kV and above installed on the Company’s system. Information suggests that up to 79 percent of all surge arresters are the silicon carbide type, with a large volume estimated to be in a state requiring replacement. The Company experiences on average three surge arrester failures each year and the vast majority of the surge arrester failures are of the silicon carbide type. As the arresters are predominately installed on transformers, outage availability will limit this program and therefore replacement will be undertaken during planned maintenance. The failure of a surge arrester can lead to damage to expensive wound equipment such as power transformers during switching or lightning transient over-voltages. This program will be funded for $0.25 million in FY12, $2.7 million in FY13, and $2.6 million in FY14, for a total of $5.56 million for the period, as indicated in Exhibit __ (IOP-1), Schedule 8, Sheet 23. Different project stages will close throughout the program life, with closing occurring 12 months following expenditure of the funds.

Sub-Transmission and Distribution

Sub-Transmission Steel Tower Replacement Strategy and Program. This strategy and program provides an approach to managing more than 3750 of the Company's sub-transmission and distribution steel towers. (Wood poles are addressed in the Inspection and Maintenance strategy.) This strategy is focused on system sustainability, and is designed to prevent steel members from deteriorating to the point of structural failure under expected mechanical loading or becoming weak to the point of compromised safety. Several towers have been identified for replacement with additional locations expected. The Sub-Transmission Tower Replacement Strategy is funded at $0.75 million in FY11, $2.25 million in FY12, $3.75 million in FY13, and $5.25 million in FY14, for a total of $12 million for the period, as indicated in Exhibit __ (IOP-1), Schedule 8, Sheet 20. Different project stages will close throughout the program life, with closing occurring 6 months following expenditure of the funds.

Sub-Transmission System Strategy. This strategy proactively manages planned refurbishment and or replacement of sub-transmission overhead lines and their associated assets to ensure the sub-transmission system continues to deliver in a safe and reliable manner for the foreseeable future. This strategy is condition based and incorporates information gathered by field inspections, the aerial helicopter patrol performed in 2008 and reliability performance, and is aimed at maintaining the reliability of the sub-transmission system, which provides supply to the majority of the Company's 4.16kV and 4.8kV substations, as well as some 13.8kV substations. The Sub-Transmission System Strategy is funded at $16 million in FY11, $18 million in FY12, and $9.7 million in FY13, for a total of $43.7 million for the period. Details for these projects

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are included in Exhibit __ (IOP-1), Schedule 8, Sheets 20-21. Examples of major projects that are components of the Sub-Transmission System Strategy include:

- **Lake Clear – Tupper Lake #38 Line Rebuild.** The Lake Clear – Tupper Lake #38 Line is a 46kV Line 20.3 miles long that feeds 693 customers and also the Gilpen Bay Substation. Rebuild of the line is required to replace deteriorated poles, conductors and insulators identified through inspections. Approximately 7.1 miles of 1/0 Cu will require re-conductoring. Replacement of deteriorated conductor and poles will reduce the risk of customer interruptions in the northern Adirondack area. The project is funded at $1 million in FY11, $2 million in FY12, and $1 million in FY13.
- **Batavia - Attica #206 Line Rebuild.** The Batavia – Attica #206 line is a 34.5kV line. This project will replace 97 deteriorated structures that require replacement based on inspection results. An additional 38 poles will be relocated due to severe wetland conditions to an adjacent railroad right of way. The project is funded at $2.5 million in FY11, and $0.5 million in FY12.
- **N. Leroy – Attica #208 34.5kV Line Refurbishment.** N. Leroy – Attica Line #208 is a 34.5kV 21.9 mile long line. The #208 line serves three distribution stations in Genesee County: Attica, Linden and

Sheppard. Confirmed by a field survey, the Attica - N. Leroy #208 line is in need of significant refurbishment. Numerous poles date back to 1940 and many of the structures are severely decayed. Reliability and safety are the prime drivers for this project. There are 235 of the 526 existing structures in deteriorated condition and need replacement. A small section of the line will be relocated from wetlands. A line inspection report was completed by engineering contractor, TRC. All poles to be replaced were rated 4 out of 5, on the Company's rating scale for wooden transmission poles, with 5 being the worst. The project is funded at $1.1 million in FY11, and $1 million in FY12.

- **Battenkill-Cement Mountain-Cambridge #2 Line and #5 Line.** This project will refurbish and replace poles on both these 34.5 kV lines and address safety and reliability concerns. The lines are part of a 34.5kV network and supply three hydro generators and five industrial customers. The peak loading on the #2 line is approximately 4.5MWs and the peak loading on the #5 line is approximately 7.3MWs. The poor condition of the pole plant could result in a pole failure that would create a hazard and result in customer outages. This project is funded at $1.1 million in FY11, and $1 million in FY12.
- **Rathbun – Labrador #39 34.5kV Line Rebuild.** This project will replace 193 deteriorated single wood pole structures on the Rathbun –

Labrador #39 34.5kV Line. The line is 27 miles long and serves five (5) rural substations south of Syracuse and one radial customer. The primary drivers for this project are safety and reliability: Replacement of these assets will reduce the risk of customer interruptions related to deteriorated equipment; and address the condition of the existing pole plant, much of which is leaning and in a deteriorated state with woodpecker/insect damage, split pole tops, and shell rot. The project is funded at $1 million in FY11, and $1 million in FY12.

- **Gloversville – Canojaharie #6 69kV Refurbishment.** Out of 212 structures on this line, 112 will be replaced due to structural inadequacy. Special structure framing specifically designed for this 69kV line will be used, as will an overhead ground wire for all new poles to ensure proper phase spacing, mid-span clearance to ground, and protection over all three phases with a shield wire. Replacing these structures will improve reliability to customers. The project is funded at $1 million in FY12, and $1 million in FY13.

Distribution Substation Transformer Replacement Strategy and Program. This strategy addresses a population of 807 Distribution Power Transformers (primary voltage 69kV and below), and provides both proactive asset replacement of individual units identified by condition and risk, in conjunction with capacity planning requirements, and reactive replacement of transformers which have failed in service. This is performed through:

- Ranking substation transformers in terms of asset condition, failure impact and risk,
- Identifying the nominal replacement volume of substation power transformers based on installed MVA and best analytical estimates of transformer life expectancy (currently 65 years).

The risk/adverse impact of delaying this program includes:

- Catastrophic transformer failure resulting in widespread dissemination of oil, possibly burning, and related collateral damage to the station infrastructure and environment,
- Unplanned replacement of a failed unit may take several days as opposed hours for a planned replacement,
- Contingent failures may cause significant widespread interruptions (sub-transmission and heavily loaded distribution units have high contingent impacts, compared to transmission units).

The main driver for this program is the need to address poor condition units. An individual unit that fails may have a significant impact on reliability (up to 355,000 CMI per event) with a SAIDI contribution of up to 0.3 minutes, on average. In addition, lead times for replacement units may be 6 months to 2 years (current lead time for a 5 MVA transformer is 6 months).

Examples of Distribution Substation Power Transformers being reviewed for replacement and/or re-configuration include: Fisher Avenue Station 27, 34.5-13.8kV, 6.25MVA; Fayetteville, 34.kV-2.4kV, 6.25MVA; French Creek Station, 34.5kV-13.8kV, 3.75MVA; and Chrisler Ave, 34.5kV-4.16k, 3.65MVA. The Distribution Substation Transformer Replacement strategy is funded at $1.5 million in FY11, $1.5 million in FY12, $1.5 million in FY13, and $2 million in FY14, for a total of $6.5 million for the period, as indicated in Exhibit __ (IOP-1), Schedule 8, Sheet 19. .

Substation Circuit Breaker Strategy and Program. This strategy and replacement program targets obsolete and unreliable breaker families. The strategy defines unit condition and a formal spares policy to manage this large asset class. There are approximately 4,100 distribution and sub-transmission substation circuit breakers in this population. The method for managing substation breakers and reclosers consists of periodic maintenance, refurbishment and replacement on condition. Units with obsolete technology, such as air magnetic interruption, have been specifically identified for replacement. Additionally, where cost effective and where their conditions warrant, the opportunity will be taken to bundle work and replace disconnects, control cable and other equipment associated with these circuit breakers. The distribution strategy is funded at $3.5 million in FY11, $1.7 million in FY12, $3.5 million in FY13, and $7 million in FY14, for a total of $15.7 million for the period, as indicated in Exhibit __ (IOP-1), Schedule 8, Sheet 17. The sub-transmission strategy is funded $0.3 million in FY12, $2.6 million in FY13, and $2.8 million in FY14, for a total of $5.7 million for the period, as indicated in Exhibit __ (IOP-1), Schedule 8, Sheet 19. Different project stages will close throughout the program life, with closing occurring 9 months following expenditure of the funds.

Substation Metalclad Switchgear Replacement Strategy and Program. This strategy replaces switchgear installed prior to 1970 beginning with those metalclad switchgear that have sustained a failure or are of a manufacturer type where a failure has occurred. There are approximately 220 metalclads in service operating at 13.2kV, 4.16kV and 4.8kV. Of these, approximately 70 were installed in the 1960s and 1970s. Several design factors with older vintage metalclad substations contribute to bus failures or component failures. These factors include:

- Moisture Sealing Systems - Moisture and water contribute to most of the failures of metalclad switchgear, substations and busses. Gaskets and caulking of enclosures deteriorate over time allowing rain and melting snow to enter.

- Ventilation - Metalclad interiors can reach high temperatures in the summer even if ventilation systems are working correctly. High temperatures degrade the lubrication in breaker mechanisms and other moving parts, and can cause failure of electronic controls and relays.
- Insulation - Voids in insulation, which eventually lead to failure of the insulation when stressed at high voltages, are apparent in earlier vintage switchgear.

This Substation Metalclad Replacement Strategy and Program would replace two metalclad substations per year using assessments based on age, manufacturer and conditions as determined by visual and electro-acoustic test results. The Altamont and the Market Hill Substations are two distribution locations that have been identified for replacement in FY11. The North Troy Substation and Oneida Substation are two sub-transmission locations that have been identified for FY11. The distribution strategy is funded at $1.2 million in FY11, $4.8 million in FY12, $5.0 million in FY13, and $3 million in FY14, for a total of $14 million for the period, as indicated in Exhibit __ (IOP-1), Schedule 8, Sheet 18. The sub–transmission strategy is funded at $1.25 million in FY11, and $1.9 million in FY12, for a total of $3.19 million for the period, as indicated in Exhibit __ (IOP-1), Schedule 8, Sheet 20. Different project stages will close throughout the program life, with closing occurring 9 months following expenditure of the funds.

Indoor Substation Strategy and Program. The purpose of this strategy and program is to review of site locations, determine rebuild options, and rebuild 22 indoor substations located in Buffalo and 6 indoor substations located in Niagara Falls. This refurbishment plan is required to remove safety and equipment failure risks based on asset conditions. These indoor substations were built in the early 1930s and are over 70 years old. These stations are 23kV-4.16kV. Key drivers for replacement include:

- Safety - The stations have inherent hazards/safety risks due to design and equipment condition and have been the subject of ongoing meetings with represented employees.
- Capacity and Loading - The station rebuilds have been driven by issues of station loading and transformer capacity. This has resulted in replacing the existing 2500kVA transformers with 3750kVA units at locations already rebuilt.
- Asset Condition - The bay 1-3 sections of the Buffalo stations date from 1929 to 1931. Some stations have a 4th bay that was

added in the 1940s and 50s. This places equipment ages from 50 to 75 years, which is beyond their designed service life, significantly increasing the probability of failure. In addition, obsolete equipment often does not meet current requirements for fault interrupting capability, operating interfaces, and personnel safety.

Buffalo Station 29, 23, 43, and 52 are currently being rebuilt with completion scheduled at the end of FY11. Buffalo Stations 27, 37, 59, and 25 are scheduled for FY12-13. The substation and distribution line strategy is funded at $8.6 million in FY11, $13.9 million in FY12, $17.7 million in FY13, and $17.7 million in FY14, for a total of $57.9 million for the period, as indicated in Exhibit __ (IOP-1), Schedule 8, Sheet 18. The 23kV sub-transmission line portion of the strategy is funded at $0.66 million in FY11, $1.9 million in FY12, $1.8 million in FY13, and $1.8 million in FY14, for a total of $6.16 million for the period as indicated in Exhibit __ (IOP-1), Schedule 8, Sheet 20.

Distribution Substation Battery Strategy and Program. The intent of this strategy is to replace batteries beyond 20 years old. There are slightly more than 200 distribution batteries systems in Niagara Mohawk distribution substations. The 20 year limit is based on industry best practice in managing battery systems. Substation batteries and chargers play a significant role in the safe and reliable operation of substations. Batteries and chargers provide DC power for protection, control and communications within the substation and between substations and control centers. This strategy will assist in ensuring battery systems meet current operating requirements and will perform their designed function. Delaying this replacement strategy will lead to control problems in substation operations. The strategy is funded at $470,000 in FY11, $160,000 in FY12, $405,000 in FY13, and $825,000 in FY14, for a total of $1.86 million for the period, as indicated in Exhibit __ (IOP-1), Schedule 8, Sheet 17.

Primary Underground Cable - Distribution and Sub-transmission. The distribution and sub-transmission underground cable asset replacement strategy replaces cables that are in poor condition and those identified 60 years or older with known condition issues. Replacing these cables on a planned basis is highly desirable since the work involved often includes civil work. Customers are directly affected by these extended repairs where alternate feeds are not possible or available. Sub-transmission primary cables also provide supply to the many of the 4.16kV and 4.8kV substations and some 13.8kV substations in densely populated areas such as Syracuse, Buffalo, Utica, Albany, and

Schenectady. Examples of distribution cables currently being reviewed include: Mill St Network Cables in the Central Division; Corliss Park 4kV Cables in the Eastern Division; and Buffalo Station 27 4kV cables in the Western Division. Examples of sub-transmission cables currently being reviewed include: McBride –Brighton #20 and #22 in the Central Division; Partridge-Avenue A #5 and Riverside to South Mall in the Eastern Division; and Elm St, Seneca, and Kensington 23kV Underground Circuits in the Western Division. The Distribution strategy is funded at $3.4 million in FY11, $4.5 million in FY12, $3.0 million in FY13, and $4.5 million in FY14, for a total of $15.4 million for the period, as indicated in Exhibit __ (IOP-1), Schedule 8, Sheet 17. The sub-transmission strategy is funded at $3.5 million in FY11, $6.6 million in FY12, $7.8 million in FY13, and $11.6 million in FY14, for a total of $28.7 million for the period, as indicated in Exhibit __ (IOP-1), Schedule 8, Sheets 19 and 21.

Underground Network Asset Replacement Strategy. The underground network asset replacement strategy and program targets the maintenance, monitoring and installation/replacement of: limiters, transformers, protectors, secondary cables and miscellaneous network assets. Network systems include aged assets installed in harsh environments such as manholes and vaults, and require monitoring, maintenance and replacement to maintain the reliability and physical integrity of the equipment. Though networks generally provide reliable service, when incidents do occur, restoration can end up being very lengthy and costly, with potential to interrupt large numbers if customers due to the high density areas the networks serve. Niagara Mohawk has underground network systems located in Albany, Syracuse, Buffalo, Watertown, Troy, and Utica.

The Company has initiated a number of studies to analyze the ability of the secondary network cables to clear during fault conditions as a result of previous network incidents. Load flow studies have also been completed on the Buffalo, Syracuse Ash Street, Syracuse Temple Street, Watertown and Troy networks. All networks will have a load flow study performed. The strategy is funded at $2.1 million in FY11, $2.1 million in FY12, $2.0 million in FY13 and $2.25 million in FY14, for a total of $8.45 million for the period, as indicated in Exhibit __ (IOP-1), Schedule 8, Sheet 16.

E. Non-Infrastructure

Q. Please discuss the investments the Company plans to undertake in the Non-infrastructure category during the period covered by this rate case.

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A. In addition to spending on its electric network, the Company also invests a small portion of its investment budget (<1%) in systems and tools that are not specific to the operation of a particular element of the electric system. Examples include security systems, radio systems, test equipment flood protection and substation building repairs that that are required to support the safe and reliable operation of the network. Exhibit __ (IOP-1), Schedule 7, illustrates the amount the Company plans to spend in the Non-infrastructure category in FY11-FY14.

Q. Please describe some of the major projects and programs that are included in the Company's infrastructure investment plan in the Non-infrastructure category.

A. Below we provide a description of major projects and programs in this category, segregated by portion of the electric system they address. Additional information on these programs is included in Exhibit __ (IOP-1), Schedule 8, Sheet 26.

Transmission

Physical Security NY Bulk Power System Substations. This strategy is driven by the NY DPS recommendation to install additional physical security measures at our BPS substations. The benefits from this

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BPS security strategy arise from deterring and detecting unauthorized access to BPS substations. This program will be funded for $100,000 in FY11, $6 million in FY12 and $3 million in FY13, for a total of $9.1 million for the period.

Flood Mitigation. Overall the predicted weather changes indicate that the types of heavy rainfall events that have occurred in the Northeast in recent years will become increasingly common, raising the risk of floods and flash floods. Flooding at sites such as Gardenville and Oswego have already occurred as well as sites along the Mohawk River valley (June 2006, St. Johnsville and Inghams). A study of the flooding risk concluded that flooding events were likely to increase. Sites that were classed high risk (or sites where no FEMA Insurance Rate Map existed) were then subject to a more detailed assessment in which the following factors were ascertained i) proximity of the site to water features such as streams, lakes and oceans, ii) proximity to designated FEMA flood zone, iii) elevation of the site above nearby water surface elevation and iv) the reliability of FEMA information e.g. date of maps. From this more comprehensive survey and site visits a small number of sites were identified that had an elevated risk and that measures may be required to reduce the likelihood of flooding. These sites are Adams, where the control room is located 2’ below ground level, Amsterdam which has low lying control panels, Ingahms, Lighthouse Hill which is located in the lee of a dam wall and St. Johnsville which is located next to the Mohawk River. Preventing flooding will result in enormous saving associated with equipment that could otherwise be damaged or destroyed. This project is categorized within the "Other" program and is budgeted at $3 million; however, the scope and timing of work has not been finalized. This program is currently funded at $2 million in FY13 and $1 million in FY14, for a total of $3 million for the period. These amounts are pre-conceptual level estimates and likely to change during detailed engineering.

<u>Sub-Transmission / Distribution</u>

General Equipment – These blanket programs are for field equipment, tools or specific equipment requirements which have costs are greater than $200/per unit and are not included in other capital projects. A reserve is also set up to budget for purchases of equipment known to cost more than $100,000. These reserves are based on historical calculations for specific projects within the category. The driver for this blanket is to enable the purchase of necessary non-infrastructure equipment involved in support of operations. This blanket is funded at $2.2 million in FY11, $4.3 million in FY12, in $4.5 million in FY13, and $4.6 million in FY14, for a total of $15.6 million for the period.

Distribution – Telecommunications. The driver is to allow for the purchase of non-infrastructure telecommunications related equipment involved in support of operations. This blanket is funded at $1.0 million in FY11, $1.1 million in FY12, $1.1 million in FY13, and $1.1 million in FY14, for a total of $4.3 million for the period.

Q. Does the Company's revenue requirement in this case include cost of removal ("COR") associated with the capital investment plan?

A. Yes. In addition to the capital costs discussed above, there is a level of COR required to implement the Company's infrastructure investment plan presented in this case. As reflected in Exhibit (RRP-6), Schedule 1, Sheet 5 of the Revenue Requirements Panel, the Company anticipates projected Cost of Removal (COR) of approximately $18.7 million for the last six months of FY10, $38.3 million in FY11, $46.6 million in FY12, $51.9 million in FY13 and $54.9 million in FY14.

Q. What type of activities does the Company associate with 'Cost of Removal'?

A. The Company defines removal as any work on existing assets that results in said asset being removed from the asset inventory, whether or not a different asset is subsequently added in its place. This type of work would include, but is not limited to, all the activities associated with the disconnection, removal and disposal of high voltage items of equipment such as circuit breakers and transformers; disconnection, removal and disposal of secondary items of equipment such as relays and control equipment; removal and/or demolition of foundations; disconnection, removal and disposal of insulator strings; removal of wood poles or steel structures; and disconnection and removal of shield wire.

Q. Please explain the basis for the projected COR increases for the rate years?

A. COR is estimated using recent historical experience as an indicator of the likely level of future expenditure. A ratio of actual COR to infrastructure investment for distribution, transmission and sub-transmission, typically over a period of the last three years, is calculated. The resulting percentages are applied to the amount of infrastructure investment that is projected to be spent in each category and this derives the COR amount over the planning horizon.

F. <u>Annual Budget Process</u>

Q. Please provide a brief summary of how the Company developed its budget for the infrastructure plan?

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A. We provide a brief description of the Company's budgeting process here. However, as discussed previously, the Company also addresses the management audit report recommendations, including those related to the budget process, in the implementation plan included with Mr. Zschokke's testimony in this case.

Each year, the Company develops an Annual Work Plan designed to achieve the overriding performance objectives of the business unit (safety, reliability, efficiency, and environmental performance). At the outset, the Annual Work Plan represents a compilation of proposed spending for programs and individual capital projects. Programs and projects are categorized by spending category: i.e., Statutory/Regulatory, Damage/Failure, System Capacity and Performance and Asset Condition. The proposed spending forecasts for each program or project include the latest cost estimates for in-progress projects as well as initial estimates for newly proposed projects.

In order to optimize the plan budget and resources, a risk score is assigned to each project. The project risk score is generated by a project decision support matrix that assigns a project risk score based upon the estimated probability and consequence of a particular system event occurring. The project risk score takes into account key performance areas such as safety, reliability and environmental, while also accounting for criticality. Historical and forward looking checks are made by spending rationale to identify any deviations from expected or historical trends.

All mandatory programs and projects known at this time are included in the plan. Mandatory programs and projects (i.e., Statutory/Regulatory and Damage/Failure spending rationales) include FERC bulk power system requirements, new customer and generator connections, regulatory commitments, public requirements that necessitate the relocation or removal of our facilities, safety and environmental compliance, and system integrity projects such as response to damage/failure and storms.

Once the mandatory budget level has been established, programs and projects in the other categories (i.e., System Capacity and Performance and Asset Condition spending rationales) are reviewed for inclusion into the plan. Plan inclusion/exclusion for any give project is based on several different factors including, but not limited to: project new or in-progress status, risk score, scalability, and resource availability. In addition, when it can be accomplished, the bundling of work and/or projects is analyzed to optimize the total cost and outage planning. The objective is to establish an optimized capital portfolio that optimizes investments in the system based upon the measure of risk or improvement opportunity associated with a project.

The portfolio, along with supporting risk analyses, is presented to the Company's senior executives and ultimately the Board for review and approval. The budget amount is approved on the basis that it provides the resources necessary to meet the business objectives set for that year. Company management is responsible to manage to the approved budget.

Q. Why does the Company modify or adjust its budgets?

A. From an overall perspective, the Company's objective is to arrive at a capital budget that is the optimal balance in terms of making the investments necessary to maintain and improve the performance of the system for customers, while also ensuring a cost-effective use of the Company's available resources. Because of the time horizon over which the Company must budget its infrastructure investments, there are inevitable changes in budgets and project estimates over time. Such changes may be due to changes in project scope, changing material or resource costs, or changing customer needs, or a more refined estimate based on where the project is in its development.

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Q. At what stage in the project evolution process are the projects that are included in the Company's infrastructure investment plan presented in this case?

A. The plan presented in this case represents the Company's best information on the investments it will need to make in order to sustain the safe, reliable operation of the electric system. As described above, many of the projects are already in-process or soon to be in process. Estimates for those projects are quite refined. Other projects are at earlier stages in the project evolution process. The budgets for those projects are accordingly less refined, and are more susceptible to changes in scope and budget.

Typically, projects to be delivered in the near term are more firm in their cost estimates than out-year projects. In addition, project estimates may vary based on where they are in the project evolution stage. That is, project estimates that go into developing the Company's infrastructure investment budget become more refined as they progress from the initiation stage to the delivery stage. The plan is continuously reviewed, following approval and during the current year, for changes in assumptions, constraints, as well as project delays, accelerations, outage coordination, permitting/licensing/agency approvals, and system operations, performance, safety, and customer driven needs that arise. The plan is updated accordingly throughout the current year. A graphical depiction of this "project evolution" process is included in Exhibit __ (IOP-4).

Initial estimates, prepared during project development, have a margin of error of plus or minus fifty percent. This is the wide end of the funnel. The margin of error grows progressively smaller as project development proceeds and the engineering scope and cost estimates are refined and subsequently finalized at Project Sanction. This is the narrow end of the funnel. Thus, by process, estimates made at the early stage of a project have no bearing on the efficient delivery of a project post project sanctioning

Project risks are now identified and managed earlier in the process and these project risks include variation in permitting times, field conditions that are different from what initial field reviews highlighted (particularly with respect to underground/civil work), and the availability of outages from NYISO.

Q. Are there other approval processes that are conducted in relation to the annual budget?

A. Yes. As stated above, the result of the budgeting process is the approval of a total dollar amount for capital spending in the budget year. In addition to this planning and budgeting process, specific approval must be obtained for any Strategy, program or project within the Annual Work Plan. Approval is obtained through a "delegation of authority," or "DOA," requirement prior to proceeding with project work including engineering and construction. Each project must receive the appropriate level of management authorization via a Project Sanction Paper prior to start of any work. Approval authority is administered in accordance with the Company's DOA governance.

Q. What is included in Project Sanction Papers you mentioned above.

A. Projects with projected scope and costs above established thresholds must be presented as appropriate to management. Projects presented must be accompanied by a detailed Project Sanction Paper ("PSP") for approval. The PSP must include a written summary of various major factors that are considered in any decision to allow the project, including:

- <u>Project Background, Description and Drivers</u>: These sections provide a high-level overview of the project and the factors driving the need for its completion.

- Business Issues, Options Analysis: This section provides a summary of the business issues involved in the project. The options analysis discusses other potential courses of action including the impacts of a "do nothing" strategy.
- Financial Impact and Cost Summary: This section provides an economic analysis of the proposed project. The nature of the economic analysis differs depending on the nature of the project.
- Investment Recovery: This section evaluates any factors relating to the recovery of the investment.
- Project Schedule, Milestones and Implementation Plan: This section describes any timing implications and start-up schedules.

Once an approved project is completed, the project sponsor is responsible for preparing closure papers, which present information on a number of factors including a discussion of whether and to what extent project deliverables were achieved and lessons learned as a result of project implementation.

Q. What is the process for re-sanctioning capital projects?

A. Capital projects are authorized with either a conceptual or project-grade estimate following preliminary engineering. Reauthorization is required if the project cost is expected to exceed the estimate plus the variance range identified in the PSP. The reauthorization request must include presentation of the original authorization, the variance amount, the reasons for the variance and the details and costs of the variance drivers, as well as the estimated impact on the current year's spending. Project reauthorizations above established thresholds require re-approval. Project spending is monitored monthly against authorized levels by the project management and program management groups. Exception reports covering actual or forecasted project spending greater than authorized amounts are presented and reviewed monthly. Significant projects also require re-sanctioning if the project completion date is delayed more than three months beyond the approved date.

Q. How does the Company's plan provide for unbudgeted, or "walk-in," projects?

A. The Company includes certain Reserve line items in its Spending Plan, by budget category, to allocate funds for projects whose scope and timing have not yet been determined. In such cases, historical trends are used to develop the appropriate reserve levels. As the specific project details become available, "walk-in" projects are added to the plan with funding drawn from the reserve funds. The majority of projects that are "walked–

in," are the result of in-year occurrences in mandatory project categories such as damaged or failed equipment, customer or generator requirements or regulatory mandates. Reserve funds are also established for high priority risk score projects that are may arise during the current year in response to unforeseen system reliability or loading concerns. The Company tracks and manages budgetary reserves and walk-ins as part of its investment planning and current-year spending management processes.

Q. The recent Management Audit report released on Niagara Mohawk criticized the Company's cost estimation performance. How can the Company be confident that its capital portfolio reflects projects delivered in a quality manner given the Management Audit findings?

A. As indicated in its response to the management audit report, the Company found the management audit process to be helpful in identifying areas for potential improvement of its systems and processes in order to perform more efficiently and effectively going forward. Steps the Company is taking to address the final recommendations are described in the implementation plan that is included with Mr. Zschokke's testimony, including measures to improve project estimating performance.

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Notwithstanding the importance of sound estimating, the Company does not believe that inaccurate project cost estimates would, by themselves, affect the Company's delivery of projects in a high quality manner. First, projects are identified using a risk-based approach (as described previously), which is independent of estimating accuracy. As projects progress, and additional scope, resources, duration, and scheduling information becomes available, the project estimate is refined.

Q. What steps is the Company taking to address the Management Audit recommendations regarding estimation?

A. One of the Company's major initiatives in this area is the creation of the Estimating Center of Excellence (ECoE). The ECoE was established to enable the groups and individuals responsible for project estimates to perform this task with greater consistency and accuracy. The ECoE is charged with identifying and implementing the process improvement that will overcome deficiencies in project cost estimating. The ECoE will establish and maintain the Company's actual cost data base and estimating proficiency through the use of appropriate estimating software, user training, process documentation, and continuous performance monitoring. The successful results of these efforts will provide the infrastructure investment plan with high quality, accurate cost estimates.

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The ECoE has defined the process by which project estimates mature as the need date for the defined work advances. Estimates will progress through a series of accuracy grades over the project's development timeline. The estimating software chosen for use by the ECoE, has the flexibility to modify the assumed values and estimating units as the project scope is progressively defined. This enables the estimator to effectively use the tool to furnish the investment plan with increasingly accurate cost estimates.

The software tool was configured and uploaded with Distribution and Transmission line and substation estimating units, based upon the knowledge of experienced designers and project managers. As part of its charter of responsibilities the ECoE will provide routine updates to the estimating units and underlying assumptions. Some of these revisions will result from the continuous monitoring of the actual tolerance achieved by the different grades of estimates. The ECoE will act to identify causes for those variances that have been detected and initiate the corrections to estimating units/processes/etc. as required.

G. <u>Delivering the Investment Plan</u>

Q. Please describe how the Company will deliver the proposed infrastructure investment plan over the course of the rate plan.

A. Historically, the Company has delivered its construction plan through a variety of arrangements. However, the business environment in which the Company delivers its capital program is changing. Through optimization of its internal workforce and contracting arrangements, the Company can realize sustainable value for customers through cost-effective, reliable, and improved capital plan delivery.

The Company's portfolio of construction delivery resources include:

- Distribution Alliance Contracts;
- Transmission Regional Delivery Ventures (RDVs);
- Enhanced Internal Construction Capabilities;
- Traditional "project-by-project" competitive bidding; and
- "Turn-Key" Engineer, Procure, and Construct (EPC) events for specialized installations.

Q. Could you describe the mix of construction resources you refer to?

A. *Distribution Alliance Contracts*

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Following a year-long competitive procurement event, Harlan (a subsidiary of Myr Group) was selected to deliver Niagara Mohawk's distribution line construction program under a fixed-price unit rate agreement over a three-year contract period (with an option to extend 2 years). The reduced unit and tendering costs resulting from the aggregated bid process are already factored into the Company's investment plan amounts for the rate plan period. In addition to these competitively bid units, the Company anticipates additional benefits related to reduced tendering timeframe, improved scheduling, and a stable workforce with increased safety, customer, and standards training.

Harlan's performance will be evaluated against its unit costs, workload delivery, and agreed Key Performance Indicators (KPIs). For each project, Harlan and Niagara Mohawk jointly complete a constructability review to agree to project scope, units, and schedule. A Work Request will be executed to document these delivery criteria and the workplan agreed to efficiently deliver the work. To further incentivize performance and improved customer value, Harlan is subject to a KPI scorecard focused on Safety and Environment, Quality, Delivery, and People performance measures. The release of work in subsequent years is dependent on satisfactory performance against these criteria to ensure acceptable costs and workload delivery performance. The Alliance contracts do not guarantee a minimum volume of work, nor are they exclusive arrangements.

Transmission Regional Delivery Ventures (RDVs)

The Company is improving its delivery of the infrastructure investment plan via the introduction of the Transmission Regional Delivery Venture (RDV). This RDV will operate under a long-term contract arrangement (i.e., 5-year, with an option for 3 more years) that includes the integrated provision of detailed design, project management and construction services to deliver an assigned portion of the Company's capital investment program. The RDV contract includes comprehensive "full open book" audit rights. The contract does not guarantee a minimum volume of work or exclusivity.

The selected RDV, entitled Northeast Power Alliance (NEPA), is a joint venture comprised of AMEC, Michels Corp, and Vanderweil Engineers. Assignment of project work to NEPA, has resulted in a baseline savings of $60 million for Niagara Mohawk and this has already been removed from the 5-year capital plan. These savings include a combination of the reduced unit costs and fees resulting from the competitive RDV procurement event plus reduced tendering costs and improved scheduling. Another included benefit is an insurance premium savings by direct sourcing the Transmission portfolio to the insurance market for OCIP (Owner Coordinated Insurance Program) versus traditional insurance coverage. To leverage its buying power, the Company supplies all plant materials to the RDV except for consumable items.

To further incentivize performance and improved customer value, the RDVs are also subject to a KPI scorecard focused on Safety and Environment, Quality, Delivery, and People performance measures. The KPIs ensure efficiency is not at the expense of performance by putting the RDVs' share of any efficiency "gain" at risk, subject to meeting certain KPI performance.

Enhanced Internal Construction Capabilities

The Company continues to enhance its own internal transmission and distribution construction capabilities in order to perform a portion of the capital program. For the past two years, a dedicated workforce of 30 substation and 30 transmission line workers have been performing construction work on the both the transmission line and substation assets. Additionally, a Distribution Line Construction Pilot (DLC) has been undertaken to create a competitive framework for in-house crews comprised of 56 line workers to perform distribution construction line work typically performed by contractors in the past. Pilot development began in October 2009, with pilot implementation targeted for April 1, 2010 through April 1, 2011. These new construction capabilities enable an internal workforce, dedicated to capital construction, to perform a larger portion of the infrastructure investment program while providing for greater visibility of and comparison to the value of work delivered by the external market, enabling benchmarking opportunities to drive further value.

Traditional "project-by-project" competitive bidding

The Company will continue to periodically employ the contracting model where contractors are selected on a competitive bid, project-by-project basis where applicable to enable the Company to deliver niche services or competitively-priced projects based on specific market conditions.

"Turn-Key" Engineer, Procure, and Construct (EPC) events for specialized installations.

The Company will continue to utilize a "turn key" model where complex and specialized equipment is being installed.

Q. Why has the Company chosen to perform a portion of the infrastructure investment work presented in this rate case using the RDV mechanism rather than the traditional process of selecting contractors for projects on the basis of competitive bids?

A. One of the primary value drivers of the Company's RDV model is the development of long-term, integrated supplier relationships aimed at capturing the value of negotiating a large portfolio of work. Aggregation of the volume of work through a single Procurement Event with multiple bidding entities allows for increased competitive prices and schedule improvements through reduced procurement time and program/resource optimization. The integrated RDV model, which includes detailed design, project management and construction services, optimizes design efficiencies and construction delivery through end-to-end accountability and constructability focus. In addition, the Company, like other utilities across the country, is faced with substantially increasing capital investment requirements. These requirements cannot be effectively met by increases in internal staffing or use of traditional contracting resources alone. Further, given the anticipated increase in infrastructure spending throughout the country, it is reasonable to expect that skilled engineers, designers and craft workers could be in short supply during the plan period. By entering into long-term arrangements with qualified partners,

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the Company is able to secure and retain highly skilled personnel and construction equipment needed to deliver on the investment plan. The contracted entities are familiar with the region and are capable of working in accordance with company standards, and have the capacity to work on multiple related or similar projects.

Q. How will the RDV target costing process generate value for customers?

A. The target cost incentive mechanism encourages the Company and the RDV to generate efficiencies through improved risk management and by equally sharing the difference between the project target cost and the actual costs at project completion. Thus, if actual project costs are below the target costs, the RDV has an opportunity to receive up to 50 percent of the difference between the actual and target costs in the form of a gain share. Likewise, if actual costs exceed target costs, the RDV would receive 50 percent of the amount by which the target is exceeded. Future projects benefit fully from the efficiencies as the unit costs are reduced year on year in line with the reductions in actual cost, known as "cost ratcheting".

Q. Could you please describe what "core team costs" are?

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A. Yes. Core Team Costs are RDV management and infrastructure costs that are assessed annually pursuant to the RDV contracts. There are two elements to the RDV Core Team Costs: Core Team Project Specific costs (project-specific costs directly charged to specific projects); and Core Team Overhead (non-project specific resources and costs; allocated on the basis of established allocators). Core Team project specific costs cover the RDV's Project Planning and Preliminary Engineering resources that are providing assistance to the Company to develop specific work proposals and target costs. Non-project-specific resources support and manage the RDV work in the project planning and preliminary engineering, final design, project execution and project closeout stages for work being carried out by the RDV in the year. The RDV submits Core Team invoices to the Company every two weeks that cover the RDV's actual costs, applicable fee, and certain tax expense. Following review by the Company, RDV costs are recorded as either O&M charges or capital. Capital costs are allocated to individual projects. A further description of how the costs are reflected in the revenue requirement is set forth in the testimony of the Revenue Requirements Panel.

Q. Is the Panel aware of other instances where the RDV contracting model has been used successfully?

A. Yes. In the United States, the American Transmission Company ("ATC") has successfully used a similar alliance contracting strategy for the past 3 years on its $2.5 billion, 10-year program of work. This alliance contract has recently been competitively renewed with MJ Electric for a further 4 years and a second alliance, replacing the remainder of ATC's project work, has been awarded to Henkels and McCoy. MJ Electric has quoted savings of between 6 and 12 percent each year for work performed in 2007-2009, when compared to other methods of delivering the work.

National Grid has also used the long term collaborative approach successfully in the UK. National Grid's Gas Alliance arrangement in the UK produced an 18 percent reduction in costs over the first three years it was in place when compared to costs under the prior contracting regime. Likewise, National Grid's UK East Overhead Electricity Alliance has experienced cost reductions of 18 percent in 2007/08 and 3.7 percent in 2008/09 on over $150 million of annual spend compared to the previous models employed.

H. <u>In-Service Dates Reflected in Revenue Requirements</u>

Q. What is the effect of the in-service date of a project on the Company's revenue requirements?

A. The Revenue Requirements Panel addresses this issue in greater depth, but in summary, the in-service date of a project determines when a project is reflected in the Company's rate base for purposes of affecting the revenue requirements.

Q. Could you explain how the Company determined the in-service dates you describe above?

A. Yes. First, it is the Company's objective to establish in-service dates that accurately reflect the estimated actual in-service date. The ability to accurately estimate in-service dates for large projects that are already underway and near completion is obviously greater than for projects that have not commenced and are further out in time. Smaller projects are subject to other considerations when estimating in-service dates. In the case of small projects (which may be more prone to schedule shifts for operational efficiency/bundling or other reasons), or programs comprised of recurring projects that are put in-service throughout the year, it is more difficult to predict definitive in-service dates. Therefore, in developing the in-service dates reflected in this case, the Company estimates actual in-service dates for very large projects (i.e., those with estimated costs greater than $15 million). For programs and projects budgeted at less than $15 million, the Company used in-service dates determined pursuant to accounting closing rules applicable to the type of project or program. Thus, amounts for construction work in progress ("CWIP") and capital expenditure cash flows forecasted from CWIP were estimated to go into service in the month following the applicable period under the closing rule. The relevant closing rule periods were determined based on a historical analysis of CWIP and plant closings. Sample closing periods used by the Company include: transmission substations—12-months; distribution substations—9 months; transmission lines—6 months; distribution lines and street lighting—3 months; meters and line transformers—1 month. For example, assuming a projected expenditure of $100,000 in January related to a distribution line capital project, such expenditure would be deemed closed to plant in-service in the month following the closing rule period, or April.

I. <u>Additional Projects</u>

Q. The Company's plan includes recovery of costs associated with projects identified as "Luther Forest," "Tri-Lakes" and "Hydro One." Would you please discuss these projects and how they are reflected in the Company's investment plans?

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<u>Luther Forest</u>

A. Luther Forest Technology Campus (LFTC) is a 1350 acre industrial park located in Saratoga County. The LFTC is being built by the Luther Forest Technology Campus Economic Development Corporation (LFTCEDC) to attract computer chip manufacturing facilities. The new LFTC Park will include 115kV transmission capability to serve the computer chip fabrication facilities. LFTCEDC is currently engineering, purchasing material, and constructing the following facilities: (1) four 115kV transmission circuits; (2) a transition station (Stonebreak Road) which would allow two of the four 115kV lines to transition from underground to overhead; and (3) a 115kV "Luther Forest" switching station. The design and facilities being developed by LFTCEDC are intended to provide highly reliable, redundant service to customers with a need for such high reliability. Nanotechnology computer chip manufacturers, because of the processes they use, often require such high reliability service.

Q. What is the Company's interest in the facilities being built by LFTCDC?

A. The facilities being constructed by LFTCEDC would interconnect directly to the Company's existing transmission system. In addition to enabling service to be provided to computer chip manufacturing facilities in the

LFTC, the newly constructed facilities will become part of the integrated network transmission system. Therefore, once the facilities are constructed, it is anticipated that their ownership will be transferred to the Company, and the Company would own, operate and maintain the facilities going forward. During discussions with FERC staff on a related engineering, permitting and construction services agreement, FERC staff suggested that FERC might have jurisdiction over elements of the transfer agreement, which would require FERC review of the transfer agreement.

Q. At what price will the facilities be transferred to the Company?

A. The cost of the transmission facilities being developed by LFTCEDC is estimated to be approximately $57 million, and is being paid primarily through New York State grant funds, and not being paid by the end use customer or customers. The facilities are being constructed to provide extremely reliable, redundant service considered vital to attract nanotechnology computer chip manufacturers to the newly developed LFTC, which contributes significantly to the estimated $57 million cost. It is the intention of LFTCEDC and the Company that once completed; the facilities would be transferred to the Company for $1. The assets would be put on the Company’s books at that amount, and the corresponding effect on the Company’s rate base would be negligible. However, because of the FERC's potential jurisdictional authority, that agency's determination on the transfer is also expected to determine if the cost of the facilities can be directly allocated to a single developer, which in this case is LFTCEDC. Although the Company and LFTCEDC have agreed to the transfer at $1, and the unique circumstances of the situation justify the contemplated $1 transfer price (e.g., facility designs in excess of the Company's standard design in order to satisfy the unique needs of nanotechnology computer chip manufacturers, construction in advance of firm end-use customer commitments, development intended for New York State economic development purposes funded through State grants), there is uncertainty whether FERC will authorize the transfer at $1. Therefore, the Company's rate base forecast in this case reflects the value of the facilities to be received from LFTCEDC at $57 million in the event that the FERC approves the transfer, but directs the cost of the facilities to be funded by all of the Company's customers. The Company believes there is a reasonable basis for FERC authorizing the transfer under the terms agreed to by the Company and LFTCEDC. However, due to the unclear FERC precedent, the Company's rate base forecast reflects the full amount of the estimated market price of the assets ($57 million). Once the final transfer price is established, the Company will notify the PSC and make necessary and appropriate adjustments to its books of account, and will reflect corresponding changes in the revenue requirement. The Electric Delivery Adjustment Mechanism ("EDAM") is the mechanism by which an adjustment would occur. The EDAM is described in the testimony of the Revenue Requirements Panel.

Q. What is the timing of the anticipated transfer of assets?

A. The project schedule is largely in the control of the LFTCEDC and its contractors. We anticipate that the transfer and energizing of the facilities will take place some time before March 2012. For ratemaking purposes, the Company has reflected the $57 million payment in March 2012.

Q, Is the $57 million cost reflected in the Company's infrastructure investment budgets that the Panel described previously?

A. The $57 million payment amount is not reflected in the Company's infrastructure investment plan described previously; however, the payment is reflected in the Company's revenue requirements calculations as described above.

Q. Are there other facilities being developed in the area of the LFTC that relate to that project?

A. Yes. In addition to the specific facilities investments being developed by LFTCEDC, additional investment is needed to upgrade seven substations with new high speed relay and communication equipment required for nanotechnology manufacturing. The addition of two new 115kV breakers at Battenkill substation and the expansion of Malta substation to accommodate a new underground cable are being constructed by LFTCEDC. The upgrades on the Company's existing system are to accommodate the new LFTC interconnection at a cost of approximately $9 million.

Q. Are the costs associated with these connection upgrades reflected in the Company's infrastructure investment forecast?

A. Yes they are. Although the need to upgrade the interconnection facilities results from the need to accommodate the new LFTC facilities, it is appropriate to include these costs in the Company's investment plan and rate base because these facilities are part of the existing interconnected system and they provide benefits to both Niagara Mohawk and its customers. First these upgrades are replacing older electromechanical relays that are obsolete. In addition, the upgrades will include communication equipment that will provide high speed protection allowing the system to remove faults much faster than with current protection schemes. Removing faults from the system faster provides higher power quality in the area by reducing the voltage dips caused by faults. It also can reduce the stress on existing high voltage electrical equipment in the area potentially extending the life of equipment such as transformers and cables that are exposed to the fault currents.

Q. Could you please describe how the Northeast Regional Reinforcement Project ("NRRP"), described earlier in your testimony, relates to the LFTC project?

A. Yes. As mentioned previously**,** the NRRP was developed based on a comprehensive assessment of the reliability needs of the northeast region of the state. This assessment considered load growth, reliability needs and asset conditions in the region, and the resultant project elements address these factors. The NRRP was developed independent of and without consideration of the LFTC project, and then refined to insure compatibility with the LFTC project. As a result, the NRRP does not include elements intended to specifically interconnect the LFTC project. However, because the anticipated new customer load at the LFTC will increase area demand sooner than anticipated in prior studies, some portions of the NRRP will be accelerated and constructed earlier than initially envisioned. Therefore, while the overall design and level of investment relating to the NRRP is not significantly affected by the LFTC project, the timing of the construction of certain portions of the NRP will be accelerated.

<u>Tri-Lakes</u>

Q. Please describe the "Tri-Lakes" project.

A. Niagara Mohawk provides electric transmission service to several communities within the Adirondack Park. Rapidly increasing load growth in the Villages of Lake Placid, Tupper Lake and the surrounding area (referred to as the "Tri-Lakes area") in the late 1990s and early part of this decade placed increasing load on the electric assets in this region. The 115 kV and 46 kV transmission system assets serving the Tri-Lakes area are radial and the systems and the customers they serve are exposed to extreme weather and serious consequences exist if extended outages occur (e.g., some of the communities rely extensively on electric space heat). In addition, Niagara Mohawk uses its assets in the Tri-Lakes area to serve its retail customers; and, the New York Power Authority ("NYPA") relies on the Company's transmission facilities for the commodity service it provides to its wholesale municipal customers, Lake Placid and Tupper Lake. To improve the reliability of the system and ultimately improve the service to Niagara Mohawk and NYPA customers, both parties entered into an agreement to construct two new Static VAR Compensators (SVC), a 46kV SVC located at Tupper Lake, and an 115kV SVC located at Lake Colby. In addition to the voltage support facilities, the project included the construction of a new 46kV line from the Townline Substation to the Piercefield Substation.

Q. What are the commercial arrangements relating to the Tri-Lakes project?

A. Under the agreement reached between NYPA, the Company, the Village of Lake Placid and the Village of Tupper Lake on September 15, 2004, and revised October 24, 2006, NYPA agreed to own, finance and hold title to all of the facilities constructed until January 1, 2012 when the Company was expected to enter into a new rate plan. The construction of the new facilities has been completed and are now in service, and providing customers with enhanced reliability. The Company is proposing to purchase the assets from NYPA on January 1, 2011, one year earlier than anticipated, to coincide with the timing of the new rate plan and intent of the Tri-Lakes agreement.

Q. What is the financial effect of moving the buy-back up one year?

A. The earlier purchase would reduce the “buy back” price of the facilities by $2.0 million. In addition to reducing the overall buy back cost, purchasing the assets early would also reduce the risk of litigation of the contract in the event of unforeseen circumstances which could occur, such as injury or damage of equipment.

Q, Is the $35 million payment for the Tri-Lakes project reflected in the Company's infrastructure investment budgets that the Panel described previously?

A. The $35 million payment amount is not reflected in the Company's infrastructure investment plan described previously; however, the payment is reflected in the Company's revenue requirements calculations as described above.

<u>Hydro One</u>

Q. Please describe the "Hydro One" project.

A. The Hydro One project relates to the replacement of a large transformer in which the Company has a direct interest. The Beck-Packard No. 76 Regulating Transformer ("BP76 Transformer"), which is owned by Hydro One and is located at Beck substation in Ontario, Canada, suffered a catastrophic internal fault on January 30, 2008. Hydro One conducted a rigorous post fault analysis and determined the asset could not be repaired, and would need to be replaced. The replacement costs of the transformer are projected to be approximately $9 million; actual cost will be dependent on the exchange rate at the time of purchase. The transformer regulates the flows on the Beck – Packard No. 76 line, and the line can not be placed back into operation without the regulating transformer in service.

Q. What is the Company's interest regarding the BP76 Regulating Transformer?

A. The Company and Hydro One have an Interconnection Facilities Agreement which manages the operation of the International Tie-line (Beck – Packard No. 76) and institutes the concept of an "Asset Owners' Committee" of which both Hydro One and the Company are members. The Asset Owners' Committee is required to agree prior to making many decisions which affect the tie-line including performing extraordinary maintenance or replacement of the BP76 Transformer. If the Asset Owners Committee agrees to replacement of, or perform extraordinary maintenance on, the BP76 Transformer, costs would be shared equally between the parties.

Q. Has the Company determined whether it makes economic sense to replace the transformer?

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A. Yes. The availability of the Beck – Packard No. 76 tie-line can have significant economic implications on the region when combined with major outages. For instance, based on an economic analysis done by the New York ISO, if the transformer is not replaced and is combined with 345kV outages on the NYPA system, this would cause an estimated $44 - $78 million in congestion in the market. Based on the existing New York ISO tariff, Niagara Mohawk customers would contribute approximately $8.8 - $15.6 million to the congestion shortfall and all other New York customers would contribute the remaining $35.2 - $62.4 million. Based on the value to the Company's customers and the benefits to the region, the Company proposes to share the transformer replacement costs with Hydro One.

Q. What is the timing of the transformer purchase and proposed cost recovery?

A. Hydro One has recently advised the Company that it intends to order the replacement transformer once it receives notice of agreement to share the costs of the new transformer. The Company intends to make payment for its share of the transformer to Hydro One (currently estimated at approximately $4.5 million). To mitigate the impact on rates and provide reasonable rate stability, the Company proposes to amortize the transformer payment over three years, from the date of payment. The accounting treatment for inclusion of the Hydro One costs in the revenue requirements is described in the testimony of the Revenue Requirements Panel.

J. Comparison to Prior Infrastructure Investment Plans

Q. How do the levels of proposed infrastructure investment in this case compare to prior and current investment levels?

A. The Company's currently effective base rates were established pursuant to the Merger Joint Proposal ("MJP") approved by the PSC in Case 01-M-0075. These currently effective rates reflect an annual capital investment plan budget of approximately $143 million.

Coincident with experiencing declining reliability performance associated, in large part, from diminished performance of deteriorating assets reaching the end of their useful lives, the Company undertook reviews of the condition of its system and its assets, and has for several years been investing pursuant to the asset management approach in an effort to address the findings of those reviews. Those investments have been at levels far in excess of the investment levels provided in current rates.

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As a result of reliability issues raised in the National Grid/KeySpan merger proceeding (Case No. 06-M-0878), the Company was directed by the Commission to invest at least $1.47 billion over five years in the Upstate New York electric system--an amount significantly greater than what is reflected in current rates.

Under the $1.47 billion investment requirement, the Company was to invest $255 million in FY07, $275 million in FY08, and $301 in FY09. Actual investment for this period has been $279 million in FY07, $284 million in FY08, and $318 million in FY09.

Q. Please explain why the Company has been investing at a pace even higher than the $1.47 billion requirement.

A. As explained in the October 22, 2007 Capital Investment Plan filing, while the Company committed to spend a minimum of $1.47 billion on transmission and distribution infrastructure, we also outlined a plan where capital spending necessary to attain the reliability metrics set for the Company would require $2.4 billion in investment. The expanded plan promotes the long-term reliability and sustainability of the network, and is in the best interest of customers. However, to date the Company has exceeded the $1.47 billion level. This additional investment and the

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investment outlined in this rate filing is the minimum necessary to meet mandatory obligations and near-term reliability without unacceptably increasing risk.

Q. How do the proposed investment levels for the rate plan period compare to prior planned investment levels the Company has submitted to the Commission?

A. The infrastructure investment plan present in this case is significantly reduced from the investment plan submitted last year. That plan totaled \$3.57 billion for the 5-year period FY2010 to FY2014. In its most recent five-year plan (filed the same day as this rate case), the Company describes an investment plan that totals \$2.86 billion (\$2.95 billion with inclusion of Luther Forest Technology Campus and Tri-Lakes projects) for the five-year period FY2011 to FY2015.

Q. Why is the investment plan presented in this rate case lower than the investment level submitted to the Commission last January?

A. The Company's infrastructure investment planning process provides for on-going and continuous evaluation and refinement to reflect changed circumstances and new information. Thus, we are continually adjusting the plan to meet the needs of current and future customers in the most effective way possible. The current economic conditions facing our customers and the Commission's calls for austerity measures by utilities required identifying opportunities to defer or minimize spending where possible, consistent with our obligation to provide safe and reliable service. Thus, the infrastructure investment plan reflected in this case is designed to mitigate rate impacts on customers while also managing the near-term reliable performance of the system.

K. <u>System Planning</u>

Q. The management audit report included several recommendations relative to system planning. Could you provide a brief summary of the Company's system planning process?

A. Yes. As discussed previously, the Company's plans to implement the audit report recommendations, including those related to system planning, are described in the implementation plan included with Mr. Zschokke's testimony, in this case. However, in general, the Company's system planning process integrates two types of system assessment. The first type is system capacity planning, in which the ability of the Company's assets to handle customer loads and power flows is studied, extending out to a planning horizon 10-15 years in the future. Modeling programs are used to represent present and future conditions, for a variety of normal and contingency conditions. The models calculate power flows, voltages, dynamic performance, and fault currents. The modeling results are compared with planning standards and criteria to identify potential noncompliance situations. These assessments also address interconnection requests from customers, and ensure compliance with NPCC and NERC standards and criteria. They will generally lead to investments in the system in the Statutory/Regulatory or System Capacity and Performance categories of our investment plan.

The second type is an assessment of the physical condition and performance of the assets. This assessment yields important information about which assets should be given priority for replacement or refurbishment and considers factors such as degree and rate of deterioration, performance, criticality and the age the assets. Additionally, these assessments will look to improve reliability performance through the refurbishment or installation of new equipment such as reclosers or sectionalizing switches. Ensuring safety of both the public and employees, reliability of supply to customers, and protecting the environment are goals of this process. As discussed previously in detail, these assessments are done are in a number of ways including ongoing inspection and maintenance activities and targeted condition assessments.

These assessments can lead to investment in System Capacity and Performance and Asset Condition categories of our investment plan.

Both types of assessment are performed for all of the Company's electrical assets at all voltage levels, including transmission, sub-transmission, and distribution. To ensure that capital resources are utilized as efficiently as possible, the Company's planning process requires that asset condition planning and system capacity planning be coordinated with each other. Early in the process, both asset condition needs and system capacity needs in each area under study are identified and considered. Wherever appropriate, capital projects are sequenced and designed to address both types of system needs.

Niagara Mohawk's transmission system is extensively interconnected with the systems of other utilities in the Northeast U.S. To a more limited extent, there are also distribution interconnections. Full consideration is given to the effects of neighboring systems on the Company's system, and to the effects of Niagara Mohawk's plans on its neighbors. The Company participates in the planning processes of the NPCC and the NYISO, as well as other interregional planning initiatives.

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L. <u>Capital Investment Reconciliation Mechanism</u>

Q. Is the Company proposing a mechanism to reconcile its actual capital expenditures with the level of capital recovery authorized in the rates approved by the Commission?

A. Yes. The Company is proposing to track its actual annual capital investment expenditures, including those associated with third party actions, against the target capital budget authorized by the Commission in this case, and to reconcile the difference annually.

Q. Why does the Company believe it needs a capital tracker?

A. The Company has a commitment to provide safe, reliable, environmentally sound service at a reasonable cost to customers. As discussed previously, the need for investment in the Company's infrastructure is significant and is increasing, and the infrastructure investment budget and associated O&M costs presented in this case are substantial. A tracker would protect customers in two ways. First, it would ensure that customers pay the appropriate amount. To the extent that actual investment falls short of the level forecasted by the Company, customers would receive a rate credit. Second, however, the proposed budgets in this case have been reduced from optimum levels in order to mitigate rate impacts on customers in light of the economic downturn,

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while still enabling the Company to sustain reliability over the near-term. Establishing a limited tracker (capped at 10 percent of the approved annual budget level) will provide the Company with necessary flexibility to respond to unforeseen circumstances that may warrant significant capital investments that are in the best interest of customers. It would eliminate any disincentive to do the right thing on behalf of customers due to the lack of a rate mechanism to recover such prudently incurred costs during the rate plan period in order to provide service.

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In addition, due to the interconnected nature of the New York transmission system, as Transmission Owners ("TO") replace or upgrade aging infrastructure and make reliability improvements on their systems, projects can have spillover effects on neighboring systems, not all of which are known and measurable by the Company at this time. For instance, in order for one utility's project to be put into service, the completion of related upgrades on a neighboring system may be required. If another utility's activities trigger investment needs or unanticipated reliability upgrade investments on the Company's system, and it is appropriate to put the costs of these unanticipated upgrades into the Company's rate base (because they provide benefits to the Company's own customers), the proposed tracker mechanism would provide for recovery. Conversely, to the extent it is appropriate that the Company enter into an agreement to fund upgrades on a neighboring utility system arising from the Company's investments (e.g., if it is not appropriate for the neighboring utility to put the costs into its own rate base), the proposed tracker mechanism would provide for recovery of those costs. The tracker mechanism is designed to provide flexibility and ensure timely recovery of costs associated with the spillover effect of neighboring TO's investment plans, and to enable required investments to proceed without delay. In light of the fact that the Company does not have control over spillover effect of neighboring TO's investment plans, we are proposing a limited exception to the 10 percent cap as explained in the testimony of the Revenue Requirements Panel.

Q. How would the capital tracking mechanism work?

A. The design and mechanics of the reconciling capital investment tracker are set forth in the testimony of the Revenue Requirements Panel.

V. Facilities, Properties and other Capital Investments and Lease Costs

Q. Please provide an overview of the Company's approach to property management.

A. The Company's property-management strategy is designed to meet customer service needs effectively and efficiently. In conjunction with the merger with KeySpan, the Company reviewed of all of its property holdings and those of the former KeySpan organization to consider the potential benefits to be achieved from consolidations and other improvements in the way in which the companies manage their facilities and deliver services to customers. As a result of that review, the Company determined that closing certain facilities and consolidating operations into others would achieve long term cost reductions and improve the efficiency with which it serves its customers. The Company also seeks to reflect its environmental commitment in the design and selection of its locations.

The plans described below provide potential cost savings by reducing the number of facilities the Company operates, and provide an opportunity to increase workforce productivity through co-locating employees who perform related functions together and changing the manner in which its workspaces are utilized. However, perhaps more important is that the facilities plans described below are critical and integral elements of the Company's broader Transformation initiatives we discussed previously, that are being undertaken to deliver even further benefits for customers. To that end, this testimony focuses on the Company's proposed property related capital and lease expense changes related to facilities for the rate plan years.

Q. What parameters does the Company take into account in its review of its facilities?

A. The Company reviews its properties on an ongoing basis to ensure they continue to serve its customers effectively and efficiently. In undertaking any review, the Company looks at customer response, proximity to planned work, anticipated growth, opportunities to co-locate functions, and financial costs and benefits including: ongoing operating costs, anticipated capital investment and potential disposition proceeds. Through this economic and qualitative analysis, the Company has initiated property consolidations and respective investments that will achieve long-term benefits to its customers.

Q. You indicated that the Company's efforts to consolidate facilities include a focus on integrating business teams. How is this reflected in the Company's decision-making process for consolidating facilities?

A. In addition to considering economic factors as part of the property consolidation process, the Company considers several qualitative criteria to guide its decision-making process:

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- Office workers should be consolidated into as few locations as possible;
- Large, end-to-end processes should be physically co-located in a single facility, where possible;
- Managers should be located with their manager or work group when possible, preferably both;
- Critical infrastructure facilities should be in fewer locations;
- There should be no more than one office or workstation per employee; and
- Lower-cost facilities and low-cost, off-site storage should be utilized to the maximum extent possible.

Although we describe these as "qualitative" criteria, they obviously have a significant impact on the efficiency and effectiveness with which the Company delivers service to customers, and, therefore, ultimately do have a financial impact.

Q. Please provide an overview of the kinds of facilities the Company uses to provide service to its customers.

A. The Company's Property Services group oversees the maintenance and operation of 55 occupied locations: a main office location at Syracuse (approx. 467,000 sq. ft), six specialty/non-operating sites including warehouses and an airport hangar (155,000 sq. ft), and 48 operating sites (approximately 2,213,000 sq. ft) which house its physical work force, fleet operations, warehouse and other field support groups.

Q. Please describe the Company's facilities-related capital investments reflected in the revenue requirements in this rate case.

A. The levels of planned capital investments in properties and facilities are set forth in Exhibit __ (RRP-6), Schedule 1, Sheet 4, of the Revenue Requirements Panel's testimony, and are approximately $36.4 million in FY11, $32.4 million in FY12, and $4.4 million in each of FY13 and FY14. These capital investment amounts include a base level of spend in each of the years in the rate plan period ($3.9 million in FY 2011, and $4.4 million in each of FY12 – FY14), as well as investments associated with seven specific major facilities projects. These seven projects are: (1) the Syracuse Office Complex ("SOC") façade; (2) the SOC interior renovation; (3) the North Albany Renovation; (4) the Henry Clay Boulevard ("HCB") Control Center Consolidation; and separate consolidation projects in (5) the Saratoga area; (6) the Syracuse area; and (7) the Buffalo area.

Q. Please describe the basis for the baseline facilities capital dollars.

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A. The baseline facilities capital expenditures are allocated for capital projects associated with the maintenance of facility assets. The capital projects are comprised of projects that are designed to enhance the safety, security and infrastructure at facilities. The majority of safety related projects are made up of upgrades to life safety systems within facilities. For example, numerous facilities require upgrades to the fire alarm systems to provide adequate warning for employees in the event of a fire. Pavement replacement projects also fall into the safety category of spend. The pavement at many of our facilities has exceeded its useful life. Significant cracking and potholes have lead to dangerous conditions for our employees. Uneven walking surfaces can lead to slips, trips and falls particularly in the winter months when these areas tend to accumulate water and form ice.

Infrastructure improvement projects are intended to replace or enhance the life of an existing asset. Such projects include, but are not limited to, roof replacements, HVAC replacements, system upgrades and electrical upgrades within a facility. Many of the roofs across the system have exceeded their useful life with some over 50 years old. Leaking roofs can lead to water damage within facilities including the potential for mold growth. Many HVAC units have also exceeded their useful life and

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require replacement because many of the parts required to repair the units are no longer available and in many instances it is more economical to replace a unit than to make repairs.

Security projects intended to enhance the security at our buildings including, fencing, gates, card readers and video surveillance equipment are also included in the asset maintain category.

Q. How are the baseline capital expenditure estimates derived?

A. The baseline capital expenditure level is based on historical levels of spend as outlined in Exhibit__ (IOP-5), Schedule 1.

Q. How were the capital estimates for the larger projects included in the Company's facilities plan developed?

A. Initially, the Company uses historical data on its own projects or similar projects undertaken in other regions of its business. Preliminary estimates may be developed using external commercially available estimating firms. As a project evolves from conceptual to preliminary to the detail design phase, the Company will employ outside architects, engineering firms, specialist contractors or general contractors to develop and refine the details and scope of work. In any procurement of an outsider service, the

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Company's property team will follow the appropriate procurement procedures to ensure the most cost effective services are obtained for its customers and business.

Q. Please describe the Syracuse Office Complex façade project.

A. The Syracuse Office Complex ("SOC") main building is one of the finest examples of art deco architecture in Upstate New York. Completed in 1932, the building has been a source of civic pride for many decades. The ongoing SOC façade project involves replacement of multiple roofs, including limited stone replacement. Work on upper level exterior windows and building front, and stone work to address weather and water damage, is also included.

Q. What are the benefits of the SOC façade project?

A. This building is over seventy years old and such reconstruction is often required. The benefit of this work is safety related as certain stone pieces have dislodged, and, within the building, the Company has been experiencing various water leaks and interior damage. The work began in 2009 and is ongoing and anticipated to be completed by December of 2011.

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Q. What costs are reflected in the Company's plan for the SOC facade project?

A. The budgeted costs for the remaining work to complete the SOC façade renovations are reflected in Exhibit __ (IOP-5), Schedule 2. The project totals $8 million for the period February 2007 through December 2013, of which $6.8 million is allocated to electric and $1.2 million to gas. All of the costs associated with the SOC project are reflected as capital costs.

Q. Please describe the Syracuse Office Complex interior renovations project.

A. As part of its overall property strategy, the Company affirmed its commitment to maintain the Syracuse Office as one its main offices. The ongoing renovations are to accommodate business consolidation related to support of the TDC (Transaction Delivery Center) referenced in Mr. Andrew Sloey’s testimony and Transformation initiatives which are described in other parts of this testimony and will allow an expansion from 1,530 occupants to 2,100 occupants at completion. Some of the renovations were begun in 2008 and 2009, but will be done on a more broad scale in 2010 and 2011. The project includes room reconfigurations, new office equipment, office areas, seating and walkway area renovations, paint, carpet, and furniture replacement and reconfiguration. The work is ongoing and anticipated to be completed by August 2011. A reduction of expenses will result from the expiration and non-renewal of the “E” building lease (2011) at the SOC. In addition, the parking lease for an area near the SOC expires in CY 2013 and will not be renewed resulting in additional savings. Both leases and corresponding reductions are reflected in the Company’s revenue requirement.

Q. What benefits are achieved from the SOC interior renovation project?

A. The Company is consolidating certain functions as well as establishing a new Transaction Delivery Center which will result in improved service delivery to customers, and improve the overall efficiency of its work practices. The investment is also good for the local community by solidifying the Company’s presence in Syracuse.

Q. What costs are reflected in the Company's plan for the SOC interior renovations project?

A. The budgeted costs for the remaining work to complete the SOC interior renovations are listed in Exhibit __ (IOP-5), Schedule 2, and total $20 million covering the period October 2009 through December 2013 of which $17 million is allocated to electric and $3 million to gas. All of the costs associated with the SOC interior renovations project are reflected as capital costs.

Q. Please describe the Henry Clay Boulevard Control Center (“HCBCC”) project.

A. The Company currently has three electric distribution control centers in New York: one in Buffalo, another in Liverpool and a third in Guilderland. The Company proposes to consolidate the three control centers into a single, centralized control center in Liverpool.

Q. Why is the Company proposing to consolidate its control centers?

A. The objective of the consolidation is to improve operational performance across the Company. This would be achieved by developing new roles, responsibilities and work flow segments that are aligned with a newly designed control room. The new control room would take advantage of industry best practices and new systems, visual displays, versatile control room consoles, more accurate outage reporting, standardized outage restoration practices, process standardization, and improved operator training at one central location. The overall goal is to provide control room employees with new tools that result in better situational awareness and decision making in the management of the distribution system.

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Control center consolidation will also yield efficiency and operational improvements. For example, centralizing the management of storm response in a consolidated control center in Liverpool reduces the number of times field offices need to be opened to support the dispatch and assignment of outage calls associated with small and medium scale events, and enables more effective use of clerical and design personnel that have been centralized in Syracuse at the Syracuse Office Complex. A consolidated control center will also bring together highly technical personnel in an environment that fosters the sharing of best practices and provides a consistent means of managing and operating the distribution system.

In addition, the consolidated control center will work in conjunction with a similarly consolidated control center in Northborough, Massachusetts. The implementation of the same technologies used by personnel within both centers will allow for the sharing of best practices and the ability to 'back each other up' in the event of an evacuation of a control center or to provide additional personnel to assist customer restoration in response to a major event.

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Q. When is the control center consolidation planned to take place and what costs are associated with the project?

A. The Company plans to start construction on the consolidation in September 2010, with a target completion date of May 2012, and estimated capital costs of $13.5 million. Of the total amount, $11,475,000 is allocated to electric and $2,025,000 to gas. In addition, approximately $100,000 would be incurred in 2010 in preparatory work.

Q. Please describe the Syracuse area project.

A. The Syracuse area project also involves the Henry Clay Boulevard (HCB) site. The Syracuse area project will support renovation and consolidation of operating locations resulting in improved efficiency. The Company intends to close its leased facility at Beacon North in Syracuse and consolidate the operations there into its owned operating facility at Henry Clay Boulevard, thereby reducing the number of operating facilities. The Syracuse area project, scheduled to commence in April 2010 and to be completed in March 2011, will include renovations and building new facilities to accommodate movement in personnel, vehicles and material to HCB to accommodate a consolidation of electric and gas personnel at the site including crew rooms, meeting areas, storage, warehousing, yard and parking.

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Q. What benefits are anticipated by consolidation of operation sites in the Syracuse area?

The Beacon North facility is leased and represents a significant ongoing operating cost to the Company. With its closure, these costs will be eliminated. The Company will see reductions in annual operating expenses including maintenance, janitorial, landscape, snow removal plus avoid capital investment. Further, the Company expects to gain improved workforce efficiencies, including improved training opportunities where a large concentration of its physical workforce will now have close proximity to training facilities.

Q. What costs are reflected in the Company's plan for the Syracuse area project?

A. The costs for outstanding work to complete the Syracuse area project are listed in Exhibit __ (IOP-5), Schedule 2, and total $10.0 million covering the period January 2010 through December 2013 of which $8.5 million is allocated to electric and $1.5 million to gas. All of the costs associated with the Syracuse area project are reflected as capital costs.

Q. Please describe the North Albany renovation project.

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A. The North Albany renovations are to accommodate office needs for identified consolidation opportunities for the Company's operating facilities in the Capital region. The Company intends to consolidate its two Troy, New York locations and a single site at Glenmont, New York into its existing North Albany facility. A small crew facility will be maintained in the Troy area to ensure adequate response times for customers east of Troy. The North Albany project will improve utilization of shared facilities such as warehousing, yard and meeting space. The renovations will include required fit-outs, parking improvements, room renovations, storage upgrades, locker facilities, and utilities as required. The plans for the renovations are currently under development and may also include exterior work as needed. The renovations are scheduled to start in December 2009 and are anticipated to be completed by August of 2011.

Q. What are the benefits of the North Albany consolidation project?

A. The benefits from the North Albany project include: reductions in annual operation expenses such as maintenance, janitorial, landscape, snow removal; avoided capital maintenance, and property tax savings from the closure of the Troy and Glenmont sites. The Company expects to gain improved workforce efficiencies including: improved training opportunities, more flexibility to schedule work over a broader area, improved utilization and sustained or improved service to customers through the integration of its crews. The Company will also undertake improvements to its warehousing and materials storage practices, as well as environmental remediation work at the same time to ensure efficient scheduling of work and spending on this project. Finally, sale or lease of the Troy and Glenmont sites may produce proceeds on disposition.

Q. What costs are reflected in the Company's plan for the North Albany renovations project?

A. The costs for outstanding work to complete the North Albany project are listed in Exhibit __ (IOP-5), Schedule 2, and total $8.25 million covering the period from October 2009 through December 2013 of which $7,012,500 is allocated to electric and $1,237,500 to gas. All of the costs associated with the North Albany project are reflected as capital costs.

Q. Please describe the Saratoga area project.

A. The Company currently occupies two leased facilities, one at Weibel Avenue in Saratoga and another in Glens Falls. The Company's lease for the Weibel Ave location was not extended by the landlord beyond the current term (which ends October 2011) and the Company needs to

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replace this location. The project will renovate or build a new operating location in the Saratoga area. The Saratoga area project is scheduled to commence in August 2010 and be completed by November 2011, and will include consolidating some personnel from the Glens Falls location.

Q. What are the benefits of the Saratoga area project?

A. The Company has enjoyed the benefit of its relatively low cost, leased facility at Weibel Avenue in Saratoga to service this area. The Company does not have the option to extend its terms beyond October, 2011. With a strong continuing need to serve its electric and gas customers in the area, the Company must replace this facility location to ensure continued safe and efficient service its customers, alignment to its business model and flexibility to meet anticipated future growth.

Q. What costs are reflected in the Company's plan for the Saratoga area project?

A. The costs to complete the Saratoga area project are listed in Exhibit __ (IOP-5), Schedule 2, and total $10 million covering the period from January 2010 through December 2013 of which $8.5 million is allocated to electric and $1.5 million to gas. All of the costs associated with the Saratoga area project are reflected as capital costs.

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Q. Please describe the Buffalo area project.

A. The Buffalo area project will involve closing the Company owned Tonawanda facility and consolidating the operations and personnel there into existing Company owned facilities at Dewey, Kensington and Niagara Falls. The project will include all necessary renovations to the Dewey, Kensington and Niagara Falls facilities to accommodate consolidation of the Tonawanda operations, including fit-outs to accommodate people and equipment. The work is scheduled to commence in June 2010 and to be completed in November 2010.

Q. What are the benefits to be achieved from the proposed consolidations of the Buffalo area project?

A. The benefits achieved by the Buffalo area project include reductions in annual operation expense such as maintenance, janitorial, landscape, snow removal as well as avoided capital improvements and property tax savings through closure of the Tonawanda site. Further, the Company expects to gain improved workforce efficiencies, including improved training opportunities, more flexibility to schedule work over a broader area, improved utilization and sustained or improved service to customers through the integration of its crews. In addition, the Tonawanda site will be marketed for sale or lease which will result in potential disposition proceeds.

Q. What costs are reflected in the Company's plan for the Buffalo area project?

A. The costs for outstanding work to complete the Buffalo area project are listed in Exhibit __ (IOP-5), Schedule 2, hereto and total $2.0 million covering the period January 2010 through December 2013 all of which is allocated to electric. All of the costs associated with the Buffalo area project are reflected as capital costs.

Q. Please describe the new facility at Reservoir Woods and its benefit to the Company's customers.

A. Early in the process of the integration of KeySpan and National Grid, National Grid determined to consolidate its main office space to support its customers. After considering leasing or purchasing space at a number of locations, National Grid decided to lease a new facility at Reservoir Woods located in Waltham, Massachusetts.

Q. What support to Niagara Mohawk customers is based at Reservoir Woods?

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A. The Reservoir Woods facility provides shared services functions such as general corporate support, human resources, legal, and regulatory as well as functions related to the New York transmission and distribution electric system including:

- Distribution and Transmission Asset Management- management of strategic objectives relating to New York transmission and distribution assets, network performance and business targets for New York;
- Capital Program Management – managing programmatic type of work and developing resource allocation plans;
- Project and Construction Management - management of the New York based project managers;
- Operations and Maintenance – management of the New York divisions for O&M; and
- Operations Performance Reporting - network performance reporting, circuit event analysis, control centers policies, systems and operational objectives.

Q. How are the costs associated with the Reservoir Woods facility reflected in the Company's revenue requirements in this case?

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A. Niagara Mohawk's portion of the costs of the Reservoir Woods facility is reflected in the Revenue Requirements Panel's Exhibit __ (RRP-2), Schedule 8.

Q. Are there any other facility closures reflected in the Company's rate year filing?

A. Yes, the Star Lake facility has been closed and its lease will not be renewed. Similarly, a leased facility at Federal Street in Saratoga, has already been closed. Reductions in lease expense of $5,500 and $165,000 per year respectively are reflected in the Company's revenue requirements for the rate plan years.

Q. Please describe the capital investment of $0.6 million per year related to fleet services, inventory management and investment recovery.

A. For the rate plan period, Fleet Services plans annual capital expenditures of approximately $0.4 million for items such as: diagnostic software/hardware, Hetra columns, lift replacements, fuel pump upgrades, cabinets, tool boxes, and other miscellaneous garage tools and equipment. The Company also projects annual capital expenditures of approximately $0.2 million in the inventory management and investment recovery areas relating to things such as hand held devices and "carousel software," which are used extensively for warehouse tracking materials of materials.

VI. <u>Information System Investments</u>

Q. Is the Company proposing any information system ("IS") investments that affect electric system infrastructure or operations?

A, Yes. As reflected in Exhibit __ (IOP-6), the Company is implementing several such IS initiatives that affect the Company's electric infrastructure and operations, resulting in IS expense that is incremental to the historic test year of $1.5 million in CY 2011, $2.1 million in CY 2012, and $6.5 million in CY 2013. In addition, the Company will be implementing a new Energy Management System ("EMS"), which will include a capital investment of $20.1 million over the period FY11-FY14.

Q. Please describe some of the major electric infrastructure and operations IS initiatives the Company will be implementing.

A. The most significant IS projects affecting electric operations are the Distribution Management System and Outage Management System, the Mobile – Electric Distribution Grid Mobile Expansion, the Transformation Key Performance Indicator ("KPI"), and the Radio Console Standardization projects.

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Q. Describe the Distribution Management System and Outage Management System project.

A. The Distribution Management System (DMS) and Outage Management System (OMS) project will offer several significant benefits to Niagara Mohawk customers. First, the version of the Outage Management System (General Electric PowerOn) currently in use by the Company has not been updated to the latest version, and is no longer fully supported by the vendor. The risks associated with providing adequate support of PowerOn continue to grow and will be resolved with implementation of the new OMS. Second, an updated OMS system will allow for the implementation of DMS functionality which will maximize control room expertise and efficiency with regards to safety, reliability and productivity. It will also allow standardized training and operator development and streamlined processes and procedures (including minimizing/eliminating the use of paper maps, reducing manual processes, and creating one, current view of the network model available to all necessary resources). Further, the addition of a DMS is critical to moving forward with a fully functional Smart Grid program. Lastly, the Company is working with ABB (vendor) on integrating DMS/OMS with an upgraded EMS system that will substantially improve our ability to ensure the reliability of the electric network as well as our ability to quickly restore service in the event of an outage. All of these new systems (DMS/OMS/EMS) will add functionality that will allow more automated network switching in our network control centers. The Company's planned EMS system investment is described later in our testimony.

Q. What are the costs associated with the DMS/OMS project?

A. The costs of the OMS/DMS will be shared among the National Grid operating companies that use the system. The total cost of the OMS/DMS is $30 million, and it is to be amortized over 5 years from its in-service date, now expected to be April 2013. Niagara Mohawk's share of OMS/DMS costs in 2013 will be $2.534 million. Derivation of these costs and the allocation to Niagara Mohawk is addressed in the Revenue Requirement Panel's Exhibit __ (RRP-2), Schedule 8.

Q. Describe the Mobile – Electric Distribution Grid Mobile Expansion project.

A. Many electric operations field workers in the Niagara Mohawk service territory are not equipped with mobile computers. This project will provide that equipment and enhanced capabilities and functionality. The ability to access work management and other applications online from the field will significantly improve both the accuracy and timeliness of information collected in the field, will improve timely and accurate responses to outages, ensure that the most up to date safety procedures are available to working field crews, and support more efficient use of or reductions in clerical staff. Examples of field transactions that will be supported by this project include the ability to dispatch trouble orders directly from the OMS to field crews for initial and follow-up work, real time access and update capability to the geographic information system (GIS), and online capture of field construction design and "as-built" information. In addition, status of customer work in the field will be captured and updated in the customer system (CSS) so that the information will be readily available to contact center personnel in their discussions with customers. This investment will include the implementation of the required hardware, telecommunications and software. Start-up costs are required for FY2013 with implementation beginning in FY 2014, therefore the benefits identified will be realized and incorporated into future rate cases.

Q. Describe the Radio Console Standardization project.

A. The radio console equipment in our Electric Distribution Control Centers and Transmission Control Center is well beyond normal end of life. It is no longer supported by the vendor (Motorola), and the risk of continuing to operate this equipment is unacceptable. Replacement parts are largely unavailable from the vendor. The radio console equipment is the primary means of communication between the control centers and field crews, and its reliability is critical to crew safety and to ensuring timely repairs to the electric distribution and transmission system.

Q. Describe the Transformation Key Performance Indicator ("KPI") project.

A. The Transformation Program is a major initiative designed to implement a new operating model that is introducing best practices across a number of work streams. A key element in this transformational program is the ability to measure the performance of the new operating model through relevant measures and detailed metrics. The Transformation KPI project establishes a framework and centralized solution that allows the company to draw information from a number of operational systems and create scorecards at all levels of the organization to display performance against those metrics to the individuals responsible for the work and to their management. This investment allows us to deliver specific reporting, measures and scorecards, as outlined during the PSC Management Audit, specifically the 29 value measures for productivity. This KPI capability was supported by the PSC Management Audit, and is established as an assumption for delivery of specific recommendations surrounding performance management and work management. This investment will allow electric operations senior management to have visibility into the performance of the organization and highlight potential problem areas to ensure that we are optimizing service to Niagara Mohawk customers. In addition, the KPI project will also enable regulatory reporting of the Company's performance and service to customers and provide a basis by which to benchmark against peer utilities.

Q. Please discuss the new Energy Management System ("EMS") the Company will be implementing.

A. The EMS replacement project is a combined transmission and distribution project. The EMS system is used for monitoring, control and operation of the transmission and distribution electrical system. The current EMS system is 23 years old and the vendor, Stagg Systems, is no longer in business. Therefore, vendor support and upgrades are no longer available. The planned investment in new operator workstations and primary and back-up servers will allow the Company to follow a 4-6 year refresh cycle that is in line with current industry practice.

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This investment modernizes the EMS to mitigate reliability risks associated with the loss of system control and situational awareness of the electric system and will insure information and data is exchanged with the regional Independent System Operators and transmission owners. The implementation of this project will coincide with the DMS/OMS system upgrades described previously. The total capital investment cost for the EMS replacement project is $20.1 million, with $13.0 million associated with transmission and $7.1 million associated with distribution. Implementation of this project began in May 2009 and will continue through the end of 2012.

Q. Is the Company undertaking other operations-related IS projects that are reflected in the rate case revenue requirement?

A. Yes. In addition to the projects described above, the company has a number of smaller yet very important projects in the electric operations area that will improve the customer experience and help reduce operating costs. These projects, and their associated costs, are listed in Exhibit __ (IOP-6).

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VII. Operations and Maintenance Expenses

Q. Please describe generally the nature of the Company's electric system operations and maintenance expenses.

A. Operations and Maintenance (O&M) expenses relate to work performed specifically for the purpose of preventing failure, restoring serviceability, or maintaining the life of capital assets. Niagara Mohawk has a significant maintenance program implemented with the goal of ensuring the assets installed on the system can be utilized to their fullest potential life expectancy. However, due to the current physical condition of many assets, the Company is likely to experience increases in maintenance costs until these assets can be replaced. These costs include such things as increased costs for more frequent inspection and testing, more significant repair costs (e.g. major overhaul of circuit breakers versus standard minor work), and costs for emergency work. These expenditures are required to prevent failure and maintain the life of the assets until replacement occurs.

Reduced inspection cycles are warranted if it is determined that an asset cannot last until the next normal inspection. One example would be increasing the frequency of Dissolved Gas Analysis (DGA) performed on power transformers when scheduled maintenance test results indicate

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deterioration has occurred within the main tank of the transformer or the Load Tap Changer (LTC).

Q. What is reflected in the Company's rate case filing relating to O&M expenses for the electric transmission and distribution system.

A. As described in the testimony of the Revenue Requirements panel, the Company's total electric operations and maintenance ("O&M") expense for the rate years 2011, 2012 and 2013 is $1,112.5 million, $1,114.5 million, and $1,114.5 million, respectively. These amounts are presented in detail in Exhibit __ (RRP-1), summary schedule, to the testimony of the Revenue Requirements Panel.

Q. How do the rate plan expense levels presented in this rate case compare to the historic test year expenses for operating the T&D System?

A. For the historic test year ending September 30, 2009, the Company's adjusted electric O&M expense was approximately $898.9 million, as set forth in Exhibit __ (RRP-2), Schedule 45 of the Revenue Requirements Panel.

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Q. Please describe those adjustments needed to the historic test year electric operating expense necessary to arrive at the proposed rate year expense.

A. There are several known or anticipated changes in the Company's rate year expense levels from what the Company incurred during the 12-month test year period of October 2008 – September 2009. Many of these changes are addressed in the testimony of the Revenue Requirements Panel. In our Panel's testimony, however, we provide additional detail with respect to several of the known and measurable cost changes totaling approximately $81.2 million reflected in the Company's rate filing in this case, including:

- costs of mandatory and enhanced inspection and maintenance requirements;
- transmission tower painting costs, and comprehensive aerial inspection costs;
- costs associated with changes to the Company's vegetation management program;
- operating expenses associated with the increased levels of infrastructure investment;
- changes to the current mechanism for recovering extraordinary storm expense; and

- increased costs associated with site investigation and remediation activities.

Taken together, these changes account for approximately $81.2 million of the difference between the Company's historic test year expense and forecast rate year expense in 2011.

In this part of our testimony, the panel also addresses the status of the Company's service quality performance program.

A. <u>Inspection and Maintenance</u>

Q. Please describe the Company's proposal in regard to increased O&M costs to the inspection and maintenance program as a result of the 2008 Safety Order

A. Pursuant to the 2008 Safety Order, the PSC directed utilities to undertake enhanced inspection and maintenance activities on their electric system. These activities included additional elevated voltage testing requirements, and the establishment of specific timeframes for the remediation of deficiencies identified as part of a utility's system inspection activities.

Q. Could you describe the nature of the additional elevated voltage testing requirements in the 2008 Safety Order?

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A. In the 2008 Safety Order, the PSC adopted changes to its electric safety standards to require that all utilities serving cities with populations of at least 50,000 (based on the 2000 census) conduct a mobile elevated voltage detection survey of their underground electric distribution system in those areas. The initial survey was to be completed during calendar year 2009, with annual surveys to follow thereafter. Based on their populations, the Company is required to conduct an annual mobile elevated voltage survey in Buffalo, Niagara Falls, Syracuse, Utica, Albany and Schenectady.

Q. What costs are associated with the new mobile testing requirement?

A. The Company estimated the annual costs at approximately $5.4 million. This amount includes the use of a certified mobile test vehicle and additional contractor costs to “stand by” locations identified to be above the relevant elevated voltage threshold.

Q. What is the basis for the Company’s estimated costs of the mobile test vehicle and contractor stand by resources?

A. The Company’s estimate of approximately $5.4 million per year is based on actual contractor costs experienced in 2009. The Company completed the first annual survey of the six cities mentioned above as of December 2009.

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Q. Does the 2008 Safety Order require enhanced remediation efforts by utilities?

A. Yes. In the 2008 Safety Order, the PSC directed that utilities are required to mitigate all elevated voltage findings of 1 volt or more. Previously, utilities (including the Company) were required to take corrective action to mitigate elevated voltage findings of 4.5 volts or greater.

Q. What impact does the Company project the tightened standard will have on its elevated voltage activities?

A. For elevated voltage findings between 1 and below 4.5 volts, the Company will act to cordon off the affected area (e.g., using cones, barricades or warning tape) to indicate the existence of a possible safety hazard. Under PSC requirements, once the area has been cordoned off, the Company is to return as soon as practical to mitigate such findings.

The Company will also continue to mitigate elevated voltage situations of 4.5 volts or more. Because the higher potential creates greater concern, these mitigation efforts will require the protection of the area (e.g., by posting utility or contractor personnel) until repair crews arrive to repair the situation and make the location safe.

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Q. What is the Company's estimate of the costs of complying with the mobile test requirement in the 2008 Safety Order?

A. In addition to the approximate $5.4 million in vendor costs for the certified mobile test vehicle and stand by contractors described above, the Company estimates that it will incur approximately $1,180,000 annually in additional expense associated with complying with the reduced voltage requirements from the 2008 Safety Order. This estimate is based on the number of elevated voltage locations identified in the field by the test vehicle in Buffalo during the first few weeks of testing, a typical repair cost, then extrapolated across the system. The cost of the test vehicle plus repair costs brings the total estimated annual incremental O&M expenses associated with these activities to $6.58 million.

Q. Is it possible the estimated costs to repair deficiencies located by mobile testing will vary from the $1,180,000 you mentioned above?

A. Yes. The Company has only recently completed the mobile test initiative, and the estimate was based on a relatively small sample of repairs. More recent information developed following the estimate reflected in this rate case suggests the actual annual repair costs could be higher than $1,180,000. The Company will seek deferral treatment of any charges in excess of $1,180,000. The actual program costs through December 31,

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2009 were previously submitted in a report to Staff dated January 15, 2010, a copy of which is included in Exhibit __ (IOP-7).

Q. Are there other requirements stemming from the 2008 Safety Order that affect the Company's projected rate year expenses and that are not reflected in the historic test year?

A. Yes. In addition to the mobile testing and reduced voltage requirements described above, the Commission established a condition-based schedule for addressing deficiencies identified by utilities when they conduct their annual system inspections. Specifically, the PSC established four priority categories of deficiencies (as described in Appendix A to the 2008 Safety Order):

Level I – repair as soon as possible, but not longer than one week. A Level I deficiency is an actual or imminent safety hazard to the public or poses a serious and immediate threat to the delivery of power. Critical safety hazards present at the time of the inspection shall be guarded until the hazard is mitigated.

Level II – repair within one year. A Level II deficiency is likely to fail prior to the next inspection cycle and represent a threat to safety and/or reliability should a failure occur prior to repair.

Level III – repair within three years. A Level III deficiency does not present immediate safety or operational concerns and would likely have minimum impact on the safe and reliable delivery of power if it does fail prior to repair.

Level IV – condition found but repairs not needed at this time. Level IV is used to track atypical conditions that do not require repair within a five-year timeframe. This level should be used for future monitoring purposes and planning proactive maintenance activities.

Q. What is the impact of the Commission's order on the Company's projected costs during the period covered in this case?

A. The revised requirements of the 2008 Safety Order have effects on the Company's future operations expense as well as on its infrastructure investment plan. First, Level I deficiencies must be addressed as soon as possible, and it is the Company's expectation that the costs associated with those efforts will be primarily expense-related. The Company does not project a specific increase over historic test year spending.

Level II deficiencies, which must be addressed within 12 months of identification, are expected to lead to remediation efforts which will be more evenly balanced between expense activities and capital expenditures. Because the 12-month timeframe for addressing Level II deficiencies has the effect of advancing some of the Company's projected capital and maintenance spending, the rate case spending projections are greater than what is reflected in the historic test year.

Finally, Level III deficiencies would need to be addressed within 3 years. Typically, Level III-type of situations would be less likely to be addressed through maintenance activities, and instead more likely to be remedied through capital expenditures. Level III work typically will enhance the reliability of the system but is not required to maintain it at present levels. Examples of such work include: poles, cross-arms and other capital assets that are deteriorated but still have sufficient life that they do not pose an imminent risk to public safety or reliability prior to the next five-year inspection cycle; replacement of missing animal guards; repair of equipment bonds; and addition of lightning arresters at conductor transitions and feeder open locations such as feeder ties and at the end of circuits to improve lightning performance. Because of the required 3-year remediation timeline established in the 2008 Safety Order, the Company's infrastructure investment plan presented in this case reflects an increased amount associated with projected capital investment related to Level III projects.

Q. What incremental costs are associated with implementing the 2008 Safety Order you mentioned previously?

A. The incremental capital investment necessitated by the 2008 Safety Order is described previously in this testimony as part of the description of the infrastructure investment plan. In addition to the estimated capital investments (and O&M expense related to those capital incremental as described later in our testimony), the Company will incur additional O&M expenses to address issues identified as part of its inspections program. The Company estimates these additional O&M expenses will be $2.65 million in CY11, $2.7 million on CY12 and $710,000 in CY13. The expense is lower in CY13 because the Company anticipates that Level II remediation work will decline after one full five-year cycle of inspection and maintenance under the new criteria is completed. Exhibit __ (IOP-8) provides a calculation of these estimated costs.

Q. Please describe the Company's proposal with regard to its non-mandatory enhanced inspection and maintenance program costs that are incremental to the requirements of the 2008 Safety Order.

A. In addition to the incremental work that will result from the 2008 Safety Order, the Company is also undertaking additional non-mandatory enhanced inspection and maintenance initiatives intended to help improve the safety and reliability of the electric system, as well as the efficiency of performing its inspections and maintenance programs. These initiatives include infrared inspections of pad-mounted transformers and hand holes to identify defective or loose cable connections before they fail. Additional "fast" distribution feeder patrols of mainlines are intended to identify conditions in the field that may lead to an imminent outage. Finally, enhancements to the inspection and maintenance QA/QC program are designed to improve the collection and monitoring of field inspection data and work completed information. The Company anticipates incremental annual expenses of these initiatives to be $2.45 million in CY11, $2.9 million on CY12 and $2.9 million in CY13. Exhibit __ (IOP-8) provides a calculation of these estimated costs.

B. Transmission Tower Painting and Comprehensive Aerial Inspection Programs

Q. The Company's proposed rate year expenses reflect approximately $4.6 million in additional costs associated with transmission tower

painting and a comprehensive aerial patrol program. Could you elaborate?

A. Yes, the Company plans to spend an incremental $2.6 million annually for the transmission tower painting program and $2.0 million annually for a comprehensive aerial and footer inspection program as compared to the historic test year.

Q. Can you describe the transmission tower painting program?

A. The Company has adopted a tower painting initiative following the implementation of the NY Steel Towers Mitigation Strategy described previously. This initiative, the Tower Painting and Structure Replacement Strategy, is aimed in part at extending the life of mature steel transmission towers in Visual Category 4. In addition, this strategy seeks to delay or prevent Visual Category 1, 2, and 3 structures from degrading into the Visual Category 4 condition or worse. The Company has approximately 20,000 steel structures operating at 115kV or higher in New York, with an average age of 65 years. Approximately 1,350 of the 17,500 steel towers inspected to date are in Visual Category 4. The painting program maintains the integrity of these existing steel towers, promoting longer service lives, reliability and safety in a very cost-effective manner. Presently, the tower painting program is operating on a 15-year cycle (after this cycle, it will be modified to a 20-year cycle). A 15-20 year painting cycle is consistent with cycles used by other utilities in the northeast.

Q. How was the $2.6 million adjustment to the historic test year expense determined?

A. Due to vendor safety performance issues, the tower painting program was suspended from August 2008 to June 2009, and again suspended in August 2009. As a result, the total annual estimated costs of this on-going program are not reflected in the historic test year expense. The $2.6 million adjustment to the rate year expense is intended to capture the costs of the work, which is anticipated to restart in June 2010. The $2.6 million adjustment is based on historical information on tower painting costs. The Company's annual tower painting budget is approximately $3.4 million, based on the historical average cost to paint a tower and the targeted number of towers to be painted annually. However, due to the program suspension, tower painting expenses for the historic test year were only about $800,000. The $2.6 million adjustment reflects the difference between the historic test year spend and our estimate of what the program will cost during the rate year. Exhibit __ (IOP-9), Schedule 1, illustrates how the $2.6 million adjustment was determined.

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Q. Please describe the comprehensive aerial patrol and footer inspection programs.

A. The Company is undertaking a comprehensive aerial helicopter patrol program with an estimated incremental cost of $1.4 million per year over a three year period, and a footer inspection program plus additional inspection programs to further investigate structural issues identified by the aerial patrol at an estimated cost of $600,000 per year for a three year period.

Q. What are the expected benefits of the comprehensive helicopter patrol?

A. This program utilizes helicopters with high resolution cameras that will hover over structures to identify defects such as cracked insulators, defective hardware and structural steel members, and deteriorated foundations. The patrol will take place on the 20 worst performing circuits over a three year period to develop a comprehensive maintenance schedule to correct the identified issues prior to failure in order to improve the reliability of the identified circuits.

Q. What are the expected benefits of the footer inspection program and other miscellaneous inspection work identified by the aerial patrol?

A. As discussed previously, the aerial patrol will identify deficiencies in the overall structure and the foundations. It is anticipated that additional on-site below grade footer inspections will be required as a follow-up to determine the full extent of the repairs required or if replacement is warranted. As with the aerial patrol, this effort will identify issues prior to failure in order to improve the reliability of the identified circuits.

Q. How were the estimated costs of the aerial patrol and footer inspection determined?

A. As shown in Exhibit __ (IOP-9), Schedule 2, the estimated costs for the comprehensive aerial patrol and footer inspections are based on actual vendor costs in the test year which are then multiplied by the expected level of work.

C. Vegetation Management

Q. Please explain the Company's $5.0 million adjustment to historic test year expenses related to vegetation management activities.

A. The adjustment for vegetation management activities includes $2.1 million of anticipated new costs for work on the transmission system, and approximately $2.9 million on the distribution system.

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The Company strives to be a leader in appropriate vegetation management practices to maintain and improve reliability and follow all regulatory requirements. Pursuant to PSC rules, the Company files a Transmission Right-of-Way Management Program (Part 84 Plan), which is subject to approval by PSC. The Company's most recently approved Part 84 Plan is dated November 2003, and incorporates proven vegetation management practices in order to facilitate uniform and consistent management of our transmission system. Additionally, in June 2005, the PSC issued an Order requiring enhanced transmission right-of-way management practices by electric utilities (Case No. 04-E-0822 – In the Matter of Staff's Investigation into New York State's Electric Utility Transmission Right-of-Way Management Practices). Niagara Mohawk has been complying with the PSC orders, and enhancing our vegetation management program to further improve reliability.

In an effort to improve reliability, the Company plans to widen many 115 kV rights-of-way (ROWs). Trees located outside of transmission ROWs that fail and fall into the lines are the source of most tree-caused service interruptions. As the growth of trees outside the existing ROW (i.e., the "utility forest") increase, so does the potential for the trees to grow into the electric lines, or upon failure, interrupt electric service. The Company's

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115kV system has the greatest risk exposure to tree-related outages on our transmission system, and intervention in the form of enhanced ROW widening efforts provides a cost-effective means of reducing future reliability effects from off-ROW trees, and improving safety. Widening activities will be performed in accordance with Transmission Group Procedure No. 25, Right-of-Way Vegetation Management Plan, Level 6 requirements, which are defined as the removal of all trees to a new cleared width, where property rights allow. The projected annual cost of the 115 kV widening program is $1.5 million. Exhibit __ (IOP-10), Schedule 1, illustrates how this amount was determined.

The Company's rate year expense also reflects costs associated with new initiatives aimed at the protection of two rare butterfly species: the Karner Blue Butterfly and the Frosted Elfin. The Karner Blue Butterfly is listed on both the Federal and New York endangered species lists, while the Frosted Elfin is on the New York State list of threatened species. The local principal habitat of these species in the area of the Albany Pine Bush, and previous studies of the Company's vegetation management practices have determined that decades of ROW management is largely responsible for creating habitats favorable to the Karner Blue Butterfly and Frosted Elfin. In order to be able to continue to operate and maintain its electric transmission system in the habitat area of the Karner Blue Butterfly and Frosted Elfin, the Company was required to develop and fund a Habitat Conservation Plan ("HCP") in support of its application to the U.S. Fish & Wildlife Service for an Incidental Take Permit ("ITP") under the Endangered Species Act. Exhibit __ (IOP-10), Schedule 2, is a copy of an April 30, 2009 letter to the U.S. Fish and Wildlife Service describing the Company's HCP and the estimated funding for the HCP. It is anticipated that the ITP will cover the Company's utility activities on affected ROWs and other properties for up to 50 years. The anticipated cost of the program varies over time, but it is projected to have a start-up cost of approximately $200,000 per year during the proposed rate plan period. These costs are not reflected in the historic test year.

In addition, the Company is proposing an upward adjustment to the historic test year cost associated with ROW floor trims. The historic test year costs for ROW floor trim sites are the result of a lower than average number of trim site acres. The number of trim site acres fluctuates annually, but costs are expected to average approximately $935,000 in the proposed rate plan period, an increase of $400,000 over the historic test year amount. Exhibit __ (IOP-10), Schedule 4 provides a calculation of these estimated costs. Trim site costs and acres are reported annually to the Secretary of the Department of Public Service.

Q. Can you please explain the Company's current programs for removing hazard trees?

A. The Company's has two reliability-based programs that involve hazard tree removal: cycle pruning of circuits, and Enhanced Hazard Tree Mitigation ("EHTM"). During routine maintenance cycle pruning, in addition to pruning trees, imminent danger hazard trees immediately next to the lines are identified and removed. Alternatively, the EHTM program targets circuits specifically in need of extensive hazard tree removal work independent of the cycle pruning schedule. The EHTM program is aimed at minimizing the frequency and damaging effects of tree and large limb failures from high-risk trees located along side or above the Company's primary distribution facilities, and therefore focuses on hazard removal to a much greater extent than cycle pruning. The EHTM program uses a risk analysis protocol to prioritize high risk and poor performing areas on a circuit and evaluate them for the potential need for hazard tree work. These identified areas are then extensively inspected for risk trees and large limbs, and those above a pre-determined risk level are scheduled for removal. The EHTM program comes at a higher cost per mile than cycle pruning since more trees are being removed. For this reason, EHTM is only performed on circuits showing poor reliability, specifically in need of intensive hazard tree removal. This program has had favorable results and has shown to improve circuit reliability.

Q. Can you please explain the proposed incremental cycle maintenance hazard tree program changes requested by the Company?

A. The Company's reliability performance indicates we are experiencing continued interruptions due to tree or large limb failure. In an effort to realize reliability benefits similar to those of the EHTM program, without reaching the intensity level and higher cost of the EHTM program, the Company wishes to increase the number of routine maintenance pruning hazard tree removals on the remaining pruning circuits not scheduled for EHTM for a projected cost of $2.9M as shown in Exhibit__ (IOP-10), Schedule 5. Since this enhancement is new, the $2.9 million cost is incremental above historic amounts. The same EHTM tree risk analysis protocol will be applied to these maintenance pruning hazard removals, ensuring that the highest risk trees along a circuit are properly prioritized. This will allow us to reduce the risk of interruptions by tree and large limb fells when compared to historic cycle pruning hazard tree removals providing the potential for greater reliability improvement.

D. <u>Increased O&M Expense Related to Infrastructure Investment</u>

Q. The Revenue Requirements Panel addresses projected increases in O&M expenses of approximately $12.9 million in 2011, $18.6 million in 2012, and $22.8 million in 2013 from historic test year expense levels associated with the Company's proposed infrastructure investment plan in Exhibit __ (RRP-2), Schedule 35. Please explain the basis for these projected expense increases for the rate years?

A. In addition to general O&M cost discussed above, there is a level of O&M required to implement the Company's infrastructure investment plan presented in this case. The Company follows established accounting rules governing how work is classified as O&M, capital, or removal that are based on the Federal Energy Regulatory Commission (FERC) accounting regulations.

The accounting rules provide that O&M accounts shall be charged for labor, materials, overheads and other expenses incurred for certain types of work that include the following activities:

- Direct field supervision of maintenance;

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- Inspecting, testing and reporting on conditions of plant specifically to determine the need for repairs, replacements, rearrangements, and changes; and inspecting and testing the adequacy of repairs which have been made;
- Work performed specifically for the purpose of preventing failure, restoring serviceability or maintaining the life of plant;
- Rearranging and changing the location of plant not retired;
- Repairing for reuse of materials recovered from plant;
- Testing for, locating and clearing trouble;
- Net cost of installing, maintaining, and removing temporary facilities to prevent interruptions in customer service; and
- Replacing or adding minor items of plant which do not constitute a plant unit.

Virtually all capital projects constructed involve interfacing with existing facilities. Many of these projects involve a combination of complicated reconfigurations of existing facilities and construction of many interface points between new and old facilities. When there are existing facilities of any kind involved, there will be O&M costs.

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Q. Could you provide an example of a capital project that would require the incurrence of O&M costs?

A. Yes. Using a tower replacement as an example and following the established guidelines, an example of O&M costs that could be incurred include:

- Maintaining previously constructed access roads or ROW:
  - Repairing roadways, bridges etc.
  - Trimming trees and brush to maintain previous roadway clearance
  - Maintenance work on publicly owned roads and trails when complete
  - Chemical treatment of right-of-way areas
- Performing the work
  - Detaching conductor and shield wire from the old tower, transferring and reattaching it to the new tower
  - Cleaning insulators
  - Repairing grounds
  - Re-sagging, re-tying or re-arranging position or spacing of conductors

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Other indirect project costs which are required to perform the capital project yet cannot be attributed to a specific capital asset, will also contribute to O&M charges for a project. These costs are apportioned to capital, cost of removal and O&M based on the overall project estimate and include: engineering, direct field supervision, railroad flagmen, police protection, switching, grounding, wildlife protection, and the installation of swamp mats and hay bales/silt fences.

Q. How did the Company calculate the annual amounts for incremental O&M expense related capital?

A. As mentioned previously, the Company's infrastructure investment plan presented in this case represents an increase from the investment reflected in the historic test year. To calculate the amount of incremental O&M expense the Company would expect to incur to deliver the increased capital plan, the Company took a three-year average (FY 2007 – FY 2009) of the ratio of annual O&M costs to capital costs for electric transmission (segregated into lines and substations, sub-transmission and distribution, and applied the resulting percentages to the planned incremental capital investment in each segment to arrive at an estimated annual adjustment. For example, for transmission lines, the 3-year (FY 2007 – FY 2009) average ratio of total O&M costs to capital costs is 10.26%; for transmission substation: 0.88%; for sub-transmission: 4.27%; and for distribution: 7.89%. These percentages were then applied to the plan incremental capital investment (compared to the test year) in each area. The result is that the Company expects to incur total increased O&M expense associated with the increased capital plan of $12.9 million in CY 2011, $18.6 million in CY 2012, and $22.8 million in CY 2013 (as compared to the historic test year).

Q. Will the Company realize any O&M cost savings as a result of the planned infrastructure investments?

A. Yes, but they will be relatively small. In 2007, the Company forecast that it would achieve $598,485 in O&M savings during 2008 as a result of the incremental expenditures it made on electric system capital projects and related O&M during 2008. After reviewing data from 2008, the Company estimated that it achieved a total of $492,715 in O&M savings for 2008. A similar level of cost savings would be anticipated for FY11 through FY14 under the plan presented in this case.

Q. Given the scope of the investment, why wouldn’t the Company anticipate a greater level of O&M savings?

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A. O&M cost savings are limited because generally, substantial O&M savings would be produced by capital or capital-related O&M spending only if the expenditures enable the Company to reduce the total number of personnel devoted to maintenance and repair of the electric system. The Company did not reduce the number of personnel performing those tasks during 2009 and it does not expect that going forward the increased capital expenditures on the electric system will enable it to do so.

Even though the Company is spending hundreds of millions of dollars on its transmission and distribution facilities, those expenditures result in the replacement of a small percentage of circuit breakers, conductor miles, steel towers, and other such assets that make up the entire electric system. The replacement of a small proportion of these assets makes no significant difference in the volume of routine maintenance activities such as visual and operational inspections, infrared surveys, and foot patrols. These activities are required whether an asset is new or old, and in the case of relay equipment, station batteries and diesel generators, maintenance intervals are mandated by NPCC standards. For the same reason, while it is assumed that there will be a decrease in the amount of “found-on-inspection” and “follow-up” maintenance activities associated with new equipment, this decrease is relatively small due largely to the vast number of assets on the system. Even though equipment is replaced, the system in aggregate continues to deteriorate and thus requires continual maintenance.

E. Storm Response Costs

Q. How does the Company recover its costs associated with responding to storm events that affect the electric system?

A. The Company currently recovers the costs of responding to storm events in two ways: (1) through base rates for normal storm events; and (2) through a deferral mechanism for major storms. Responding to normal storm events is part of the ordinary cost of business for an electric utility, and the costs of doing so are generally reflected in the utility's base rates. However, utility systems are occasionally also affected by significant weather events that cause substantial damage and result in the incurrence of costs that are out of the ordinary. These costs are also legitimate and necessary costs of providing service to customers. However, because the costs of responding to extraordinary storms vary and cannot be accurately predicted year-to-year, base rate recovery for such costs is generally not provided. Rather, in the Company's case, the costs of responding to extraordinary storms are reflected in a deferral account.

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Q. Please describe the Company's major storm deferral mechanism?

A. The Company's existing major storm deferral mechanism was established in the MJP, and further refined pursuant to the March 22, 2007 Stipulation of the Parties in that case, which the Commission approved by order dated July 19, 2007. Under the storm deferral mechanism, the Company is authorized to include in its deferral account those incremental costs above $2 million associated with any individual major storm in a calendar year, subject to a $6 million annual deductible for incremental major storm costs. Under the Merger Joint Proposal, every two years (coincident with the Company's CTC reset filing) the Company is required to seek recovery, or provide a refund, of the cumulative amount by which the deferral account exceeds $100 million. The Company made its most recent CTC reset and deferral account recovery filing on August 3, 2009 for the actual deferrals as of June 30, 2009 and forecasted deferrals through December 31, 2011.

Q. What is considered a "major storm" for deferral purposes?

A. The Commission's regulations (16 NYCRR pt. 97) define "major storm." The Stipulation of the Parties mentioned above further refined a "major storm" for purposes of deferring response costs. For deferral accounting purposes, a major storm is essentially a period of adverse weather which results in electric service interruptions to 10 percent or more of customers in an operating region, or at least one percent of the customers within an operating region being interrupted for over 24 hours.

Q. What level of storm costs has the Company deferred under the deferral mechanism you describe?

A. From April 2005 through August 2009, the Company incurred approximately $152 million—or about $34 million per year— of costs that qualified for deferral under the criteria established under the Merger Joint Proposal and Stipulation of the Parties. This deferral amount includes $78 million for the October 2006 Buffalo storm, and $47 million for the December 2008 ice storm.

Q. Please describe the Company's proposal relating to the recovery of storm costs.

A. The Company proposes establishing a fully reconciling storm fund of $30 million to offset the costs of responding to uncontrollable major storm events. This storm fund amount is approximately 88 percent of the average annual amount of major storm costs that have been eligible for deferral during the same 4.5 year period.

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Q. Why is the Company proposing to modify the current mechanism for addressing major storm costs?

A. Currently, if the Company's system is affected by a major adverse weather event, the Company may have to incur tens of millions of dollars in unforeseen costs in a very short time period. These costs are often payments to third-party contractors and suppliers, and can have a significant effect on the Company's cash flow. Although the current deferral mechanism provides an opportunity to recover these costs, such recovery may occur more than 4 years after a storm, depending on the timing of the event.

Establishing a storm fund to which customers contribute over time would provide a source of funds to respond to these significant events, and reduce the potentially significant cash flow impacts which can result from a major storm. In addition to enhancing the availability of funds needed to respond to a major storm, a storm fund is also expected to provide greater matching of cost recovery with cost incurrence.

Q. How would the storm fund operate?

A. The storm fund would work as a pre-funded account. The Company would include an amount in base rates which would be used to fund the storm fund, and major storm costs would be assessed against this account balance. If the balance of the storm fund is brought below zero as of December 31 of any year because of major storm costs, the Company would recover an amount to bring the fund balance to zero through the EDAM described in the Revenue Requirements Panel testimony.

Q. Is the Company proposing to change the types of major storm costs that are eligible for recovery?

A. No. The Company proposes to use the existing criteria that were established for deferral of storm costs.

Q. How did the Company determine the proposed storm fund amount?

A. The proposed storm fund amount is slightly less than the annual average of the Company's deferred major storm costs from April 2005 through August 2009 (i.e., \$152 million/4.5 years = \$33.78 million/year). The establishment of the storm fund is not intended to insure the availability of all the funds necessary to respond to every major storm, but rather to help meet the substantial short-term cash demands that result when the inevitable major storm event occurs. Exhibit __ (IOP-11) provides a summary of the major storm deferral amounts described above that were used to arrive at the proposed \$30 million storm fund amount.

F. Site Investigation and Remediation

Q. What is the Site Investigation and Remediation ("SIR") program?

A. The SIR program refers to those activities undertaken and costs incurred by the Company in connection with the management and remediation of environmentally contaminated sites. Such sites might include former manufactured gas plant sites, other Company operating sites that have become environmentally contaminated, or non-Company sites where the Company faces potential PRP (Potentially Responsible Party) exposure relating to alleged liabilities under Federal or State Superfund law or other law or regulation relating to the control of hazardous waste or substances. The Company's current electric rates include base recovery of $12.75 million per year for SIR costs. This amount represents the 85% electric allocation of the total $15 million SIR costs previously established in rates for both electric and gas operations. To the extent actual electric SIR costs exceed or are less than the annual rate allowance, the difference is deferred for subsequent recovery or return.

Q. What types of costs are incurred under the SIR program?

A. Allowable costs under the SIR program include associated consultant and contractor costs, base labor expense as well as incremental internal labor used for SIR activities, remediation activities aimed at reducing the volume, toxicity or mobility of pre-existing contamination, and incremental external costs, including insurance and legal costs, incurred to seek recovery from third parties or to otherwise seek to mitigate the Company's costs or liability associated with the SIR program. Under the MJP, allowable SIR costs are to be offset by: (1) net gains from the sale or transfer to Non-utility Property of the Company's land and buildings included in rate base, or from the sale of stone, gravel, sand or timber from such land; (2) any net gains recognized from the leasing of such land or from the sale or lease of mining or drilling rights to such land; and (3) net insurance proceeds and net recoveries from third parties.

Q. What have the Company's historic SIR costs been?

A. The Company's current level of SIR recovery in electric rates is $12.75 million. However, the Company's actual total SIR expenses over the period FY 2003 – FY 2009 have been:

FY 2003:	$28,675,183
FY 2004:	$22,045,153
FY 2005:	$29,610,349
FY 2006:	$21,680,242
FY 2007:	$18,644,941
FY 2008:	$14,731,334

FY 2009: $33,663,069

The variability in annual amounts results from the fact that SIR project spending is significantly affected by whether SIR activities are focused on investigation (when spending is lower) or construction (when spending increases).

Q. What is the most recent level of SIR deferrals associated with the Company's electric operations?

A. As of September 30, 2009, the Company had an SIR deferral balance of $82.3 million. Its forecasted deferral balance at December 31, 2010 is $109 million.

Q. Is the Company proposing a change in the amount of SIR recovery in base rates?

A. Yes. The Company is proposing to increase the annual level of SIR recovery in electric base rates from the current level of $12.75 million to $29.75 million. This is based on annual projected total SIR costs of $35 million, with 85% allocated to electric and 15% to gas.

Q. Was SIR expense addressed in the Company's recent gas rate case (Case 08-G-0609)?

A. Yes. In that case, the Commission approved a settlement which included annual gas SIR expense of $4.5 million. This amount was based on a total gas and electric SIR expense of $30 million per year, with 15% of the total expense allocation to gas operations (0.15 x $30 million = $4.5 million).

Q. Why is the Company proposing total SIR expense of $35 million in this case?

A. As described in the gas case, and as indicated by the historic spending above, the Company's actual SIR spending has been far in excess of its actual rate allowance. Future SIR expense is expected to increase still further as more projects move from the investigation stage to construction. In the gas case, the Company noted that the $30 million estimate it proposed was conservative, and additional recent information bears out that characterization. For the first 6 months of FY 2010, the Company's SIR spending has total $22 million. For the 16 month period from September 2009 through December 2010, the Company projects SIR spending at $64.1 million (with the 85% electric share at $54.485 million). To provide for more current cost recovery, therefore, the Company proposes that annual base rate recovery of electric SIR costs be set at $29.75 million (85% of $35 million).

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Q. What is driving the increased SIR expense?

A. The projected average annual spend of $35 million is based on recent spending and ongoing/near term construction projects. It is increased to reflect more recent actual data, as well as for inflation. The project schedule for the MGP sites, which comprise the vast majority of the spending, is controlled by the DEC under Orders on Consent. A copy of the most recent schedule is attached as Exhibit __ (IOP-12). The schedule is intended by DEC to set ambitious completion goals and does not account for project delays related to such things as extended regulatory reviews, permitting, third-party property access issues, or other common occurrences. The DEC meets with the Company and other New York utilities to discuss adjustments to the schedule. Spending projections using the DEC schedule would result in even higher proposed recovery levels.

Q. Does the Company propose to continue the SIR deferral mechanism?

A. Yes. For each year of the rate plan, the Company will compare its net actual electric SIR costs with the amount collected in rates and will reflect the difference, positive or negative, in the EDAM, which is discussed in the Revenue Requirements testimony. The increase in base rate recovery requested here is intended to provide for more current cost recovery and a corresponding reduction in the amounts deferred annually.

Q. What is the Company's proposal relative to SIR labor costs?

A. In the gas rate case settlement, the Company agreed to transfer internal labor costs from the gas SIR deferral account to base rates. The Company proposes the same treatment for electric-related SIR expense, and proposes to transfer deferred SIR labor expense into base rates. Currently, four positions are included in base rates, while five positions are accounted for in the SIR deferral account. Consistent with the treatment reflected in the gas settlement, it is proposed that all nine SIR positions be included in base rates.

Q. The Commission's Order Approving Transfer with Modifications, in Case 09-E-0593, issued December 23, 2009, directed the Company to make a number of adjustments to its accounting books and take other steps to address treatment of costs, including among other things, SIR costs, associated with non-utility property. Does the Company's filing address the Commission's directives in that case?

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A. Yes. The actions that the Company is taking to address the Commissions order in Case 09-E-0593 are described in the testimony of the Revenue Requirements Panel and in Mr. Sloey's testimony.

G. Service Quality

Q. Please describe the Company's reliability service quality performance associated with electric operations.

A. The Company's electric reliability performance is measured through the Company's Service Quality Program established in accordance with the requirements of the Commission's July 2, 1991 Order in Case 90-E-0119 (the "1991 Order"). In the 1991 Order, electric service standards were adopted for large New York electric utilities, as a means of ensuring that the utilities provided adequate levels of service. The Service Quality Program includes three discrete metrics for electric reliability: SAIFI (System Average Interruption Frequency Index), CAIDI (Customer Average Interruption Duration Index), and momentary interruptions ("MI").

SAIFI is calculated based on the total number of customers interrupted divided by the number of customers served and is a reflection of the number of times the average customer is without service annually. CAIDI is a measure of the average interruption duration experienced by those customers who have had an outage and is calculated from the total customer minutes interrupted divided by the customers interrupted. MI are momentary operations recorded at the substation breakers.

The Company's current reliability targets for SAIFI of 0.93 and for CAIDI 2.07, are based historic performance between 1986 and 1990. Despite being established in the late 1980s from a legacy paper-based manual reporting system, the historical SAIFI and CAIDI targets form the baseline for present-day measurement of the Company's reported electric reliability performance.

Q. What events are classified as interruptions?

A. Interruptions are outages of at least 5 minutes in duration and include all outages except those related to major storms. For reliability reporting purposes, a weather event is classified a major storm when at least 10 percent of customers are interrupted or one customer experiences a 24 hour interruption within an operating area.

Q. How are interruptions recorded by the Company?

A. The recording of interruptions for the measurement of SAIFI and CAIDI is accomplished utilizing the System Interruption Reporting database (SIR-SQ), a mainframe-based system that records and stores data related to system interruptions. The legacy SIR-SQ system, which was state of the art when implemented, is a manual, paper-based system that has been used to report reliability performance over the last 14 years. The SIR-SQ system stores information recorded on paper tickets that are manually filled out by line crews during their shifts. Information includes time off, estimated number of customers interrupted and time on. Data on SIR-SQ tickets is then manually entered into the SIR-SQ database by an office technician.

Q. How has the Company performed against the Service Quality Reliability based targets?

A. Following a period of worsening performance in the early 2000s, the reliability of the Company's system has shown steady improvement from 2004 through 2008. In addition, preliminary results for 2009 indicate that the Company has again met its SAIFI and CAIDI performance objectives as illustrated in the chart in Exhibit__ (IOP-3). This will mark the second consecutive year that the Company has met both its SAIFI and CAIDI metrics.

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Q. What measures has the Company taken to address reliability performance?

A. To meet its reliability objectives, the Company has developed and executed a work plan that involves substantially increased levels of system maintenance and capital investment to stabilize and improve the system. This investment has been a necessary precursor to the achievement of significant improvement in safety and reliability performance and the Company's recent efforts in this regard are already yielding results.

The Company has taken a number of major steps to improve reliability performance, including implementation of the Reliability Enhancement Program ("REP"), initiation of the Overhead Transmission Line Refurbishment Program, and other operational improvements. The REP and Overhead Transmission Line Refurbishment programs combine infrastructure investment projects and maintenance activities designed to enhance the long-term performance and health of network assets through the implementation of a portfolio of asset strategies. In addition to the base level of spending, since 2006, the Company has spent approximately $190 million in capital and approximately $22 million in associated expenses to achieve targeted reliability performance and renewed asset health. The key elements of the REP included a targeted program to

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enhance the performance of distribution feeders (Feeder Hardening), feeder sectionalizing through the installation of reclosers and fuses, asset replacement, improved inspection and maintenance, and a vegetation management program. The Company has delivered on this program and customers have experienced improved service reliability as a result. The Overhead Transmission Line Refurbishment Program is a long-term program to rebuild over 30 transmission lines that have demonstrated poor performance because of their condition. Lessons learned from implementing the REP and Overhead Transmission Line Refurbishment Program have helped guide the development of the Company's current business plan, and the associated infrastructure investment and operations plans.

From an Operations perspective, the Company has negotiated new job classifications with the IBEW to utilize line trucks operated by one person crews (OPC's) that are positioned throughout the service territory to improve response time to outages. In addition, the Company has renewed the focus of its control center and field personnel to 'switch before fix' whenever possible to restore as many customer as possible in the shortest amount of time. The reduction in the duration of interruptions resulting from these efforts contribute toward improved reliability performance.

Q. How does the weather affect reliability metrics?

A. Service interruptions associated with adverse weather events are a primary factor affecting the Company's reliability performance. As mentioned previously, outages associated with major storms are excluded from the calculation of SAIFI and CAIDI. In some years, the Company experiences a large number of major storms that are excluded, such as in 2008. In other years, the Company's service territory may be affected by a large number of smaller storms that cause many customer interruptions, but are not excluded, thereby contributing to lower reported reliability performance.

Q. Is the Company proposing any changes to the electric operations service quality thresholds for SAIFI and CAIDI?

A. Not in this case. The Company is addressing modifications to its service quality metrics through a separate effort with DPS Staff.

Q. Are there any other changes the Company wishes to make regarding reliability service quality metrics?

A. Yes, the Company is proposing two additional changes. First, the Company is proposing to modify the existing service quality penalty terms by providing an additional incentive for the Company to improve its

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reliability performance if it becomes subject to the maximum double penalties established under the MJP. That is, the Company proposes that in the event it is subject to the maximum double penalties under the MJP, and that its reliability performance for at least two consecutive years is within the established reliability targets, that the risk of double penalties would be reduced to the standard single penalty for the following year. Thus, when the reliability penalty level for SAIFI or CAIDI is at $8.8 million based on the current penalty doubling provisions of the MJP, the penalty level would be reduced to the pre-doubling level of $4.4 million upon meeting the reliability metrics for two consecutive years. This process would not otherwise affect the doubling provision.

Q. What is the basis for this request?

A. The Company accepted the risk of increased penalties for poor reliability performance in the MJP. However, once the double penalty band is triggered, there is no provision for the return to the standard penalty levels established in the MJP. This proposal establishes a mechanism to return to the standard penalty bands in the event of continued reliable performance, and provides an additional incentive to consistently achieve reliability goals.

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Q. What is the second additional request?

A. The Company proposes to eliminate PSC Cause Code 7 for Pre-arranged Outages from the calculation of SAIFI and CAIDI.

Q. What is the basis for this request?

A. The number of planned interruptions has steadily increased as the Company has increased its proactive management of its assets to address system reliability and sustainability issues. Including planned outages in the calculation for SAIFI and CAIDI creates a disincentive for the Company to correct reliability and asset health issues that require a planned outage. The Company works diligently to minimize the number of planned outages through utilization of energized work practices. In addition, the Company attempts to reduce the impact of pre-arranged outages on our customers through timely notification based on internal Company procedures. However, there are certain types of work that absolutely require an outage. These include voltage conversions, as part of feeder upgrades, where individual transformers must be de-energized to change the operating voltage from 4 to 13.2kV.

The second factor is worker safety. Certain work practices have been established in conjunction with the IBEW, to ensure worker safety and comply with internal and external (OSHA) safety requirements for energized work by line mechanics. These cases are typically due to proximity to energized conductors or, in the case of the replacement of defective equipment such as potted porcelain cutouts, to reduce the risk of failure while the equipment is being replaced. Thus, removing PSC Cause Code 7 from the calculation of the Company's performance metrics promotes long-term reliability and modernization of the system in a safer manner.

VIII. Research, Development and Demonstration ("RD&D") Programs

Q. Please describe the Company's RD&D program generally.

A. The purpose of the Company's RD&D program is to drive innovation through new technologies to improve the efficiency of the Company's electric operations while meeting the challenges and future needs of providing safe, reliable, efficient reasonable cost service to our customers. The program identifies new technologies, tests and evaluates these technologies, and ultimately integrates them into our day-to-day operations. The Company uses a centralized RD&D model to guide, monitor, and report these activities. The objectives of the program are to: 1) reduce customers' costs through reductions in the Company's capital and O&M expenses, 2) improve the reliability of the electric system, and

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3) meet the challenges of climate change from a mitigation perspective (e.g., facilitating the integration and interconnection of renewable generation) and an adaptation perspective (creating a better understanding of the impacts of climate change on customers and the electric system).

Q. Can you provide an example of how a program in the Company's RD&D portfolio might reduce customer costs or lead to improves reliability?

A. Yes. Included in the Company's proposed portfolio of projects is the Wireless EMS (Energy Management System) project, which the Company would undertake jointly with other utilities and vendors. Wireless EMS would enable further penetration of EMS capabilities and improved SCADA (Supervisory Control and Data Acquisition) information throughout expansive electric networks (such as the Company's) at lower cost than using dedicated communications lines would allow. Other examples include vegetation management projects in the RD&D portfolio. These projects would develop models, tools and techniques that would improve reliability by reducing tree-caused outages without increasing costs.

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Q. What sort of work in the RD&D portfolio is aimed at addressing climate change and efficiency initiatives?

A. The Company's plan also calls for continued work in the Renewable Integration area. In the past, the Company participated in EPRI studies focused on Renewable Integration, including, for example: Integrating High Penetrations of Variable Utility-Scale Renewable Power Sources into the Electric Power Infrastructure; Enhancing Grid-Connected Photovoltaic Systems with Advanced Interface Devices; Distributed Photovoltaic: Utility Integration Issues and Opportunities. The Company also has an ongoing project at Niagara Falls, in collaboration with NYSERDA, the objective of which is to install and evaluate the performance of a 100-kW, 150-kWh zinc-bromide (ZnBr) flow battery in conjunction with a nominal 30-kW photovoltaic (PV) system installed on a Niagara Falls State Park facility. Of primary interest to the Company is evaluating the opportunity to shift the renewable generation to meet the customer's peak demand.

The Company will start work on Adaptation Strategies for Climate Change. The purpose of this program is to develop climate change adaptation strategies for the electric distribution and transmission infrastructure. Two studies are envisioned; one focusing on network resilience and the other on flooding. The results of these studies will provide the basis for the Company to potentially modify its system design and operational procedures to mitigate the effect of and to adapt to weather trends going forward and ensure the best location placement of new infrastructure and assess the locations of existing infrastructure.

The Company has and will continue to work collaboratively with other utilities, NYSERDA, and DOE, thereby leveraging the Company's investment in RD&D. All of the opportunities for external funding require a commitment of co-funding which is included in the funds requested for this program. The Company has already negotiated a corporate agreement with EPRI, which covers all National Grid's activities. This has the effect of leveraging funds such that it reduces the cost of the EPRI program to the Company's customers in New York.

Q. Is the Company proposing to recover the costs of its RD&D program in this case?

A. Yes. The Company's revenue requirement reflects incremental recovery above the historic test year amounts of $1.26 million in CY 2011, $2.73 million in CY 2012, and $3.08 million in CY 2013 associated with the RD&D program.

Q. Why is the Company proposing cost recovery for RD&D initiatives in this case?

A. The importance of this program is clear. These investments are needed to reduce the size of future larger investments that would be required if we continued down a business as usual path. Additionally, the program will focus on many of the urgent needs as identified in by New York State Energy Plan (NYSEP) over its 10-year planning horizon. Specifically the program supports all five of the NYSEP's policy objectives[7]:

- Assure that New York has reliable energy and transportation systems;
- Support energy and transportation systems that enable the State to significantly reduce greenhouse gas (GHG) emissions, both to do the State's part in responding to the dangers posed by climate change and to position the State to compete in a national and global carbon constrained economy;
- Address affordability concerns of residents and businesses caused by rising energy bills, and improve the State's economic competitiveness;
- Reduce health and environmental risks associated with the production and use of energy across all sectors; and
- Improve the State's energy independence and fuel diversity by developing in-state energy supply resources.

[7] State Energy Planning Board, 2009 State Energy Plan - Volume I; Governor David A. Patterson, State of New York, December 2009.

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Further the program supports four of the five strategies identified in the NYSEP to achieve these objectives: (1) produce, deliver and use energy more efficiently; (2) support development of in-state energy supplies; (3) invest in energy and transportation infrastructure; and (4) stimulate innovation in a clean energy economy. As a matter of business practice, the program supports the fifth objective: (5) engage others in achieving the State's policy objectives through collaborative effort.

The NYSEP Plan identified energy efficiency as the priority resource to meet its multiple objectives. It sets a goal of reducing electricity use by 15 percent below 2015 forecasts. The NYSEP energy plan identifies electric system efficiency as a "wedge" in achieving this goal. The NYSEP states, "Improving efficiency in the delivery of electricity from generation facilities to end-users in a cost effective manner by reducing transmission and distribution system losses will also mitigate prices and environmental impacts." The Company will continue to collaborate with stakeholders across the state in this area. In addition, staff supported by this Program will analyze methods to reduce electric system losses including, for example use of amorphous core distribution transformers. Energy storage is another technology that was identified in the NYSEP to improve system efficiency. The Company's RD&D program has invested in energy storage demonstrations in the past and will continue to evaluate this technology.

To support the development of in-state energy supplies, the NYSEP calls for expanding the Renewable Portfolio Standard (RPS) to 30 percent of the State's electricity needs with renewable resources by 2015. Distributed Renewables, including photovoltaics (PV) have a large technical potential to help meet this expanded RPS. PV installed costs dropped 30 percent from 1998 to 2008.[8] The high level of incentives provided in New York contributed to it being the state with the lowest net installed cost for residential PV systems.[9] New York's net metering law will continue to increase the customer interest in PV. The proposed RD&D program would address the impacts of high penetrations of Distributed Renewables and work to address other barriers associated with the interconnection of these resources.

The NYSEP states, "Because New York's electric infrastructure is old, significant capital investments will need to be made in the utilities' electric transmission and distribution systems to meet future electric

[8] US Department of Energy Lawrence Berkeley National Laboratory Report "Tracking the Sun II: The Installed Cost of Photovoltaics in the U.S. from 1998-2008" Wiser, R., G. Barbose, C. Peterman, and N. Darghouth. LBNL-2674E. October 2009
[9] Ibid

demand and allow them to continue to provide reliable service. Replacement and improvement of existing aging infrastructure are critical, as system failures not only raise safety and reliability concerns but can also lead to increased system congestion and therefore higher emissions and costs." A major focus on the Company's RD&D program will be to accelerate the use of technology and innovation to ensure that these required investments are made in the most cost effective manner to relieve some upward pressure on rates. For example, the Program's portfolio would include a project to test the Communications and Network systems in substations standard IEC 61850. This new international protocol has been developed to enhance substation automation and is expected to result in significant improvements in both cost and performance of electric power systems. However, despite the projected benefits of IEC 61850, it is essentially untested on the Company's system and within the industry. Once proven, the Company would roll out this standard across its operations and reap the savings benefit for its customers.

In addition to the urgent needs that these RD&D investments will address for our customers, this program will also play a role in stimulating innovation in the clean energy economy. The Company will continue to work with local universities, such as Syracuse University, Rensselaer

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Polytechnic University, and Clarkson University and entrepreneurs both inside and outside of upstate New York who are interested in creating businesses and jobs in New York. According to recent studies, New York is behind in developing jobs in and for the green economy. A recent Pew Center study found that jobs in the clean energy economy grew at a national rate of 9.1 percent per year, while traditional jobs grew by only 3.7 percent between 1998 and 2007.[10] In contrast to this national trend, New York lost clean energy jobs at a rate of -1.9 percent per year.[11] According to the same Pew Center study, New York is also further behind in attracting venture capital to the state attracting just 1.7 percent of the $12.6 billion invested in clean energy from 2006-2008.[12] Through its "Capstone" program, the Company would sponsor student design projects at Clarkson University, Syracuse University, RPI, Union College, and the University at Buffalo. The investment in these projects provides the region with the necessary engineering talent to participate in the global green economy. The benefit to the Company, in addition to the project work product, is creating student interest in the energy delivery industry. Participation in capstone design projects also allows the Company to attract candidates for future employment.

[10] Pew Charitable Trusts, "The Clean Energy Economy: Re-powering Jobs, Businesses and Investments Across America," June 2009.
[11] Ibid.
[12] Ibid.

Q. Does the Company provide a description of the projects included in its RD&D program?

A. Yes. Exhibit __ (IOP-13) includes a summary description of the each of the projects included in the Company's RD&D portfolio, along with the estimated annual funding during the proposed rate plan period for each identified project.

IX. Safety and Environmental Performance

Q. Please describe the Company's approach to enhancing safety and environmental performance.

A. The Company believes a focus on operational excellence results in a safer environment for both employees and the general public. To that end, the Company is working to improve environmental compliance, reduce the risk of environmental incidents and comply with legal and regulatory requirements.

For example, to meet environmental objectives, the Company is working with its construction alliance partner, Northeast Power Alliance ("NEPA"), to implement best management practices ("BMPs") in connection with transmission line re-builds in New York State to protect sensitive areas. Work on hundreds of miles of electric transmission line rights-of-way will involve or be close to freshwater wetlands, rivers, streams, other water bodies, forestlands, wildlife habitats and important agricultural, cultural and historical resource areas. Use of environmental BMPs will help assure that critically-needed transmission line reinforcements and refurbishments are accomplished in an environmentally compatible and responsible manner.

Another example of the Company's environmental stewardship is its SF6 (sulfur hexafluoride) gas program. Equipment containing SF6 gas is monitored for leaks and leaks are mitigated as part of the Company's SF6 Mitigation Plan. Through the use of emerging technologies such as a camera using ultraviolet technology, determining SF6 leak locations and making equipment repairs is addressed on a more expedited basis. The Company also joined the U.S. Environmental Protection Agency Voluntary SF6 Reduction Partnership in 2004 and continues to report reductions on a yearly basis to the EPA.

With respect to safety, the Company is implementing a series of initiatives to enhance the safety of employees and the general public. Through formation of Safety Strategy Committees ("SSC"), the Company is focused on increasing union participation and enhancing safety for all employees. This improved involvement approach and continued focus on ERGO power teaching should provide continuous improvements to our safety performance.

The reporting of near-miss incidents and hazardous conditions has also exposed some areas of concern that may have otherwise gone unnoticed. The SSC teams will further evaluate identified trends in order to recommend corrective actions, and teams are being developed now to evaluate ways of eliminating the most significant safety concerns. The Company's safety department also works closely with our contractor alliances and their safety professionals to share best practices and promote a safe work place.

The Company's objective is to create a working culture directed towards achieving zero injuries and zero work-related illnesses—and at this time the results have shown the effectiveness. Our efforts to enhance public safety are equally robust and evidenced by the on-going improvements with our electric system infrastructure and the creation of a new position within the safety organization, Manager, Contractor, Public Safety and Fleet.

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X. Reporting Requirements

Q. Please describe the Company's proposal relative to modifying certain reporting requirements.

A. Niagara Mohawk is subject to several periodic reporting requirements. One such requirement established under the Merger Joint Proposal approved in Case 01-M-0075 is the filing of a Load Pocket Study. The Load Pocket Study filing requirement does not appear to serve any useful purpose at this point, and the Company is seeking authorization from the Commission to cease submitting this study in the future.

Q. Please describe the Load Pocket Study requirement.

A. Section 1.2.22 of the MJP provides in part that:

> Niagara Mohawk will provide to DPS Staff, within six months of the Effective Date and every two years thereafter, economic analyses of the costs and benefits (including the expected impacts on customer commodity costs) of potential transmission investments. These studies will include transmission investments which will have the potential to benefit Niagara Mohawk customers, including, but not limited to, analyses of congestion costs, and local "load pockets," that is, those load pockets within

Niagara Mohawk's service territory whose impacts primarily affect Niagara Mohawk customers.

The Company has produced the required load pocket study every two years, and filed it with the Commission. There are several reasons why this requirement should be reexamined, and potentially eliminated.

Q. Why is the Company seeking to be relieved of the requirement to file the Load Pocket Study?

A. First, the development of the Load Pocket Study requires the engagement of numerous Company resources to produce; yet, there is no evidence that the study is useful. The Company has received no comments, questions, or feedback of any kind from the Commission or its staff on any load pocket study report it has submitted since 2003, suggesting to the Company that the study has limited value to the agency.

Likewise, the Company itself does not derive any business value from the load pocket study. No transmission capital projects have been created or implemented as a result of the findings of a load pocket study. Had the load pocket studies not been required and not performed, there would have been no difference in the Company's construction program or operations during the corresponding period.

Further, independent of any load pocket studies developed to satisfy the reporting requirement, the Company also continues to improve its transmission system in ways that mitigate or eliminate "load pockets." For example, the 2009 load pocket study showed that transmission projects planned for the Company's Northeast Region to fulfill reliability requirements and serve load growth could eliminate the load pocket entirely. In Western New York, the Huntley load pocket is caused by a specific double circuit contingency (lines 193 and 194) and a resulting constraint imposed by loading on line 195. For reliability reasons, the Company has an approved project to re-conductor the line, mitigating the load pocket as an additional benefit. Thus, load pocket mitigation is occurring irrespective of any studies done to fulfill the reporting requirement.

Eliminating the Load Pocket Study requirement would avoid what appears to be an unnecessary use of resources, and promote greater efficiency for the benefit of the Company and its customers.

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Q. Does this conclude the panel's testimony?

A. Yes, it does.

BY MR. GAVILONDO:
Q Now, Panel, as part of your direct pre-filed testimony, do you sponsor any exhibits?
A (Smith) Yes, in our pre-filed direct testimony we sponsor 14 exhibits.
Q Were those exhibits prepared by you or under your direction?
A (Smith) Yes, they were.
Q Okay.
MR. GAVILONDO: I ask that those exhibits to the direct pre-filed testimony be marked for identification. I believe, Your Honor, there is a list that appears to begin at Exhibit Number 81 through 94 for the 14 exhibits that represent the exhibits of the pre-filed direct.
ALJ BOUTEILLER: We've reserved those numbers for the exhibits associated with the direct testimony of this panel, and they'll be used. Exhibits Numbers 81 through 94 are now provided for those exhibits that were pre-filed with the direct testimony.
MR. GAVILONDO: Thank you.
BY MR. GAVILONDO:
Q Panel --
MR. GAVILONDO: I'm going to forego

approaching, Your Honor.
Q I direct your attention to a document that consists of a cover page and 17 pages of questions and answers and ask if you could please identify that document for the record?
A (Smith) This document is the pre-filed corrections and updates testimony of the Infrastructure & Operations Panel dated May 3, 2010.
Q Do you have any changes or corrections to that document?
A (Smith) Changes or corrections to our corrections and updates testimony are addressed in our subsequent submittal, rebuttal testimony.
Q Panel, if I were to ask you here today the questions that appear in your pre-filed corrections and updates testimony, would your answers be the same as they are in that testimony?
A (Smith) Yes.
Q Okay. Do you adopt that pre-filed testimony as your sworn testimony in this proceeding?
A (Smith) Yes.
MR. GAVILONDO: I request that the pre-filed corrections and updates testimony dated May 3rd of the Infrastructure & Operations Panel be moved into the record.

ALJ BOUTEILLER: Absent objection I'll instruct the reporter to copy into the record as if given orally today the pre-filed corrections and update testimony offered by this panel.

MR. GAVILONDO: Thank you.

(The referenced testimony is inserted into the record as follows.)

Before the Public Service Commission

NIAGARA MOHAWK POWER CORPORATION d/b/a NATIONAL GRID

Corrections and Updates Testimony

of

The Infrastructure and Operations Panel

Dated: May 3, 2010

Testimony of Infrastructure and Operations Panel

I. Introduction

Q. Please identify the members of the Infrastructure and Operations Panel.

A. The Panel consists of Ellen Smith, Bruce Walker and Keith McAfee.

Q. Is this the same panel that testified previously in this proceeding?

A. Yes. The Infrastructure and Operations Panel ("IOP") provided direct testimony as part of the Company's January 29, 2010 filing.

Q. What is the purpose of your corrections and updates testimony?

A. The purpose of the Panel's corrections and updates testimony is to identify and explain certain updates and/or corrections to direct testimony and exhibits from the January 29, 2010 filing.

Q. Are you sponsoring any exhibits through your corrections and updates testimony?

A. Yes. The Panel sponsors the following exhibits:

1. Exhibit __ (IOP-1CU), Schedules 1, 2, 5, 6, and 8 (revised infrastructure investment plan funding schedules to reflect revised capital investment plan);

2. Exhibit __ (IOP-6CU) (revised information systems projects table reflecting corrected amortization amounts and actual spending through March 2010);
3. Exhibit __ (IOP-9CU) (corrected aerial inspection program information);
4. Exhibit __ (IOP-13CU) (corrected and revised description of research, development & demonstration ("RD&D") programs and funding levels); and
5. Exhibit __ (IOP-13ACU) (new exhibit setting forth RD&D program cost allocation percentages and annual funding levels).

Q. What updates and/or corrections do you have to your January 29, 2010 testimony and exhibits?

A. The Panel's corrections and updates testimony describes the following changes to the January 29, 2010 filing:

1. Downward adjustment to the infrastructure investment plan of approximately $99 million for the FY11-FY14 period to reflect removal of some proposed projects from the plan and the addition of others;

2. Updates to reflect a revised in-service date for the Company's Energy Management System ("EMS") replacement project;
3. Changes in the amounts for capital-related operations and maintenance ("O&M") costs and cost of removal ("COR");
4. Corrections in the testimony relating to facilities investments;
5. Corrections relating to information system investments;
6. Corrections relating to the Company's aerial inspection program; and
7. Corrections relating to the proposed research, development and demonstration ("RD&D") programs.

II. Corrections and Updates

<u>Update to Infrastructure Investment Plan</u>

Q. Please describe the Company's updates relating to its infrastructure investment plan.

A. The Company is proposing an overall downward adjustment of $99 million for the period FY11-FY14 in the transmission portion of its investment plan. This adjustment reflects the removal of a number of projects related with the Frontier Region Program described in our direct testimony, as well as the addition of other projects required as a result of the removal of the Frontier Region projects.

Testimony of Infrastructure and Operations Panel

Q. Please describe the Frontier Region Program and explain the basis for removing the projects associated with it from the plan.

A. Based on information evaluated after development of the infrastructure plan reflected in the January 29 filing, the Company is proposing to remove from the plan a number of projects included in the Frontier Region Program. The removal of the projects in the Frontier Region Program will also impact the Other Asset Condition Program and the Reliability Criteria Compliance Program. The Frontier Region Program is described at pages 72 and 73 of the direct testimony of the IOP, and we do not repeat a description of the program here.

As part of its continuing review of system needs, in February 2010 the Company performed an extensive review of the drivers behind the planned construction of Tonawanda Station, the closure of the Packard 115 kV bus tie and the re-conductoring of circuits between Packard, Tonawanda and Gardenville substations. The review included 2009 Summer peak results and the latest economic load growth forecast. The updated system representation reflected significant load reductions at several large industrial customers, a modified load distribution across the area and a lower growth rate well into the future. The result of this evaluation indicates that the capacity need driving the Frontier Region Program projects will not likely materialize within the 15-year horizon for system projections. Therefore, the Company has removed these projects from the capital investment plan proposed in this rate case. Removing these projects from the plan is appropriate, and is consistent with the Commission's directives to eliminate or defer spending when doing so can be accomplished without compromising the provision of safe and reliable service.

Q. Please explain the changes proposed for the Reliability Criteria Compliance and Other Asset Condition programs.

A. As part of the Reliability Criteria Compliance Program, the Strategy to Reinforce the Transmission System in New York's Frontier and Southwest Region (Strategy Paper SG 075 v2 – April 2009) included work to reconductor the #180 and #181 circuits, create a new 115 kV circuit between Packard and Gardenville using retired, in-place assets, and associated substation work at Packard, Tonawanda and Gardenville (referred to in SG 075 v2 as "Frontier Line Rebuilds (T Line and Station)" – project numbers C24018 and C24019, respectively). The reconductoring was originally required to prevent post-fault overloads under N-1 conditions; however, without the system changes at Tonawanda, these overloads are no longer an issue and the reconductoring is no longer necessary. Nevertheless, because the reconductoring projects would have also addressed important asset condition issues at the same time, it is now necessary to undertake additional projects in the Other Asset Condition Program and the Other System Capacity & Performance program.

Q. What specific projects are affected by removal of the projects in the Frontier Region Program and what are the funding amounts associated with those projects?

A. The affected projects in the Frontier Region Strategy include project numbers C11494 and C11495, as indicated in Exhibit __ (IOP-1), Schedule 8, Sheet 13 of 26. The aggregate funding amounts for these two projects were $29.3 million (FY11), $54.3 million (FY12), $12.2 million (FY13), and $3.4 million (FY14), for a total of $99.2 million for the period FY11-14.

The affected projects in the Reliability Criteria Compliance program include project numbers C24018 and C24019, as indicated in Exhibit __ (IOP-1), Schedule 8, Sheet 15 of 26. The aggregate funding amounts for these two projects were $1.6 million (FY11), $2.1 million (FY12), $14.5

million (FY13), and $21.0 million (FY14), for a total of $39.2 million for the period FY11-14.

Q. Does removal of the Frontier Region Program projects result in the need for other capital work not reflected in the January 29, 2010 plan?

A. Yes. To ensure the long-term reliability of the Buffalo / Niagara Falls area, the Company must undertake six projects in the area - predominately on assets that would have been replaced or made less essential if the Frontier Region Strategy projects had moved forward under the period covered by this case. The projects needed include: (1) installation of permanent capacitor banks at the Huntley 115 kV bus and improvements to grounding at Huntley (project number CNYPL11-1); (2) replacement of the remaining shield wire on the #182 line (project number CNYAS11-1); (3) refurbishment of the Niagara-Gardenville #180 line (southern part) with the double circuited Packard-Urban #181 line (southern part) from Ellicott Junction to the Gardenville substation (project number CNYAS11-2); (4) interim safety related shield wire replacements (under Strategy SG073) on the Huntley – Lockport #36 / #37 lines (project number C28707); (5) replacement of shield wire on the Huntley – Gardenville #38 line (project number C28676); and (6) replacement of the shield wire on

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the Packard-Huntley #130 and Walck-Road #133 lines between Huntley and Ellicott Junction (project number C28712).

Planned annual spending for the capacitor bank and grounding improvement project is as follows: FY11 $0.100 million, FY12 $0.400 million, FY13 $2.60 million, and FY14 $0.950 million, for an aggregate cost of $4.05 million over the FY11-FY14 period. Planned annual spending for the Huntley-Lockport #36 / #37, Huntley-Gardenville #38 and Huntley-Walck Road shield wire replacement work is $1.275 million in FY11 and $0.275 million in FY12, for a total of $1.550 million. Planned annual spending for the refurbishment of the #180 and #181 lines is as follows: FY11 $0.02 million, FY12 $0.5 million, FY13 $15.0 million, and FY14 $15.0 million, for an aggregate amount of $30.52 million over the FY11-FY14 period. Planned annual spending for the replacement of the remaining shield wire on the #182 line is as follows: FY11 $0.02 million, FY12 $0.08 million, and FY13 $2.0 million, for an aggregate amount of $2.1 million over the FY11-FY14 period.

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The revised capital investment amounts are set forth in Exhibit __ (RRP-6CU), Schedule 1, Sheet 4, to the corrections and updates testimony of the Revenue Requirements Panel.

Q. Has the Infrastructure and Operations Panel prepared revised exhibits that reflect the described changes to the infrastructure investment plan?

A. Yes. Included with our testimony are Exhibit __ (IOP-1CU), Schedules 1, 2, 5, 6, and 8, which reflect the changes described above. In Schedule 8, the pages that include the changes described above are Pages 13-15 and 22-25.

Q. Is the Company proposing any other changes to the infrastructure investment plan proposed in the case?

A. The Company will continue to review system needs; however, at this time, no other changes in the plan are warranted.

<u>Updated In-Service Dates for EMS Replacement Project</u>

Q. Please describe the update related to the revised in-service date for the EMS project.

Testimony of Infrastructure and Operations Panel

A. The Company's Energy Management System ("EMS") Replacement Project is described at pages 203-204 of the panel's January 29 direct testimony. In our direct testimony, we indicated that work on the EMS project was expected to continue through the end of 2012. The Company now anticipates that the EMS project will be implemented earlier than initially projected, with a current estimated in-service date of February 2012.

<u>Revised capital-related O&M and COR costs</u>

Q. Please describe the changes to the Company's filing relating to capital-related O&M costs.

A. As described in the IOP testimony (pages 226-230 of 266), whenever the Company undertakes capital investment work that affects existing facilities, it incurs O&M costs related to that capital work. Because the infrastructure investment plan presented in this case reflects an amount of investment greater than in the historical test year period, the Company's January 29, 2010 filing included an amount of incremental capital-related O&M expense. Because of the downward adjustment to the Company's infrastructure investment plan described previously, it is necessary to reduce this level of incremental capital-related O&M expense.

Testimony of Infrastructure and Operations Panel

Q. What adjustment is the Company proposing to its capital-related O&M expense?

A. The Company is proposing reductions in capital-related O&M expense associated with the downward adjustments in the infrastructure plan as follows: CY11: $2.22 million reduction; CY12: $0.75 million reduction; and CY13: $0.40 million reduction.

Q. Did the Company identify any other corrections needed in capital-related O&M?

A. Yes. In preparing its response to IR AJR-8, the Company identified a spreadsheet cell reference error that resulted in an overstatement of annual capital-related O&M amounts of $0.64 million. The Company has addressed the cell reference error and calculated a corrected capital-related O&M amount. Adding this adjustment and the adjustment associated with the reduced capital plan amount produces total annual capital-related O&M reductions of: $2.86 million in CY11, $1.39 million in CY12 and $1.04 million in CY13. These reduced amounts are reflected in Exhibit __ (RRP-2CU), Schedule 35, Sheet 4 to the corrections and updates testimony of the Revenue Requirements Panel.

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Q. Please describe the changes to the Company's filing relating to cost of removal ("COR").

A. As described in the IOP testimony (pages 134-135 of 266), whenever existing assets are removed from the Company's asset inventory (e.g., due to replacement, retirement, etc.), the Company incurs costs considered COR. The amount of COR estimated in this case is based on the investment levels included in the infrastructure plan. Because of the downward adjustment to the Company's infrastructure investment plan described previously, it is necessary to reduce the level of incremental COR in the case.

Q. What adjustment is the Company proposing to its COR amount?

A. The Company is proposing reductions in COR amounts associated with the downward adjustments in the infrastructure plan as follows: FY11: $2.20 million reduction; FY12: $4.18 million reduction; FY13: $0.53 million reduction; and FY14: $0.61 million reduction. These reduced amounts are reflected in Exhibit __ (RRP-6CU), Schedule 1, Sheet 5 to the corrections and updates testimony of the Revenue Requirements Panel.

Testimony of Infrastructure and Operations Panel

Facilities-related investments

Q. Please describe the corrections identified to the Company's facilities-related investment.

A. We describe two corrections to the panel's January 29 testimony. First, at page 188 of 266, the panel describes that National Grid's Northborough, Massachusetts consolidated control center would serve to "back up" the Company's Henry Clay Boulevard consolidated control center in the event of an evacuation of the Henry Clay Boulevard facility. Although the Northborough facility will have visibility over the Company's system, the primary back-up facility in the event of an evacuation of the Henry Clay Boulevard control center will be at the Company's Syracuse Office Complex in Syracuse. This correction is only for purposes of clarification, and has no other impact on the Company's operations or revenue requirements.

Q. Please describe the second facilities-related correction.

A. At page 197 of 266, line 9, of the direct testimony, the reduction of lease expense related to the Star Lake facility should read "$8,725," not "$5,500."

Testimony of Infrastructure and Operations Panel

Information System investments

Q. Please describe the corrections identified to the Company's information systems investments.

A. The Company's infrastructure-related information system ("IS") investments are described at pages 198-204 of 266 of the IOP's direct testimony, and in Exhibit __ (IOP-6). In responding to IR MM-42, the Company determined that it had reflected only a portion of the applicable amortization amounts for the following Operations-related IS projects in Exhibit __ (IOP-6): INVP 1185, 1242, 1243, 1246, 1363, 1482, 1484, 1642, 2144, 2182, and 2195. Attached as Exhibit __ (IOP-6CU) is a revised table reflecting the correct amortization amounts and actual spending through March 2010.

Aerial Inspection Program

Q. Please describe the corrections identified to the Company's aerial inspection program.

A. The aerial inspection program is described at pages 219-220 of 266 of the IOP's direct testimony. In preparing its response to IR VVP-13, the Company identified several reference errors in Exhibit __ (IOP-9), Schedule 2, relating to the transmission aerial patrol program. These errors were described in detail in the response to IR VVP-13, and are reflected in revised Exhibit __ (IOP-9CU), Schedule 2, included with this corrections and updates testimony. The corrections do not impact the Company's proposed funding level of the aerial inspection program.

<u>Research, Development and Demonstration ("RD&D") Program</u>

Q. Please describe the corrections identified to the Company's RD&D program.

A. The Company's RD&D programs are described at pages 251-260 of 266 of the IOP's direct testimony, and in Exhibit __ (IOP-13) of the January 29 filing. Exhibit __ (IOP-13) provides a detailed description of each program as well as annual funding amounts for each program. In responding to IR MM-120, the Company determined that the incremental funding amounts described for the programs reflected total funding levels, and not just the portion of funding that was allocable to Niagara Mohawk. In addition, the Company determined that in Exhibit __ (IOP-13), it had reflected the costs (unallocated) of the EPRI Reactive Power Management Program twice ($80,000 annually), incorrectly included the Grid Wise Alliance program ($20,000 annually), and misstated the CY 12 funding for the DV2010 program (should have been $50,000, but was reflected as $150,000).

Q. What has the Company done in this filing to address these errors.

A. The Company calculated Niagara Mohawk's allocated share of the RD&D program costs and included those costs in its updated revenue requirements submission. As a result of these corrections, the corrected incremental RD&D funding levels above the historic test year amount are $0.635 million in CY11, $1.378 million in CY12, and $1.559 million in CY13, for a three-year incremental funding total of approximately $3.57 million. The corrected funding amounts associated with the individual RD&D programs, as well as the allocation percentages and the revised annual funding levels are reflected in Exhibit __ (IOP-13A-CU) included with our testimony. In addition, the panel is sponsoring Exhibit __ (IOP-13CU), which presents the program information originally included in Exhibit __ (IOP-13), revised to reflect removal of the Grid Wise Alliance and redundant EPRI Reactive Power Management programs, as well as the corrections to the funding levels as described above.

Q. Does the panel have any other corrections or updates at this time?

A. No. However, conditions facing the Company are always changing, and the Company is continually evaluating opportunities to reduce costs and provide service to customers in the most efficient manner practicable. To the extent the panel identifies additional corrections or updates that

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significantly affect its testimony in this case, it will seek to bring them to the attention of the Commission.

Q. Does this conclude the panel's testimony?

A. Yes, it does.

BY MR. GAVILONDO:

Q Panel, do you sponsor any exhibits as part of your pre-filed corrections and updates testimony?

A (Smith) Yes, in our pre-filed corrections and updates testimony we sponsored five exhibits.

Q Were those exhibits prepared by you or under your direction?

A (Smith) Yes, they were.

MR. GAVILONDO: I request that the five exhibits that accompany the corrections and updates testimony which have been identified, reserved Exhibits Numbers 95 through 99 be applied to those exhibits.

ALJ BOUTEILLER: We will use those numbers which have been reserved for this portion of the testimony, Numbers 95 through 99.

MR. GAVILONDO: Thank you, Your Honor.

BY MR. GAVILONDO:

Q Were those exhibits prepared by you or under your direction? I think I may have already --

A (Smith) Yes, you did.

Q Yes, I did. Thank you. Panel, I turn your attention to a copy of a document that consists of a cover page, a two-page table of contents and 167 pages of questions and answers, and ask if you can identify that for the record?

A (Smith) This document is the pre-filed rebuttal testimony of the Infrastructure & Operations Panel dated August 6, 2010.

Q And, Panel, do you have any changes or corrections to your pre-filed rebuttal testimony?

A (Walker) Yeah, we do. At page 24 of 167 on line 10, the amount 133,000 should be replaced with 104,000. And on page 25 of 167 the -- similarly, the 133 which is at line 6 should be replaced with 104,000. And at line 8, the sentence beginning with the word "however," all the way through the 150,000 should be stricken. And at line 12, the amounts 70 and 180,000 should be replaced with 27,000 and 143,000 respectively. And at line 13 the 133,000 should be replaced with 104,000. And at page 26 the amounts on line 1 -- states 133,000, should be replaced with 104,000, and the forecast amount of 26.6 million should be replaced with 20.8. And then the 20 million should be replaced with 15.6 million.

Q Thank you, Mr. Walker. Does the panel have any corrections to any exhibits that were included in the corrections and updates -- I'm sorry, in the rebuttal testimony?

A (Walker) Yes. In Exhibit IOP-1R, schedule 1, page 1 of 1, the note at the bottom of the sheet refers to exhibit (the Revenue Requirement Panel-20R). It should be

21R instead of 20R.

Q Thank you. If I were to ask you here today these same questions that appear in your pre-filed rebuttal testimony, would your answers be the same as contained in that testimony as you've just described corrected?

A (Smith) Yes.

Q Do you adopt that as your sworn testimony in this proceeding?

A (Smith) Yes.

MR. GAVILONDO: I ask that the pre-filed rebuttal testimony as corrected be entered into the record.

ALJ BOUTEILLER: Absent objection it will be entered into the record as you've described it by the witness today.

(The referenced testimony is inserted into the record as follows.)

Before the Public Service Commission

NIAGARA MOHAWK POWER CORPORATION d/b/a NATIONAL GRID

Rebuttal Testimony

of

The Infrastructure and Operations Panel

Dated: August 6, 2010

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Rebuttal Testimony of Infrastructure and Operations Panel

I. <u>Introduction</u>

Q. Please identify the members of the Infrastructure and Operations Panel.

A. The Panel consists of Ellen Smith, Bruce Walker and Keith McAfee.

Q. Is this the same panel that testified previously in this proceeding?

A. Yes. The Infrastructure and Operations Panel ("IOP") provided testimony as part of the Company's January 29, 2010 and May 3, 2010 filings.

Q. What is the purpose of your testimony?

A. The purpose of our testimony is to respond to issues raised in the testimony of the Staff Infrastructure Panel on the Company's infrastructure and operations plans presented in this case. We also respond to the testimony of the Staff Vegetation Management Panel, the Staff Reliability Performance Mechanism Panel, and portions of the testimony of the Staff Accounting Panel and Policy Panel to the extent that testimony relates to matters addressed in the January 29, 2010 direct pre-filed testimony and the May 3, 2010 Corrections and Updates testimony of the Infrastructure and Operations Panel. In addition, we respond to the testimony of James M. Van Nostrand on behalf of the Pace Energy and Climate Center and the Natural Resources Defense Council.

Q. Are you sponsoring any exhibits through your rebuttal testimony?

A. Yes. The Panel sponsors the following exhibits:

Rebuttal Testimony of Infrastructure and Operations Panel

1. Exhibit __ (IOP-1R), Comparison of Company and Staff proposed Capital Adjustments and Balances;

    Schedule 1—Summary Comparison of Transmission, Sub-Transmission and Distribution Capital Adjustments and Balances;

    Schedule 2—Comparison of Transmission Adjustments and Balances by Program;

    Schedule 2A—Transmission Capital Investments-Reserve Adjustments;

    Schedule 3— Comparison of Sub-Transmission Adjustments and Balances by Program;

    Schedule 4— Comparison of Distribution Adjustments and Balances by Program;

2. Exhibit __ (IOP-2R), Comparison of Select Company and Staff Proposed Incremental Operating Expense Adjustments and Balances;
3. Exhibit __ (IOP-3R), Condition Report: Mortimer – Golah #109 Line;
4. Exhibit __ (IOP-4R), Conductor Clearance Strategy: Average Cost per Span;
5. Exhibit __ (IOP-5R), Oil Circuit Breaker Trouble Report History;
6. Exhibit __ (IOP-6R), Revised Facilities Capital Budget;
7. Exhibit __ (IOP-7R), Additional Employee Summary Information;
8. Exhibit __ (IOP-8R), 115 kV ROW Widening—Target Circuits;
9. Exhibit __ (IOP-9R), Sub-Transmission ROW Widening—Target Circuits;

10. Exhibit __ (IOP-10R), Saratoga Springs SIR Site Memorandum;
11. Exhibit __ (IOP-11R), National Council on Electricity Policy Report; and
12. Exhibit __ (IOP-12R), Select Information Request Responses Referenced in Company Testimony but Not Contained in Staff Exhibit __ (SPP-1).

Q. Summarize the Company's position on the Staff's testimony.

A. The Staff did a thorough job in reviewing the Company's presentation, and made several recommendations based on its view of the Company's proposal. In a number of instances, Staff identified errors or proposed adjustments with which the Company agrees. Where the Company accepts an adjustment or agrees with an issue raised by Staff or another party, such acceptance or agreement is affirmatively noted. However, on many other issues, the Company does not agree with the Staff's proposed adjustments. With respect to issues on which the Company does not accept Staff's position, and for which additional information is necessary to clarify the record, we provide testimony. In the case of issues on which the Company disagrees with Staff and relies solely on its previously filed testimony to support its position, we do not repeat our previous testimony here.

Q. How is your testimony organized?

A. To try to facilitate comparison and review, our testimony will generally follow the organization of the Staff's testimony.

Q. Does your testimony reflect any updates?

A. Capital planning for an electric utility by necessity is done on a multi-year timeframe due to the long-lead time, capital intensive nature of the infrastructure investment. The Company is continually refining its spending plans based on new information on field conditions, more detailed project estimates, and reprioritization based on system and customer needs. To the extent that the Company has identified material changes in its capital or operational plans that would affect the proposal set forth in this case, we identify such updates here in the context of the particular projects or programs affected.

Q. Has the Company revised its proposed capital investment and operations plans in this rebuttal testimony?

A. Yes, the Company proposes several adjustments to its capital investment plan, the net effect of which would be a downward adjustment of $111.279 million for the period FY11-FY14 when compared to the Company's May 3 filing. The Company's filing also supports a downward adjustment of $4.489 million for rate year 2011 relating to various operational expenses. A summary of these adjustments and the resulting balances is provided in Exhibit __ (IOP-1R) (capital) and Exhibit __ (IOP-2R) (operating expenses).

II. <u>Capital Investment Plan</u>

Q. Please address the Staff's proposal regarding a one-year rate case versus three-years.

Rebuttal Testimony of Infrastructure and Operations Panel

A. Staff proposed moving forward on the basis of a one-year case. However, the Staff Infrastructure Panel evaluated and proposed testimony based on the Company's proposed three-year capital plan. A multi-year period is appropriate in the context of evaluating a utility's capital investment plans given the long-term planning horizon and long lead-times associated with planning and implementing such plans. Such a time-frame provides improved planning stability compared to a one-year plan. Thus, the Company appreciates the effort and willingness of the Staff Infrastructure Panel to evaluate the Company's proposed multi-year plan, and believes the Commission should likewise establish rates in this proceeding to cover the three-year period 2011-2013.

Q. Staff recommended several adjustments relating to several specific capital programs and projects. Could you please address them?

A. Yes. As noted above, we will follow the general format set forth in the Staff Infrastructure Panel's testimony to facilitate comparison.

A. <u>Transmission Upgrade Projects</u>

1. <u>Northeast Region Reinforcement Strategy</u>

Q. What is the Staff's position with respect to the Company's proposed Northeast Region Reinforcement ("NERR") project?

A. Staff's position is that the Company used too stringent a reliability planning standard in designing the NERR project. As a result, Staff is recommending no funding on the fourth Rotterdam transformer or Turner Road Substation, and a total downward adjustment of $54.6 million in FY12-FY14 in connection with this strategy.

Q. Does the Company agree with the Staff Infrastructure Panel's views on transmission planning criteria and study methods?

A. No. Although Staff states that they "fully support adherence to all applicable reliability criteria," (p. 43) there are two specific areas in which the Company disagrees with the panel. The Company differs with the Staff Panel on how contingencies involving large power transformers should be reflected in planning studies, and also on how generation should be represented in planning models.

Q. Please describe how the Company's position on how contingencies involving large power transformers should be reflected in planning studies differs from that of the Staff Panel.

A. In its discussion of the Northeast Region Reinforcement program (p. 44), Staff states that the Company "is relying on double contingency outages (loss of two area transmission transformers)" to justify the Turner Road and Rotterdam projects, "both of which go beyond reliability criteria requirements." The Staff Panel continues by stating that they do not recommend funding of these projects on Niagara Mohawk's schedule "because it goes beyond single contingency criteria."

Rebuttal Testimony of Infrastructure and Operations Panel

These statements indicate a misunderstanding by the Staff Panel of the transmission planning criteria that form the foundation for the Company's planning studies. The Staff Panel presents as its Ex. __ (SIP-4) National Grid's procedure TGP28, Transmission Planning Guide. Section 4.2.6 of TGP28 discusses expected restoration time, noting that "Restoration times are typically longer than 24 hours for generators, gas insulated substations, underground cables, and large power transformers." TGP28 goes on to state, "When the expected restoration for a particular contingency is expected to be greater than 24 hours, analysis should be performed to determine the potential impacts if a second design contingency were to occur prior to the restoration of the failed equipment."

In the event a large autotransformer (such as one of the Rotterdam 230-115 kV banks) fails, restoration could easily take many weeks or months, far exceeding the 24 hour period described in TGP28. If the assessment of the cause and damage reveals that repairs can be achieved on site, the assessment and repairs alone would likely take more than 24 hours. If the failure is serious enough to require factory repair, or so serious that the bank is not repairable, it would take two to three weeks to drain the oil, prepare the unit for removal, arrange for the equipment needed to remove the transformer from the foundation, and transport it to a different location. If a spare transformer of the appropriate specifications is available, moving it onto the foundation (after removal of the failed unit), and preparing and testing it for energization and service would take an additional two to three weeks. If no spare is available, the time the system will be without the transformer would be longer. All these factors combine to result in a period of weeks or months during which the system will be operating in an N-1 state.

During this lengthy period, the system would be vulnerable to the loss of another system element, such as a transmission line or another transformer, resulting in what is commonly referred to as an N-1-1 situation. Ensuring that system voltages will be acceptable and that transmission lines, transformers and other equipment will not exceed their ratings is essential to meeting the expectations of TGP28.

Q. **What would be the potential consequences of not designing the system to sustain such N-1-1 situations?**

A. The exact consequences would vary depending on what time of year the events were to occur, the system load level and bulk power system transfers at that time, how long the two contingencies overlap, and other factors. However, if the heavy summer load periods were to be involved, it is likely that significant (and costly) constraints in bulk power transfers and system dispatch may be required, and emergency operating procedures including customer appeals and other measures would be activated. Although a last resort, it is quite possible that service to large numbers of customers might have to be interrupted (rotating blackouts) to prevent serious damage to the remaining, undamaged transformers.

Rebuttal Testimony of Infrastructure and Operations Panel

Q. Are there additional reasons why the Company considers it consistent with good utility practice to plan for situations involving two transformers out of service at the same time?

A. Yes. NERC planning standard TPL-003-0a, NPCC planning criteria contained in NPCC Directory 1 (section 5.4), and the New York State Reliability Council Reliability Rules (which are approved by the Commission and for which compliance is mandatory) all contain provisions for contingencies involving more than one bulk power system element at a time. Of particular note are the requirements for planning the system for N-1-1 contingencies, which result in two bulk power system elements being out of service simultaneously (although triggered by separate events). A further illustration that planning for more than a single contingency is good utility practice is present in the local reliability rules section of the NYSRC Reliability Rules, where it states that "Certain sections of the Con Edison system are designed and operated for the occurrence of a second contingency." Thus, the Company believes the planning criteria underlying the development of the Northeast Region Reinforcement project are consistent with good utility practice and industry standards, and disagree that planning for projects that go "beyond single contingency criteria" is inappropriate.

Q. Are there other concerns with the Staff Panel's position on the Northeast Region Reinforcement project?

A. Yes. In its testimony (p. 42) the Staff Panel extensively quotes from the Company's Strategy paper SG060, dated September 2006, and which was provided in response to information requests. However, more recent information was provided in response to IR DPS-556 (JJA-65). In response (2) (D) of that IR the Company clearly states that the GlobalFoundries load (the current, correct name for Advanced Micro Devices) is expected to reach 36 MW by 2012. A more recent load projection from GlobalFoundries puts this load at 74 MW, with the potential to more than double, depending on economics associated with the customer's initial plant. This updated information further underscores the need for transmission reinforcement for the area following the Company's current schedule.

Q. Based on the factors you've discussed, does the Company believe that it is appropriate to plan its system to sustain N-1-1 situations involving large power transformers?

A. Yes, in many situations the Company believes that the reliability implications for its customers, should it fail to plan its system this way, would be serious and that it is prudent, and consistent with planning standards and criteria, to do so. Applying N-1-1 analysis for the large power transformers, consistent with TGP28 and other industry standards, supports the need to complete the Turner Rd. substation and to install the Rotterdam 230-115 kV autotransformer. Failure to fund these components of the Northeast Region Reinforcement project, as suggested by the Staff Panel, will expose the Company and its customers to significant reliability risks. Accordingly, Staff's proposed adjustment should be rejected.

Q. Is the Turner Road substation required for reasons unrelated to the N-1-1 analysis?

A. Yes. Turner Road will also help to maintain 115 kV transmission line loadings in the Albany area within limits for N-1 contingencies. Without Turner Road, several N-1 contingencies would trigger the potential need to reconductor 20-25 miles of 115 kV lines, at substantial cost. The Turner Road project should not be viewed as solely justified by the N-1-1 analysis.

Q. Does the Company agree with the Staff Infrastructure Panel's proposal to procure one or two additional 230/115kV spare transformers as an alternative to the planned work at Rotterdam and the Turner Road substation under the Northeast Region Reinforcement program?

A. No. As stated above, the Company believes that applying N-1-1 analysis for the large power transformers, consistent with TGP28 and other industry standards, supports the need to complete the Turner Rd. substation and to install the Rotterdam 230-115 kV autotransformer. Failure to fund these components of the Northeast Region Reinforcement project, as suggested by the Staff Panel, will expose the Company and its customers to reliability risks.

Q. Is the Company recommending to update the capital expenditures for the Northeast Region Reinforcement Strategy?

Rebuttal Testimony of Infrastructure and Operations Panel

A. No. Based on the foregoing testimony, we recommend total capital forecasts of $7.34 million, $41.16 million, $64.99 million and $38.45 million in FY 11, FY 12, FY 13, and FY 14, respectively, as shown in Exhibit __ (IOP-1R), Schedule 2.

2. <u>Clay & Porter Station BPS Upgrades</u>

Q. The Staff Panel proposed no adjustment to the Clay and Porter substation upgrade projects based on the Company initial filings. Has the Company updated the information for these projects?

A. Yes. The table below shows the Company's latest forecast for the Clay and Porter BPS rebuild projects.

Project #	Title	FY11	FY12	FY13	FY14	Total
C28686	Porter – 115kV (Original)	$0.1 m	$12.0 m	$12.0 m	$0	$24.1 m
	Porter 115kV (Revised)	$0.3 m	$3.0 m	$8.0 m	$20.0 m	$31.3 m
C28705	Clay 115kV (Original)	$9.75 m	$8.0 m	$11.0 m	$0	$28.75 m
	Clay 115kV (Revised)	$11.68 m	$16.65 m	$5.83 m	$5.99 m	$39.15 m
Total	Original	$9.85 m	$20.0 m	$23.0 m	$0 m	$52.85 m
	Revised	$11.98 m	$18.65 m	$13.83 m	$25.99 m	$70.45 m

Q. What has changed since the original Capital Investment Plan submission in January 2010?

Rebuttal Testimony of Infrastructure and Operations Panel

A. The originally approved strategy for Porter proposed a single straight bus layout. After further analysis it was determined that the number and duration of outages required to implement the original plan would make it infeasible from a construction perspective. It was also recognized that with this layout a stuck tie breaker would cause an outage of both 115kV busses at Porter which would separate the surrounding 115kV system from all bulk power support. As a result a revised breaker-and-a-half arrangement was recommended in July 2010 to maintain reliability. In addition to the layout change, short-circuit analysis has since identified nine 230kV circuit breakers at Porter that are over duty and hence in need of replacement. As a consequence of needing to replace the 230kV breakers, upgrades to protection and controls are also required since the 230kV site was previously 'grandfathered,' or exempted, from the more stringent NPCC Bulk Power requirements, and the exemption will no longer apply once the breakers are replaced. The 230kV circuit breaker replacements were originally budgeted under project CNYAS36. The movement of funding from this project to the BPS Station Upgrade project does not change on the Company's overall revenue requirement.

Q Is the Company recommending to update the capital expenditures for the Substation BPS Upgrades Strategy?

A. Yes. Based on the foregoing testimony, we recommend total capital forecasts of \$11.98 million, \$18.65 million, \$13.83 million and \$25.99 million in FY 11, FY 12, FY 13, and FY 14, respectively. Compared to the Company's original testimony forecast of $9.85 million, $20 million and $23 million in FY11, FY12 and FY13, this is a net increase of $17.6 million over the period FY11 – FY14, as shown in Exhibit __ (IOP-1R), Schedule 2.

3. <u>Reliability Criteria Compliance</u>

Q. You previously described the Company's approach to the N-1-1 planning standards. Please describe how the Company's views on the modeling of generation differ from those of the Staff Panel, and why.

A. The Staff Panel asserts that "reliability criteria do not call for the elimination of dependence upon local generation" (p. 52). Although the Company agrees with this statement in general, it also believes that this is an oversimplification and not correct in many planning situations.

Section 3.5.6 of the TGP28 describes the generation dispatch approach that should be used in transmission planning studies. There it states: "The intent is to bias the generation dispatch such that the transfers over select portions of the transmission system are stressed pre-contingency as much as possible." In some cases, this may mean modeling a particular generator at its maximum output, as that would provide the maximum stress to the system. However, when local 115 kV systems are studied, especially in weaker parts of the system, the system may be stressed most when a particular generator is out of service. Where this is the case, the Company performs its local 115 kV area studies with the largest or most critical generator in the study area out of service as a base case condition. This does not, as the Staff Panel asserts, constitute a double contingency test (p. 53) when a contingency involving another system element is studied. It is a recognition that the base condition on any given day may involve the generator being unavailable, and that reliability must be maintained for the remaining system.

An alternative way to look at this situation is to consider that loss of a generator can be a long restoration time event. Generators can be off line not only because they fail to be selected in the NYISO unit commitment process, but also because of equipment failures. In fact, there have been cases where generators have gone off line and never returned to service because of equipment failures that the owners considered too expensive to repair. In this sense, loss of a generator could be thought of as the first contingency in an N-1-1 scenario, for which the system must be operable without voltage or loading violations. The Company, however, believes that the more appropriate view is that the generator should be out of service in the base case, with N-1-1 testing applied to that case. Either way, sound and responsible transmission planning should not consider a generator outage to be an N-1 contingency and ignore the consequences of other elements failing while the generator is out of service.

Q. What evidence is there that planning with one or more generators out of service in the base case is regarded as an appropriate practice?

A. The Company has not attempted to identify all utilities that conduct planning with generators out of service, but is aware of significant utilities that do. For example, utilities in California follow the California ISO Grid Planning Standards, which state, in Section II.3: "Combined Line and Generator Outage Standard - A single transmission circuit outage with one generator already out of service and the system adjusted shall meet the performance requirements of the NERC Planning Standards for Category B contingencies." Thus, with respect to the assumption that a generator should be out of service in the base case prior to conducting N-1 testing, California's transmission planning approach is very similar to the Company's approach. Closer to home, ISO-New England's ISO-TO Study Coordination Group has determined that New England studies should be done with two generators out of service in the base case. They are working on possible changes to their Reliability Guide. While this has not yet been formally approved, there is consensus and it is probable that this approach will be adopted. While not binding on New York studies, these examples demonstrate that the Company's practice of taking one generator out of service in the base case is not out of line with practices elsewhere in the industry.

Q. What implications do these differences regarding planning criteria for generator out of service have for the Company's capital projects?

A. Properly testing the Company's Southwest area with the Indeck Olean generation out of service, consistent with TGP28 and other industry practices, supports the need for the Southwest 345-115 kV substation. The Staff Panel discusses out-of-merit generation costs (p. 52) as if the sole purpose of these projects is to avoid those costs, and as if running out-of-merit generation is a sufficient alternative to constructing the proposed system reinforcements. This is a mischaracterization. Failure to plan the system for the absence of the Indeck Olean generation would be more than an economic issue; it would expose customers in the area to reliability risks in the event of a serious equipment failure.

It is true that the Company's strategy paper SG075 notes that the projects will provide the benefits of eliminated reliance on local generation and avoidance of out-of-merit dispatch costs. However, these are not the drivers for the projects. The projects are a complete package of components that together will ensure that all applicable reliability criteria are met, including needs that are either unrelated to the local generation or not entirely addressed by its presence. The fact that independence from the local generation will result should be viewed as an ancillary benefit. Paying out-of-merit generation costs is not, by itself, a sufficient alternative to meeting the system needs.

The Staff Panel portrays N-1 contingencies with the Warren-Falconer #171 line out of service and Indeck Olean generation off line as a "triple contingency" (p. 53). However, in actuality, Line #171 was out of service 26% of all hours between 2003 and 2009. This increases to 35% if only summer hours are considered. This is because First Energy, the utility that owns the southern portion of the line, and whose equipment limits the overall capability of the circuit, must open it to prevent overload. The line is most likely to be open at the precise times when it might be useful to support the Southwest region needs. In fact, a Special Protection System exists at First Energy's Warren substation that will trip the line if it surpasses its limits. Thus during real time system emergencies, operators would not have the ability to keep the line in service and may not have any warning prior to the line tripping. This is a normal, frequent situation that is so prevalent that it must be regarded not as a contingency but as a base case condition. Seasonal Operating studies performed by the NYISO reflect this condition. Transfer levels for the NY-PJM interface are calculated with and without three 115 kV lines, one of which is #171. Relative to the Indeck Olean generation, as noted previously, it is the Company's practice, based on TGP28, to take a local generator out of service in the base case. Thus, it is inaccurate to portray the scenario studies as triple contingencies, when they do not reflect very rare occurrences, and are at most N-1 or N-1-1 situations.

Q. Are there any other concerns with the Staff Panel position relative to the Southwest and Frontier projects?

A. Yes. Staff supports the reconductoring of the Warren-Falconer #171 line (p. 54) but does not support the Southwest 345-115 kV station. This will not work because First Energy owns 59% of the line and must pay for the reconductoring of their portion, which is 11.55 miles. They will only do this if there are reciprocal system benefits. If the Southwest station is not built, then reconductoring will benefit only Niagara Mohawk but yield no benefits to First Energy, because the

Company's system will be too weak to provide support to First Energy for contingencies on their system. Thus, there is no option to pursue the #171 line reconductoring unless it is accompanied by the other system reinforcements. Accordingly, Staff's proposed downward adjustment associated with this project should be rejected.

Q. Does the Company agree with the Staff Panel position relative to the Mortimer-Golah #109 project?

A. No. The Staff Panel associates the need for the Mortimer-Golah #109 project with the fact that testing was done with the Seneca Power generator out of service. Aside from the fact that this is the appropriate way to test, as previously discussed, the need for this project is completely independent of the Seneca Power generator. The Mortimer-Golah #109 project is needed to prevent a low voltage condition at the Golah substation for the loss of the existing Mortimer-Golah #110 line (an N-1 contingency). The low voltage condition is not remediated if the Seneca Power generator is on line. The Mortimer-Golah #109 project is still needed, with the same timing, and the associated funding for the project should be as proposed by the Company.

Q. **Are there any condition issues affecting the Mortimer – Golah #109 line that would need to be addressed if funding is not provided to convert the line to 115kV?**

A. Yes, the attached Computapole report highlights serious condition issues on this line that would need to be addressed (See Exhibit __ (IOP-3R)). The cost to remediate these condition issues has not been separately determined as they are planned to be addressed during the 115kV conversion project.

Q. The Staff Panel recommends that a study be performed of the potential impacts of retirement of the Jamestown generating plant. Does the Company agree to perform this study?

A. The Company is willing to perform such a study under appropriate conditions. The study scope, including the scenarios to be reviewed relative to Jamestown load and generation assumptions, will require the Jamestown BPU to work with the Company before the study commences. Adequate time must be allocated for the study, given the Company's many other planning responsibilities, such as the mandatory NERC studies. A schedule that provides six months for the completion of the study would be appropriate. Since the study would be performed for the benefit of Jamestown customers and not National Grid's retail customers, Jamestown should pay the costs of the study. Finally, should such a study be performed, and the need for system reinforcements identified, appropriate funding mechanisms will be required to ensure that those reinforcements can be supported.

Q Is the Company recommending adjustments to the proposed capital expenditures for the Reliability Criteria Compliance Strategy?

Rebuttal Testimony of Infrastructure and Operations Panel

A. No. Based on the foregoing testimony, we recommend adopting the Company's capital funding levels of $9.97 million, $27.7 million, $18.78 million and $2.09 million in FY 11, FY 12, FY 13, and FY 14, respectively, as shown in Exhibit __ (IOP-1R), Schedule 2.

4. Other Damage/Failure

Q. Does the Company have a position on Staff's recommendation with regard to the adjustment of the Other Damage / Failure budget?

A. Yes. The Staff Panel's testimony does not reflect the fact that the Damage / Failure spending rationale is made up of four separate programs of which 'Other Damage / Failure' is one element. The three other programs are NY Inspection Projects, Steel Tower Strategy and Wood Pole Strategy.

The sub-category of Other Damage Failure program itself includes four relatively small budgetary reserve amounts for Transmission Line Replacements, Transmission Storm budgetary Reserve, Transmission Underground budgetary Reserves and Transmission Station Failures.

The Transmission Station Failures budget accounts for only a small proportion of the overall spend on damage/failures. The remaining spend comes from the overall 'Budgetary Reserve' line (as distinct from the Transmission Storm budgetary Reserve, Transmission Underground budgetary Reserves mentioned above) which the Company uses to balance its overall spending budget. The actual expenditures for Transmission Station Failures were $931,782, $927,812 and $1,591,520 in FY08, FY09 and FY10 respectively while the overall Damage / Failure spend the Company incurred was FY08 - $11.9 million, FY09 - $14.1 million and FY10 - $10.4 million. Consequently the Company does not agree with the proposed reduction.

Q. Are the replacement costs for forced transformer outages included in the Damage / Failure budget?

A. No. The replacement cost for transformer failures is currently not included within the Damage / Failure budget. The procurement, installation and commissioning costs for these failures are walked-in to the business plan and projects are walked-out of the plan or the ‘Budgetary Reserve’ line is adjusted to manage the overall budget. We recognize that the Company should have a clearer understanding of what projects are likely to be undertaken and at what cost, especially in the near-term. Therefore the Company proposes to increase the Damage / Failure budget line item to $13 million each year and corresponding allocated reductions to the Budgetary Reserve category in the respective years to reflect the 3 year average of actual damage / failures. See Exhibit __ (IOP-1R), Schedule 2A.

This $13 million budget item would include the cost of replacement for the unforeseeable transformer failures that are currently not included in either the Transformer Replacement Strategy or the Transmission Station failures budget.

Rebuttal Testimony of Infrastructure and Operations Panel

Including unforeseeable transformer failures in the Damage / Failure budget will increase the amount of 'planned' work included in the Capital Investment Plan.

Q Is the Company recommending adjustments to the proposed capital expenditures for the Other Damage / Failure category?

A. Yes. Based on the foregoing testimony, we recommend an adjusted capital forecast of $13.0 million, $13.0 million and $13.0 million in FY 12, FY 13, and FY 14, respectively. This represents an increased forecast for FY11 – FY14 of $29.7 million compared to the Company's previous position, as shown in Exhibit __ (IOP-1R), Schedule 2. However, as mentioned above, the Budgetary Reserve line is being reduced by corresponding amounts in the respective years, resulting in no net overall budget impact for the period set forth in the rate case. See Exhibit __ (IOP-1R), Schedule, 2A.

5. <u>Conductor Clearance</u>

Q. Does the Company agree with the Staff's proposed downward adjustment of approximately $15 million to the Conductor Clearance strategy?

A. No. The Company agrees with Staff that "the Conductor Clearance strategy . . . [is] necessary to comply with the NESC's (National Electric Safety Code) governing codes." However, we do not agree with Staff's view that the proposed program funding level represents an inappropriate ramp-up of spending. The Company's initial efforts have centered on aerial laser survey (ALS), validation of the ALS results and the engineering design necessary to rectify sub-standard clearances. Physical construction activity commenced to rectify sub-standard clearances in FY09 and Niagara Mohawk has a responsibility to act in an expedient manner to bring these spans up to code.

Q. Is the Staff's proposed downward adjustment of $5.0 million in FY12 appropriate?

A. No. Preliminary engineering is completed or nearly completed for 13 conductor clearance projects planned to be addressed by the end of FY12. These 13 projects include the remediation of Level 1 and Level 2 substandard spans at an average cost of $104,000 per span. See Exhibit __ (IOP-4R).

Preliminary engineering for a further thirty projects still in conceptual engineering is expected to be completed in FY11 and FY12. While most of these projects will undergo construction in FY13, a few others will be targeted for implementation by the end of FY12.

Q. Why has the forecast number of substandard spans gone down since the original strategy paper was published, and from the time of the response to IR DPS-415 (VVP-29)?

A. The verification process determines whether the Level 1 and 2 substandard spans identified during Aerial Laser Surveys (ALS) are valid. This process frequently requires field visits and a manual span-by-span analysis against the appropriate governing code. As a result of the field visits and the manual span by span analysis, it was determined that a number of spans initially identified as substandard by ALS were not in fact substandard. Once conceptual engineering is completed, the number of substandard spans is confirmed and preliminary cost estimates are generated.

Q. Why has the average cost per span increased from $75,000 to $104,000?

A. In the Company's response to IR DPS-415 (VVP-29), we stated that the cost per span (to bring it up to code) was expected to average about $75,000. Following recently completed preliminary engineering for the 13 projects mentioned above, the cost per span ranged from $27,000 to $143,000 with an average cost of approximately $104,000 per span. The average cost has increased because in some cases live line working will be required for the 230kV and 345KV bulk circuits and in some cases spans requiring correction are geographically remote requiring high mobilization costs.

Q. Does the Company agree with the Staff Infrastructure Panel's recommendation that capital expenditures of $10 million in FY13 and $10 million in FY14 provide reasonable funding under the conductor clearance strategy?

A. No. Based on the forecast number of spans scheduled for remediation in FY13 and FY14 (200 and 150 respectively) and using an average cost per span of $104,000 establishes a forecast of $20.8 million in FY13 and $15.6 million in FY14. However, based upon the field engineering walk downs (mentioned above) we anticipate additional spans will be confirmed as not needing remediation, therefore a forecast of $15 million per year (FY12 – FY14) as set forth in the Company's testimony represents reasonable funding for this strategy.

Niagara Mohawk has a responsibility to act in an expedient matter to bring these spans up to code in a timely method. The speed of bringing these spans up to code must be commensurate with the risk that is reasonably foreseeable. Since we are focusing on the Level 1 and Level 2 substandard spans first, we feel it is prudent to correct these spans within the time period outlined by the Conductor Clearance Strategy SG029. This requires higher budgetary levels than the Staff Infrastructure Panel's recommendation.

Q. Does the Company agree that only considering ratepayer financial risk is a valid reason to limit proposed capital expenditures?

A. The Company is sensitive to the need for holding down costs to customers. However, timely compliance with the NESC requirements is required to minimize the safety risk to the general public and a prudent ramp-up in span correction is required to achieve this. In addition the Company believes that timely compliance with the Orders Instituting Safety Standards, Case 04-M-0159, issued January 5, 2005 ("2005 Safety Order") and December 15, 2008 ("2008 Safety Order") requires a ramp-up in span correction.

Rebuttal Testimony of Infrastructure and Operations Panel

Q. **Is the Company recommending adjustments to the proposed capital expenditures for the Conductor Clearance Strategy?**

A. No. Based on the foregoing testimony, we recommend capital expenditures of $1.5 million in FY 11 and $15 million in FY 12, $15 million in FY 13 and $15 million in FY 14 to provide reasonable funding under this strategy, as shown in Exhibit __ (IOP-1R), Schedule 2.

6. Other System Capacity & Performance

Q. Does the Company agree with the Staff Infrastructure Panel's recommendation to limit capital expenditures in the Other System Capacity and Performance category to $6.5 million in FY13 and FY14?

A. No. Although the Company stated that reconductoring of the Boonville – Rome #4 line (project CNYPL4) will only be pursued if found necessary in the 2010 Northern Area study, the facilities would require refurbishment in FY13 in any event due the condition and performance of the line. The Boonville-Rome 4 and the Boonville-Rome 3 lines (both installed in the 1930s) have experienced recent conductor related failures due to arc damage caused by insulator flashovers at locations where suspension clamps have loosened. Comprehensive engineering field walk-downs are proposed for FY13 at a cost of $0.5 million.

Q. The Staff Panel discusses projects CNYPL1, CNYPL25 and CNYPL26 (p. 63). Do you have information that will assist in understanding the status of these projects and their respective funding requirements?

Rebuttal Testimony of Infrastructure and Operations Panel

A. Yes. The 2010 Northern Area study has progressed to the point where we no longer will pursue CNYPL1. The funding originally requested for CNYPL1 ($0.1 million in FY13 and $5.0 million in FY14) will no longer be needed for this project.

However, CNYPL25 and CNYPL26 are needed and full documentation will be available in the fall upon completion of area studies in progress. (Note: These projects are related to different studies, not the 2010 Northern Area Study, which was incorrectly referenced in the testimony.) These studies demonstrate that Maplewood plus the Central and Mohawk Valley areas show the combined need for at least 18 breaker replacements, and possibly as many as 22. At approximately $500,000 each, that suggests that a total of between $9.0 and $11.0 million will be needed. The exact number of breakers and a more accurate cost estimate will be established when the studies are completed, but it is clear that these expenditures are not speculative and funding will be required in excess of the combined levels ($6.0 million through FY14) shown in the Company's plans. For 20 breaker replacements (the middle of the range of 18-22), the Company now estimates that the combined requirements for CNYPL25 and CNYPL26 will be $0.67 million in FY12, $3.63 million in FY13, and $5.7 million in FY14. This has the effect of increasing the FY12 requirements by $0.27 million and the FY13 requirements by $1.53 million over the Company's original filing, and decreasing the FY14 requirement by $2.9 million. As a result the total for FY11 through FY 14 decreases by $1.1 million.

Rebuttal Testimony of Infrastructure and Operations Panel

Q Is the Company recommending adjustments to the proposed capital expenditures for the Other System Capacity & Performance category?

A. No. Based on the foregoing testimony, we recommend total capital forecasts of $5.95 million, $7.97 million, $14.10 million and $19.05 million in FY 11, FY 12, FY 13, and FY 14, respectively, as shown in Exhibit __ (IOP-1R), Schedule 2.

B. <u>Transmission Asset Replacements</u>

1. <u>Overhead Line, Tower and Pole Refurbishment Strategy</u>

Q. Does the Company agree with the Staff Infrastructure Panel's position that "absent the existence of physical deterioration, we do not recommend refurbishment based strictly upon outage experience"?

A. Yes. The Company employs a selection methodology that takes into account outage experience particularly outages that affect customers as a way to prioritize circuits for remedial work. These circuits are then subjected to an extensive engineering field walk down to identify the existence of physical deterioration and to classify the level of that deterioration (Level 1 through 4). Only circuits with Level 1 through 3 physical deterioration identified during the field walk down are brought forward for refurbishment. The selection methodology is only a screening tool; the physical condition of overhead lines drives the refurbishment need.

Q. Could the Company clarify what it means when it says "refurbished".

A. The term “refurbished” encompasses a wide range of intervention options available to the Company to address physical deterioration whether or not it results in poor outage performance. At one end of the scale, refurbishment could entail the wholesale replacement of steel and wood structures, conductor replacement and the replacement of all hardware and fittings. At the other end of the scale it could for example mean replacement of shield wire to improve lightning performance. The actual defined scope of work for a refurbishment is determined during conceptual engineering.

Q. Does the Company believe that the selection methodology used by Niagara Mohawk will maintain reliability?

A. Yes. For the refurbishments listed in the Company’s testimony in all cases except the refurbishment of the Ticonderoga #2-3 lines (which is safety driven) the majority of outages (momentary, sustained or long-sustained) are attributable to either line physical condition or weather (including lightning), to which the Staff Infrastructure Panel recognizes that lines in poor condition are somewhat more susceptible.

Line	**Performance (CY2005 – 2009)**
Dunkirk – Falconer #161 / 162	75% of momentary outages caused by line equipment, weather and lightning.
Niagara / Packard – Gardenville #180 / 182	84% of outage duration and 100% of sustained outages caused by line equipment, weather and lightning.
Gardenville-Dunkirk #141-142	89% of outage duration caused by line equipment, weather and lightning.
Gardenville-Homer Hill #151-152	53% of sustained outages caused by line equipment, weather and lightning.
Lockport-Batavia #112	100% of long sustained outages caused by line equipment, weather and lightning.
Lockport-Mortimer #111	88% of long sustained outages caused by line equipment, weather and lightning

Rebuttal Testimony of Infrastructure and Operations Panel

Lockport-Mortimer #113-114	100% of long sustained outages caused by line equipment, weather and lightning.
Pannell-Geneva #4-4A	67% of sustained outages caused by line equipment, weather and lightning.
Indeck Oswego-Lighthouse Hill #2	44% of momentary outages caused by line equipment, weather and lightning.
Taylorville-Booneville #5-6	92% of momentary outages caused by line equipment, weather and lightning.
Taylorville-Moshier #7	86% of momentary outages caused by line equipment, weather and lightning.
Porter-Rotterdam #31	67% of momentary outages caused by line equipment, weather and lightning.
Ticonderoga #2-3	Safety driven refurbishment. These radial lines are in poor condition but do not generate many outages; however, the negative customer exposure from potential failure is significant.
Lockport #103-104	44% of sustained outages caused by line equipment, weather and lightning.

Q. Does the Company agree with Staff's conclusion that total outage duration should be the main selection criterion for overhead line refurbishment?

A. While total outage duration is important, it is a lagging indicator of performance and, over time, numerous short interruptions can be just as disruptive to customers; and if they occur at inopportune times (i.e. during other events or peak demands, etc) can be more disruptive. Therefore the Company uses a number of performance indicators to select and prioritize overhead lines for intervention.

Q. Does the Company agree with the Staff Infrastructure Panel's recommendation that "funding be provided to refurbish overhead transmission line facilities that are in unacceptably severe deteriorated condition (i.e. Niagara Mohawk's defined Level 1, Level 2 and Level 3 conditions), as opposed to entire lines, unless a compelling justification can be provided for the full refurbishment"?

A. Yes. Unless the Company believes there is a compelling justification that the full refurbishment of a line is required, only refurbishment of Level 1, Level 2 and Level 3 type items are sanctioned. If however, the Company determines that a line does require refurbishment then engineering discretion will be used for Level 4 type items plus structural components nearing end-of-life. For example, a leaning structure might be classified as a Level 4 item but further evaluation may show that this structure might no longer meet applicable ice loadings. In these cases, failure to address the level 4 work and only the Level 1, Level 2 and Level 3 items will be more expensive in long run for customers due to repeated visits to the line and additional mobilization costs, including, for example, repeated use of swamp matting.

Q. Does the Company believe that for FY13, the $38.0 million funding amount recommended by Staff will be sufficient?

A. No. In FY13 two overhead line refurbishment projects (Gardenville – Dunkirk #141 / 142 and Lockport – Mortimer #111) will be well into construction. The proposed reduction in FY13 could only be achieved by either: (a) reducing the capital expenditure on these two projects by $15.7 million (which would effectively add an additional year to the overall project timescale); or (b) doing less work and not fully addressing the condition based needs of the project. Alternative (a) would likely result in longer outage requirements, longer construction schedules, increased overall project costs and a longer time period before obtaining the safety, reliability and capacity benefits of the project.

Alternative (b) would likely result in the need for future work to address the deficiencies and concerns that would not be addressed as part of the reduced project and result in additional overall project costs (e.g. additional mobilization and de-mobilization costs, additional permitting and licensing , etc). The Company does not believe that either alternative is in the best interests of customers.

Q. Does the Company believe that for FY14, the $42.0 million funding level proposed by Staff will be sufficient?

A. No. In FY14, there are five major projects (including the two from FY13) plus the Gardenville #180 / 182 lines, the Lockport – Batavia #112 line and the Indeck Oswego – Lighthouse Hill #2 line. Conceptual engineering is well underway for the Gardenville #180 / 182 lines and the Lockport – Batavia #112 projects. Originally, the Gardenville #180 / 182 project was for the section of these circuits North of Ellicott Junction (in Tonawanda). The cancellation of the Tonawanda and Frontier project means that the Gardenville #180 / 182 project will require additional work due to the poor condition of the 182 circuit South of Ellicott junction. The scope of the Indeck Oswego – Lighthouse Hill 2 project will depend upon the results of conductor testing. The reduction in funding would result in project delays that would likely create a backlog of circuits with safety, condition and/or reliability concerns.

Rebuttal Testimony of Infrastructure and Operations Panel

Q. Is the Company recommending adjustments to the proposed capital expenditures for the Overhead Line Refurbishment Strategy?

A. No. Based on the foregoing testimony, we recommend total capital forecasts of $20.2 million, $32.5 million, $53.7 million and $92.0 million in FY 11, FY 12, FY 13, and FY 14, respectively, as shown in Exhibit __ (IOP-1R), Schedule 2.

2. Transmission Substation Rebuild Strategy

Q. Does the Company agree with the Staff Infrastructure Panel's recommendation to stagger the scheduling of the rebuild projects?

A. Yes. The Company agrees to stagger the scheduling of the station rebuild projects by deferring Elm Street and Lighthouse Hill by 1 year, and by deferring the Lockport, Mohican, North Leroy, Rotterdam and Reynolds Road projects by several years. In addition the Company has re-assessed the spend profile for the rebuild of Gardenville and Rome with completion now postponed until FY16 and FY15, respectively. These rebuild projects have been staggered as far as practical to reduce the financial impact on customers. This extension to timescales introduces additional safety, environmental and reliability risks in the meantime.

Q. What impact does the staggering and re-phasing have on the FY11 – FY14 forecast spend?

A. Overall, these changes will reduce the FY11 – FY14 spend by $68.75 million.

Rebuttal Testimony of Infrastructure and Operations Panel

Q. Has the Company made any further adjustments to the Station rebuild projects?

A. Yes. In FY14, $10.0 million was transferred from project CNYAS36 (which is part of the Substation Rebuild program) into the Porter BPS Upgrade project to replace over-duty 230kV circuit breakers at Porter. Project CNYAS36 now only includes the replacement of the 230kV disconnects at Porter and the budget has been adjusted to reflect this. This transfer has a net zero effect on the overall capital budget.

Q. Does the Company agree with Staff's proposal to limit spending in FY14 to $25 million?

A. No. With the revised spend profile for the substation rebuild projects a required investment of $45 million in FY14 is needed (compared to the previously forecast $73.8 million) to rebuild Gardenville and Rome in a timely manner. Limiting investment to $25 million in FY14 would unacceptably delay completion of these two seriously deteriorated stations into FY17 and FY16 respectively.

Q. Does the Company accept the recommendation that the time allotted for planning and design of these retrofits be lengthened?

A. No. The Company believes it allocates sufficient time and resources to properly plan and design these projects and to provide a realistic opportunity to develop alternatives.

Rebuttal Testimony of Infrastructure and Operations Panel

Q. Does the Company agree that staggering these rebuild projects will allow improvements developed at one site to be adapted to rebuilds at other sites?

A. Not necessarily. Given the large variations in size, complexity and overall layout of Transmission substations it is uncertain to what extent improvements developed at one site could be adapted to rebuilds at other sites. However, the Company does recognize the value of standardization in design and will adopt the approach where practical and cost-effective.

Q Is the Company recommending adjustments to the proposed capital expenditures for the Substation Rebuild Strategy?

A. Yes. Based on the foregoing testimony, we recommend total capital forecasts of $2.66 million, $6.42 million, $17.14 million and $44.45 million in FY 11, FY 12, FY 13, and FY 14, respectively (compared to $2.80 million, $8.91 million, $58.86 million and $68.86 million proposed previously by the Company). These adjustments represent a total reduction of $68.75 million in this category from the Company's previous position but it should be noted that this includes the transfer of $10 million from CNYAS36 in the Substation Rebuild program to Substation BPS Upgrades program.

3. <u>Transmission Transformer Replacement Strategy</u>

Q. Does the Company agree with the Staff Infrastructure Panel's recommendation that "a transformer be replaced if its dissolved gas in oil

analysis is deemed excessive in terms of industry standards indicating imminent failure"?

A. Yes. However, the Company's initial assessment using current DGA results and only the IEEE Standard C57.104.1991 guidelines is that this approach may produce a requirement to replace more transmission transformers than currently proposed by the Company. IEEE Standard C57.104.1991 provides guidance on specific methods and procedures to assist the transformer operator in deciding on the status and continued operation of a transformer that exhibits combustible gas formation. Using the IEEE Standard C57.104.1991 guidelines shows 58 Transmission units with Code 4 which, depending upon the rate of gas generation, should be considered for removal from service or where the owner should exercise extreme caution and plan an outage.

Q. Does the Company agree with Staff that "given the existing diverse stock of transmission transformers on Niagara Mohawk's system, that a certain number of transformer forced outages will occur each year; based upon historical averages, this could average approximately six forced permanent outages annually".

A. Yes. The number of unforeseeable failures for the past 10 years (2000 - 2009) was 64 and the average failure rate was approximately 6 per year.

Q. Does the Company believe that an incremental amount of $4.0 million for FY11 and $3.0 million for FY12, FY13 and FY14 will be sufficient?

A. No. The reduction proposed by the Staff Infrastructure Panel would in FY12, FY13 and FY14 only allow the replacement of one 115kV transformer per year beyond the first year (at an average installed cost of $1.7 million). Recently obtained prices for transformers at the factory gate for 115kV units range from $712,646 to $971,550; 230kV units are approximately $2 million, and for 345kV units range from $3.1 million to $4.5 million. The reduced budgeted amount in FY12, FY13 and FY14 would not cover the purchase price of a single large auto-transformer.

Q. Does the Company agree with the Staff Infrastructure Panel's recommendation that Niagara Mohawk not proceed with its transformer replacement program?

A. No. The Company maintains that given a population of over 500 transformers a modest preemptive replacement program of 4 (typically 115kV 25MVA with Load Tap Changer) units per year at an average cost of $1.7 million (in addition to the 6 average failures) is not unreasonable. The Transformer Replacement Strategy proposes to replace transformers where DGA trends do not necessarily show an active internal fault but this information in conjunction with other factors such as poor oil quality, known design weaknesses, poor mechanical condition, provide sufficient justification for replacement of the equipment.

Q. Will the Company simply replace transformers that are deteriorated to an unacceptable level with like-for-like replacements?

Rebuttal Testimony of Infrastructure and Operations Panel

A. No. Transformers will be replaced with standard units. Standard units with identical voltage ratios, vector groups and MVA ratings will be less expensive in the long run than purchasing many different units and will help promote a manageable spares inventory level. Single phase transformers will be replaced with three phase transformers. Replacing single phase transformers with three phase transformers will also reduce the impact on the spares inventory requirements. In addition, all long-term transformer replacements will consider the protection schemes (i.e. circuit breakers, circuit switchers and relays) and, where their condition warrants, these too will be included in the overall transformer replacement. In substations where a transformer is to be replaced, oil containment will be included as part of the replacement infrastructure.

Q. Does the Company support Staff's recommendation to submit updated, detailed analysis to determine the appropriate number of additional spare transformers that are needed for back-up and/or replacement of transformers that do fail?

A. Yes. The Company fully supports Staff's recommendation and looks forward to discussing with Staff how cost recovery and allocation would be determined for any additional spare transformers identified as required.

Q. Is the Company recommending adjustments to the proposed capital expenditures for the Transformer Replacement Strategy?

A. No. Based on the foregoing testimony, we recommend total capital forecasts of $4.0 million, $7.0 million, $7.0 million and $7.0 million in FY 11, FY 12, FY 13, and FY 14, respectively.

4. <u>Circuit Breaker Replacement Strategy</u>

Q. Does the Company agree that "it is not possible to predict if reliability would decline by curtailing capital expenditures for the circuit breaker replacement strategy for fiscal years 2013 and 2014"?

A. No. The Company's recent history with oil circuit breaker trouble reports is shown in Exhibit __ (IOP-5R). This exhibit shows an increasing amount of trouble work (typically found on inspection or following alarm) and follow-up work (typically found during maintenance) on oil circuit breakers. Without capital investment to replace obsolete equipment that has already deteriorated to unacceptable levels this trend will continue leading to lower reliability. As the Company stated in Exhibit_ (IOP-14) Schedule 2, "11 percent of sustained outages on the bulk system and 12 percent of sustained outages on the non-bulk system are caused by substation equipment including circuit breakers." Without the proposed investment in 2013 and 2014 the Company will be unable to maintain its reliability.

Q. Does the Company agree with the Staff Infrastructure Panel's recommendation to limit capital expenditures for the circuit breaker

replacement strategy in FY13 and FY14 to no more than $5 million and $7 million respectively?

A. No. The Company maintains that given a population size of 377 oil circuit breakers a modest replacement program of 13 units per year at an average cost of $500,000 is reasonable. This is particularly true as there is evidence of deterioration through known failure mechanisms and a lack of suitable replacement parts inventories. The Company maintains that this approach is not sustainable and a modest asset replacement and refurbishment program is required over the coming decade to replace equipment that has already deteriorated to unacceptable levels. A modest replacement rate of 13 units per year will take approximately 40 years to replace the entire oil circuit breaker population of which 59% is already between 40 and 59 years old.

Q. Has the Company or affiliates experienced failures of any of the types of oil circuit breakers proposed for replacement?

A. Yes. In 2000, a GE FK-115 circuit breaker R8205 at Ash Street failed. In 2002, a GE FK circuit breaker R350 failed at Union. In 2003, a FP RHE-84-10000 230KV circuit breaker R84 failed at Rotterdam. In 2003 a GE FK-115 circuit breaker R252 failed at Dunkirk. In 2003, an AC BZO-115-10000 circuit breaker R213 failed at Lockport. In 2005, an AC BZO-115-10000 failed at Porter. In 2005 a FP RHE-84-10000 230KV circuit breaker R82 failed at Rotterdam. In 2007, a GE FK-115-5000 circuit breaker R130 at Schuyler failed. In 2008, a GE FK circuit breaker R210 failed at Schuyler.

In New England recent oil circuit breaker failures include: in 2006, a GE-FK 115KV circuit breaker 11-45 at Salem Harbor, MA. In 2008, a GE-FK 115KV circuit breaker 9085 failed at Kent County, RI. In May 2010, an AC-BZO 115KV circuit breaker 1802 failed at Bell Rock. In June 2010, an AC-BZO 115KV circuit breaker TL812 failed at Somerset, MA. In July 2010, a GE-FK circuit breaker 120 failed at Bellows Falls, VT. In New England, the Company's affiliates recently approved the replacement of 20 highest priority oil circuit breakers over 5 years based on their condition. A further 50 high priority oil circuit breakers will also be replaced for condition deficiencies during load related projects.

The Company has also had numerous instances of interrupter failures associated with these breaker types. In most cases, we were able to replace with spare parts from removed breakers. For future occurrences, with spare parts supplies low, we will increasingly need to replace the entire circuit breaker. Unplanned replacement following failure is always more costly in the long-term and in the short-term creates a safety hazard to Company personnel, and causes disruption to the system and to customers.

Q Is the Company recommending adjustments to the proposed capital expenditures for the Circuit Breaker replacement strategy?

A. No. Based on the foregoing testimony, we recommend total capital forecasts of $0.1 million, $1.1 million, $7.25 million and $14.45 million in FY 11, FY 12, FY 13, and FY 14, respectively, as shown in Exhibit __ (IOP-1R), Schedule 2.

Rebuttal Testimony of Infrastructure and Operations Panel

5. Other Asset Condition

Q. Does the Company support a macro adjustment for the Other Asset Condition program?

A. No. The Company does not believe a downward macro adjustment in spending levels is appropriate given the nature of the spending and projects in this category.

Q. Does the Company agree to the Staff Infrastructure Panel's recommendation of capital expenditures of approximately $14 million and $12 million for FY13 and FY14 respectively?

A. No. As part of the Company's Updates and Corrections testimony filed on May 3, 2010 an additional $15 million was added into the Capital Investment Plan in the FY13 and FY14 periods for this category. The Updates and Corrections testimony stated that:

> "As part of the Reliability Criteria Compliance Program, the Strategy to Reinforce the Transmission System in New York's Frontier and Southwest Region (Strategy Paper SG 075 v2 – April 2009) included work reconductor the #180 and #181 circuits, create a new 115 kV circuit between Packard and Gardenville using retired, in-place assets, and associated substation work at Packard, Tonawanda and Gardenville (referred to in SG 075 v2 as "Frontier Line Rebuilds (T Line and Station)" – project numbers C24018 and C24019, respectively). The reconductoring was originally required to prevent post-fault overloads under N-1

conditions; however, without the system changes at Tonawanda, these overloads are no longer an issue and the reconductoring is no longer necessary. Nevertheless, because the reconductoring projects would have also addressed important asset condition issues at the same time, it is now necessary to undertake additional projects in the Other Asset Condition Program and the Other System Capacity & Performance program."

Planned annual spending for the refurbishment of the #180 and #181 lines is as follows: FY11 $0.02 million, FY12 $0.5 million, FY13 $15.0 million, and FY14 $15.0 million, for an aggregate amount of $30.52 million over the FY11-FY14 period. The Company would note that this work is a result of not undertaking the Tonawanda project and a simple downward macro adjustment is not justified.

Q Is the Company recommending adjustments to the proposed capital expenditures for the Other Asset Condition category?

A. No. Based on the foregoing testimony and our Updates and Corrections testimony, we recommend total capital forecasts of $21.81 million, $7.04 million, $28.01 million and $24.06 million in FY 11, FY 12, FY 13, and FY 14, respectively, as shown in Exhibit __ (IOP-1R), Schedule 2.

6. <u>Relay Replacement Strategy</u>

Q. Does the Company accept the Staff Infrastructure Panel's recommendation to limit capital expenditures on this strategy in FY12 to $0.5 million?

Rebuttal Testimony of Infrastructure and Operations Panel

A. No. The Company accepts that its Relay Replacement Strategy is not yet fully developed but does not believe Staff's recommendation to limit capital expenditures in FY12 to $0.5 million is warranted. The relay replacement project will be extremely complicated and will require a significant up-front engineering design effort to ensure that relay replacements are undertaken efficiently and without jeopardizing transmission system reliability. In the Company's response to Information Request DPS-400 (VVP-23), we indicated that we anticipated replacing relay packages on approximately 16 circuits during FY13 at an average cost of $200,000 per circuit. As stated above, the proposed relay replacement work requires engineering and design along with the procurement of the relays in advance of the installation and the Company believes that 10% of the total project spend for preliminary engineering is reasonable (i.e. $1 million). Arbitrarily limiting spend in FY12 will impede the Company's capacity to replace relays in FY13 along with our ability, as Staff states, to "help improve the reliability of the Company's transmission system."

Q. Is the Company recommending adjustments to the proposed capital expenditures for the Relay Replacement Strategy?

A. No. Based on the foregoing testimony, we recommend total capital forecasts of $0.05 million, $1.0 million, $3.75 million, and $6.45 million in FY11, FY 12, FY 13, and FY 14, respectively, as shown in Exhibit __ (IOP-1R), Schedule 2.

Rebuttal Testimony of Infrastructure and Operations Panel

Q. Does the Company agree with the Staff Infrastructure Panel's decision to make downward adjustments in several of the proposed spending rationale categories (including Conductor Clearance Strategy, Other System Capacity & Performance, Circuit Breaker Strategy, Other Asset Condition, Relay Replacement Strategy) based on what the panel refers to as "reducing rate-payers risk due to possible project overestimating" on the Company's part?

A. No. Though the Company recognizes that there is always opportunity for improvement when it comes to managing projects and producing conceptual grade estimates, project management practices in general allow for a minimum uncertainty in conceptual estimates of at least plus or minus 25%. Failing to recognize the need for a reasonable amount of conceptual grade uncertainty would undermine the value of medium and long term capital investment planning in the first place, since such a plan is mostly based on conceptual grade studies. Moreover, the Company is proposing a capital investment tracker with limited upward adjustment and full downward adjustment if the Company adds plant at less than forecasted levels:

Q. What would be the implications if Staff requires conceptual engineering estimates to be completed prior to the inclusion of a project in rates?

A. In these circumstances, it would only be possible to give visibility of the costs of conceptual engineering in the three-year period of the rate case. A utility would need to dedicate significantly more engineering and planning resources than it already does today to developing a capital plan that might nevertheless be substantially affected and undermined by circumstances outside of its control. In effect, the utility must balance the appropriate level of precision to bring to an investment plan with external factors such as shifting demands, customer mobility, and long capital lead-times. Requiring completion of conceptual engineering in order for inclusion in a utility's capital plan would severely shorten the utility's workable planning horizon.

C. Sub-Transmission and Distribution Projects

1. Distribution Line Reclosers

Q. What does the DPS Staff Infrastructure Panel recommend regarding the distribution line recloser program?

A. The Staff Infrastructure Panel recommends the installation of 70 reclosers per year decreasing the Company's proposed budget by $1.5 million in FY11, $2.5 million in FY12, $2.5 million in FY13 and $6.5 million in FY14.

Q. Does the Company agree with the recommendation?

A. No. As Staff notes, the Company has been able to meet its reliability goals (for which failure to achieve results in significant financial penalties) in part, by making investments in the recloser program. The utilization of reclosers is cost effective in light of the realized reliability benefit and an important component of the Company's ongoing effort to continue to achieve its reliability metrics. The Staff notes the diminishing return as additional reclosers are installed on the system but the Company does not believe that the saturation point has been reached or will be reached over the FY11-14 period.

Q. Why is Staff's position that the saturation point for the installation of reclosers inaccurate?

A. Staff's position appears to be based on its view of the effect of having multiple reclosers on a feeder. This is evidenced in the ratio cited by Staff. Under Staff's view there would be diminishing returns since the "next" recloser on a feeder that already had a recloser must by definition provide less reliability opportunities than the first. However, the Company has many locations where the first reclosers have not yet been installed, which is why it uses a "recloser model" to identify potential site locations. Thus, claims of saturation for those locations are not accurate. Further, the ratio cited by Staff was used to initiate the recloser program, which was premised on the installation of three phase gang operated reclosers. Three phase gang operated reclosers, although very useful in achieving reliability, are limited in their capability to optimally minimize outages that are single phase in nature. A three phase gang operated recloser opens all three phases for a downstream fault – even if the downstream fault is single phase. Thus, the Company, in order to maintain reliability has begun to evaluate through pilots opportunities to utilize three phase single phase operated reclosers as well as independent single phase recloser technology on the same feeders that have three phase gang operated reclosers. Thus, the assertion that the Company has reached a point of diminishing returns does not consider the benefits that can be achieved by isolating significant portions of the system (downstream of a three phase gang operated recloser) by using single phase recloser technology. Ultimately, the use of this technology will further protect areas of the system that, but for the inclusion of the single phase recloser, would result in all customers downstream of the three phase gang operated recloser being without power for a single phase fault. This provides a significant opportunity to continue to cost-effectively maintain reliability and address the overall exposure to the predominantly overhead system from tree-related outages, which continue to be the leading cause of outages on Niagara Mohawk's distribution system. (It should be noted that the continued use of reclosers will ultimately have the effect of increasing system CAIDI as each outage becomes more discrete – and the total number of impacted customers is reduced - yet the precipitating event causing the outage and the resulting amount of time to correct the issue does not change).

The Company is in the process of evolving the recloser strategy from one that focuses primarily on three phase reclosers to one that will increasingly install single phase reclosers or three phase reclosers that can be used to isolate single phase faults.

Q. What does the Company recommend as a practical approach to the application of reclosers in a balanced and proactive manner?

A. The Company recommends the utilization of a feeder specific combination of gang-operated three-phase reclosers, three-phase reclosers that accommodate single-phase operation and single phased reclosers or Trip Savers. While three phase recloser saturation will be a concern at some point in the future, we are not there yet.

Q. How is the inclusion of the additional types of isolation devices reflected in the investment forecast?

A. The investment level set forth in the testimony is driven by continued investment (for the FY11-FY14 period) in three phase reclosers at 100 per year to support meeting reliability performance metrics. The installation of the 100 reclosers per year requires the investment of $5 million annually in FY11-FY14. In addition, for FY12 and beyond, we include investment for additional single phase isolation devices in the amount of $1.0 million in FY12, $1.0 million in FY13 and $5.0 million in FY14, which in conjunction with the $5 million annually for three-phase reclosers results in the amounts originally set forth by the Company. The Company would recommend maintaining the existing budget of $5.0 million for FY11 and $6.0 million for FY12 and FY13.

Q. What does the Company recommend for FY14?

A. Although the Company believes that investment in this category is needed in order to maintain reliability, it is also conscious of the challenging economic times and the ramp up in this program as it relates to investment in alternative recloser technology. Accordingly, we believe it is appropriate to reduce the funding in FY14 by $2 million resulting in an investment for FY14 of $8 million.

The Company's proposed funding amounts for this program are shown in Exhibit __ (IOP-1R), Schedule 4. It should be noted, that the additional investment in alternative recloser technology is in recognition that the Company's ability to achieve its reliability metrics is continually challenged by tree related events which represent 40% of the causes for outages and that the existing tree related outage exposure due to the size and design of the overhead system is too large to not undertake further isolation actions.

2. Distribution RTU Program

Q. What are the Staff's recommendations regarding the Company's Distribution RTU program?

A. The Staff Infrastructure Panel recommends the budget for the Distribution RTU program be decreased by downward adjustments of $0.5 million in FY11, $1.0 million in FY12, $1.0 million in FY13, and $2.0 million in FY14 for a total decrease of $4.5 million over the period FY11-14. The stated basis for Staff's proposed adjustments is a mismatch between the estimated cost per installation ($150,000) and the 120 locations that were identified, which resulted in a calculated overall investment requirement of $18 million through FY14. It should be noted that the Company had included more than $21 million in investment need for the same period.

Q. What was the basis for the Company's original budget forecast for Distribution RTUs?

Rebuttal Testimony of Infrastructure and Operations Panel

A. In response to IR DPS-127 (WEL-4), the Company sets forth 88 RTU replacements and an additional 32 new distribution RTU installations expected to be placed in service at the end of FY14. These volumes were based on best available information at the time. However, when the necessary investment level was developed, variations to the program were accounted for because additional RTU investment opportunities were anticipated.

Q. Have additional units been identified to the program?

A. Yes. Since the submission of IR DPS-127 (WEL-4), the Company has continued to review new RTU locations and prioritization with a view of ensuring efficient and effective application of RTUs. Specifically, a review was conducted in May 2010 with regional control operators, field operations, and network planning to identify locations where substation status, metering and control would be most advantageous based both on their experience in mitigating customer outages and with a goal of improving system integrity and operability. Further, the heat wave during the beginning of July 2010 confirmed the need for many of the additional RTU investments identified in the May review. An additional 24 distribution substations, for a total of 56 locations (32 original locations plus the additional 24 locations), have been identified for new RTU installations. In addition to input from regional control operators, a review of all candidate locations was performed based on substation loading and the relative importance of the station to the overall system. No previously identified locations were removed from the original 32 stations.

Q. What does the Company recommend for RTU related capital investment levels?

A. Due to the additional 24 locations identified, the Company recommends that the capital investment levels for Distribution RTUs of $4.7 million for FY11, $5.2 million for FY12, $5.2 million for FY13, and $6.4 million for FY14, budgeted for by the Company and shown in Exhibit __ (IOP-1R), Schedule 4 be maintained and the Staff's proposed adjustment not accepted.

Q. Why does the Company believe that investments in RTUs are important and how do they benefit customers?

A. Utilization of RTUs at substations is fundamental to modernizing the electric grid and will enable improving energy efficiency by controlling line losses through phase balancing, integrating distributed and renewable resources through better visibility of the actual performance of a feeder, increasing the capability of operators to manage the system – especially during emergencies and peak periods, and improving load forecasting through a better understanding of actual feeder loading and system / feeder peaks.

3. <u>Distribution Planning Criteria</u>

Q. What did Staff recommend with respect to the Company's Planning Criteria program?

Rebuttal Testimony of Infrastructure and Operations Panel

A. The Staff proposed reductions in this program for FY11 of $3.157 million, FY12 of $3.9375 million and FY13 of $0.750 million.

Q. Why did Staff recommend these reductions?

A. Staff recommended these reductions because nine projects were cancelled for which investments had been allocated in these amounts and the Company had not reduced its budget.

Q. Does the Company agree with Staff's proposed reductions?

A. No. As part of this program, the Company evaluates its system and its work plan annually to ensure that work that has been identified is still necessary based upon the most recent realized loads and load forecast. Accordingly, as is demonstrated by the nine cancelled projects, there is every expectation that circumstances may change and these changed circumstances may necessitate the addition or removal of work from the work plan.

Q. Has the Company identified additional work during this period that is necessary based upon the annual system evaluations?

A. Yes. The Company has identified eleven additional projects that are necessary during FY12 and FY13.

Q. What is the aggregated level of investment necessary for the eleven projects?

Rebuttal Testimony of Infrastructure and Operations Panel

A. The investment level necessary in FY12 is $2.1 million; in FY13 it is $5.0 million; and FY14 it is $2.0 million.

Q. How do these amounts compare to Staff's proposed adjustments?

A. The Company accepts the Staff's downward adjustment of $3.157 million in FY11. In FY12, the Company accepts the Staff's downward adjustment of $3.9375 million, offset by the $2.1 million for the eleven additional projects for a net downward adjustment of $1.838 million. In FY13 the Company accepts the Staff's downward adjustment of $.75 million, offset by the $5.0 million impact for the eleven additional projects for a net upward adjustment of $4.25 million. There is no proposed adjustment for FY14. These net adjustments will provide adequate funding for the eleven newly identified projects that are needed in order to provide reliable service to customers under the Company's planning criteria. These changes are shown in Exhibit __ (IOP-1R), Schedule 4.

4. Underground Networks

Q. What was the Staff's recommendation regarding the Networks program?

A. The Staff recommends reducing Underground Network Project #C33173 (Albany Network) by $0.8 million in FY11 and FY12 in an effort to bring the anticipated investments in line with typical costs similar to Projects #C29205 and #C29206 (Buffalo – Elm Street Network). The Staff also recommends removing all Underground Network expenditures for FY13 through FY15 ($2.0 million, $2.25 million and $2.5 million respectively) due to lack of specific projects.

Rebuttal Testimony of Infrastructure and Operations Panel

Q. What is the scope of the Albany Network project?

A. The Albany Network project is comprised of two distinct portions. One portion is the annual replacement of 5 network transformers and 5 network protectors based upon condition which will be an ongoing investment for the FY11-FY14 period. It is for this portion of the project that Staff recommends using the estimates from the Buffalo - Elm St. projects. The other portion of this project involves investment requirements that were identified through a detailed network study; the Albany Network Secondary Distribution Study.

Q. Do you agree with the proposal set forth by Staff?

A. We agree in part and disagree in part.

Q. Do you believe it is reasonable to compare project #C33173 with projects #C29205 and C29206?

A. We do believe it is reasonable to compare the projects as the general scope of the work is similar. However, the estimates that were used for the projects #C29205 and #C29206 were based upon 2008 estimates and we have better information based upon actual work for this type of project.

Q. What is the scope of the projects on the Buffalo – Elm Street Network and what were the projects estimates?

A. The scope of Buffalo – Elm Street Network consists of replacing 5 network transformers at an estimated cost of $0.05 million to $0.1 million (Project

#C29205) and replacing 5 network protectors at an estimated cost of $0.025 million to $0.06 million (Project #C29206).

Q. What does the Company believe is the appropriate cost for each component of this portion of the Albany Network project?

A. The Company believes based upon similar completed work that the cost of replacement of each network transformer is $0.110 million for a total of $0.550 million annually and the cost of replacement for each network protector is $0.060 million for a total of $0.300 million annually. In total this portion of this project will require the investment of $0.850 million annually.

Q. What was the purpose of the Albany Network Secondary Distribution Study?

A. The purpose of the Albany Network Secondary Distribution Study was to analyze the network secondary distribution system serving the City of Albany. The study included: the analysis of thermal and voltage limits during normal, single contingency and double contingency conditions; and the expected performance of the network secondary distribution system for solid faults in the secondary cable system. The additions designed to alleviate all of the calculated thermal criteria concerns, voltage criteria concerns, and fault criteria concerns are recommended in the study.

Q. When was the study completed and what were its findings?

A. The Study was completed in April 2010 and recommendations from the study have resulted in Project #C36274 which is part of the overall Albany project Underground Network Project #C33173 (Albany Network). Project #C36274 consists of replacing an additional 3 network protectors, 6,707 circuit feet of secondary network sets and 28 secondary manhole and ring buses ($0.095 million FY11, $0.817 million FY12 and $0.629 million FY13).

Q. Is Project #C36274 replacing Project #C33173?

A. No. Project C#36274 is in the budget as a sub project of Project #C33173.

Q. What is the total cost of the Albany Network Underground Network Study Construction?

A. As a result of the Albany study (Project #C36274) and the estimated costs of replacing 5 network protectors and transformers annually (Project #C33173), the Albany Underground Network Study Construction is estimated to cost a total of $4.1M (FY11-$0.95 million, FY12-$1.7 million, and FY13-$1.5 million).

Q. Does the Company recommend similar underground network projects in FY 14 ?

A. Yes. The Company intends to continue being proactive and plans on performing similar network related projects on other underground secondary networks such as those located in Syracuse, Utica, Watertown, and Buffalo. Therefore the Company's forecasted expenditures in FY14, although not supported by specific projects due to the fact that the detailed studies have not been completed at this time, is reasonable. In is reasonable to assume that the Company should continue to modernize critical underground network, many of which were installed many decades ago.

Q. Why does the Company consider its proactive approach in maintaining its Underground Networks to be important?

A. The underground network systems are highly integrated and complex, and as their condition is deteriorating, they require monitoring, maintenance and replacements based on network studies to maintain safety and reliability. When network failures do occur they have a significant impact on the reliability and integrity of the overall network due to the length of time required to make repairs, the complexity of making the repairs and the associated costs for such repairs. Additionally, unlike the overhead system, in the secondary underground networks system failure is designed to cascade in an attempt to sustain the reliability of the network. This places added importance on the need to ensure that the equipment in the network is viable and able to operate as designed. By continuing with the network program beyond the Albany network the Company is taking a proactive approach to maintaining and sustaining the underground secondary network system.

Q. What does the Company recommend?

Rebuttal Testimony of Infrastructure and Operations Panel

A. Based upon the investment requirements as set forth above for the Albany project (FY11-$0.95 million, FY12-$1.7 million, and FY13-$1.5 million) the Company recommends that; its FY11 investment as DPS Staff recommends, its FY12 investment level be set at $1.7 million which is $0.400 million more than Staff recommends, its FY13 investment be set at $1.5 million which is $1.5 million more than Staff recommends and that the FY14 be set consistent with the investment required in FY13 of $1.5 million, which is $1.5 million more than Staff recommends, in anticipation of work that will be identified similar to the work delineated for the Albany Network.

5. <u>Mercury Vapor Replacement Program</u>

Q. What does the Staff recommend regarding the Company's Mercury Vapor (MV) replacement program?

A. The Staff recommends reducing the MV replacement program budget, which currently ranges from $2.5 million to $3.0 million in FY11 through FY13, to $0.75 million per year in FY11, FY12 and in FY13.

Q. What is the basis of the Company's MV replacement program?

A. The MV luminaire replacement program is based upon several key points. First, when developing this program, the Company understood that applicable legislation adopts an attrition model for luminaire replacement beginning in 2008. Second, the Company was also aware of criteria proposed within the federal Clean Energy Policy Act which would establish efficacy standards for lamps which the MV lamps may not achieve. Ultimately the legislation would result in the termination of production of MV lamps beginning in 2016. Although the legislation is still pending, the direction of energy policy at both the federal and state levels is towards greater energy efficiency. We therefore believe that it is reasonable for the Company to plan now for the adoption by government at some level of efficiency standards for lamps that will require the replacement of MV luninaires. The Company's replacement strategy provides sufficient time and resource allocation to achieve the luminaire conversion in a way that promotes quality consistency and efficiency.

Q. When is the expected completion date of the MV replacement program?

A. The MV replacement program is expected to be completed in FY13.

Q. Would a spot replacement process as proposed by Staff achieve a similar objective?

A. Yes. The individual spot replacement process would eventually achieve the elimination objective; however, it will not promote quality consistency and efficiencies in the use of all resources.

Q. Why are there comparative differences between the program and historical unit cost values?

A. The comparative difference between the program and historical unit cost values are due to the current program’s future cost, which includes estimates of all associated in-house costs, current purchase costs of the specific luminaires and reasonable production rates. The historic costs include actual costs for activities involved in design through construction with all other costs being applied as supplemental factors.

Q. Is it recommended that the Company continue with the MV replacement program?

A. Yes. The Company believes its current coordinated, bundled approach to the replacement of all MV luminaires by the FY13 target date is the right approach and is justifiable given the associated environmental concerns and improved energy efficiency that will be gained from alternative light sources.

Q. What is the most beneficial aspect of the MV replacement program?

A. The most beneficial aspect of the project is achieved through the efficiencies of managing large volumes of luminaire replacements at all stages of the work order process flow, procurement, materials management, installation and resource recovery. The program will address geographically targeted customers to maintain a uniform and continuous performance model across the service territory promoting the efficient utilization of labor, transportation, material resources and retired equipment disposal. This approach minimizes the impacts to labor and material resources associated with unplanned and random customer contacts.

Rebuttal Testimony of Infrastructure and Operations Panel

Q. Are there any other benefits from implementing the Company's MV replacement program?

A. The proposed replacement program further addresses the Company's timely commitment to achieve energy efficiency targets, promote reductions in carbon emissions and mercury usage.

6. Pockets of Poor Performance

Q. What did Staff recommend with respect to the Company's Pockets of Poor Performance Program?

A. The Company proposed funding of $2.13 million/year for each year FY11-FY14 for the Pockets of Poor Performance program. Staff recommended the Company not receive any funding in this case for the program.

Q. What is the intent of the "Pockets of Poor Performance" Program?

A. The main driver for the program is improved customer reliability at the local level. There are a number of customers who undergo repeated interruptions, but because these events affect only a relatively small number of customers, prioritizing this work on a system reliability basis is difficult. It is these small, localized events that the Company terms "pockets of poor performance." The reliable service for individual pockets is very important to the customers adversely impacted and the Company believes it appropriate to address these issues to improve reliability and promote greater customer satisfaction.

Rebuttal Testimony of Infrastructure and Operations Panel

Q. How does the Company intend to identify and manage the pockets?

A. The Company conducts quarterly reliability reviews to identify both poorly performing feeders and local pockets of poor performance. This program targets 3 identified pockets per division per quarter to be addressed. Local Divisional Field Engineers perform Engineering Reliability Reviews (ERRs) and perform field studies and identify appropriate mitigation opportunities based upon the specific needs of an identified pocket. Local divisional recommendations are endorsed by the Divisional Reliability Council and approved in the System Reliability Council.

Q. How many pockets are there, and how many customers are affected?

A. When the Pockets of Poor Performance Strategy was updated in March 2010, there were approximately 125 pockets affecting about 10,500 customers. Subsequent analyses are ongoing.

Q. Does the Company believe such pockets of poor performance could be addressed through other on-going reliability programs?

A. Reliability blankets are typically utilized to address larger interruptions at the feeder level, which provide, or have the potential to provide, substantial interruption improvements in terms of customer counts and durations. On an overall basis the existing reliability programs help pockets of poor performance by reducing overall system exposure. However, because these broader reliability programs are designed to maintain overall system reliability, the Company believes they are not necessarily focused enough to effectively address localized reliability issues that generate pockets of poor performance. The pockets of poor performance program is more targeted and focused to address these localized issues than a broader reliability blanket can.

Q. What are some causes of pockets of poor performance?

A. Causes of pockets of poor performance are numerous but may include small sections of overhead conductor prone to tree events or inadequate step down transformer capability which may have resulted through shifting or increased loading in any particular area. Addressing such pockets may include actions such as reconductoring small sections of deteriorated overhead line, or performing voltage conversions.

Q. Is it possible that mitigation for some pockets would be identified through other programs, such as Reclosers or I&M?

A. It is unlikely that issues relating to an individual pocket would be identified through recloser analyses, as the number of customers addressed is likely to be too small. Similarly, the I&M program, which is a visual inspection program looking at discrete asset integrity, would not likely address local reliability issues. Further, neither program is likely to identify root causes of local problems which are addressed as part of the pockets of poor performance program. Accordingly, the Company believes Engineering Reliability Reviews resulting from identification of pockets of poor performance are the appropriate tool to identify mitigations and recommend action.

Q. Are there generic solutions to pockets of poor performance?

Rebuttal Testimony of Infrastructure and Operations Panel

A. No. Although there may be common issues, each pocket must be evaluated individually and separate mitigation plans prepared.

Q. How does a separate program help in managing pockets of poor performance?

A. The separate program allows for pockets to be managed as separate entities distinct from the overall reliability budget. Metrics can then be developed on mitigations performed and improvements made with reference to the pockets alone. By maintaining a separate budget it is possible to prioritize work on pockets at the beginning of the year which would otherwise be unlikely to be addressed under 'normal' reliability initiatives.

Q. Is there a generic budget forecast for an individual pocket?

A. Some pockets will have operational solutions requiring no capital; others may require significant capital (e.g., installation of spacer cable and reconductoring). Unfortunately there is no generic solution and consequently no generic budget forecast. In initial investigations, an average of $100,000 per pocket is a reasonable estimate for capital solutions.

Q. Is $2.13 million an appropriate amount to budget for pockets of poor performance each year?

A. The Company believes the budget of $2.13 million is sufficient to address, on average, 3 pockets per division per quarter. As noted, each pocket is an individual and unique occurrence of localized poor performance. With a $100,000 per pocket as capital, and 60% of pockets requiring capital rather than operational mitigation, and an aim of 36 pockets annually, $2.13 million is an appropriate budgetary figure. Given the beneficial customer effects of this program, the Company's proposed funding level of $2.13 million annually as shown in Exhibit __ (IOP-1R), Schedule 4, should be accepted, and the Staff's recommendation not adopted.

D. Sub-Transmission and Distribution Asset Replacements

1. Sub-transmission - Inspection and Maintenance Program (I&M)

Q. The Staff recommends that the capital estimated budget for sub-transmission repairs in response to visual inspection be reduced by 50% per year. Please explain the Company's concern about this reduction.

A. Staff correctly notes that the primary driver for capital investments in the Inspection and Maintenance program for Sub-Transmission is the replacement of poles based on condition assessments. The Company's proposed level of funding for this program was determined using actual Sub-Transmission inspection results for calendar year 2008. This proposed level of spending was confirmed by the results of the 2009 inspections and aligns with a pro-rated level for the inspections conducted thus far in 2010. Accordingly, because the Company recognizes that the main driver of necessary capital investment for this work is driven by pole replacement, and the Company utilized an average cost multiplied by the number of poles to be replaced as identified during the past inspections to develop the anticipated capital investment, the Company's proposed level of funding is reasonable and should be adopted.

Rebuttal Testimony of Infrastructure and Operations Panel

Q. Describe how the Company developed the budget levels it proposes for this program.

A. The Company budgeted $9.6 million, $10.0 million, $11.0 million, $11.5 million and $11.0 million for repairs to its sub-transmission system for FY 11 through FY 15, respectively. The budgeted estimate was developed based on 2008 actual inspection findings. The table below highlights the total remaining poles to be replaced on the Sub-Transmission system based on our current outstanding work for both Level 2 and Level 3 deficiencies identified through the inspection process. In fact, based on the work that is necessary to complete Level 2 and Level 3 findings consistent with the requirements set forth in the Safety Order we estimate work for FY2012 already in excess of $ 7.0 million. As 2010 inspections continue we anticipate that there will be additional Level 2 work identified which will need to be completed by the end of 2011.

Year Inspected	Total Found	Total Completed	Total Remaining
2008	772	413	359
2009	681	52	629
(YTD) 2010	323	0	323

Q. Is there a way that the Company can provide Staff with an annual identification of the work completed under this program?

A. Yes. The Company, consistent with the requirements of the PSC Safety Order evaluates 20% of its sub-transmission system annually through field inspections and captures the results of this by discrete maintenance codes each with a unique description (for example, maintenance code 511, description visual rotting of a pole). Based upon the assessment and the severity of the deficiency which defines the relative level and thus the replacement schedule for the work, this work is scheduled for future investment consistent with the requirements of the PSC Safety Order. All of the maintenance codes are captured in a computer program; Computapole, and the resulting work is scheduled from the work that is queued during each cycle. The investment levels identified as part of this filing are based upon the actual inspection data that is presently in the queue from 2008 and 2009. The Company, using the data that is captured in the Computapole program and the work that is completed by the Company each year can provide Staff a summary of discrete investments in the system.

Q. What is the Company's recommendation regarding this program?

A. The Company's proposed funding levels for this program, as shown in Exhibit __ (IOP-1R), Schedule 3, should be accepted, and the Staff's recommended adjustments not adopted.

2. Sub-Transmission Line Overarching Strategy

Q. What are the Staff's recommendations for the Sub-Transmission Overarching Strategy?

Rebuttal Testimony of Infrastructure and Operations Panel

A. The Staff recommends the budget for the Sub-Transmission Line Overarching Strategy forecast be set to $11 million per year, which would result in a total program decrease of $10.7 million over the period FY11-FY13.

Q. On what did the Staff base its recommendations?

A. Staff accepts the Company's line selection process and the projects identified; however, it recommends the forecasted budget be reduced so as to align it with historic spending in 2008 and 2009.

Q. Why does the Company view historical spending to be an inaccurate way of determining budget levels for a suite of projects?

A. The choice to match past spending by Staff does not align with the Company's identification of reliability opportunities on the sub-transmission system that were previously not focused due largely to the Company's concentration on distribution reliability opportunities in order that the Company expeditiously begin to meet its reliability targets. However, in order to maintain the Company's present reliability levels the additional work has been identified on the sub-transmission system. Work in this category has been identified through reliability reviews and the aerial helicopter survey which was just recently completed over the last two years. Moreover, the Company has taken a holistic view of opportunities to improve reliability through these targeted investments in its sub-transmission system as informed through detailed reviews with Operations and Engineering personnel. The projects identified provide Operational capabilities by making the system more discrete from the standpoint of isolating and restoration capabilities.

Each project identified in the Company budget has specific scopes based on design, construction configuration, topography in the work area, permitting requirements, and outage availability. Due to the above variations in project scopes, historic spending levels are not an accurate method of determining forecast levels.

The projects identified in the budget are quantified, well-developed projects with engineering complete, materials procured, permitting requirements met, and ready for schedule. Because these projects are in advanced stages of development, the spend and project schedules are accurate and realistic. Accordingly, the funding levels proposed by the Company, as shown in Exhibit __ (IOP-1R), Schedule 3, should be adopted and the Staff's recommended adjustment rejected.

3. Indoor Substations

Q. What has Staff proposed for this program.

A. Staff has proposed a reduction in the number of substations that should be funded annually based upon the Company's slower than expected progress in the past for substation rebuilds under this program. Additionally, Staff proposes to reduce the investment level consistent with the three substations they recommend to be funded annually.

Rebuttal Testimony of Infrastructure and Operations Panel

Q. Does the Company agree with the proposed reduction in the number of substations to be completed annually?

A. Yes. The Company agrees with the reduced number of substations that are to be funded on an annual basis based upon the complexity and amount of work that is being realized at these substation upgrades.

Q. Does the Company agree with the reduced investment level for these projects?

A. No. Although the Company has progressed at a slower pace than anticipated it is due to the complexity and volume of work that is being realized at these locations. The result of the complexity and volume of work is that in aggregate the program is costing more than the $4 million that has been proposed by Staff and was identified in IR Response DPS-302 (CVB-21). Average cost per station is approximately $8 million based on latest estimates. Despite the reduction in the number of substations proposed under the program, the original investment level proposed by the Company is more consistent with the funding requirements for three substations as proposed by Staff. The Staff proposed adjustment should be rejected and funding as shown in Exhibit __ (IOP-1R), Schedule 4, should be adopted.

4. <u>Distribution Station Transformers</u>

Q. What does Staff recommend regarding distribution substation power transformers?

A. The Staff acknowledges the need to proactively replace substation transformers based upon condition which, as Staff notes, the Company does. Staff's recommendation is to replace two transformers per year at a cost of $0.4 million per unit resulting in a downward adjustment for FY11, FY12 and FY13 of $0.7 million and $1.2 million for FY14. This investment level provides the capability for less than the number of transformers the Company believes should be replaced in order to properly manage the system.

Q. How many distribution transformers has the Company identified that need to be replaced based upon condition?

A. The Company has identified 62 units which are included on its 5 year replacement list. Of these, 13 replacements already have project numbers assigned and are progressing through engineering.

Q. How many transformers does the Company need to replace a year and why?

A. The Company replaces between 4 and 8 units a year in order to ensure that:

- the condition of the transformer inventory currently in service is adequate for purpose
- the Company has the capability to deal with significant events which require use of spare units
- the system is sustainable; and

- the uncontrolled occurrence of transformer failures is minimized.

Q. Why must transformers be replaced and not just maintained?

A. Power transformers deteriorate (degrade) with time. Some elements of deterioration, such as oil quality or tap changer contacts, may be addressed through maintenance. However, a key component of transformer insulation is paper, which is cellulose based, and which can suffer deterioration as a result of three key processes: oxidation, hydrolysis and thermal heating. The oxidation and hydrolysis can be controlled, to a degree, through maintenance activities such as gasket refurbishment and oil preservation systems. The thermal deterioration, however, is cumulative and irreversible and is a consequence of the natural operation of the transformer. It cannot be addressed via maintenance.

Q. What would happen if transformers were not replaced in a timely manner?

A. Deferred or delayed replacement of transformers creates additional risk that a significant number of transformers would deteriorate simultaneously to the point where they are no longer fit to perform their function or can operate in a manner which is reliable. Moreover, if this occurs the necessary replacement rate to restore the reliability of the system would be difficult and not cost efficient.

Q. Does the Company recommend transformers be replaced on the basis of age?

A. No. The Company takes a condition based approach to replacement, based on available inspection, test and maintenance data (including dissolved gas in oil analysis). Age is a contributing factor to cellulose degradation but it is used as an indicator of possible concern rather than as a driver for replacement of a unit. Our present list of replacement candidates for transformers tends to have older units, but is not limited to those above a certain age. In fact, the correlation between age and the units that have been previously been identified for replacement based on condition is what establishes our concern about deferring investment in distribution transformer replacement. It should be noted that of the 62 units identified based upon condition, 48 or 77% of them are older than 50 years old. Furthermore, 27 or 43% of those identified are older than 70 years and 21 or 33% of those identified are more than 80 years old.

Q. How old are the Company's transformers?

A. More than 50% of our approximately 806 substation transformers are greater than 50 years old.

Q. What would happen if we only replaced 2 transformers per year?

A. In twenty years, if the Company replaced only two substation transformers per year in this age grouping, 57% of our transformers (or 456 units) would be greater than 70 years old and nearly 600 units (or greater than 72%) would be greater than 50 years old. And while age is not a direct indicator of condition it is reasonable to assume that with a larger population of older transformers that the number identified for replacement based upon condition will likely be larger as well. If this were to occur the Company's ability to efficiently and effectively replace the large number of complex assets would be compromised. Table 1 and Figure 1 represent the present day age of our distribution substation transformers.

Station Transformer Age in Years	Percentage of Population	Count
>30	77.0%	621
>40	70.9%	572
>50	61.5%	496
>60	44.1%	356
>70	39.8%	321

Table 1. Age of Transformer Population

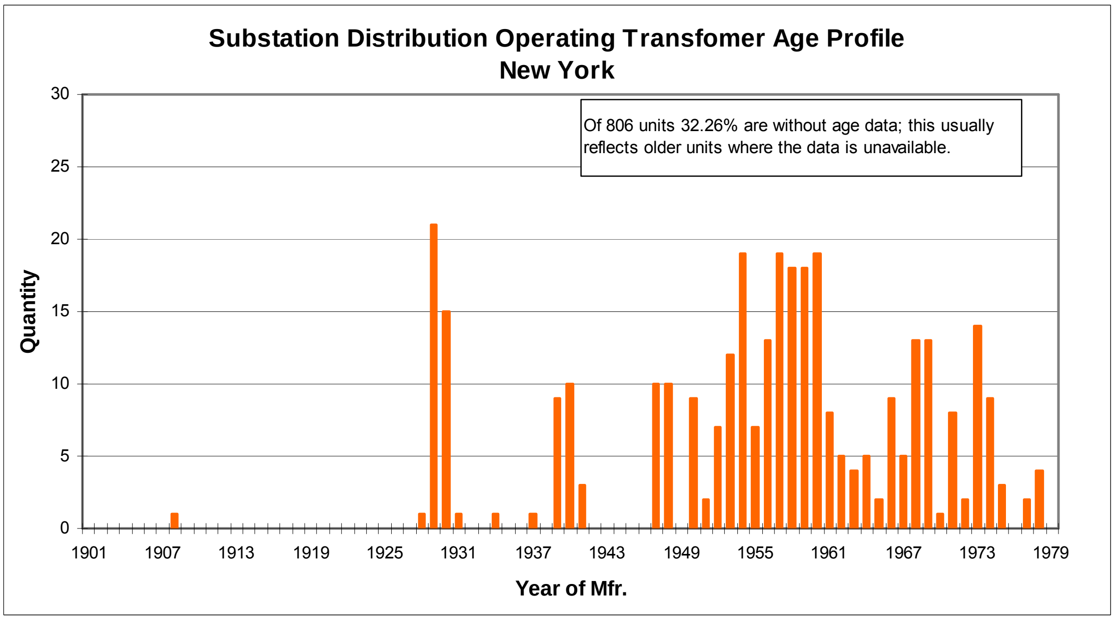

Figure 1. Distribution Substation Transformer Age Profile

Q. What does the Company recommend for the distribution substation transformer investment forecast?

A. Given the current condition of the transformer population and the identified substation units to be replaced, the Company believes it is prudent to maintain the level of forecast originally set out ($1.5 million for FY11, FY12 and FY13 and $2.0 million for FY14), as shown in Exhibit __ (IOP-1R), Schedule 4.

E. Non-Infrastructure Capital Investments

Q. What does Staff recommend in regards to the forecasted level of expenditures for non-infrastructure general equipment and telecommunications?

A. Staff has proposed a reduction in the forecast for non-infrastructure general equipment and telecommunications of $2.1million in FY12 to a recommended funding level of $3.2 million, and funding at $3.2 million per year, adjusted for inflation, for FY13 and F14. The Company points out that although these adjustments were described in Staff's testimony, they were not reflected in the Staff's exhibits. In order to address this apparent inadvertent discrepancy, the Company's Exhibit __ (IOP-1R), Schedule 4, reflects Staff's proposed adjustment as if it had been originally reflected in Staff's exhibits.

Q. Does the Company accept that flood mitigation projects are "too speculative to include in the projected budgets"?

A. No. As the Staff Infrastructure Panel states, "the Company has a history of flooding events at the high risk substation locations" and, based on analysis by independent consultants, the Company has identified specific flood mitigation actions required at each of the high risk sites.

Rebuttal Testimony of Infrastructure and Operations Panel

Q. Does the Company have specific projects in mind to address these historic flooding events?

A. Yes. At the Amsterdam 115 kV Station, 2006 flooding from the Mohawk River resulted in some upgrades at the site. An impermeable berm surrounding the station and/or raising the height of the equipment in the station should also be added. At the South Oswego 115 kV Station, the southern portion of the yard has a history of flooding due to beaver dams that are periodically built in the upstream culverts. The culverts are periodically cleaned out manually, but a more permanent resolution such as a gated concrete culvert to replace the existing metal culvert needs to be installed. The manual cleaning of the culvert poses a safety risk to personnel so the gated culvert would eliminate this risk as well. Flooding associated with Zimmerman Creek, a significant tributary of the Mohawk River, occurred in 1995 and 2006 resulting in inundation of the St. Johnsville 115 kV Station with almost three feet of water. A new berm along the western side of the station four feet high would protect it from future overflow from the creek. Likewise, the same flooding event of the Mohawk Valley in 2006 resulted in overflow of the East Canada Creek tributary into the Inghams 115 kV station. A stone berm was constructed between the station and the creek, but it does not have an impermeable interior liner or barrier (like clay or sand). An impermeable barrier needs to be added. Other recommendations from the consultant study regarding Gardenville and Lighthouse Hill will be addressed as part of the separate plans to rebuild those stations.

Rebuttal Testimony of Infrastructure and Operations Panel

Q Is the Company recommending adjustments to the proposed capital expenditures for the Non-Infrastructure Investments?

A. No. Based on the foregoing testimony, we recommend total capital forecasts of $2.0 million and $1.1 million in FY 13, and FY 14, respectively, as initially proposed by the Company, as shown in Exhibit __ (IOP-1R), Schedule 2.

F. Cash Outlays

Q. The Staff Infrastructure Panel addresses three projects that it groups in a category it calls "cash outlays." Could you respond to the Staff's recommendations in this area?

A. Yes. The Staff classified three projects included in the Company's filing as "cash outlays": (1) the Tri-Lakes project; (2) the Luther Forest project; and (3) the Hydro One BP76 Transformer Replacement project. Staff's testimony indicates that the Company's proposed cost recovery for the Tri-Lakes and Hydro One BP76 Transformer Replacement projects be allowed. However, the Staff recommends that the potential costs of the Luther Forest project not be included in rate base as the Company had proposed.

Q. Please summarize the Company's proposal regarding the Luther Forest project.

A. As described in our direct testimony, the Luther Forest project involves the development by Luther Forest Technology Campus Economic Development Corporation (LFTCEDC) of a new technology park designed to serve the needs of large, high-tech customers with requirements for highly reliable electric service, such as nanotechnology computer chip manufacturers. LFTCEDC is constructing facilities that would interconnect directly to the Company's existing transmission system. In addition to enabling service to be provided to computer chip manufacturing facilities in the new technology park, the new facilities would become part of the integrated network transmission system. Once the facilities are constructed, it is anticipated that their ownership will be transferred to the Company, and the Company would own, operate and maintain the facilities going forward. It is estimated that such transfer will occur in stages as construction is completed, with the first transfer of assets occurring no later than September 2010. This is substantially in advance of the March 2012 transfer date identified in our initial filing in this case. The estimated cost of the transmission facilities being developed by LFTCEDC is approximately $37 million. This updated amount is approximately $20 million less than the estimate reflected in the Company's January 29 filing. The bases for the reduction include a change in project scope, as well as the availability of actual costs information versus previously estimated costs. LFTCEDC and the Company have previously discussed that once completed, the facilities would be transferred to the Company for $1. The assets would be put on the Company's books at that amount, and the corresponding effect on the Company's rate base would be negligible. In other cases where a transfer of assets has occurred substantially below their value, the U.S. Internal Revenue Service has held that there is a resulting income tax liability for the asset recipients. The amount of the tax is based on the recipient's tax rate. In a case like this, where the assets are estimated to cost approximately $37 million, the resulting tax liability could be significant (perhaps as much as $14.8 million when using a 40% tax rate). To the extent the Company incurs any income tax liability as a result of the transaction, it would propose to handle such tax liability as a deferred tax asset on the Company's books.

Q. What's Staff proposal for treating the costs of the transferred Luther Forest assets in the Company's rate base?

A. The Staff recommended that the cost of the facilities not be included in the rate base until there is a signed contract for the transfer of the assets, and that contract is finally adjudicated at FERC.

Q. What is the Company's understanding of Staff's position?

A. Staff is concerned that customers may be asked to bear costs for capital investments the Company is not required to make. Indeed, aligning cost responsibility with actual capital investments is the primary protective mechanism provided by the Capital Investment Reconciliation Mechanism (the "Tracker") proposed by the Company in this case. To the extent the capital investment upon which rates are set is greater than the actual capital investment amount on the Company's books for the given period, customers would be credited the revenue requirement effects of that difference.

Rebuttal Testimony of Infrastructure and Operations Panel

Q. Does Staff's recommendation rely upon the Tracker to provide customers the benefit of a potentially lower capital cost of the facilities on transfer?

A. No, it does not.

Q. What is the Company's response to the Staff's proposal?

A. The Company believes the Tracker mechanism could have been used in this scenario but understands Staff's concerns about including the entire cost of the project in rate base prior to any direction from FERC on the allocation of costs associated with the transfer. In order to ensure the customer is energized on their timeline, the Company proposes that the assets be transferred from LFTCEDC to the Company and to the extent that the Company incurs any income tax liability as a result of the transaction, it proposes to include the tax liability as a deferred tax asset on the Company's books. The Company would then earn a return on the timing difference of the tax liability over the life of the asset.

Q. Is there any other issue associated with the Luther Forest transaction that you would like to discuss?

A. Yes. FERC's approval of the asset transfer. In light of FERC's potential jurisdictional authority over the transfer of looped high-voltage facilities, that agency's determination on the transfer is also expected to determine if the cost of the facilities can be directly allocated to a single developer (which is not the ultimate end-use customer), which in this case is LFTCEDC. Although the Company and LFTCEDC have agreed to the transfer at $1, and the unique circumstances of the situation justify the contemplated $1 transfer price, there is uncertainty whether FERC will authorize the transfer at $1. If FERC requires the Company to fund the entire market value of the assets now estimated at $37 million the Company would adjust its revenue requirement prior to this case being resolved to reflect their decision. To the extent FERC's decision were to occur after the resolution of this case, the Company would propose to include the amount of increased capital investment in rates through the proposed capital tracker mechanism or petition the Commission for appropriate rate treatment.

G. Facilities, Properties and Lease

Q. Please respond to the Staff's proposal regarding capital funding for the Company's facilities projects.

A. The Staff recommended removing all capital funding for the Company's proposed control center consolidation project, and further proposed levelizing facilities capital funding over the remaining fiscal years covered by the Company's proposed rate plan period. However, the proposed profiled investment plan set forth in the Company's initial filing was intended to reflect actual or planned spending commitments during those periods. The Staff's proposed flattening of the profile, while intended by Staff to provide a comparable level of non-control center project funding, would nevertheless result in a significant mismatch in the Company's capital investment schedule and the recovery schedule in rates. Although the Company presents updated information below which reduces total facilities investment levels in FY11 and increases it slightly in FY12 from what we presented in our Corrections and Updates filing, the updated investment levels are still based on anticipated expenditure dates, and the Staff's flattening proposal would still produce a mismatch, as seen in Exhibit __ (IOP-6R). Finally, as described below, the Company believes Staff may not have properly or completely evaluated the benefits from the proposed control center consolidation project, and we therefore recommend that Staff's proposed adjustments be rejected.

Q. Please address Staff's concern that the Company's proposed facilities capital budget in the rate plan exceeds its historic level of facilities capital spend.

A. Most of the spend forecast in FY11 and FY12 is for the purchase of two facilities as discussed later in this testimony. As such, while there is risk that commercial factors may contribute to a delay, there is lower risk with this type of spending as compared to a major renovation or new construction project.

Q. Please describe the mentioned updates to the Company's facilities capital budget.

A. There are two major changes. The first is that the full scope of the North Albany area project will not take place due to the estimated costs received from contractors for the proposed work being higher than originally estimated by the engineering firm hired by the Company to address the needs of the building and the addition of scope to the project. The second is that the consolidation of the Beacon North facility to Henry Clay Boulevard will not take place. This also is due to the estimated cost from contractors coming in higher than anticipated from the Company's engineering firm as well as the addition of scope to the project

Q. **Regarding the North Albany Area project, will the two existing facilities in Troy and the one in Glenmont still be utilized?**

A. It is possible that one of the Troy facilities will be closed in the future. However, the Company has not completed a re-evaluation of its options.

Q. Is work still required at the North Albany facility without the consolidation?

A. Yes. A condition assessment of the building identified upgrades necessary to address components such as HVAC, electric infrastructure, fire alarm system, restrooms and windows which are beyond their useful life. The total estimated cost for renovations (without consolidation) is approximately $7 million.

Q. How has the Company addressed the operations savings for the consolidation project?

A. The operations savings associated with Troy-Smith Ave, Troy – Oakwood and Glenmont shown in Attachment 1 of IR MM-81 will no longer be realized and have been removed from the Cost of Service.

Q. Has the capital spending plan been revised for the North Albany area project?

A. Yes. The capital plan has been staged as shown in Exhibit__(IOP-6R) to complete the North Albany upgrades identified earlier into fiscal years FY12, FY13 and FY14.

Q. Have capital building system upgrades been identified at Henry Clay Boulevard (HCB) absent the relocation requirements of the Beacon North Facility?

A. Building system upgrades are not anticipated at this time for the Henry Clay Boulevard facility.

Q. Is there an alternate plan to address the Beacon North facility under the Syracuse Area Project?

A. The Company is currently in negotiations to purchase a property that meets the needs of the departments located at the Beacon North facility and will be less expensive than the HCB retrofit.

Q. Does Staff's proposed capital spending schedule set forth in Exhibit__(SIP-12) match the Company's anticipated spending for the proposed purchase of the property?

A. No, it is anticipated that negotiations will conclude shortly and the Company would make the purchase as quickly as possible to take advantage of substantial savings in avoided lease payments. Therefore, the capital spending schedule proposed by Staff does not match the Company's anticipated capital requirements.

Q. What are the Company's plans if the purchase is not completed?

A. The Company intends to continue leasing the Beacon North facility for the foreseeable future if the property purchase option is not implemented.

Q. What effect will not consolidating the Beacon North operations to HCB have on the facilities capital plan proposed by the Company and the adjustments to operation expense spend?

A. There are two options, depending on whether the Company succeeds in its proposed facility purchase, or whether it remains at the Beacon North site under a continued lease arrangement. Under the first option, the capital spending level will be approximately $8.0 million in FY11, a downward adjustment of $2.0 million in FY11 from the Company's capital plan submitted in the Corrections and Updates filing. This option is presented in Exhibit __ (IOP-6R). If the Company remains at the Beacon North facility under a continued lease arrangement, the capital spending plan for this project will be $0.0 million for FY11 and FY12. In addition, the operational expense savings shown in Attachment 1 of IR MM-81 will not be realized. However, no adjustment has been made to the cost of service as this scenario is currently speculative.

Q. Regarding the remainder of the facilities capital plan for FY11 and FY12, what is the Company's proposal for baseline facilities spending compared to Staff's recommendation?

A. As shown in Exhibit __ (IOP-6R), the Company proposes to spend $3.9 million in FY11 and $4.4 million in FY12 as compared to Staff's proposal of $1.6 million and $3.4 million, respectively.

Q. Why is the Company proposing a higher spend level than Staff for FY11 in baseline spending?

A. The Company has already committed to $3.4 million in spend based on submitted purchase orders and received bids. It would be difficult to retract the work four months into FY11. In addition, $0.5 million of additional projects are already in progress.

Q. How is the Company's Buffalo area project progressing?

A. The Company has completed the relocation of personnel and material from its Tonawanda facility and anticipates that actual spending levels will be at or near the original budget. However, the Company has moved $1.2 million in capital spend from FY11 to FY12 at the Kensington site in Buffalo, as shown in Exhibit __ (IOP-6R), to further evaluate the renovations needed to accommodate the relocation of personnel, vehicles and material from the Tonawanda facility.

Rebuttal Testimony of Infrastructure and Operations Panel

Q. Can the Company accommodate Staff's proposed spending levels for the Syracuse Office Complex (SOC) façade project?

A. No, as shown in Exhibit __ (IOP-6R), the Company proposes to spend $3.5 million in FY11 and $1.0 million in FY12 as compared to $1.4 million and $0.8 million proposed by Staff, respectively. It is anticipated that the planned budget amounts will likely be spent since the SOC façade repairs are in progress. In fact, it is anticipated that FY11 spending will exceed the proposed budgets due to the discovery of more extensive damage by the contractor as the masonry and window repairs have progressed. The Company has implemented a stringent review of the work and alternative repair options are being investigated in an effort to keep cost over-runs at a minimum.

Q. Can the Company's plan for renovating the SOC be adjusted to meet Staff's proposal?

A. No, renovation work is in progress at the SOC in order to make room for an additional 570 work spaces necessary to implement the Transaction Delivery Center (TDC), EDO Transformation initiatives to consolidate clerical staff plus other additional initiatives such as the consolidation of departments within the SOC. The Company requires its original proposed budget levels of $10.5 million in FY11 and $2.0 million in FY12, as shown in Exhibit __ (IOP-6R), as compared to Staff's proposal of $4.4 million and $1.5 million respectively to complete the project.

Q. Can you address Staff's concern related to the negative cost/benefit ratio of the Saratoga Area project?

A. The Company currently leases a facility in Saratoga at a very favorable rate. Unfortunately, the lease agreement will expire in October 2011. Given the very favorable rate that the Company now pays, the cost/benefit ratio of the alternatives of purchasing an existing facility or constructing a new one to accommodate business needs should be expected to be negative.

Q. Can the Company modify the Saratoga Area project to meet Staff's proposed spending schedule?

A. Because the Company is currently planning to purchase an existing facility, it would not be possible to accommodate the Staff's proposed spending schedule for this project. If the Company elected to construct a new facility, it could adjust spending in FY11 and FY12 per Staff's proposed schedule; however, it is anticipated that in that case, the total spending level will be higher and would require a longer timeline. The anticipated move-in date is no later than March 31, 2012 to an existing facility.

Q. Please comment on the Staff's recommendations regarding the proposed control center consolidation.

A. The Staff concluded that the Company's proposed control center consolidation was not justified and recommended removing $13.5 million in capital funding for that effort. However, we believe the Staff did not properly or completely evaluate the benefits from that project, and their proposed downward adjustment should be rejected.

Staff based its conclusion on the benefits of the consolidation, in part, on the incorrect view that consolidation will actually adversely affect the efficiency of the system operators, and that the benefits from the consolidation arise from upgraded systems alone. In fact, the consolidation of the control centers will allow for improved sharing of best practices during real time events, which should lead to a more consistent application of real time monitoring and response from one central location. The sharing of knowledge of a consolidated group within one building is expected to improve effectiveness during emergency situations.

A consolidated control center also allows for more efficient management of emergency events, such as major storm response. The pooling of control room expertise and experience during storms will help to reduce the number of times the field will need to open field storm rooms/boards. In addition, a consolidated control room is also closely linked to the centralization of clerical and design employees at the SOC. When additional help is required due to the size of a storm, employees will be brought into the control center to work in storm rooms from other groups such as design, clerical and mapping technicians. These resource capabilities will enable the new center to manage storm events for longer periods with personnel within the control center. In addition, the centralized resources will allow small to medium scale events to be managed from within the consolidated center, significantly reducing the number of times decentralized field storm rooms / boards are needed to be opened to support the dispatch, and assignment of outage calls. It is also expected that operations supervision that typically managed storms from the local office in the past will spend significantly more time in the field expediting restoration efforts. Further, at its central location at Henry Clay Boulevard, the consolidated control center would be located along with the Transmission Control Center and Gas System Operation Dispatch at a single location. Such proximity will promote further sharing of best practices and help support resource availability in response to emergency events.

In summary, the Company believes there are significant operational and efficiency factors that result from the control center consolidation that may not have been considered by Staff. Upon consideration of those factors, the benefits of consolidation are apparent. Therefore, the Company proposes that its proposal to fund the consolidation of the control center be accepted and that Staff's proposal be rejected.

H. Inventory Management

Q. Does the Company accept Staff's adjustment with respect to inventory management (IM) capital funding?

A. No. While the Company agrees that historic spending in this category has been lower than requested in this rate case, there are specific plans that require capital funds to implement improvements. For example, IM is in the process of consolidating warehouses and current "par locations" (crew barn stock rooms). This effort will require additional items such as racks, bins, "tailgaters" and forklifts at the existing locations following consolidation. In addition, all of the existing handheld units will need to be updated with new software when the Company migrates to the new SAP system. Lastly, the existing handhelds are approaching the end of their useful life. A new five year program should be implemented to replace the outdated units. Therefore, the Company proposes that its proposal to fund upgrades within Inventory Management be accepted and that Staff's proposal be rejected.

I. Capital Investment Plan Implementation

1. Transmission Regional Delivery Ventures

Q. Could you describe the Company's proposed capital work plan delivery model?

A. In our initial testimony, we described the portfolio of construction delivery resources the Company proposed to use to deliver the capital plan. These included a combination of:

- Enhanced Internal Construction Capabilities;
- Traditional "project-by-project" competitive bidding;
- Distribution Alliance Contracts;
- Transmission Regional Delivery Ventures (RDVs); and
- "Turn-Key" Engineer, Procure, and Construct (EPC) events for specialized installations.

This portfolio of resources provides a range of different delivery means for different parts of the Company's capital plan, and represents an evolution in approach from our historic practice. Relatively new in the mix of work delivery resources are the Transmission RDV and the Distribution Alliance contracting models.

Q. Please describe the Transmission RDV and the Company's goals in using that work delivery model.

A. The Transmission Regional Delivery Ventures (RDV) represents the Company's adoption of an innovative contracting strategy aimed at improving capital plan work delivery and increasing value for customers. The RDV was designed to operate under a long-term contract (i.e., 5-years) for the integrated provision of detailed design, project management and construction services to deliver an assigned portion of the Company's transmission capital investment program. The model includes an open costing framework and shared risk arrangement, coupled with performance incentives, which are intended to produce superior results at efficient cost.

During the competitive procurement event used to select the RDV partners, a total cost analysis was performed by the Company to evaluate the cost to deliver the 5-year capital program based on competitive bid pricing. Based on its analysis of projected savings under the RDV model versus traditional work delivery methods, the Company estimated total savings of 6.5% for the contractor element of the five-year capital plan, or approximately $45 million. These savings, combined with estimated insurance cost savings of $15 million over the contract period, were reflected in the Company's five-year capital budget plan presented in this case, thereby reducing the budget to deliver the identified work versus what it otherwise would have been under a "business as usual" approach.

One of the primary value drivers of the RDV model is the development of long-term, integrated supplier relationships aimed at capturing the value of negotiating a large portfolio of work. Faced with substantially increasing capital investment requirements, the RDV arrangement provides the Company with resources to deliver the capital plan that we felt could not be effectively provided through increased internal staffing or use of traditional contracting resources alone. Given the upward trend in infrastructure spending throughout the country, and the anticipated high demand for skilled engineers, designers and craft workers that existed at the time the Company was evaluating capital delivery plan options, the long-term RDV arrangement enabled the Company to secure highly skilled personnel and construction equipment needed to deliver on the investment plan.

Q. What position has Staff expressed on the RDV model?

A. Staff opposes the RDV model. Staff has expressed a clear concern that the RDV model may not provide the same level of certainty and competitive contract results that the more traditional construction contracting model would provide. The Staff therefore recommends that the Company revert to a more traditional contracting model, where fixed-price, design/build and design/procure/build contracts are competitively bid on an individual, site-specific, project-by-project basis.

Q. What is the Company's position with respect to Staff's recommendation?

A. Given the environment in which the Company is operating, particularly where capital investment demands are increasing and the pool of qualified resources to deliver that investment are limited, we believe the RDV model represents an innovative strategy for providing long-term customer value. Identifying innovative approaches to do traditional work is part of the Company's commitment to continuous improvement, and something the Commission expects us to undertake. Although the traditional contracting model is not necessarily broken, its "business as usual" approach was not viewed by the Company as the most effective or efficient means of addressing the pressing challenges it faced.

Nevertheless, we acknowledge that the traditional contracting model advocated by Staff provides a level of certainty, familiarity, and comfort with which the marketplace, regulators, and, indeed, the Company are accustomed. Despite our belief that the RDV model as structured by the Company has the potential to provide substantial customer value over time, the Company is willing to undertake a review of the RDV model and assess whether there is a basis for incorporating more elements of the traditional competitive contracting model advocated by Staff. The objective of such a review would be to determine whether there are any reasonable opportunities to revise the existing arrangements to provide additional customer benefits and efficiencies in the delivery of the work plan.

Q. Has the Company developed a plan for how it might incorporate more traditional contracting elements into the RDV arrangements, or what a revised RDV model might look like?

A. No. Other than committing to explore the incorporation of more traditional competitive contracting elements, the Company has not developed a plan yet. The RDV arrangements were designed to be long-term relationships, and revising them will require careful consideration. Importantly, as we explore options for refining the RDV arrangement, the Company must strive for seamless delivery of on-going work, and attempt to avoid delays or interruptions in the schedule for its infrastructure projects.

Q. Please respond to Staff's recommendation that Niagara Mohawk review how its various lines of business and departments can work together more effectively, and the level of staffing necessary for delivery of its capital investment plan.

A. The Company is always considering ways to more effectively and efficiently provide service. With respect to the specific recommendation made by Staff, we note that it is substantially similar to Recommendation III-2 of the Management Audit. In response to Recommendation III-2, the Company has implemented an organizational model that combines the distribution and transmission work delivery and operations functions. Under the consolidated organizational model, the Chief Operating Officer, Ellen Smith, is responsible for combined operating activities. Therefore, through its actions to implement the Management Audit recommendations, the Company is addressing the Staff's recommendation in this case.

2. <u>Distribution Alliance Contracts</u>

Q. Could you describe the Company's Distribution Alliance Contracts?

A. The Distribution Alliance Contract arrangement is a three-year fixed-price unit rate contract arrangement between the Company and Harlan (a subsidiary of Myr Group) for the delivery of Niagara Mohawk's distribution line construction program. Under the Alliance contract, Harlan's performance will be evaluated against its unit costs, workload delivery, and agreed Key Performance Indicators (KPIs). The KPIs are focused on Safety and Environment, Quality, Delivery, and People performance measures and are designed to drive improved customer value. The release of work in subsequent years is dependent on satisfactory performance against these criteria to ensure acceptable costs and workload delivery.

Q. What recommendations did Staff make regarding the Distribution Alliance Contract?

A. The Staff proposed that the Company should competitively bid out 20 percent of distribution and sub-Transmission work that would have gone to Harlan under the

Alliance contract in order to test the market and benchmark Harlan's performance.

Q. Does the Company agree with Staff's recommendation?

A. The Distribution Alliance contract structure and KPI mechanisms impose sufficient incentives on Harlan to deliver the work efficiently and effectively. Nevertheless, the Company is willing to direct a reasonable portion of the work that would otherwise have gone to Harlan to other providers in order to better assess Harlan's performance. Such providers could include internal workforce resources, competitively selected contractors, or other contract providers.

III. Operation & Maintenance Expense

A. Operating Expense Associated with Incremental Capital Investment

Q. Please explain the Staff Infrastructure Panel's adjustment to reduce incremental Opex associated with Capex directly related to the capital expenditure budget.

A. Staff's incremental Opex associated with Capex adjustment considers two items. First, the adjustment considers a flow through adjustment associated with Staff's capital budget forecast adjustment. Secondly, the adjustment imputes an O&M savings forecast.

Q. Does the Company agree with the flow through adjustment associated with Staff's capital forecast adjustment?

A. The Opex associated with Capex amount included in the Company's filing is based on applying the historic ratio of operations expense incurred in connection with capital investment to the amount of incremental capital investment reflected in the infrastructure plan. As explained in our testimony previously, the Company does not agree with many of Staff's adjustments to the capital budgets, and correspondingly does not agree with the amount of the flow through adjustment of incremental Opex associated with Capex.

Q. Does the Company agree with the imputed O&M savings adjustment included in the Opex associated with Capex adjustment?

A. The Company does not dispute the methodology used by Staff to calculate an amount of imputed O&M savings resulting from incremental capital investment. However, we do not agree with the incremental capital investment levels used by Staff in calculating their proposed adjustment, and therefore do not agree with the amount of the proposed adjustment.

Q. Does the Company agree that if there are capital budget reductions, there would be an associated reduction for the incremental operating expenditures associated with capital expenditures?

A. Yes, the Company agrees that capital budget reductions would also impact incremental operating expenditures associated with capital expenditures. Additionally, based on the Commission's determination of Staff's proposed capital reductions, Staff's incremental opex savings adjustments would need to be revised accordingly.

B. Additional Employees

Q. Can you provide additional explanation regarding the 'Additional Employees' described in Section 8 of the Staff Accounting Panel?

A. Yes. The Company's original proposal was to hire 136 incremental FTEs primarily to accomplish the capital work plan proposed in this rate case. Incremental funds were added to capital related expense recognizing that the incremental FTEs will contribute significantly to this cost.

Q. Does the Company agree with the Staff Accounting Panel's operating expense adjustment to exclude entirely the additional Transmission employees?

A. No. The Company has already hired 30 employees to date as detailed further below. However, our most recent view of the organization under the T&D re-alignment which has been prepared in response to recommendations of the Management Audit indicate the total number of FTEs may be reduced to sixty-five (65) from the previously proposed level of 136.

Q. Can you provide additional detail regarding the revised number of additional FTEs proposed by the Company and their responsibilities?

A. Yes. This information is also summarized in Exhibit __ (IOP-7R).

Rebuttal Testimony of Infrastructure and Operations Panel

Transmission Management - (1) FTE reduction as originally proposed by the Company.

Asset Management – (14) incremental FTEs originally proposed by the Company Nine (10) incremental FTEs have already been hired between September 30, 2009 and July 31, 2010:

- Three (3) in Transmission Planning to support NERC/NPCC requirements, Smart Grid and renewable planning activities, CEII document protection requirements and STARS.
- Three (3) in Transmission Line Engineering to fulfill need for system condition assessment, system incident analyses, engineering due to condition of transmission infrastructure in New York and to accurately estimate projects.
- Two (2) in Asset Strategy to support system condition and risk analysis, and PSC and ISO reporting requirements.
- One (1) Forester to assist in managing the maintenance of transmission right of ways.
- One (1) in Investment Management responsible for putting together the capital and maintenance work plan and coordinating with work delivery groups.

Four (3) incremental FTEs are still required:

Rebuttal Testimony of Infrastructure and Operations Panel

- Two (1) in Transmission Planning to assist in the development of coordinated T&D system plans, reporting and management of increasing asset replacements and to help manage the planning staff.
- Two (1) in Asset Strategy to support system condition and risk analysis due to the condition of transmission infrastructure in New York, project justification via the Transmission Cost Allocation process, and increasing regulatory compliance requirements.
- One (1) in Portfolio Management to manage the number of projects in our capital investment plans and work with the PM to provide support and forecasting of project spend.

One (1) incremental FTEs is no longer needed:

- One (1) in Forestry was deemed unnecessary given the current workforce.

<u>Network Operations</u> – Four (4) incremental FTEs originally proposed by the Company.

Two (2) incremental FTEs have already been hired between September 30, 2009 and July 31, 2010:

- Two (2) Outage Coordinators to determine, plan, and manage the outage system and schedule due to increased work load resulting from an increasing capital plan.

Two (2) incremental FTEs are still needed:

Rebuttal Testimony of Infrastructure and Operations Panel

- One (1) Outage Coordinator to determine, plan, and manage the outage system and schedule due to increased work load resulting from an increasing capital plan.
- One (1) Control Room Trainer to ensure compliance with new or revised NERC Standards and as a result of increased NERC training requirements as defined in NERC Standards PER-005.

<u>Regulation & Commercial</u> – Two (2) incremental FTEs originally proposed by the Company.

One (1) incremental FTE has already been hired between September 30, 2009 and July 31, 2010:

- One (1) analyst to assist with department workload, expanded business needs, and to provide continual workflow.

One (1) incremental FTE is still needed:

- One (1) budget analyst to assist with department workload, expanded business needs, and to provide continual workflow.

<u>Transmission Finance</u> – One (1) incremental FTE originally proposed by the Company.

One (1) incremental FTE has already been hired between September 30, 2009 and July 31, 2010:

- One (1) incremental FTE was filled to assist with additional workload driven by corporate, regulatory, and statutory financial reporting requirements.

<u>Regional Delivery</u> – Nine (9) incremental FTEs originally proposed by the Company.

Two (2) incremental FTEs have already been hired between September 30, 2009 and July 31, 2010:

- Two (2) Construction Administrators to oversee RDV work to ensure that they are following the pre-set arrangements determined by the contract.

One (1) incremental FTE is still needed:

- One (1) FTE to analyze, manage and optimize risk and administrative/ control compensate events.

Six (6) incremental FTEs are no longer needed:

- Six (6) in Regional Delivery were deemed unnecessary given the current workforce.

<u>Works Program Management</u> – Eleven (11) incremental FTEs originally proposed by the Company.

Eight (8) incremental FTEs have already been hired between September 30, 2009 and July 31, 2010:

- Seven (7) in Program Management to develop the capex schedule and milestone reports, evaluate and analyze schedule deliverability with workforce and PMs, and analyze the capital portfolio.
- One (1) in Quality Assurance to document and ensure procedures are being followed within various steps of a project's lifecycle, perform construction audits, write quality manuals/procedures, document work instructions and perform quality checks/audits and documentation.

One (1) incremental FTE is still needed:

- One (1) in Program Management to support opex and capex reporting requirements, develop the capex schedule and milestone reports, evaluate and analyze schedule deliverability with workforce and PMs, analyze capital portfolio, and fulfill financial reporting requirements.

Two (2) incremental FTEs are no longer needed:

- Two (2) in Program Management were deemed unnecessary given the current workforce.

<u>Transmission Project Manager</u> – Ten (10) incremental FTEs originally proposed by the Company.

One (1) incremental FTE is still needed:

- One (1) Project Manager is still needed to determine, plan, and manage capital projects.

Nine (9) incremental FTEs are no longer needed:

- Nine (9) FTEs in Project Management were deemed unnecessary given the current workforce.

System Delivery – Eighty-six (86) incremental FTEs originally proposed by the Company.

Seven (7) FTEs have already been hired between September 30, 2009 and July 31, 2010:

- Two (2) in Estimating to estimate and prepare Good Faith Estimates and work proposals for internal RDV projects due to increase in work loads/new work operating model.
- One (1) in Scheduling to produce and update the daily, weekly, and monthly rolling work plans in Primavera and other scheduling tools.
- One (1) in Transmission Line Services (TLS) to oversee Western Division construction and maintenance projects.
- One (1) in TLS Construction to complete the extensive amount of work expected in the Central Division.
- One (1) in System Delivery Construction to support forecasting, budgeting, and monitoring O&M and Capital spending.
- One (1) in Maintenance to oversee contractor work relating to the maintenance program.

Twenty-seven (27) FTEs are still needed:

- Eleven (11) electricians in Electrical Service Construction to support the expanding capital work plan.

- Fifteen (15) in TLS Construction to support the expanding capital work plan.
- One (1) in Maintenance to oversee contractor works relating to the maintenance program.

Fifty-two (52) FTEs are no longer needed:

- Twenty (20) FTEs in Electrical Service Construction were deemed unnecessary given the current workforce.
- Nine (9) managers in Substation Construction Services were deemed unnecessary given the current workforce.
- Two (2) in TLS were deemed unnecessary given the current workforce.
- Twenty-one (21) in TLS Construction were deemed unnecessary given the current workforce.

Q. What adjustment does the Company propose for this issue?

A. The Company proposes to reduce its incremental funding request from $3.067 million to $1.978 million. The reduced funding level reflects the Company's reduced incremental staffing needs, comprised of $1.214 million for employees already hired since the end of the historic test year, and $0.764 million for employees remaining to be hired. Exhibit __ (IOP-7R) includes additional information on the breakdown of costs and the proposed adjustment.

C. <u>RD&D</u>

Q. Does the Company agree with the Staff's recommended adjustments regarding the Research, Development and Demonstration ("RD&D") program?

A. No. Staff proposes to reject all incremental RD&D funding identified by the Company for the rate years, and also proposes incorrect accounting treatment for a $150,000 contract rescission payment received by the Company in the historic test year.

Q. What is the basis for Staff's proposed rejection of incremental RD&D funding?

A. Staff acknowledges that RD&D can provide financial benefits to customers. However, it says that in the existing economic conditions, incremental RD&D funding should be curbed. Staff also claims that the Company did not sufficiently demonstrate the benefits of the RD&D programs it identified in its filing.

The incremental funding for the RD&D programs identified in the filing are designed to produce customer benefits which will result in lower costs to customers, and the proposed funding levels should be approved. While the immediate savings is unknown for the projects contained in RD&D the resulting realized benefits are captured in future years and thus customers realize benefits when the cost of service is evaluated in future rate cases.

Rebuttal Testimony of Infrastructure and Operations Panel

Q. What effect would Staff's proposed adjustments have on the Company's ability to undertake electric system RD&D efforts?

A. The impact would be very significant. As an initial matter, it is important to recognize that the Company pays nearly $2.2 million of the $2.552 million base RD&D funding amount recommended by Staff to NYSERDA under its state assessment. This leaves only $0.352 million remaining for the Company to invest in other beneficial RD&D programs. At a time when elected officials and policy leaders are highlighting the historically inadequate level of research and development investment in the nation's electric utility infrastructure, such a minimal investment level seems counterintuitive. Indeed, even the spending levels proposed by the Company in the corrections and updates filing is far below the average research and development investment by utilities throughout the US and in New York.

In addition to being below the average level of utility RD&D spending, the funding level recommended by Staff would severely limit the Company's ability to leverage other available funding sources for the benefit of customers. The Company is working with its affiliates in pursuing applicable collaborative funding, and has submitted applications in response to solicitations of relevance issued by various external funders. Generally, all funding mechanisms available through external entities require co-funding by the participant. Both the DOE and NYSERDA funding mechanisms require co-funding. For example, NYSERDA programs often include a co-funding amount that is generally between 30 and 50 percent of total project costs. Availability of RD&D funds for co-funding will enhance the Company's ability to leverage additional funds for the benefit of customers, including potential federal funds to address New York State issues.

Q. How does the Company's RD&D program contribute to reduced customer costs?

A. In addition to providing technical evaluation and input to the asset strategy development process, there are opportunities to make specific improvements to projects that have multi-year time frames. An example of this would be the recent collaborative on elevated voltage, which is also a good example of these partnerships and leveraging. New York State utilities are required to perform regular elevated voltage testing to protect the public from unsafe conditions. Prior to the work of the collaborative, the equipment and methodology for utility testing has been proprietary and available through only one vendor. As a result utilities were unable to competitively bid this work. The desire to perform this work effectively and economically led to a collaborative between Niagara Mohawk, Consolidated Edison and EPRI, which has resulted in a new detection technology that is expected to become available in the public domain and is anticipated to significantly reduce future costs for all utilities. These cost reductions will be captured by future rate cases as the extent of the savings is known.

Q. What other ways might the RD&D program provide value to the customer?

Rebuttal Testimony of Infrastructure and Operations Panel

A. The RD&D program's investment in technology and innovation is valuable to the ratepayer in several ways. These include potentially reduced energy costs, and accelerated penetration of new technologies that require utility participation in the development, testing and evaluation stages. Some of these technologies that are identified in the proposed RD&D program include:

- Increased system reliability and power quality through the use of smart switches, and VAR support devices.
- Managing intermittent renewable generation, using, for example, energy storage; and,
- Reduced transportation energy costs by encouraging the acceptance of and understanding the impact of plug-in electric vehicles.

Q. Please describe the Company's position on Staff's recommended treatment of the $150,000 contract rescission payment received during the test year.

A. The Company disagrees with Staff's proposed treatment. First, Staff incorrectly characterizes the rescission payment as a royalty payment. As indicated in the Company's response to IR DPS-347 (RAV-122), the subject payment was for the rescission of a contract, not the liquidation of future royalties. Therefore, there is no basis for suggesting that the rescission amount should be amortized over a period of years as Staff proposes. Further, Staff's proposed treatment of this issue item as an adjustment to rate base (as shown on Exhibit __ (SAP-1), Schedule 6, page 4) appears to be an error. Staff's adjustment and proposed accounting treatment for this item should be rejected.

Rebuttal Testimony of Infrastructure and Operations Panel

Q. What is the Company's recommendation?

A. The Company recommends that the RD&D program be funded at the levels set forth in the May 3 corrections and updates testimony in order to best leverage our investments and help enhance our ability to modernize the energy infrastructure, and that Staff's recommended downward adjustment, and its proposed amortization of the $150,000 contract rescission payment, be rejected.

D. Tower Painting

Q. Do you agree with Staff's method for calculating tower painting costs per tower?

A. No. Staff's method of averaging the per unit cost of three prior years and escalating for inflation it is not applicable in this case.

Q. Please explain.

A. Staff's method would be reasonable provided there were no changes to the tower painting program. As described in our response to Question 2 of IR DPS-356 (VVP-18), a new painting procedure has been established to enhance worker safety. Improvements include not allowing work on the upper section of a structure unless the circuit is de-energized for a single circuit structure or at least one circuit is de-energized for a double circuit structure. In addition, painting activities on the top part of the structure will require qualified lineman in place of electrically unqualified laborers.

Rebuttal Testimony of Infrastructure and Operations Panel

Q. Does the Company have a contract in place that can be used to provide a firm cost for the program?

A. Despite the Company's determined efforts, we have not yet secured a qualified painting contractor that meets the updated requirements. However, preliminary pricing from a potential vendor indicated the new procedures may increase the cost of the tower painting program to $2,635 per tower for an 80 foot tall suspension tower which is considered the average size on the Niagara Mohawk system. Therefore, $952,219 should be added back to the Company's funding levels and the Staff's proposed adjustment reduced accordingly. This is shown in Exhibit __ (IOP-2R).

E. Infra-red and Aerial Patrol

Q. Does the Company accept Staff's adjustment for Activity TO1165 – Perform Aerial patrol – Non Fault?

A. Yes.

Q. Does the Company accept Staff's adjustment for Activity TO1166 – Perform Aerial patrol – Post Fault?

A. The Company has implemented this program in FY11 to provide more aggressive post fault patrolling in order to identify deficiencies that cannot be spotted from the ground. Items identified as having a high potential for causing a future fault are corrected thereby improving the availability of the transmission system.

Based on actual spending through the first four months of FY11 the Company anticipates an annual cost of approximately $321,000. Therefore, $221,000 should be added back to the Company's funding levels and the Staff's proposed adjustment reduced accordingly. This is shown in Exhibit __ (IOP-2R).

F. Transmission Footer Inspections

Q. Does the Company accept Staff's adjustment for transmission footer inspections and repairs?

A. Yes.

G. Incremental Distribution I&M Program

Q. Does the Company agree with Staff's recommendation not to implement fast feeder patrols and infrared inspections of pad mounted transformers and hand holes under the Distribution Inspection program?

A. Yes.

Q. In addition to complying with Safety Order, why does the Company feel a QA/QC program which audits 25% of the Inspection work identified and 25% of the work performed is necessary under the Distribution Inspection program?

A. The Company has forecasted budget levels of $135.5 million for Inspection and Maintenance of Distribution and sub-Transmission facilities. With this volume of capital, the Company feels that a comprehensive QA/QC program to audit the end-to-end process of the Inspection and Maintenance program is warranted to continually improve data quality, training requirements, and inspection criteria.

Q. What is the current QA/QC process?

A. Current audit of the Inspection and Maintenance program is conducted by an outside contractor to satisfy the requirements of the 2008 Safety Order to use a third party. A small sample size of work identified and completed in the field is audited. A more robust audit program that evaluates the entire Inspection and Maintenance process, from identification of the work through work order closeout, will offer opportunities to improve inspection data collection, streamline work flow, and more efficiently manage resources. The scope of this QA/QC process will include:

- Perform QA Inspection on 25% of the locations where Level 2 and Level 3 work is identified within 30 days of initial inspections.
  - Compare data gathered during initial inspections that was identified as Level 2 and Level 3 against QA inspections.
- Perform QA Inspection on 25% of inspection-generated, completed work orders.
  - Compare construction against work order ‘design.’
- Determine root causes of discrepancies found and report findings to management.
- Identify and track actions to completion

In other programs within the Company, both the Company and customers have benefited from a comprehensive QA/QC program in terms of improving overall quality of work and increasing accountability. These improvements have led to improved data accuracy for design which, in turn, reduces labor in the field due to a lower number of field corrections. This leads to more efficient use of resources since field labor accounts for the largest component in manhours within the program. In addition, audit of data collection results alone may result in reductions of identified work, identify training issues, and assist in further enhancement to the equipment inspection codes. In light of the potential efficiencies that may be realized by implementing a full QA/QC program, the Company recommends that Staff's proposed downward adjustment in the distribution inspection program be reduced by $1.2 million and the appropriate adjustments made to allow the enhanced QA/QC program to be implemented. The program would consist of hiring approximately 12 QA/QC inspectors to implement the program.

IV. Capital Investment Reconciliation Mechanism

Q. Could you respond to the Staff's recommendations regarding the Company's proposed Capital Investment Reconciliation Mechanism?

A. The Revenue Requirements Panel sets forth the Company's position on the Staff's recommended changes to the capital investment reconciliation mechanism.

V. Staff Vegetation Management Panel

Rebuttal Testimony of Infrastructure and Operations Panel

A. Transmission Vegetation Management

Q. Has the Company proposed a $12.1 million plan for the transmission vegetation management program including requests for incremental funding?

A. Yes, as outlined in the response to IR DPS-22 (DSM-1), the Company has proposed a comprehensive plan that includes right-of-way ("ROW") Integrated Vegetation Management floor maintenance with cycle pruning (Floor Trim), Danger Tree removal, Off-cycle work to address unplanned hazard tree removal, Sub-transmission widening program, treatment of substations, grass mowing and the 115kV ROW widening program.

Q. How many acres does the Company propose to floor trim during the rate years?

A. The Company plans to perform floor trim site maintenance on approximately 628 acres per year during the rate plan. This includes: 1) trim, prune, 2) cut, stump treat, chip, and 3) mechanical brush mowing. The average acreage amount is based on actual performance between the 2006 through 2009 as described in the response to Question A of IR DPS-23 (DSM-2).

Q. How did the Company derive an estimate of $935,000 for the activity of Floor Trim Sites?

A. In summary, an increase in the allocation for trim sites in the years subsequent to the historic test year is needed because our estimated floor trim acres for 2011 through 2013 are higher than the historic year, but closely reflect the average number of acres for the years 2006 through 2009.

Q. Can you address Staff's concerns related to when the floor trim site inventories will be completed?

A. As described in the response to Question A of IR DPS-23 (DSM-2) and Question 1 of IR DPS-88 (DSM-4), the Company maintains detailed site-by-site inventories for each transmission line right-of-way which are updated within the year prior to scheduled maintenance. These inventories are performed after the previous growing season ends and prior to the treatment of the right-of-way. Since the cycle length for the scheduled lines could be 4-8 years, changes in acres and treatment type are expected. Once the inventories are completed, the specifics of the work will be recorded in the Company's GIS System in early 2011, 2012, and 2013. In addition, accurate inventories are necessary when addressing landowner, environmental and aesthetic concerns for each right-of-way on a case by case basis to insure that the right-of-way remains in a condition that is reliable, manageable, as well as pleasing to the neighbors and community.

Q. Can the Company address Staff's concern that a list of potential 115kV circuits for widening is not available.

A. The Company has developed a list of 115kV circuits, plus alternates, that will be widened over a three year period and the list is provided in Exhibit__(IOP-8R). The 115 kV system has been prioritized and scheduled by right-of-way utilizing recorded outage history, Line Importance Factors, danger tree maintenance cycles, and recommendations by the Division Foresters.

This list reflects the lines chosen for work for each fiscal year as well as an alternate list. The widening program for each year will target the lines on the assigned list. Due to changes in priority, field conditions or other circumstances not identified at this time, the list will be updated annually, and each line on the list may not be able to receive the work intended. These lines will be replaced, first by lines from the following years' lists or the alternate list. Lines not identified on the yearly schedule may also be inserted if it becomes evident that work should proceed. The proposed work lists will be updated annually and be provided in the Company's annual vegetation management report to Staff. Statistics (miles, costs, etc.) on the work will be maintained and reported in the Company's annual report.

Q. Has the Company performed an inventory of the work that is required for the selected 115kV circuits?

A. No, as with the floor trim program, it is not practical to perform an inventory too far in advance of the actual work that will be performed in 2011, 2012 and 2013. Inventories will be performed during the year prior to scheduled work and after the growing cycle to capture accurate data about the work that needs to be done.

Q. Has the Company completed any 115kV ROW widening projects in the past?

A. Yes, the Company has widened the Ticonderoga-Republic and Gardenville-Homer Hill ROWs. The Ticonderoga-Republic ROW was reviewed by PSC Staff. It was our understanding that Staff generally acknowledged the need for the work and the manner in which it was executed. In fact, our experience with these circuits was used to develop the budget estimate for the program.

Q. What type of contracting arrangement will be used to complete the 115 kV widening work in the field?

A. The work will primarily be completed on an hourly basis based on the field walk down that will occur prior to initiating the work. In addition, to address Staff's concerns, the Company will assemble work packages for lump sum bidding on 17 of the 58 miles planned for fiscal year 2012. Work packages for lump sum bidding on approximately 30% of the lines will also be utilized in the remaining two rate years as a means to determine the effectiveness of lump sum bidding as compared to the hourly contracts.

Q. Can you address Staff's concerns related to the Sub Transmission (SubT) ROW Widening program?

A. The Company plans to widen approximately 140 miles of sub-transmission ROW's per year as part of its Transmission Vegetation Management program. Staff was provided a list of sub-transmission ROWs to be widened in Attachment 1 of DPS-444 (DSM-6). The previously provided attachment has been updated in Exhibit__(IOP-9R) to identify which circuits will be widened in rate years 2011, 2012, and 2013, as well as an alternate list. This list will be adjusted annually so as to include an updated list of the highest priority lines based on customers interrupted due to tree related events.

Q. Has the Company performed an inventory of work for each SubT line?

A. The Company will perform a comprehensive review of its property rights prior to performing widening activities on a specific sub-transmission line. If the Company has the appropriate rights to perform widening activities, then the work will be scheduled and performed. If there are a burdensome number of deed or other restrictions that preclude the Company from performing widening activities to desired specifications, another line will be selected from the list and reviewed.

Q. Does the Company agree with the Staff's proposed downward adjustment to the transmission vegetation management program, or the Staff's basis for proposing that adjustment?

A. No. Staff stated that Niagara Mohawk's recent four-year historical spending on transmission vegetation management program averaged $8 million, and it proposed a downward adjustment of $3 million from the Company's projected $12.1 million spending level. However, the Company's actual program expenditures for the period FY08, FY09, and FY10 have been $9.892 million, $9.919 million and $10.830 million, respectively, for an average of $10.214 million annually for the most recent three year period. Staff's proposed funding level would prevent the Company from performing all of the work it has historically performed. Additionally, it would not allow the Company to initiate the incremental programs described previously to maintain reliable service for our customers.

Q. What is the recommendation of the Company?

A. The Company recommends that Staff's proposed $3 million adjustment be rejected in order to maintain the number of acres treated during the floor trim program; maintain the current SubT ROW Widening program; implement the 115kV ROW Widening program to ensure reliability performance does not degrade on the 115kV system; and fund start up costs for a Habitat Conservation Plan ("HCP") in support of the Company's application to the U.S. Fish & Wildlife Service for an Incidental Take Permit ("ITP") under the Endangered Species Act (which is described in our initial testimony but not specifically addressed in Staff's comments).

B. Distribution Vegetation Management

Q. Do you agree with Staff's proposed downward adjustment to proposed distribution vegetation management funding?

A. No. First, Staff's proposed adjustment is based on an error due to the use of incomplete cost data in arriving at its estimated total cost for distribution cycle trimming. Staff also did not acknowledge or provide recovery for cost-effective incremental hazard tree and large limb removal work to be done on circuits scheduled for cycle trimming.

Rebuttal Testimony of Infrastructure and Operations Panel

Q. Please explain the data error you mentioned.

A. In its testimony, Staff states it used information provided by the Company in IR DPS-48 (CVB-4) to derive the annual cost for cycle pruning. In response to question 6D of IR DPS-48 (CVB-4), the Company provided a forecasted average cost of $3,303/mile for cycle pruning, and multiplied that per mile amount by the 7,200 miles the Company plans to prune annually to arrive at an annual amount of $23.7 million annually. Staff then compared this amount to the Company's proposed cycle trim funding amount of $28.9 million to arrive at a downward adjustment of $5.2 million.

Q. What is wrong with that analysis?

A. The average cost per mile information provided in response to IR DPS-48 (CVB-4) was the bare contractor cost for pruning: it did not include New York State sales tax or the cost of publications. The effect of sales tax adds approximately $2.0 million to the contractor cost. In addition, there are costs for printing publications and mailings utilized by the Company to notify customers of scheduled vegetation management activities in their neighborhood. This cost is approximately $300,000 per year. Therefore, the total cycle pruning cost is $26.0 million per year, as opposed to $23.7 million.

Q. Can you explain the remaining $2.9 million difference between the $26.0 million cost for pruning with sales tax and publication costs, and the Company's original request of $28.9 million?

A. The remaining $2.9 million relates to the Company's proposal to include incremental funds to expand the number of hazard tree and large limb removals on circuits scheduled for pruning. As described in our January 29th testimony on page 225 of 266, the incremental funds will be utilized to identify the highest risk trees for removal based on the same risk analysis protocol as the Enhanced Hazard Tree Mitigation (EHTM) program, also described in testimony.

Q. What is the purpose of addressing hazard tree removals during cycle pruning?

A. As described in our testimony, tree-related interruptions are the most significant driver in the Company's reliability performance. The Company proposes to include this level of funding in order to increase hazard tree removals done on cycle pruning. This work is expected to realize benefits which will help the Company efficiently maintain its level of reliability consistent with recent performance, recognizing that trees continue to be the single largest challenge. These additional removals focus on minimizing the frequency and damaging effect of large tree and limb failures on circuits undergoing cycle pruning.

Q. How is this different from the current EHTM program?

A. The current EHTM program addresses only those circuits with a specific need for extensive hazard tree removal independent of the cycle pruning program. This proposal takes the EHTM program, which has had success reducing tree related interruptions by up to 25% in the years following hazard removal, and combines it with the cycle pruning program to maintain reliability performance in a cost effective manner. It should be noted that feeders that are addressed under this program coincident with the cycle trimming cycle will address 20% of the system annually - due to the 5 year trim cycle. This increased hazard tree removal during cycle trimming is intended to realize benefits similar to the EHTM program as cost effectively as possible, and therefore the projected $2.9 million cost for this work should be added back to the Company's funding levels and the Staff's proposed adjustment rejected.

VI. Staff Reliability Performance Mechanism Panel

Q. Please summarize the Company's position regarding the Reliability Performance Mechanism presented in the testimony of Mr. Christian Bonvin of Staff.

A. Staff's testimony recommends rejecting the Company's proposed changes to the existing electric reliability performance mechanism ("RPM") regarding planned outages and the doubled penalty threshold, proposes additional changes to integrate the Company's interruption disturbance system ("IDS") reporting into the electric RPM, and proposes creating entirely new mechanisms to track the accuracy of the Company's capital project estimating and performance on implementation of generation standard interconnection requirements. The Company disagrees with Staff that doubled penalties are necessary in order to maintain the Company's focus on the delivery of reliable service. However, given the Company's agreement to Staff's proposal for a new 2-tier performance mechanism associated with the transition to IDS, as discussed below, the issue is not relevant. With respect to setting estimating performance criteria, we believe it is premature in light of the on-going efforts to implement management audit recommendations on this very issue; and with respect to interconnection performance criteria, we disagree that the Company's performance warrants the imposition of penalties; and if a performance mechanism is established, it should be done in a different, broader forum.

Q. What is the Company's position on Staff's proposed changes to the electric RPM to integrate the Company's IDS?

A. National Grid has used the Interruption and Disturbance System (IDS) database to capture, track, and report on the Company's reliability performance in parallel with Niagara Mohawk's legacy System Interruption Reporting (SIR-SQ) system for nearly four years. The SIR-SQ system is a manual, paper-based system that has been used to report reliability performance for over twenty years. Over the past several years, National Grid has worked with Staff to transition from the SIR-SQ system to the IDS application. The Company has continued to compare IDS against SIR-SQ to understand any differences in reliability reporting between the two systems, and this information has been shared with Staff.

In its initial direct testimony, the Company proposed to address the transition to IDS in a separate proceeding. However, the Company is willing to address transition to the IDS system in this proceeding as Staff proposes. It is the Company's position that transition to IDS should be done in a performance neutral manner such that the standards are neither tightened nor relaxed as a result of the transition.

Q. Why do the paper-based SIR-SQ system and the newer IDS application generally produce different results?

A. The use of the IDS system produces different results from the SIR-SQ based system because it captures all reported outage calls automatically and utilizes an algorithm which is representative of the overall electric system's connectivity to predict, based on the aggregation of all outage calls and the logic contained in the algorithm, the number of customers that are out. The SIR-SQ process relies upon field personnel in conjunction with operators in the control center to determine the number of customers affected by a particular outage. Therefore, in order to move from the SIR-SQ-based system to the IDS-based mechanism, it is necessary to modify the performance in order to maintain neutrality performance assessment.

Q. Are the standards proposed by Staff performance neutral?

A. No. For SAIFI (System Average Interruption Frequency Index), Staff proposes a two-tiered system with negative revenue adjustments of $3 million and $6 million for failure to achieve average SAIFI of 1.10 and 1.15, respectively. However, based on the Company's analysis, we maintain that an average SAIFI of 1.20 is needed for performance neutrality. A twenty-four month comparison of SIR-SQ and IDS between April 1, 2008 and March 31, 2010 shows a 29% difference between the two systems. Applying this 29% differential to the previous SAIFI target of 0.93 results in an adjusted, performance neutral SAIFI target of 1.20. Given that this is a transition period, the Company believes the two-tiered approach is reasonable, and using 1.20 as the average SAIFI target would result in performance tiers at 1.17 and 1.22 instead of the 1.10 and 1.15 proposed by Staff. Accordingly, the respective penalties for failing to meet the performance tiers would be $3 million (for SAIFI = 1.17) and $6 million (for SAIFI = 1.22).

For CAIDI (Customer Average Interruption Duration Index), Staff proposes a similar two-tiered system, with penalties of $3 million and $6 million for failure to meet system-wide CAIDI of 2.05 and 2.15, respectively. Similar to the discussion above with SAIFI, the analysis that was completed identifies that there should be a 1% increase in the CAIDI target to ensure that it is neutral. The SIR CAIDI target was 124.2 minutes or 2.07. An increase of 1% places the CAIDI at 2.09 which is within the upper and lower limits set forth by Staff's proposal and therefore the Company agrees with this proposal.

Q. What other performance mechanisms does Staff propose?

Rebuttal Testimony of Infrastructure and Operations Panel

A. Staff proposes adding new performance mechanisms for project estimating and generation interconnection performance with an aggregate penalty exposure of $7 million. The Company agrees with the elimination of momentary outage performance metrics and in principle with the establishment of performance criteria in the areas of project estimation and generation interconnection. However, the Company believes Staff's proposal is premature with respect to project estimating, in the wrong forum with respect to interconnection standards, and would significantly increase the Company's financial exposure compared to what is in place today.

Q. Please describe the Company's position regarding measuring project estimating performance.

A. The Company believes that the measurement of project estimating accuracy is both valuable and beneficial. However, it would be premature at this stage to specify the metrics upon which significant penalties could result. The Company has just completed the configuration of the estimating software package, along with related process steps, and will shortly begin processing new projects in the plan through the new software package. The Company has committed to the application of metrics to measure the accuracy of project estimating by September 30, 2010, as part of its Management Audit Implementation Plan. The metrics will take into account the experience we have gained in the development of the Estimating Center of Excellence (ECoE) and the implementation of the Success Enterprise estimating application. There are several key factors that will need to be taken into account before committing to one or more metrics, including how to incorporate the impact of influencing variables, such as external delays due to permitting, licensing, third party pole sets, property rights acquisition, delays driven by customer or governmental schedules, and the timing and impact of outsourcing decisions. Other considerations would be treatment of legacy projects, which were estimated using prior methods and tools.

The Company proposes that the final review and decisions for estimating metrics be undertaken after the Company completes development of estimating metrics under the Management Audit Implementation Plan. Subsequently, the Company will commit to working with DPS Staff to incorporate the appropriate metrics in the Quarterly Capex Report submitted to Staff. Accordingly, as experience is gained across a range of estimate amounts and types and estimating improvements are quantified through selected metrics, it may in the future be appropriate to consider a penalty/reward system to maintain a continued estimating focus and improvement. However, until we have experience using the new estimating processes and application, and measure their effectiveness through selected metrics, the adoption of a performance metric with potential financial penalties is premature.

If however, the Commission chooses to impose a penalty mechanism for estimating distribution and sub-transmission specific projects the tolerances for achieving the metric should be consistent with the maturity of the revised process.

If the metrics are simply unattainable the penalties are punitive and do not encourage or foster improvement. As noted above, there have been on-going improvements and changes to the existing process in an effort to provide consistent and accurate project estimates. Notwithstanding the recent and on-going improvements, the level of accuracy (plus or minus 10%) and the frequency (90% of the time) are simply not attainable given the maturity of the process. The Company would recommend that if a penalty is imposed despite the immaturity of the process that the accuracy be set at 25% and the frequency be set at 70%. Furthermore, final estimated costs should take into account agreed upon and authorized scope changes encountered during field construction. Lastly, the application of this penalty should be applied prospectively rather than retroactively thus ensuring that improvements in the process are being evaluated and include improvements made since the implementation of ECoE. Thus, if the mechanism were to be ordered by the Commission, the mechanism should apply to new specific projects approved after January 1, 2011.

Q. What does Staff propose with respect to generator interconnection performance metrics?

A. Staff proposes that two new performance metrics be applied to Niagara Mohawk relating to the standardized interconnection requirements and application process adopted by the Commission for distributed generators 2 MW or less that are connected to a utility's distribution system ("SIR-DG"). First, Staff proposes that Niagara Mohawk be held to a target of evaluating and responding to 95% of all applications under the SIR-DG within 10 business days for systems 25 kW or less (per Section IB of the SIR-DG) and 15 business days for those systems above 25 kW (per Section IC of the SIR-DG), with a negative revenue adjustment of $2 million if the Company fails to meet the target. Second, Staff proposes that the Company meet a target of installing 90% of net meters for systems 25 kW or less within ten business days of receiving a customer request (per Section IB of the SIR-DG), with a negative revenue adjustment of $2 million if the Company fails to meet the target.

Q. What reasons does Staff provide for seeking to implement these performance metrics?

A. Staff maintains that these performance metrics are appropriate because Niagara Mohawk has not complied with the rules set forth under the SIR-DG. Specifically, Staff states: 1) that Niagara Mohawk has not revised its bulletin advising customers regarding the distributed generation interconnection process to match the most recent version of the SIR-DG; 2) that Staff has received "frequent" complaints from customers and contractors regarding their dealings with the Company with respect to the SIR-DG process, particularly with respect to returning phone calls and following certain steps in the SIR-DG requirements; and 3) that the Company has not been installing net meters for systems 25 kW or less within the 10 day timeframe specified in the SIR-DG.

Rebuttal Testimony of Infrastructure and Operations Panel

Q. How do you respond to Staff's claim that Niagara Mohawk has not provided customers with accurate and up-to-date information regarding the SIR-DG process?

A. We disagree. Staff states that it obtained a copy of the Company's bulletin (ESB-756) from its web site which still lists the requirements in place prior to February 2009,[1] and furthermore, that the link provided by the Company in its response to IR DPS-588 (WEL-23) that requested a copy of its SIR-DG bulletin was simply a link to the same non-updated document. Staff, however, overlooks the fact that in addition to the base Electric System Bulletins documents, the Company also maintains errata and revisions documents for all of its ESBs, including ESB-756. In its response to DPS-588 (WEL-23), the Company provided a link to the relevant errata and revisions document for ESB-756. Page 9 of that document contains a notification regarding the updated SIR-DG and a link to the updated SIR-DG on the DPS website. Moreover, following the link for "Distributed Generation/Interconnection of Generators" on Niagara Mohawk's website leads to a page which refers specifically to the updated SIR-DG process, and contains a link to the February 11, 2010 version of the SIR-DG, which was the current version as of Company's response to DPS-588 (WEL-23).

Further, the PSC updated the SIR-DG information on their website on or about July 15, 2010. The Company promptly updated its link to the PSC website.

Finally, the Company is not aware of any customer complaints relating to its provision of information regarding the SIR-DG process. Thus, it appears Staff's

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[1] Staff's testimony refers to the revisions to the SIR-DG being made in February *2008*. We assume that Staff actually meant to reference February *2009*, which is the date that the set of revisions referred to by Staff were made to the SIR-DG.

belief that Niagara Mohawk is providing incorrect information to its customers regarding the SIR-DG process is based on an incomplete understanding of the facts, and is therefore wrong.

Q. How do you respond to Staff's statement that DPS has received "frequent " complaints from customers and contractors regarding their dealings with the Company with respect to the SIR-DG process?

A. With respect to complaints regarding not returning phone calls relating to distributed generation interconnections, it is difficult to address this statement fully, given that Staff has provided no specific information regarding such complaints. Regardless, Niagara Mohawk is committed to providing excellent service to all of its customers, and therefore takes such issues very seriously. Niagara Mohawk welcomes the opportunity to work with Staff and customers to resolve any such concerns. Indeed, the Company has promptly resolved any specific complaints that Staff had forwarded from customers. The Company also continues to update is interconnection inventory database on a regular basis as requested by Staff. However, it seems that Staff's primary concern revolves around following the process as set forth in the SIR-DG, given that Staff's proposed performance metrics would be based on the Company's compliance with that process, rather than on some level of customer complaints.

Rebuttal Testimony of Infrastructure and Operations Panel

Q. How do you respond to Staff's statement that Niagara Mohawk has not been installing net meters for systems 25 kW or less within the 10 business day timeframe specified in the SIR-DG.

A. Although Staff is correct that Niagara Mohawk has not always met the 10 day timeframe for installing net metering, it is important to place this information in the appropriate context. First, over the past two years, Niagara Mohawk has faced significant logistical and administrative challenges in meeting a greatly increased level of demand for net metering installations relating to distributed generation interconnections. This increased demand is driven largely by recent New York legislation promoting distribution-level interconnections, particularly for renewable resources such as solar photovoltaic systems. The original February 2000 SIR-DG addressed interconnections up to 300 kW. In 2004, legislation amended the upper limit of such interconnections to 2 MW. In 2009, peak demand limits on residential solar and wind service, farm service, and non-residential service customers were increased. In 2010, micro-combined heat and power ("CHP") and fuel cell electric generating systems were designated as generation eligible for net metering and, most significant to the increase in customer applications, removed the peak demand limit on non-residential solar and wind generating equipment.

As a direct result of these significant legislative changes, the Company received over 30% more applications in 2008 (184) as compared to 2007 (140). The acceleration of applications has continued with over 50% more applications received in 2009 (274) versus 2008 (184). Further, 2010 is proving to be another record year, with the Company already having received 242 applications through June. As Staff points out, more customers have requested interconnections and net metering arrangements under the SIR-DG in Niagara Mohawk's service territory than any other utility in the state. Given the increasingly high level of demand, and the revised SIR-DG requirements which provide less time for utilities to turn around metering requests, it is not surprising that Niagara Mohawk has faced the greatest challenge in meeting the demand for such services.

However, the Company has significantly improved its performance in meeting the 10 business day installation requirement by deploying additional trained personnel and improving its internal processes. In 2010 to date, only 10% of net meters were installed after the deadline, as compared to 34% in 2009 to 48% in 2008 and. Thus, during the last six months, the Company has, on average, been meeting Staff's proposed 90% target for net metering installations. This performance improvement reflects the challenge that the Company initially faced in implementing the SIR-DG requirements combined with the greatly increased level of demand for distributed generation interconnections, but shows that the Company is moving towards successfully meeting that challenge.

Q. Has Niagara Mohawk also improved its performance with respect to the 10 and 15 business day requirements for processing applications under the SIR-DG?

A. Yes. As with net metering installations, the internal process improvements implemented by Niagara Mohawk over the past several years have also led to substantially increased performance in processing applications received under the SIR-DG standards. This has culminated in the Company achieving the 95% target proposed by Staff for the month of July 2010, despite the ever-increasing number of applications that the Company is receiving.

Q. What is your recommendation regarding Staff's proposed performance metrics for distributed generation interconnections?

A. Given the information provided above, and in particular, the significant improvement that the Company shown with respect to its performance in processing distributed generation interconnection requests and installing net meters, the performance metrics proposed by Staff are not warranted. Moreover, putting aside the substantive merits of this issue, this proceeding is not the appropriate forum to consider such metrics. If Staff continues to believe that performance metrics are necessary for distributed generation interconnections, then the fairest and most efficient way to address Staff's concerns would be through a generic statewide process, rather than one focused on Niagara Mohawk specifically. Such a process would be consistent with the manner in which the SIR-DG requirements were adopted in the first place, and would have the advantage of encouraging the participation of all parties interested in this issue, which would presumably include utilities, customers contractors and system developers throughout the state, many of which are not parties to this particular rate proceeding.

VII. Storm Costs/Storm Fund

Q. Does the Company agree with the Staff Accounting Panel's recommendations and adjustments to the Company's proposal for funding for its storm response expenses?

A. No. The Company disagrees with Staff's characterization of the Company's efforts in responding to storms. We also disagree with the Staff's analysis of the Company's storm response costs, and Staff's recommended adjustments to the Company's proposed storm funding levels. While we address much of the basis for our disagreement, the Revenue Requirements Panel provides a detailed analysis of concerns with the derivation of Staff's proposed adjustment. The Company believes the proposal that was included in the filed case is correct in regards to treatment of storm costs.

Q. Why is the means and amount of storm response funding so critical to the Company?

A. It is very important not to lose sight of the purpose of the Company's storm funding proposal in the first place. Customers rely on Niagara Mohawk to restore their electric service as promptly as possible when it has been interrupted during a storm. The Company has no control over the timing, location or severity of storm events. The rate allowance and recovery mechanisms proposed in this case are intended to allow for recovery of the Company's costs to restore and maintain essential electric service for customers in response to storm events, and are based on the Company's actual historic costs.

Q. What is the purpose of and basis for the Company's storm response funding proposal?

A. Quite simply, the purpose of the Company's storm funding proposal is to provide for recovery of costs incurred in responding to storm events in order to restore service to customers and return the system to its pre-storm condition and configuration. The basis for the proposed funding level is the Company's actual historic storm-related costs.

Q. Has the Staff of the Department of Public Service advised the Company that it should scale back its storm response efforts?

A. We are not aware of Staff advocating that the Company's storm response activities should be scaled back; however, the positions and recommendations set forth in the Staff Accounting Panel's testimony, if adopted, would result in the Company being unable to recover its actual costs to restore service in response to storm events. We believe Staff's proposals are not well-founded, and contain three fundamental errors which make their conclusions incorrect and should therefore be rejected. The first two errors pertain to the fact that Staff's proposed $18.928 million rate year reduction effectively negates any recovery of incremental non-deferrable major storm costs and incremental minor storm costs. The third error relates to Staff's calculation of its proposed $9.219 million incremental major storm rate year allowance. Detailed analysis of these errors is included in the testimony of the Revenue Requirements Panel.

Q. Could you please address some of the Staff's statements regarding the Company's operational response to storm events?

A. Yes. Staff's testimony on the storm response funding issue is focused primarily on accounting and financial issues, and does not delve too deeply into operational issues. However, in several instances where Staff's testimony does address operational considerations, we do not find them to be accurate in all cases. For instance, the Company might incur costs for storm response activities up to six months after a major storm. In some cases, vegetation management activities and/or repairs to storm damaged equipment can take place months after customers have been restored following a major storm. As described in the response to IR DPS-41 (RAV-27), question I, "major storm related" costs would not generally be incurred more than 3-4 months from the end of the event restoration. However, in some extraordinary cases, costs can be incurred even later.

After a devastating major storm the Company typically conducts post-storm surveys to identify and subsequently repair damage to the system caused by the storm event. Such damage may not have been necessary to repair in order to immediately restore service, but still was caused by the storm. For example, the

December 2008 ice storm required follow up patrols and maintenance from January through March due to the extent of the severe damage incurred during the event. Experience in major events has provided insight into complete restoration requirements, which may require surveys, tree trimming, and construction/maintenance of facilities. It is also important to note that there is a difference between when costs are incurred and invoicing, which could differ greatly. For example, invoices for mutual assistance, reconciling and verifying invoices, etc., may be received long after actual incurrence of the costs reflected in the invoices. In any event, all deferred costs would still be subject to audit, and Commission approval.

Q. Why would such costs incurred months after a major storm be storm-related as opposed to normal maintenance work?

A. When the Company restores customers' service during a major storm, it often utilizes temporary repairs to expedite the restoration process. The Company will then follow up with permanent repairs to restore the integrity of the system. Although this work is not part of the effort to immediately restore service during the storm event, the repairs are a direct result of the storm event, and are not part of routine maintenance.

Q. Are these later-incurred storm repair costs accomplished at a lower cost than would otherwise be the case?

Rebuttal Testimony of Infrastructure and Operations Panel

A. Yes. When the Company is able to make non-emergency storm repairs to restore the system to its pre-storm integrity, it allows the work to be completed in a more efficient manner. In these cases, the permanent repairs may be completed after initial storm restoration, and can be done during normal work hours, with reduced overtime, thus lowering the overall costs as compared to completing the work during or immediately following the actual major storm.

Q. Does the Company utilize internal resources or its contracted work force to accomplish the permanent repairs?

A. In the past, the Company has utilized both internal and contracted work force to accomplish permanent repairs. Crews are assigned based on the workload at the time as well as customer and other work plan priorities.

Q. Do you agree with Staff's assertion that the Company would utilize contractors ahead of Company crews because the cost of contractors can be fully deferred during a major storm as opposed to the base labor of internal crews?

A. No, we strongly disagree. When an operating division is impacted by a storm, the Company's first priority is public safety and electric service restoration to customers. The Company will first utilize all available and qualified internal resources, as well contractors that are working locally, to begin the restoration process. Should an operating division require resources beyond this level, the System Storm Room will coordinate the efforts to provide a supplemental work force to assist with the storm. The System Storm Room's priority in these situations is to obtain the necessary or requested staffing as quickly as possible to meet customer expectations.

The first resource that is evaluated by the System Storm Room is available internal Company crews from other divisions. The next resource that is evaluated are available contractors who are working for the Company performing planned construction and maintenance work in other divisions. Should additional resources be necessary beyond these levels, the Company will then reach out to other utilities through the mutual aid process and contractors not on Company property when the storm originally occurred.

Contrary to the Staff's suggestion, the deferral mechanism does not enter in the staffing decisions made by the Company during a major storm. In fact, the preferred labor resource during any restoration effort are internal Company crews due to their inherent knowledge of Company standards, safety practices, clearance and control procedures, electric operating procedures and electric emergency procedures.

Q. What has the general response been to the Company's storm restoration efforts?

A. The Company has received positive feedback from government officials for its storm response in recent years. In fact, the Company was awarded the EEI

Emergency Response Award for its response to the December 2008 ice storm. In addition, the Company has integrated comments received from DPS Staff during post storm critiques into its Electric Emergency Procedures to enhance the overall process from the customer's perspective.

Q. How is the Company's storm funding proposal in this case structured?

A. The Company's proposal has two elements: (1) base rate recovery for storm costs that are not eligible for deferral; and (2) a reconciling storm fund for deferrable major storm costs. The first element provides for base rate recovery of costs for minor storms (not-deferrable) and major storms (not-deferrable), and is based on actual historic test year costs. The second element (i.e., the reconciling storm fund) is based on (and slightly below) the annual average of deferred major storm costs incurred by the Company over approximately the past five years. The rebuttal testimony of the Revenue Requirements Panel addresses several errors the Company found in examining the Staff's recommended adjustments to the Company's base rate allowance for storm costs. As described in the Revenue Requirements Panel's testimony, correcting the calculation errors demonstrates that Staff's recommended downward adjustment of $18.928 million to the storm base funding amount should be eliminated entirely.

In addition, while our panel addresses some of the reasons for creating a reconciling fund to cover the costs of responding to extraordinary storm events, the Revenue Requirements Panel discusses additional rationale justifying establishment of such a fund.

Q. Does the Company agree with Staff's proposal to eliminate the major storm deferral mechanism?

A. No. Major storms represent a significant source of costs for the Company. They are not predictable or controllable. Furthermore, the broad geographic range of the Company's system makes it particularly susceptible to impacts from severe weather events among utilities in the State. The major storm deferral mechanism provides a means for the Company to recover legitimate incremental costs it incurs in restoring service to customers in response to major storm events.

As Staff's testimony acknowledges, the existing deferral mechanism contains substantial annual and per-event deductible mechanisms to encourage the Company to aggressively manage its storm costs where it can control them. Eliminating the deferral mechanism would result in a considerable and unwarranted shift in the risks faced by the Company. Increasing the risk of non-recovery for costs the Company incurs to restore service to customers following a significant weather event is unreasonable and should be rejected.

Q. Is the Company asking to change the criteria of the allowable costs that are recoverable by the proposed Storm Fund as compared to the deferral mechanism that is in place presently?

A. No. The Company purposely used the same criteria for allowable costs recovered under the proposed Storm Fund that are presently in place under the deferral mechanism. The Company is not proposing to recover more funding than it does presently, but rather change the timing of that recovery through the proposed Storm Fund.

Q. Please comment on Staff's proposal that a "major storm" for deferral purposes be defined as an individual event with storm costs in excess of $20 million?

A. The Revenue Requirements Panel addresses this issue in greater detail. However, from an operational risk perspective, such a proposal creates substantially increased risk to the Company and should be rejected. Under that proposal, if the Company incurred expenses in responding to major storms that exceeded the Staff's proposed based rate allowance of $9.219 million, it would be unable to petition for deferral of any of those extraordinary costs except costs from a storm with $20 million or more in damage. Thus, if the Company incurred extraordinary storm costs of $60 million due to two $17 million storms, four $5 million storms and three $2 million storms, it would be precluded from seeking deferral treatment for more than $50 million in legitimate costs incurred to restore customers to service. Moreover, Staff's proposal would impose restrictions on the Company's ability to seek deferral treatment which would be significantly more stringent than exist under the Commission's general guidelines for deferral treatment. Therefore, the proposal should be rejected.

Q. What is the Company's position regarding the Staff's recommendation to eliminate the proposed major storm fund of $30 million from the Company's rate proposal?

A. The Company believes that establishment of a major storm fund is reasonable and appropriate and Staff's recommendation should be rejected. Whether you believe in climate change, or are a climate change skeptic, it is clear that media reports linking significant weather events to changing climate have increased. It is also clear that the frequency of significant weather events affecting the Company's service territory has also increased when compared to prior periods. The storm fund amount was calculated using actual major storm costs incurred over approximately the last five years. Given the Company's expansive service territory, which stretches from west of Buffalo to east of Albany and north to the Canadian border, its susceptibility to impacts from future severe weather events, which are beyond its ability to predict or control, is considerable. The fund would also be reconcilable. Therefore, to the extent actual costs are below the funding level, customers would be credited accordingly. Establishing a storm fund that would provide the Company with current recovery of the incremental costs associated with a major storm is reasonable and it should be approved.

Rebuttal Testimony of Infrastructure and Operations Panel

VIII. <u>Site Investigation and Remediation</u>

Q. Please respond to the Staff's proposed adjustments related to the Company's Site Investigation and Remediation ("SIR") program funding.

A. Staff proposed two adjustments to the Company's SIR program: (1) an adjustment to remove acquisition costs for two properties (Excelsior Avenue in Saratoga Springs, and Woodrow Avenue in Rome) that the Company acquired in order to perform SIR clean-up actions; and (2) an adjustment to remove the estimated cost of remediating those properties. However, these costs are appropriate for recovery through the SIR deferral, and Staff's proposed adjustments should not be made.

Q. Why would the Company need to acquire properties to effectuate its clean-up efforts under the SIR program?

A. The Company described the need to acquire non-utility properties in order to undertake its obligations under the SIR program in its response to IR DPS-130 (AAE-14). There, the Company explained:

> Pursuant to environmental laws and Orders on Consent with the NYS DEC and US EPA, Niagara Mohawk is required to address contamination associated with former utility operations, regardless of where the contamination is currently located. For example, former MGP plants operated by Niagara Mohawk and its predecessors operated

in a period spanning the 1840's to 1960's. The formerly owned properties were either sold after the plants were decommissioned or were converted to other utility use, such as gas regulator stations, operations centers, etc. Contamination from the plants may have migrated onto adjacent properties or water bodies; were transported to remote locations; and/or were deposited on other properties, or water bodies. Therefore, Niagara Mohawk is required to address contamination from the former MGP operations located on property owned by Niagara Mohawk (utility and non-utility property), as well as property not owned by Niagara Mohawk.

During the investigation of a property that is not owned by Niagara Mohawk, the property is initially evaluated (following soil and/or water sampling results) to determine if the current use can be maintained. The NYS DEC has generic concentration thresholds that are protective of industrial, commercial, restricted residential, and unrestricted residential use. If the sampling indicates that concentrations in excess of unrestricted use are attributable to former MGP operations, the future (or current) property use will need to be restricted. Property owners are often either unwilling to place deed restrictions on their property (as required by the NYS DEC in the event that impacted material will remain following remediation), or unable to, considering the current property use (i.e., existing residence). Since the Company has no legal power to enforce a deed restriction on an unwilling property owner, the Company must remediate the site to unrestricted use levels. In those situations, a purchase analysis is conducted to determine if it is cost effective to purchase the property from the owner, and remediate the site to a lower cleanup level (such as commercial or industrial), or to compensate the property owner (typically the property value) to maintain a deed restriction on the land.

Q. What adjustment does the Staff propose related to the Saratoga Springs and Rome properties?

A. The testimony of the Staff Accounting Panel provides that in response to IR DPS-130 (AAE-14), the Company provided some analysis to show that for eight of ten non-utility property purchases, the "reduction in remediation expenses associated with the purchase exceeded the cost of the purchase and ongoing remediation of the property." Staff Accounting Panel, p. 70, ll. 5-12. However, Staff noted that "for the Saratoga and Rome properties, no analysis was provided." Id., p. 70, ll. 12-13. Staff thus proposes downward adjustments of $1.003 million for the purchase of the Saratoga Springs property, $0.190 million for the purchase of the Rome property, and $0.119 million for the estimated costs to clean up these properties.

Q. Please explain the Company's basis for acquiring the Saratoga Springs property.

A. As summarized in the response to IR DPS-130 (AAE-14), the Saratoga Springs property was acquired in order to reduce the overall costs of environmental remediation associated with a former manufactured gas plant ("MGP") site in the area. Contaminants from the former MGP site had migrated onto an adjacent parcel, and Niagara Mohawk was obligated to remediate that parcel pursuant to a 1995 U.S. EPA Record of Decision. By acquiring the property, Niagara Mohawk was able to remediate the property to less stringent commercial clean-up standards, rather the more stringent residential standards, thereby reducing the net remediation costs by approximately $1 million from what they otherwise would have been had it not owned the property.

Q. Does the Company have an assessment of the benefits of acquiring the Saratoga Springs property?

A. Yes. Attached as Exhibit __ (IOP-10R) is a December 17, 2002 memorandum from William R. Jones to Alan J. Rabinowitz describing the basis for the acquisition. That memorandum details the specifics and justification for the purchase, and explains the basis for the Company's determination that the acquisition would reduce SIR deferral costs by $1 million.

Q. Why didn't the Company include a copy of the December 17, 2002 memorandum with the response to IR DPS-130 (AAE-14)?

A. Because many of the older files related to prior purchase of MGP properties are archived off-site, the Company was unable to locate and retrieve the memorandum in time to include with its initial response to DPS-130 (AAE-14). Nevertheless, the memorandum does clearly demonstrate the reasonableness of the purchase, and the savings that accrued as a result of the Company's actions. Although we acknowledge that providing the documentation sooner would have been preferable, it is clear that a cost/benefit analysis prepared around the time of the purchase does exist which clearly demonstrates that the Company's purchase action produced positive customer benefits. Under such circumstances, the Staff's proposed $1.003 million adjustment should be reversed.

Q. Please explain the Company's position regarding the Rome property.

A. The Woodrow Avenue property in Rome was part of former MGP operations in that area. Niagara Mohawk was obligated under the Order on Consent with the NYS DEC to clean up the contamination from the former MGP operations. The owner of the Rome property was unwilling to grant the Company access to the property to complete the remediation. Attempting to remediate contamination from a property without being allowed access to that property is extremely difficult, if not impossible, and is certainly not the most cost-effective way to remedy environmental contamination. Because the Company was under an obligation to remediate the contamination (including the contamination on the Woodrow Avenue property), and because the then-owner of the property would not grant access to the Company in order to perform the clean-up, the Company acquired the property in order to obtain access and complete the required remediation in a cost-effective manner. Because the $0.190 million purchase price for the Rome property was a necessary expenditure to enable Niagara Mohawk to undertake required clean-up efforts, Staff's proposed downward adjustment should be rejected.

Q. Did the Company provide a cost-benefit assessment for the acquisition of the Rome property?

A. As we mentioned previously, retrieval from off-site storage of historical documentation associated with many of the Company's legacy SIR sites is challenging. The Company was not able to locate a specific cost-benefit assessment for the Rome property. However, in its response to IR DPS 130 (AAE-14) the Company did provide a copy of a September 23, 1998 letter describing Niagara Mohawk's plans for remediation on the property. In the next to last paragraph in the letter, Niagara Mohawk's Director of Environmental Affairs noted that the property owner had expressed an interest in purchase of the property by Niagara Mohawk, and stated that Niagara Mohawk was "willing to consider it [purchasing the property] on the basis of achieving fair and reasonable economic and legal terms . . . ." Although the provided documentation is not a specific cost-benefit assessment, it does evidence the Company's objective of purchasing a property for remediation only if it was "fair and reasonabl[y] economic" to do so. Furthermore, the Company was under an obligation to remediate the site, and given the property owner's refusal to grant access to the parcel, such remediation would have been virtually impossible had the Company not purchased the property. Under these circumstances, the Staff's proposed downward adjustment of $0.190 million should be rejected.

Q. Could you please address the Staff's proposed adjustment to disallow the estimated costs to clean-up the Saratoga Springs and Rome properties you just discussed?

A. Yes. As we described, the Company's purchase of the Saratoga Springs and Rome properties produced benefits for customers (in the form of overall lower SIR deferrals) which outweighed the purchase prices of those properties. However, irrespective of whether the Company owned or did not own those properties, the relevant U.S. EPA and NYSDEC obligations required Niagara Mohawk to clean up those sites. In other words, the Company was under a regulatory requirement to remediate those properties regardless of their ownership. Therefore, it is irrelevant whether the Company purchased the two sites or not with respect to the clean-up obligations for those sites, and Staff's proposed adjustment to disallow $0.119 million of estimated clean-up costs for the Saratoga Spring and Rome properties should be rejected.

Q. Does the Company agree with Staff's recommendation that future actual SIR costs in excess of the base rate allowance be shared 80/20 between customers and the Company?

A. No. As an initial matter, such a proposal runs counter to the sound public policy objective of promoting cooperation between the Company and environmental agencies in the clean up of SIR sites. Imposing a risk of cost recovery on the Company would create a disincentive to the Company implementing clean up in the optimum manner as determined by NYS DEC and US EPA if the cost would exceed the amount allowed in rates. Further, it should be recognized that the Company's SIR obligations arise from the Company's legacy business operations. They do not pertain to the Company's current business of delivering electric and gas service. Imposing performance measures on a portion of the Company's activities that do not relate to its core business does not seem appropriate. These reasons alone would be sufficient to reject such a proposal.

The 80/20 sharing proposal should be discarded for other reasons as well. As we discussed in our initial direct testimony, the proposed SIR base rate allowance is based on the Company's projected actual spending to investigate and remediate contaminated sites. The timing to perform that work—and hence the associated spending profile—is dictated by a schedule controlled by the NYS DEC. Exhibit __ (IOP-12) presented with our direct testimony is the schedule of site remediation activities included in the NYS DEC Order on Consent. If work progresses in accordance with that schedule, spending will be substantially greater than the level proposed in rates. The projected annual spend provided in rates is an estimate of the average forecasted spend over the next three years. The average spend estimate is less than what would result under the schedule in Exhibit __ (IOP-12) because the Company's experience has been that project delays can extend the schedule, thereby reducing annual spending from what would be the case if the schedule were strictly implemented by the environmental agencies. Delays are typically the result of timing of regulatory approvals (NYS DEC and US EPA); timing of permits from local municipalities and the Army Corps of Engineers, where required; discovery of additional subsurface contamination; and property access issues. Thus, the Company's ability to manage the timing of its spending is extremely limited, and is largely in the hands of the State environmental regulatory agency. Inasmuch as the Company does not control the schedule of work which drives the spending, it would be inappropriate to impose increased risk on the Company tied to how it performs against the rate allowance. Under Staff's proposal, to the extent the timing of expenditures cause the Company to exceed the rate allowance in one year, the Company would be at risk for 20 percent of the difference; however, if the schedule resulted in an under spend in a year, the Company would receive zero percent of the difference. Such an unbalanced mechanism is unfair. The SIR provision is fully reconciling and should remain so, and Staff's proposed asymmetric sharing mechanism should be rejected.

IX. <u>Pace Energy and Climate Center and Natural Resources Defense Council</u>

Q. How does the Company respond to the comments and recommendations of the Pace Energy and Climate Center and Natural Resources Defense Council ("Pace/NRDC") regarding the Company's system planning processes?

A. Pace/NRDC's characterization of the Company's efforts to incorporate potential "Non-Wires Alternatives" ignores the obligation of the Company to provide safe, reliable service versus the obligations of customers, the efforts the Company has undertaken so far, the difficulty of implementing Non-Wires Alternatives (NWA) effectively as they continue to evolve, and the need to ascertain the ability of customers to provide demand-side options that maintain safe, reliable service on an ongoing basis.

Q. Please describe the different obligations of the Company and customers and its significance for evaluation and use of NWA.

A. The Company has an obligation to provide safe, reliable and reasonably priced service to all of its customers. Customers who may participate in any NWA project do not have this obligation. The objective of the NWA effort is to develop processes and tools that provide enough customer-side resources to allow reliable deferral of necessary investment while recognizing the differing obligations of Company and customers.

Q. Please describe how the Company is developing its capability to assess NWA?

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The Company has dedicated significant resources to investigating how NWA might be effectively incorporated into the system in a way that allows the Company to continue to provide safe and reliable service. About 18 months ago, the NWA Team was established to develop procedures for evaluating targeted demand-side measures as an alternative to transmission or distribution investments. The team was formed partially in response to regulatory and stakeholder interest in this issue, including the Commission's August 15, 2008 order (Case 06-M-0878) directing the Company to "investigate, consider, and evaluate all reasonable options for alternatives to T&D investment, including distributed generation and energy efficiency." The formation of the team also reflected the Company's abiding commitment to providing safe, reliable and reasonably priced service to all of its customers through use of the entire spectrum of energy resources. The Team members are the personnel actively involved in the planning for new investment to remedy load or reliability issues, along with members of Distributed Resources, Energy Efficiency, Regulation and Siting.

The Team has focused on two efforts: revisions to planning procedures to allow early consideration of NWA for identified needs, and development of an interim, informal mechanism for this evaluation to be used immediately. We describe some of the interim assessment of NWA for particular projects further below. Through this initial assessment work, members of the NWA Team have developed a better understanding of the data, process, staffing requirements, and tools needed to formally implement alternative assessments across the Company.

Based on this initial assessment work, the NWA Team is currently developing "Guidelines for Analysis and Implementation of Non-Wires Alternatives to Transmission and Distribution Investments." These guidelines will be informed by the preliminary assessment work undertaken over the last eighteen months, the pilot in Everett, Massachusetts mentioned in the Pace/NRDC testimony, earlier efforts to utilize NWA in pilots in the New England service area and Niagara Mohawk's experience in an earlier pilot to elicit demand-side alternatives in a Request-for Proposal process. It is also important to recognize that the evaluation of NWA is in its infancy for the Company, and the industry as a whole, which means that we have a lot to learn to optimally utilize NWA. Thus, we expect these guidelines to evolve as the Company's knowledge and capabilities improve with time and experience.

Q. What processes has the Company established to evaluate NWA?

A. As discussed in its response to IR JVN-4, the Company is developing for implementation a process whereby planning engineers request evaluation by the Distributed Resources group of the potential energy efficiency, distributed generation, and demand response alternatives to potential capital investments. The transmission or distribution planning engineers would provide information on the size and timing of the potential resource need, the locations where load reduction would be required, and the number of hours of load reduction per year that would be needed to allow the Company to provide reliable service to its customers without additional capital investments beyond what would normally be required under traditional methods. This information would allow the Distributed Resources group to assess the types of resources that might be deployed to address the resource need, and the likelihood that such resources would be available in sufficient quantity and at reasonable cost to maintain acceptable system reliability.

The NWA assessment would be performed in parallel with development of alternatives for major capital projects with a five-to-ten year planning horizon. After assessing the types of NWA, the Distribution Resources group would determine whether any NWA are available and would notify the transmission or distribution planners for their planning analysis. This would be consistent with the planning horizon that would be needed to effectively plan, procure, and implement a NWA to a capital project. Evaluation of NWA within planning studies would provide the opportunity for the Company to develop the best overall cost-effective opportunities for NWA to serve the need with enough time for marketing and enlisting customer resources to meet the need without risk to reliability. These are the aspirations for the assessment of NWA that the industry promotes. However, the Company and the industry require more experience with NWA and, with experience, these analyses will become significantly more sophisticated and successful.

As discussed above, the NWA Team has put in place an informal, interim process for assessing NWA to capital projects, and has used this analysis for certain transmission planning studies. The Company and its affiliates have undertaken similar assessments for a number of distribution projects. These efforts have helped the Company refine its analysis methodologies and understand its requirements for further improvement.

Q. Please describe the Company's efforts to assess NWA recently.

A. Over the last eighteen months, the Company and its affiliates have evaluated the potential for NWA to a number of major transmission projects throughout National Grid's US service territory. The Company used its informal, interim approach for these analyses. In New York, the Company evaluated the potential use of energy efficiency, demand response, and distributed generation resources as an alternative to the proposed construction of its new 115 kV Spier Falls-Rotterdam transmission circuit and Turner Road substation. This analysis, documented in Exhibit 3 to the Company's Article VII filing for the Spier-Rotterdam project, explicitly took into account the increased levels of energy efficiency investments required by the Commission's EEPS (Energy Efficiency Portfolio Standards) Order, as well as assumed aggressive pursuit of energy efficiency by NYSERDA in support of the State's "15 by 15" goal. It nonetheless concluded that, given the magnitude of the area resource need and the relatively short lead time, it would have been inappropriate to rely on energy efficiency, demand response, and distributed generation as an alternative to the Spier-Rotterdam project.

Q. Does Pace/NRDC describe the Company's use of increased energy efficiency levels in the Company's forecast correctly?

A. No. Pace/NRDC asserts that the Company is not taking into account the increased levels of energy efficiency investments required by the Commission's EEPS Order in its planning process. Pace/NRDC notes on page 14 of its testimony that the Company's response to IR NM 944 (JVN-22) indicates that load forecasts developed by the Company since the rate case filing have been adjusted to reflect enhanced efficiency savings from NSYERDA and Company-sponsored programs approved by the Commission under the EEPS proceeding. These load forecasts were not available for use in the rate case filing because final Orders from the Commission establishing EEPS savings amounts were not yet available. However, the adjusted load forecasts ***are*** currently being used for system planning, as stated in the Company's response to IR NM 944 (JVN- 22), and by the NWA cross-functional team. Pace/NRDC's assumption that "the impact of the higher energy efficiency investments stimulated by the 15 by 15 (EEPS proceeding) target is *not* being taken into account as a non-wires alternative to the cross-functional team" therefore is incorrect.

Q. Please summarize what National Grid has learned over the last 18 months regarding assessment of NWA.

A. While the Company has made substantial progress over the past eighteen months, there is significant work left to accomplish in the areas of tool development, NWA cost estimation and the development of practical business models for targeting distributed generation, direct load control, and demand response in specific geographic areas. Of specific importance to this proceeding, the Company needs tools that would enable it to have detailed market intelligence with regard to its customer's loads, allowing the Company to easily link customers fed from specific circuits with their capability to utilize NWA and what type. This would allow the company to estimate costs, development cycle times, customer acceptance rates, and potential reductions from various NWA components such as targeted energy efficiency, targeted demand response, direct load control, and distributed generation deployments from specific customer groups. The NWA Team planned to request the ability to conduct pilot studies on certain projects to further develop its knowledge in these areas before recommending more permanent solutions. Experience will help design a better framework for any further development of system capabilities and tools.

Q. Please comment on Pace/NRDC's recommendation that in future proceedings, the Company be required to "demonstrate that it evaluated Non-Wires Alternatives as a means of deferring or avoiding T&D investment as an element of its *prima facie* case for recovery of T&D costs."

A. We generally agree that the Company should consider reasonable alternatives available to it when evaluating a system investment. However, the state of knowledge on the use of NWA to traditional utility investment is not sufficiently developed such that it would be reasonable to impose such a requirement. Utilities all over the country are just beginning to wrestle with how best to

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incorporate NWA into their planning. A good reference on where the industry is with regards to NWA is a document dated September 2009 prepared by the National Council on Electricity Policy titled *'Updating the Electric Grid: An Introduction to Non-Transmission Alternatives for Policymakers,'* a copy of which is attached as Exhibit __ (IOP-11R). In Section 3 of this document, examples of NWA analysis by utilities were found in CT, ME, VT, and the Pacific Northwest. Referring to those examples, the report states: "Each of these approaches is new and very little in the way of actual non-Transmission projects have resulted from these efforts as of yet."

Challenging issues must be understood and considered in NWA analyses. Some examples of issues include the degree of utility control over customer facilities, ability to hedge capabilities through diversifying customer response, whether customer performance can be mandated (or made firm), and utility ownership of generation, among others, remain to be resolved. The timeline for analysis of NWA must allow enough time for customers to elect participation while anticipating the long lead times needed to design, permit, and construct traditional infrastructure. If NWA are chosen and work has begun to prepare the wires investment, the recovery of both costs will require consideration and resolution. In addition, the issue of how targeted energy efficiency, demand response, direct load control, and costs of distributed generation activities are recovered, and the rate design changes needed to recover the costs for such activities, also need to be addressed. The evaluation of NWA itself is an admirable goal but the intent is to implement NWA when and where economic. Resolution of these issues through experience and regulatory processes will guide the success or failure of this effort.

Moreover, to the extent that Pace/NRDC is suggesting that the PSC should require the Company to explicitly evaluate NWA to each and every transmission and distribution investment as a condition of cost recovery, the Company respectfully disagrees. Even after the challenging issues outlined above are resolved, NWA must be matched to the characteristics of the need. Generally, investments driven by asset condition or statutory/regulatory drivers typically are not appropriate candidates for NWA because they are generally addressing specific issues many of which do not lend themselves to NWA opportunities. Certain projects driven by contingency loss of supply are also not appropriate candidates for any NWA that is not always deployed. Small-to-medium scale projects may prove more amenable to non-wires solutions than larger-scale or very small projects. Our customers will receive the best value when we are able to focus our analysis of targeted energy efficiency, distributed generation, and demand response on those types of needs, or geographic areas, where we are most likely to find cost-effective opportunities. In short, while the Company shares the desire of Pace/NRDC to move to a world where NWA play an increasing role in utility investment plans, a great deal of analysis remains to be done. Therefore, the Company believes a requirement to include evaluations of NWA as a condition to recovery of all infrastructure investment costs is not appropriate.

Q. What is the Company's position on Pace/NRDC's recommendation that the Company undertake a pilot program to investigate use of Non-Wires Alternatives as a means of avoiding or deferring T&D investment?

A. The Company would support such a pilot program. As stated above, the NWA Team intended to propose a Pilot opportunity to evaluate NWA and further develop our capabilities. Also, the Company has experiences with NWA pilots throughout its service territory. Indeed, doing such a pilot program would seem to be a logical precursor to any steps to implement NWA more broadly, and certainly should precede any effort to impose non-wires alternative evaluations in rate case filings as a prerequisite to the recovery of infrastructure investment costs.

The pilot program mentioned by Pace/NRDC in their testimony was implemented by Niagara Mohawk's Massachusetts affiliate. That pilot program was funded by the Massachusetts Technology Collaborative, and was aimed at evaluating the potential use of renewable energy resources to reduce loading on the distribution system in a limited and focused area. The Company would be amenable to implementing a pilot program in its service territory to advance its knowledge on this issue further, subject to identifying a suitable location for study, and subject to receiving cost recovery.

Q. Does this conclude your testimony?

A. Yes.

BY MR. GAVILONDO:
Q Panel, you described a correction to an exhibit. Has the panel prepared and sponsored exhibits as part of this pre-filed rebuttal testimony?
A (Smith) Yes, our pre-filed rebuttal testimony sponsored 12 exhibits.
Q Were those exhibits prepared by you or under your direction?
A (Smith) Yes, they were.

MR. GAVILONDO: Your Honor, I believe Exhibit Numbers 100 through 111 have been reserved for the exhibits to the pre-filed rebuttal testimony of this panel.

ALJ BOUTEILLER: We will use those numbers for purposes of identifying and including in the record the exhibits associated with the panel's rebuttal testimony.

MR. GAVILONDO: Thank you, Your Honor. Your Honor, I'd just like to indicate that a corrected version of the testimony will be provided electronically to the reporter and also corrected versions of the exhibit appear on the Bench with your copies of exhibits, and I do have corrected copies of the exhibit to provide to any parties that would like a corrected version. And with that, Your Honor, I tender the panel for cross-examination.

ALJ BOUTEILLER: Okay, very good. Can you hear me from here? I don't know if this microphone is working. It's not quite as loud as the other ones, so I'll try to compensate for that.

Before we turn to any cross-examiners, I provided you with a sheet with questions that were prepared by my colleague, Judge Stegemoeller, and I'd like to run through those questions with you and that way we can have something for the Judge when he returns to the proceeding and we can move things along from his perspective.

The first question that he had for you is a question which asks as a general matter how does the capital planning for the lines of businesses result in a capital budget for each of the individual company affiliates? Can you respond to that question?

MS. SMITH: Yes, we can, Judge. The plan that is developed begins with a ground level view up by jurisdiction. So in the example of Niagara Mohawk we begin with a condition asset study that's done every year, and we use that study as a basis for our annual work plan and then the budget that goes along with that. Mr. Walker, do you have anything to add?

MR. WALKER: I would add that with that bottoms-up approach what we do is we go and work with the various components of the businesses to identify the needs based on the system, and a large part of that is actually informed by the asset condition report, as well as other evaluations on the system, whether there are systems study on the transmission system or distribution studies on the distribution system. And fundamentally those areas are grouped into five categories, which are basically the categories that we utilize to capture the necessary work to meet the service requirements that we have. And they are comprised of the statutory regulatory work, damage failure, system capacity and performance, and then asset condition, as well as non-infrastructure. And we evaluate each one of those areas based on the needs. So much of what is done on an annual basis is well-known because approximately 40 to 50 percent on an investment basis of the work is in the statutory regulatory work. And, historically, that tends to be similar year on year.

ALJ BOUTEILLER: Okay. Is that your total answer to the question?

MS. SMITH: Yes.

ALJ BOUTEILLER: Since you parsed it out, I just want to make sure I'm getting all the pieces.

MS. SMITH: Yes, it is.

ALJ BOUTEILLER: As we understand it, you have a global risk scoring tool that's employed for purposes of funding and financing and going forward with these projects. Are projects competing across the entire line of business for the same pot of money, or is there a separate budget target established for each affiliated company? Can you respond to that question or those two questions?

MR. WALKER: Sure. I'll respond to that. The global risk tool is not done across lines of business. It's done on an affiliate basis. And again, with that ground-up approach with identifying all of the work, we basically identify, using those five categories that I outlined earlier, identify the necessary work in there, and then we use the global risk tool to basically prioritize them and each one of those categories. But when we're doing that, we do not look across the state affiliations, so we look at NiMo's very differently than we look at Massachusetts and New Hampshire and Rhode Island.

ALJ BOUTEILLER: Would you say you fully fund each affiliate or each operating company and they're not competing with one another?

MR. WALKER: They are not competing with each other. The merits of the work within the investment plan stand on their own, and they're compared on a like basis using the risk scoring tool that we have.

ALJ BOUTEILLER: Okay. The next question asks about the amount of alteration modification, the fluid nature of the change of your capital plans. When such things occur -- and I guess you call these things walk-ins and walk-outs -- how does that affect the budgets and the funding for the company-specific plans? Is that done as an exercise on the whole line of business, or is that accommodated by each individual company?

MR. WALKER: So building on the last answer, the -- because we do the evaluation on a state basis or affiliate basis, the evaluation of the walk-ins and walk-outs are therefore done on a state-by-state basis. So, again, as we develop the actual investment levels necessary for each state, we use that risk scoring tool. And when work is identified as being necessary, it means that we utilize the risk scoring tool and identify that a walk-in outranks a necessary or another job that's in the cue, and we would walk out that corresponding job in order to fund it. So the risk tool is used essentially to be able to help us prioritize and optimize our investment, but it is done on an affiliate basis. And the walk-in/walk-out process relies upon the veracity of the risk scoring tool in order to prioritize the work.

ALJ BOUTEILLER: So as a follow-up, if there was a walk-in, if I'm understanding the terminology correctly, in Massachusetts, that would not affect any of the work to be done in the Niagara Mohawk Electric service area?

MR. WALTERS: Absolutely not.

MS. SMITH: That's correct.

ALJ BOUTEILLER: Thank you for your answer.

In this area one final question. The question really is what's the relationship between the rate base that we will establish in this case and the actual spending behaviors and performance by the company within the service territory? Are the two related or correlated? How do you appreciate or understand the relationship between the established rate base and your project financing activity as it occurs in reality?

MR. WALKER: Again, when we build the

budget, we develop it and base it upon the needs of the system. And the needs of the system are then utilized to determine which work moves forward.

One of the things that we proposed in this case was a two-way capital tracker such that we define the needs of the system such that we meet our safety and reliability goals and requirements. The two-way capital tracker that we propose with the 10 percent up and an unlimited down mechanism was really meant to account for those type of things, because when a certain rate base is identified through the rate case, that's just one component that is evaluated as we develop the overall budgets for the system. But that is done on a financial basis, not on the needs of the system basis.

ALJ BOUTEILLER: Okay. I think I understood your response.

I'd like to turn to a different topic at this point, a matter that did come up in discovery and the judges were a little bit familiar with it, the regional delivery venture. Is this panel the appropriate panel to ask about that?

MS. SMITH: Yes, it is.

ALJ BOUTEILLER: We understand from our review, I guess, of the testimony and from the discovery that the company is going to reexamine or take a look at this convention or this device for purposes of letting some of the work. Will the -- I'll call it the regional delivery venture, will it remain in place pending this further review of the process?

MR. GAVILONDO: Your Honor, if I may interject, and I apologize for not mentioning this earlier, it's been in front of me for the last several weeks, so much so that it's blinded me, but the company, the staff and other parties have reached an agreement in principle on a number of CAPX and OPEX related matters that are raised in the IOP panel's testimony.

ALJ BOUTEILLER: Is this one of them?

MR. GAVILONDO: This is one of them. The agreement has not yet been executed but we have nevertheless reached an agreement in principle. The challenge is because it's the result of the settlement and it's not been finalized, I believe we can disclose what the terms of that settlement is in this proceeding, and I just wanted to bring that to your attention. I believe that will -- the intent of the agreement in principle is to effect the going forward operation of the regional delivery venture.

ALJ BOUTEILLER: Let's give the panel then a pass on that question as long as you remember that when we deal with settlements and stipulations in this case, I assume Judge Stegemoeller will be with us at that time, and if we can at least -- Counsel, if you can be well enough versed on that matter to be able to address any questions or inquiries that he might have, either at the level that I've disclosed to you currently or at a further level, I think that might be sufficient.

MR. GAVILONDO: Okay. Yes, Your Honor.

ALJ BOUTEILLER: We can skip that topic. The other topic, last remaining topic is one that maybe there's another stipulation, I don't know, transmission project management, is that a matter that I can inquire of this panel about?

MR. McAFEE: Yes.

ALJ BOUTEILLER: Okay. We recognized from looking at your testimony that you have an ambitious plan to proceed with capital projects in the future. We're also aware of the additional personnel that you're planning to add. As we understand it it's only one additional person. Given the amount of volume of activity that you have planned and only the limited amount of additional workers for this area, do you believe that the quality of your work or the cost control of this program would be jeopardized in any way by the aggressiveness of your behaviors or your plans versus the known level of staffing that you're contemplating?

MR. McAFEE: We do not believe that anything would be put in jeopardy. There's three component parts to our decision-making on this topic. First is our proposed transmission capital budget has seen some reductions in its present form. Second is through the T&D organizational realignment, which we have recently completed, the project managers report to one organization, no longer two, and those individuals report up through Ellen Smith's organization, and there's benefits to that combination. And, thirdly, we also use contracted project managers to supplement our internal work force. Presently we have ten internal project managers and five experienced contractors who provide those services, and we believe based on our present budget and plans that this is adequate. We will continue to reevaluate going forward.

ALJ BOUTEILLER: Okay. Thank you very much. Those are the questions I have from here. If there's any need for follow-up, you will hear from us in the future, but otherwise, at this time I'd like to turn to the cross-examiners for today. And again we'll begin with staff.

MR. GAVILONDO: Your Honor -- I'm sorry to interject.

MR. LECAKES: That's okay.

ALJ BOUTEILLER: They were available. They're not available any more?

MR. GAVILONDO: Number one, I appreciate everybody staying after to put the panel on today because it's just better. I have to drive back to Syracuse, and if I had to come back tomorrow morning --

ALJ BOUTEILLER: Let's go off the record. We don't need that on the record.

(Discussion off the record.)

ALJ BOUTEILLER: While we were off the record we anticipated the degree to which this panel will be cross-examined today. I understand that there is some cross-examination for the panel today, is that correct?

MR. LECAKES: Yes, Your Honor.

ALJ BOUTEILLER: We'll proceed with that. I understand as well that there is continuing discussion to simplify the issues and enter into stipulations covering some of the subject matter of your testimony. We encourage that. We welcome that. My colleague is a great proponent of those sorts of efforts, and we would want to cooperate with them to the maximum degree possible without compromising the remainder of the process and the integrity of the events as they were to occur. So you will remain subject to recall, and I won't excuse you at the end of today. However, if the stipulation process works out, you won't be called back. If it doesn't work out, then we would expect to see you revisiting us possibly next week sometime, and that's the contingency for which we will be planning.

So with all of that on the record -- that was what we discussed while we were off the record -- let's turn to staff counsel who will engage in some cross-examination of you today.

MR. LECAKES: Thank you very much, Your Honor.

CROSS-EXAMINATION

BY MR. LECAKES:

Q Panel, the questions that I'm going to ask you are going to be limited to your reply testimony or your rebuttal testimony. And, basically, there's two areas that I want to get into. The first is a little bit shorter than the second. The first deals with Luther Forest. Your discussion in your rebuttal testimony appears on pages 79 to 81. Starting with page 80 of your rebuttal testimony, lines 11 and 12, there you state that "The revised estimated cost of the Luther Forest transmission facilities is approximately $37 million," is that correct?

A (Smith) Yes, it is.

Q And also on page 80, on lines 17 to 19, you state that "The Luther Forest Technology Campus Economic Development Corporation, the LFTCEDC, and the company have previously discussed that once completed the facilities that are being built there would be transferred to the company for $1, isn't that correct?

A (Smith) That's correct.

Q If I understand your testimony correctly, then, that indicates that there are no financial transactions that will take place until the facilities are fully completed, correct?

A (Smith) That's right.

Q Is there a signed contract yet for the $1 transaction?

A (Smith) No, there's not.

Q What is the projected in-service day for the fully completed Luther Forest facilities?

A (Smith) At this time it's not determined.
Q As far as you're concerned or as you know, will that projected in-service date be after January 1, 2011?
A (Smith) The in-service date is expected to be before that.
Q For the full completion of the facilities?
A (Smith) Yes.
Q On page 80, still, on lines 9 through 12, you state that the transfer of the facilities will occur in stages as construction is completed at Luther Forest, isn't that correct?
A (Smith) That's right.
Q What are the estimated dates of each such stage of completed construction being transferred over to the company?
A (Smith) The first phase of the transfer of assets was supposed to happen in the last week. It was held up due to a commercial issue that Luther Forest had. We began some work on energization, and we've now stopped work pending their resolution of their issue.
Q So the first phase was supposed to be completed and transferred over to the company within the last week, correct?
A (Smith) That's right.
Q And that did not happen?

A (Smith) No, it did not.
Q How many other phases are there supposed to be before final facility completion, if you know?
A (Smith) I don't know. We can take a request for that.
Q If you could provide that information to staff, we would appreciate that.
Following up on that, when is the next phase supposed to be completed and transferred over to the company after the one that was targeted for this past week?
A (Smith) The one that was targeted for the past week is a significant milestone. It's the biggest piece of it. And we'll follow up with the request for the date for the second piece --
Q Okay.
A (Smith) -- or any follow-up work that is intended.
Q Okay. Are there more than two phases to this?
A (Smith) Not to my knowledge.
Q How much of the estimated $37 million total project costs or total project projected amount of facilities will be transferred over to Niagara Mohawk Power Corporation at each stage?
A (Smith) That was the amount that was intended to be transferred in the last week or so. And that will be the amount that would be transferred once this issue that

Luther Forest has is resolved. There may be some remaining small pieces of work after that, but we'll get back to you with those details.

ALJ BOUTEILLER: Just for clarity on the record, you're indicating that the $37 million spoken about in the testimony would have been the amount with your Phase I?

MS. SMITH: That's right.

ALJ BOUTEILLER: Thank you.

Please proceed.

BY MR. LECAKES:

Q I apologize in advance because I don't have a citation offhand. We can look one up if you need it, but staff's understanding as we sit here right now is that in the original testimony of the Infrastructure & Operations Panel the target date was sometime in 2012 for Luther Forest. Does that ring any bells?

A (Smith) Yes, it does.

Q Okay. Was there some sort of project acceleration that would now have that project being completed before that date?

A (Smith) Yes. They drove the acceleration through their accelerated construction and infrastructure needs with their project.

Q Okay. I'm going to now turn to storm costs, and that section begins on page 139 of your rebuttal testimony. Actually, my first question is going to rely on pages -- page 146. There on page 146 of your rebuttal testimony at lines 16 to 17, the panel states that "eliminating the storm deferral mechanism that's in place currently would result in a considerable and an unwarranted shift in the risks faced by the company." Isn't that correct?

A (McAfee) That's correct. That's what's stated.

Q Okay. On the previous page, 145, lines 7 and 8, you state that the company's storm funding proposal has two elements, isn't that correct?

A (McAfee) Yes, that's correct.

Q And the first element that the panel refers to is base rate recovery of storm costs not eligible for deferral. Is that correct?

A (McAfee) Yes, that's correct.

Q Please explain what you mean by "base rate recovery of storm costs not being eligible for deferral."

A (McAfee) In order to follow and answer this question, I would like to introduce three IRs that the company responded to, IR RAV 157, RAV 158 and RAV 160 into the record, please.

ALJ BOUTEILLER: You've referred to them. I don't know if they're included in the record. Counsel can assist us. Have we had these marked for inclusion in the record yet?

MR. GAVILONDO: Your Honor, it's my understanding that RAV 157 was included in the book that staff introduced into the record this morning.

ALJ BOUTEILLER: Okay.

MR. GAVILONDO: It is identified as DPS 613.

MR. LECAKES: It's Exhibit 326 on the reserved list.

MR. GAVILONDO: And, Your Honor, I do have copies of the other two Information Requests which Mr. McAfee referred to, and I can provide them to the Bench and a copy to staff as well, and we can reserve new exhibit numbers for those.

ALJ BOUTEILLER: If they're not included in anything that's been provided previously, either for this morning or from Multiple Intervenors or from staff's other documents with Interrogatory Responses, then I'm amenable to including the ones that have not been previously identified.

MR. LECAKES: I don't believe that either of those have been introduced yet.

ALJ BOUTEILLER: Do we want two numbers or one number?

MR. GAVILONDO: Your Honor, it's whatever the Bench prefers, two numbers or one number.

ALJ BOUTEILLER: We'll give you the benefit of two numbers.

MR. GAVILONDO: Thank you.

ALJ BOUTEILLER: 332 would be used for -- and you'll provide the company's response to staff interrogatory request preliminarily identified as RAV 158, and Exhibit Number 333 will be used for the staff inquiry and the company's response to RAV 160.

MR. GAVILONDO: Your Honor, I have one copy for the Bench at this time. I will get additional copies made.

ALJ BOUTEILLER: Okay, we appreciate that.

(Exhibit No. 332 and 333 were marked for identification.)

MR. GOODMAN: Do you have other copies?

MR. GAVILONDO: I do. Actually, Your Honor, I have an additional copy for the Bench.

ALJ BOUTEILLER: Do you have one for Multiple Intervenors?

MR. GAVILONDO: I do have one for Multiple Intervenors. I leave one for myself.

ALJ BOUTEILLER: Keep one. Just give one to Multiple Intervenors. You can cover me tomorrow or next week.

MR. GAVILONDO: Okay.

ALJ BOUTEILLER: Do you have one for yourself? Take one back, please.

MR. GAVILONDO: Okay.

ALJ BOUTEILLER: Make sure Multiple Intervenors have one.

MR. GOODMAN: Thank you, Your Honor.

ALJ BOUTEILLER: There's an outstanding question. You preliminarily indicated that your response would make reference to these interrogatories. Are you responding that everything that the question called for would be contained in your answers to these Information Requests?

MR. McAFEE: Actually, sir, I'd like to reference parts of the Information Request in my response.

ALJ BOUTEILLER: Please proceed, then.

MR. McAFEE: Thank you.

A (McAfee) I'm going to refer to RAV 157. On the second page there's a table, and I think it's important to understand the cost that the company incurs when restoring service to customers due to events.

A few years ago the company segmented costs that occurred during minor storms from routine O&M in separate work orders. This was done to better understand our cost structure. A minor storm is defined as an event that impacts customers that is somewhat isolated and the impact of that storm does not qualify for a major storm qualification. A major storm qualification is defined as, for reliability purposes, 10 percent of an operating region within Niagara Mohawk's operating companies affected by the event, 10 percent of the customers within that operating region, or a customer being impacted for an in excess of 24 hours. During the historic test year minor storm costs which are not deferrable totalled $8.221 million.

The second classification of storms are non-deferrable major storms. These storms qualify for exclusion under reliability indices purposes but do not qualify for deferral accounting. So the definition of those storms are a storm that affects an operating region that impacts customers in excess of 24 hours or 10 percent of the customers within that operating region being impacted. The total cost during the historic test year for those events is $18.086 million.

The third category are major deferrable storms. Those are defined as 10 percent of an operating region within Niagara Mohawk's service territory being impacted or 1 percent of a customer account within an operating region being impacted for in excess of 24 hours. The total cost of those storms during the historic test year was $55.972 million.

So the total cost of storms during the historic test year that impacted the company was $82.279 million. Referring back to the major deferrable storm category, there is a calculation of what is deferrable and what is non-deferrable within that $55.972 million. That calculation is conducted by our finance department and will be -- the mechanics of that calculation will be handled by the discussions within our Revenue Requirements Panel.

ALJ BOUTEILLER: That completes your answer?

MR. McAFEE: Yes, sir.

ALJ BOUTEILLER: Okay. Let's turn back to staff counsel.

MR. LECAKES: Thank you, Your Honor.

BY MR. LECAKES:

Q So if I understand you correctly, if I'm trying to find out more information about what makes, for example, in this chart that you referred to on RAV 157 this $9.945 million non-deferrable, what makes that non-deferrable, the Revenue Requirements Panel is the proper panel to ask that question to?

A (McAfee) Yes, that's correct. There's a calculation that finance does. It's outlined within our electric emergency procedure, Section EEP.01, that outlines that

calculation, and that was done by finance and will be handled by the Revenue Requirements Panel.
Q And they can answer the question, then, why those costs would not be eligible for deferral?
A (McAfee) Yes, that's correct.
Q Okay. When you started your answer after the exhibits were passed out you referenced -- I heard something along the lines of two years ago or a couple of years ago. What was that in reference to? I missed it.
A (McAfee) A few years ago we added a category which we defined as minor storms, and that segmented out of regular O&M events that were storm-related, were more than blue sky events or equipment failure but were less than that of threshold of the reliability indices that I discussed earlier.
Q Okay.

MR. LECAKES: Your Honor, I apologize for the delay, but a number of questions now we're thinking are better directed toward the Revenue Requirements Panel, so we're trying to figure out where we are for this panel.

ALJ BOUTEILLER: Take your time. I'm not rushing you.

MR. LECAKES: Thank you.

Thank you, Your Honor. We're ready to

proceed.

ALJ BOUTEILLER: Okay.

BY MR. LECAKES:

Q Panel, on page 148 of your rebuttal testimony, beginning at line 14 to line 16, there the panel states that "the storm fund amount was calculated using actual major storm costs incurred over approximately the last five years." Is that correct?

A (McAfee) Yes, that's correct.

Q So that would be a five-year average, correct?

A (McAfee) That's correct.

Q Now, am I correct that the company has over the past 20 years experienced a total of three storms that resulted in costs exceeding $20 million for restoration?

A (McAfee) I believe that's correct based on -- that data is correct based on some interrogatories.

Q Right. And for the record, the interrogatory that I'm familiar with would be the company's response to RAV-27E, and for reference that can be found in Exhibit 326.

Am I also correct, then, that the five-year average that was used in this case included two of those three storms that the company has experienced over the past 20 years where the restoration costs exceeded $20 million?

A (McAfee) Yes, that's correct. I think it's important to understand that customers rely on us to restore their service, and that when storms occur, we are relied upon by our customers to provide that level of service. We have no control over when a storm occurs. We don't have any control over the location that is impacted nor the severity, but we need to be prepared at all times for that response.

Q All other major storms in your five-year average number cost under restoration costs were under $20 million, is that correct?

A (McAfee) I believe that's what is stated in the exhibit to -- on this topic.

Q How many storms would that be, how many major storms that cost under $20 million?

A (McAfee) I'm going to reference IOP Exhibit 11 in our original January testimony, and there is slightly less than 50 storms, I believe, listed in that exhibit.

Q Okay. Setting aside the major storm restoration costs for the moment, your panel has forecasted a number of other operation and maintenance expenses in this rate case, isn't that correct?

A (McAfee) Yes, that's correct.

Q Things such as tree trimming, vegetation management, correct?

A (McAfee) Yes, that's correct.

Q When the company made these other operation and maintenance expense forecasts, were there any normalizing adjustments made to eliminate any unusually large costs or unusually large activity levels?
A (McAfee) I'm not sure I understand your question.
Q When the company made its O&M expense forecasts, getting away from the storm costs for a moment, the things such as vegetation management, did the company make any normalizing adjustments to those levels based on the historic years that they were looking at for any unusual activity?
A (McAfee) I believe the normalization topic that you're referring to would have been handled within the Revenue Requirements Panel, not within this panel. Again, I'm not sure I fully understand your question.
Q This panel did make the forecast for the costs, correct?
A (McAfee) Yes, that's correct.
Q And how were those forecasts made?
A (McAfee) We took the historic test years spent in the categories that you referenced and then looked at our plan for those activities and adjusted accordingly.
Q So when you say "adjusted accordingly," what adjustments did you make?
A (McAfee) For example, we proposed certain changes to

our historic test year and certain O&M activities and those were outlined in our testimony.

Q Okay.

ALJ BOUTEILLER: Let me ask a follow-up question. When you say "adjusted accordingly," did all those adjustments go in one direction, or did they go in two different directions? Were they always going as an increase, or in some instances were they reflected as decreases from your historical expense level?

MR. McAFEE: I believe, Your Honor, all the increases that we identified in the testimony were increases.

ALJ BOUTEILLER: Okay, thank you.

BY MR. LECAKES:

Q Getting back to the storm costs, then, in coming up with the five-year average that the panel used to forecast the storm restoration costs, am I correct that the panel did not make any normalizing adjustments, though, when it encountered two major storms' restoration costs costing over $20 million when there have been only been three such costly storms over the past 20 years?

A (McAfee) I'm not aware of any normalizations that occurred. Again, as I stated earlier, I believe that question might be better approached by or answered by the

Revenue Requirements Panel.

There also are two -- within the deductible -- excuse me -- within the deferral account -- and again, I'm not an expert in how that is calculated, but there are deductibles embedded within that calculation that the Revenue Requirements Panel can discuss in more detail.

ALJ BOUTEILLER: Okay. Let me just follow up. You're responsible for historic values that were established for this case, the historic test year values?

MR. McAFEE: That's correct.

ALJ BOUTEILLER: You escalated those historic test year values to the rate year, is that correct?

MR. McAFEE: That's correct.

ALJ BOUTEILLER: You did not reduce any of them when you provided them to the rate year, is that correct?

MR. McAFEE: That's correct.

ALJ BOUTEILLER: But you believe that it's possible that the other panel, when looking at your information and putting together the final statement of the projections for the rate year, they may have reduced your numbers? Is that what you're suggesting?

MR. McAFEE: I'm not sure what was done within the revenue requirement model when they put their schedules together.

ALJ BOUTEILLER: So they may have reduced your numbers? Is that a possibility?

MR. McAFEE: Again, I don't know the answer to that question. They may have. They may not have. I don't know.

ALJ BOUTEILLER: Do you believe that they may have increased your numbers?

MR. McAFEE: I don't believe that they increased our numbers.

ALJ BOUTEILLER: Okay. So I understand. Thank you.

Please proceed.

MR. LECAKES: Your Honor, if I can be indulged, I would appreciate if the panel could check the revenue requirement numbers that were submitted by that panel to see if the numbers had changed from the time that the panel submitted their forecasts to the time that the revenue requirement exhibits were made.

ALJ BOUTEILLER: Yeah, let's make that a homework assignment for this panel, that they can compare the values they provided to the other panel, examine what figures the other panel used, can report back to us whether or not they are the same values or different values. And if they are different values, can you tell us what direction they're moving in, okay? And this panel is subject to recall. If you can't provide that information, then that would be one of the reasons why we might recall them. Okay?

MR. LECAKES: Thank you, Your Honor.

BY MR. LECAKES:

Q Getting back to the questions, so your storm fund, then, the panel's storm fund request is based on the average incremental cost of major storms over the last five years, correct?

A (McAfee) Yes, that's correct.

Q And the averaging methodology that the panel used resulted in the company's request for a $30 million storm fund, isn't that correct?

A (McAfee) That's correct. What our intention was was to not -- was to only recover the funding that we would have recovered within those five years.

Q But if the company is allowed the $30 million storm fund, why does it need an additional $20 million in base rate operation and maintenance allowances for incremental costs associated with major storms? Why doesn't the five-year average cover those costs?

A (McAfee) Again, my understanding -- and this question, I think, is better handled by the Revenue Requirement Panel, but the intention of the storm fund is to take care of the deferrable costs associated with those major events. As I stated earlier, there is a large component part of restoration costs that's non-deferrable.

MR. LECAKES: Your Honor, we have several questions that it sounds like should be, from this panel's observations, directed to the Revenue Requirement Panel, but we do acknowledge that the panel is being left open for recall anyway, so it may be prudent for us to forego some of these questions and then direct them at the Revenue Requirement Panel with the understanding that if the Revenue Requirement Panel can't answer them, this panel should be recalled to answer the questions, since it does appear in their own testimony.

ALJ BOUTEILLER: Okay. We can do that as a last resort, and we'll have to wait and see how your questions are responded to by the other panel. The clear impression I have is that you've gained all the information this panel has on at least the questions you've asked. And if you can anticipate from your knowledge of what the other questions are that we would be running down the same course, we can pick this up with the other panel and see how that goes.

MR. LECAKES: Right. Your Honor, I can ask a couple general questions and see what the panel's opinion here is about whether it's better directed at them.

ALJ BOUTEILLER: You can test further without belaboring the point, and that's fine.

MR. LECAKES: All right.

BY MR. LECAKES:

Q The next area I had planned to get into was -- deals with the per event deductible. Is there some general understanding that the panel has that they would be able to answer some more specific questions about that, or would that be better directed to the Revenue Requirement Panel?

A (McAfee) The only thing I can provide, the only items I can provide you is that I am aware that there is a per event deductible of $2 million as well as a calculation that's done that's outlined within the EEP, as I mentioned earlier. The mechanics of that and the background of the $2 million, I would prefer to defer to the Revenue Requirement Panel.

MR. LECAKES: Your Honor, I think that concludes staff's cross-examination with the expectation that we'll be able to ask these questions

of the Revenue Requirements Panel that we have left.
ALJ BOUTEILLER: Okay. Let's see how it goes with the revenue panel. If you're not satisfied I'd expect you at that time to raise the matter and we'll try to resolve it then and see how it works.
Mr. Goodman, did you have questions for this panel?
MR. GOODMAN: Your Honor, I had anticipated that all questions I had intended to ask would be covered under the issues addressed by the stipulation, but I actually do have a follow-up question or two based on the questions staff asked, so if I may have a couple minutes?
ALJ BOUTEILLER: You may proceed.
MR. GOODMAN: Thank you.
CROSS-EXAMINATION
BY MR. GOODMAN:
Q Good afternoon, Panel.
A (Panel) Good afternoon.
Q I just want to clarify, following up on questions regarding potential adjustments to your forecast by the Revenue Requirement Panel, regarding the forecast of historic -- forecast of rate year expenses you developed, what is your understanding of what it is that the Revenue Requirement Panel does with that when you pass it off?

For example, would you give it to the Revenue Requirement Panel or rates or another group with the expectation it's going to be further modified, or do you give it to them with the expectation that they're relying on that number for insertion into their model?

A (Walker) Jay, I believe what you're referring to is when we provide an operation and maintenance number, it takes into account what we know with respect to its -- any future expense, non-measurable expenses up or down. We would pass that on to the Revenue Requirement Panel. They utilize and rely upon that information for inclusion in the revenue requirement tabulation.

Q So to the extent that there are adjustments to be made, whether to normalization or deductible, whose responsibility is it to make that for the purposes of the forecast and the rate filing? Is it the panel's responsibility, or is it revenue requirement or someone else?

A (Walker) If it's a known unmeasurable change, it would be something tied to the operational portion of it, it would come from us. If there is any other adjustment which may or may not happen, which I'm not aware of, it obviously is within the purview of the revenue requirement to be able to do that. So if there's an escalation based on inflation or something like that, that could very well be put on by the Revenue Requirement Panel. But barring those type of changes, you know, it would be relied upon based on the information we have provided them.

Q Okay. So taking a step back --

A (McAfee) One additional point to your question, to the issue of deductibles that transitions into deferral treatment which this panel hasn't dealt with, the Revenue Requirements Panel dealt with the deferral mechanisms.

Q Okay. Stepping back from storm costs, just as a general matter, any expense that needs to be normalized out of the rate year forecast, whose responsibility is it to do that?

A (Walker) It's ours. It would ours, Jay.

Q Thank you.

MR. GOODMAN: Nothing further, Your Honor.

ALJ BOUTEILLER: Does any other party have cross-examination for this panel?

MR. WALTERS: Your Honor, I don't have cross at this point, but I just wanted to reserve my rights with the other parties. We had potentially similar questions as staff had for the Revenue Requirement Panel which they had addressed to this panel, so I just want to state that for the record, that we may have some questions depending on how the Revenue Requirement Panel responds.

ALJ BOUTEILLER: Okay. Should they come back, you've reserved your rights. Should they be called back for whatever reason, you can engage in that, but you don't independently believe that you would have any separate need or use for this panel?

MR. WALTERS: Right. Correct.

ALJ BOUTEILLER: Okay. I understand. You've reserved your rights. You won't be cut off in the future.

If there is no other cross-examination, then, for this panel, counsel can approach. You can consider if there's a need for any redirect based upon the questions that have been asked today.

MR. GAVILONDO: Okay. Thank you, Your Honor. If we can have five minutes?

ALJ BOUTEILLER: Sure. You can use the other room if that's provided.

(Discussion off the record.)

ALJ BOUTEILLER: Company counsel, is there any redirect for this panel?

MR. GAVILONDO: Yes, Your Honor.

ALJ BOUTEILLER: Please proceed.

MR. GAVILONDO: Thank you.

REDIRECT EXAMINATION

BY MR. GAVILONDO:

Q Mr. McAfee, during its cross-examination staff asked a question relative to the two different buckets, as it were, of storm fund costs, and I believe the question related to the company's need for a storm fund or a reconciling storm fund and a base rate recovery amount. Do you recall that line of questioning?

A (McAfee) Yes, I do.

Q Okay. Could you please elaborate on your answer to staff?

A (McAfee) Yes. I'd like to again refer back to RAV 157, and I'm also going to refer to Exhibit IOP 11 during this response. In 157 it illustrates that there are both non-deferred costs and deferred costs with the different categories of storms. The non-deferred costs are what's required -- or what is needed to be recovered in base rates. The deferred costs are what we've used to calculate our reconcilable storm fund.

Q Thank you. And has the company answered an IR in this proceeding that relates to a very similar question to the one asked by staff counsel?

A (McAfee) Yes, it has. It was answered by -- it was answered by the Revenue Requirements Panel, and it is RAV 158, which was submitted into the record.

MR. GAVILONDO: And, for the record, that was marked for identification purposes as Exhibit

332.

Q Mr. McAfee, how long have you been in the electric utility business?

A (McAfee) Approximately 25 years.

Q And during that 25 years, order of magnitude, how many 50- or 100-year storm events have you seen?

A (McAfee) I've seen, unfortunately, dozens beginning in my career in 1985, working Hurricane Gloria, up to and including running the ice storm restoration here in eastern New York in 2008.

MR. GAVILONDO: Thank you. I have no further questions.

ALJ BOUTEILLER: Staff?

MR. LECAKES: We have no follow-up, Your Honor.

ALJ BOUTEILLER: Mr. Goodman?

MR. GOODMAN: I have no follow-up, Your Honor.

ALJ BOUTEILLER: Okay. So that's as much as we can complete today with this panel. We will not be excusing you. You'll remain subject to recall, and we'll determine later next week whether or not there will be any need for recalling you.

As I understand it, there is a stipulation in progress. As I understand it, there are questions that were presented or reserved for the Revenue Requirements Panel, so we'll elect to see both of those things play out, so there remains a possibility that you may have to appear again in the hearing. So you're excused for now, but you are subject to recall. Thank you.

Let's go off the record.

(Discussion off the record.)

ALJ BOUTEILLER: We have excused for today but have not released the members of the panel who just previously appeared. We've talked about our start time for tomorrow, and the hearing tomorrow will resume at 10:00. As a courtesy to the witness who is available now, we have a witness who is addressing depreciation, a member of the panel who still remains subject to call for purposes of the panel presentation just provided. However, he also has stand-alone or independent testimony.

Counsel, can you please introduce the topic and the testimony that Mr. Walker provides by himself?

MR. GAVILONDO: Yes, Your Honor. Mr. Walker is presenting rebuttal testimony on depreciation service lines. Shall I proceed?

ALJ BOUTEILLER: So we understand, there is no cross-examination for Mr. Walker on this testimony?

MR. GAVILONDO: No party has indicated an interest in cross-examining.

ALJ BOUTEILLER: You remain under oath. I don't need to swear you in again. You don't need to identify yourself. You are identified for the purpose of the record. Now we can turn to counsel who will describe for us your pre-filed testimony.

B R U C E W A L K E R,

having been previously duly sworn by the notary public, was examined and testified as follows:

DIRECT EXAMINATION

BY MR. GAVILONDO:

Q Mr. Walker, I direct your attention to a document that consists of a cover page and nine pages of questions and answers and ask if you can please identify that for the record?

A This is my pre-filed testimony for the depreciation asset list.

Q That dated August 6, 2010?

A That's correct.

Q Do you have any changes or corrections to that pre-filed testimony?

A I do not.

Q If I were to ask you those same questions today that appear in your pre-filed rebuttal testimony, would your answers be the same?
A Yes, they would.
Q Do you adopt that testimony as your sworn testimony in this proceeding?
A Yes, I do.

MR. GAVILONDO: I request that the testimony be moved into the record.

ALJ BOUTEILLER: For my understanding, since there's no modifications or changes to this testimony, this testimony has been previously provided to the reporter in digital format, is that correct?

MR. O'BRIEN: That's correct.

ALJ BOUTEILLER: So I can instruct the reporter to copy into the record, as if given orally today, the pre-filed rebuttal testimony on the topic of depreciation offered by this witness, Mr. Bruce Walker. Okay. His testimony now is in the record absent any objection from the parties present.

(The referenced testimony is inserted into the record as follows.)

Before the Public Service Commission

NIAGARA MOHAWK POWER CORPORATION d/b/a NATIONAL GRID

Rebuttal Testimony

Of

Bruce Walker

Dated: August 6, 2010

Rebuttal Testimony of Bruce Walker

Q. Please state your name and business address.

A. My name is Bruce Walker. My business address is 40 Sylvan Road, Waltham, MA 02451.

Q. Are you the same Bruce Walker who previously submitted testimony in this proceeding as part of the Infrastructure and Operations Panel?

A. Yes. I am.

Q. What is the purpose of your rebuttal testimony in this proceeding?

A. The purpose of my rebuttal testimony is to respond to the testimony of the Staff Depreciation Panel. Specifically, I will address the Depreciation Panel's recommendations concerning the average service lives that should be used to establish depreciation rates in this proceeding. My testimony supplements the direct and rebuttal testimony of Ronald E. White of Foster Associates, Inc. who prepared and sponsored Niagara Mohawk's depreciation study in this case. My testimony will address engineering and operating factors supporting the service lives recommended in the Company's depreciation study as opposed to the following service lives proposed by the Depreciation Panel:

(i) the proposed seventy-five year mean service lives recommended for Account No. 358 – Transmission Plant - Underground Conductors and Devices and Account No. 367-10 – Distribution Plant – Underground Conductors and Devices;

(ii) the proposed thirty-year mean service lives recommended for Account No. 353.50 – Transmission Plant – Station Equipment – EMS RTU and Account No. 362.55 – Distribution Plan – Station Equipment – EMS RTU; and

(iii) the proposed seventy-five year mean service life recommended for Account No. 361 – Distribution Plant – Structures And Improvements**.**

Q. What is your understanding of the concept and use of an average service life in establishing depreciation rates?

A. My understanding is that the average service life is intended to represent the average age (measured in dollars – years of service) at which it is expected that facilities in a particular account will be retired. It does not mean that all facilities in that account will be retired by the end of the average service life -- some will be retired earlier, some will be retired later -- but it is intended to represent the mean or average life.

Q. Please describe the facilities included in Accounts Nos. 358 and 367.10.

A. The facilities included in Account No. 358 consist of underground transmission cables. The facilities included in Account 367.10 consist of underground distribution and sub-transmission cables. The transmission system has (i) 43 miles of high pressure, fluid-filled pipe-type cable, and (ii) 8.5 miles of solid dielectric ethylene, propylene and rubber ("EPR") cable. The distribution and sub-transmission cables accounted for in Account No. 367.10 consist primarily of paper-insulated, lead-covered ("PILC") cable that was installed from the early

1900's until about 1970, and EPR cable that was the predominant cable installed after 1970.

Q. What is the nominal design life, or expected life, of the pipe-type cable at installation?

A. The pipe-type cable was designed and manufactured to last at least 40 years.

Q. Does the Company expect the cable to exceed its design life?

A. Yes. By continuing the Company's inspection and maintenance program the Company believes that the service life of pipe-type cable can be extended to a mean life of approximately fifty years. One of the causes of end-of-life of a pipe-type cable system is corrosion due to the loss of cathodic protection. Pipeline corrosion leads to the loss of dielectric fluid and can result in cable failures. As part of the Company's maintenance program, the cathodic protection system is regularly inspected and maintained.

As pipe-type cable ages, we expect to see an increased failure rate as a result of thermal cycling (the repeated heating and cooling of cables from changing loads). This leads to thermal mechanical bending ("TMB") which can cause deterioration in cable insulation over time. The effects of ongoing thermal cycling and TMB on cable are cumulative and irreversible.

Q. Does the Company believe that some of its pipe-type cable will last more than 50 years?

A. Yes. With proper maintenance we expect that some cable will last as long as 75 years or even longer. Other cables may be replaced at younger ages.

Q. What is the Company's expectation with respect to the mean service life for EPR cable?

A. EPR has been available as an insulation for distribution cables since the late 1960s and for 115 kV transmission voltage cable since 1975. The cause of end-of-life for EPR insulated cables is not currently known, but a likely end-of-life scenario would be that the insulation would become hardened and embrittled due to thermal aging and/or through chemical processes. Another end-of-life possibility could be insulation deterioration through the formation of "water trees" or "electrical trees," which have been a problem with earlier Cross Linked Polyethylene ("XLPE") cables. "Water trees" are voids that form in solid dielectric electrical insulation. These typically form in the presence of water or other contaminants. On a microscopic level, these voids have the appearance of trees. Water trees eventually turn into "electrical trees," which are sites of "partial discharge" that rapidly cause cable failure. EPR is felt to be more resistant to the formation of "trees" than XLPE, but tree development could occur as the cables age. Until such time as the end-of-life estimates become more definitive, the Company believes that a 50-year mean service life for EPR cable is reasonable.

Q. What does the Company expect to see with regard to the PILC cable installed in its distribution system?

A. The main failure mechanism for PILC cable is insulation failure due to water ingress as a result of breaches in the lead sheath. The Company believes that the most likely cause of end-of-life for PILC cables will be the mechanical movement the cables experience. Ultimately, the repeated thermal cycling and TMB of the cable will lead to fatigue and cracking of the lead sheaths. This in turn allows water to enter the cable, leading to cable failure. The Company has not experienced widespread sheath-cracking events, but has experienced splice failures and some sheath cracking. The fatigue cracking is a function of the number and magnitude of bend cycles the cable experiences and, as such, is an age-related phenomenon. The Company also believes that lead fatigue issues will become more pronounced as PILC cables become progressively older.

Q. Given the factors that you have described, do you have an opinion as to the average service life of the underground cable accounted for in Account Nos. 358 and 367.10?

A. Yes. From an engineering perspective it is my opinion that 50 years is an appropriate average service life for these cables. While some of the cables may last as long as 75 years, or even longer, I do not expect that this will be the average service life based upon our knowledge of the factors that are likely to cause failure as the cable ages. I do not believe that the 75-year average service life recommended by Depreciation Staff is reasonable for these facilities.

Q. Please describe the facilities included in Account Nos. 353.50 and 362.55.

A. The facilities included in Account No. 353 and 362 consist of Remote Terminal Unit ("RTU") equipment used for Supervisory Control and Data Acquisition ("SCADA") between a substation where this equipment is located and our Energy Management System ("EMS") at the control center. These systems are used for monitoring and controlling the power system network. The existing population of RTUs is a mixture of equipment from the early 1980s, 1990s and 2000s. The early RTUs were typically hardwired, using discrete component technologies and proprietary communication protocols. The continuation of these systems is dependent on the availability of discrete hardware components to keep them operational.

Q. What are the issues with RTUs that lead to early retirement or replacement?

A. In the past, SCADA/EMS RTUs were typically highly customized with hardware, and communication protocols specifically configured to the installation. This equipment is now built using standard commercial components and open communication protocols. These newer RTUs are hardened computers with both proprietary or Windows-based operating systems and development tools. The adoption of standard hardware, software and protocols has increased the adoption and functionality and reduced the cost of implementation. However, rapidly changing technology, along with increasing cyber-security requirements, is causing vendors to drop support of older equipment and, therefore, render this equipment obsolete. This has been the trend with computer technology in general. We expect that in the next 5-10 years there will be a requirement to encrypt the communication between SCADA/EMS and the RTU due to cyber-security issues. This is already being accomplished with the Inter-Control Center Protocol used to exchange data among regional control centers.

National Grid has experienced vendor abandonment with Systems Northwest RTUs in our New England companies. In addition, as part of the EMS Replacement project, the Company is currently replacing and upgrading the existing population of obsolete RTUs with the new protocols.

Q. Given the factors that you have described, do you have an opinion as to the average service lives of the Transmission and Distribution EMS RTUs accounted for in Account Nos. 353.50 and 362.55?

A. Yes. From an engineering perspective it is my opinion that 20 years is appropriate, but a stretch, for an average service life for this equipment. The reason even a 20-year service life will be a stretch is that the pace of technology development and the increasing cyber-security requirements (e.g. encryption) in this area will force retirements or upgrades of this equipment in a much shorter time.

While some of the RTUs may physically last as long as 30 years, or even longer, I do not expect that this will be the average service life based on our knowledge of the factors that are likely to cause obsolescence due to lack of vendor support and the lack of functionality and programming tools required to keep them operational.

This type of obsolescence is illustrated by the new SCADA/EMS (*i.e.* the other end of the RTU) that is being implemented and is scheduled to be operational in late 2011. It is planned that this equipment will be replaced/upgraded every 5 years to keep pace with the changing hardware and software technology and cyber security requirements.

Q. Please describe the facilities included in Account No. 361.

A. Account No. 361 includes the building and improvements associated with facilities such as substations that are used in the Company's distribution system.

Q. What factors lead to the replacement of existing structures and improvements? While Niagara Mohawk currently has structures of varying ages classified in this account, each structure contains numerous components and improvements such as roofs, electrical systems, plumbing, heating, ventilation and air conditioning systems, walls, flooring, fencing, paving, etc. Each of these components has varying lives and many will be retired and replaced (some several times) before the end–of–life of the entire structure. The average service life of the components as well as the life span of a structure must be considered in estimating a mean life for structures and improvements. This is analogous to estimating the average service life of an ax in which the head and handle are retired and replaced at varying ages. It would be wrong to conclude that the life of an ax is infinite or only ceases when the ax is lost or stolen.

One of the factors leading to the retirement and replacement of a structure is the deterioration of concrete. The Company has a number of concrete structures that are likely to be replaced over the next few years. Given that the mean service life of improvements is shorter than the life span of a structure and multiple structures of varying ages are classified in this account, we believe that a 65-year average service life is more appropriate than the 75-year average service life proposed by the Depreciation Panel.

Q. Does this conclude your rebuttal testimony?

A. Yes.

ALJ BOUTEILLER: Thank you very much, Mr. Walker.

THE WITNESS: Thank you.

ALJ BOUTEILLER: I may see you in your capacity again as a member of the previous panel, but you will not be appearing for purposes of your rebuttal testimony on depreciation.

If there's nothing further we can accomplish today, then we'll stand in recess until tomorrow morning at 10:00 a.m. Thank you.

* * * 6:05 a.m. * * *

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EXHIBITS (Cont'd)

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328	500
329	531
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331	546
332	1109
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C E R T I F I C A T E

I, Kay Trigilio, a Shorthand Reporter and Notary Public in and for the State of New York, do hereby certify that the foregoing record taken by me is a true and accurate transcript of the same, to the best of my ability and belief.

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Kay Trigilio, Notary Public
State of New York

DATE: September 19, 2010